PLACE: Dobbs Building
Raleigh, North Carolina

DATE: Monday, September 23, 2019
DOCKET NO.: E-22, Sub 562 and E-22, Sub 566
TIME IN SESSION: 2:00 p.m. - 5:30 p.m.
BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Application of Virginia Electric and Power Company,
d/b/a Dominion Energy North Carolina,
for Adjustment of Rates and Charges Applicable to
Electric Service in North Carolina

and

Petition of Virginia Electric and Power Company,
d/b/a Dominion Energy North Carolina,
for an Accounting Order to Defer Certain Capital and
Operating Costs Associated with Greensville County
Combined Cycle Addition

Volume 4

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P R O C E E D I N G S

CHAIR MITCHELL: Good afternoon. Let's come to order and go on the record, please.

I'm Charlotte Mitchell, Chair of the North Carolina Utilities Commission, and with me this afternoon are Commissioners ToNola D. Brown-Bland, Lyons Gray, and Daniel G. Clodfelter.

I now call for hearing Docket Number E-22, Sub 562, which is the Application of Virginia Electric and Power Company, doing business as Dominion Energy North Carolina, For a General Increase in its Rates and Charges for Retail Electric Service in North Carolina, and Docket Number E-22, Sub 566, which is Dominion's request for an Accounting Order to Defer Certain Costs Associated with Greensville County Combined Cycle Addition.

On March 29th, 2019, Dominion filed its Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, along with the supporting direct testimony and exhibits of a number of witnesses. By its application, Dominion requests authority to increase its overall base revenues by approximately 8.7 percent.

In support of the requested increase, Dominion states that since its last rate case it's made significant investments in infrastructure to fulfill its obligation to provide safe, reliable, and cost-effective service to its North Carolina customers. Dominion states that these investments have improved efficiency and operational performance of its generation fleet, created significant fuel savings, and improved the performance of its electric delivery system.

On April 29th, 2019, the Commission issued its Order Establishing a General Rate Case and Suspending Rates.

On May 2nd, 2019, the Commission issued its Order Consolidating Dockets which consolidated this general rate case with Dominion's petition for deferral accounting authority to defer post in-service costs associated with commercial operations of the Greensville power station.

On May 30th, 2019, the Commission issued its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines and Requiring Public Notice. A hearing was scheduled beginning today in Raleigh to receive the testimony of the expert witnesses proffered by the parties. In addition, hearings to receive testimony from public witnesses were held in Halifax, Williamston, and

Manteo for the purpose of receiving this testimony.

On August 5th, 2019, Dominion filed the supplemental direct testimony and exhibits, Supplemental Form E-1 items, and Supplemental Commission Rule R1-17 information.

On August 14th, 2019, Dominion filed additional supplemental direct testimony and exhibits.

On August 23rd, 2019, Intervenors, including the Public Staff, Nucor, and CIGFUR I, filed testimony and exhibits.

On September 12th, 2019, Dominion filed the second supplemental direct testimony and exhibits, Supplemental Form E-1 items, and Supplemental Commission R1-17 information.

Also on September 12th, I mean September 16th, 2019, Dominion filed a witness list in connection with today's hearing.

On the same date the Commission provided a non-comprehensive list of questions to be posed to Dominion witnesses at this hearing.

On September 17th, 2019, Dominion and the Public Staff filed an Agreement and Stipulation of Partial Settlement in Docket Numbers E-22, Sub 562, and E-22, Sub 566, along with supporting testimony and exhibit -- exhibits.

The Stipulating Parties have reached compromise on almost every issue in dispute. The main unresolved issue is the cost recovery associated with CCR expenditures.

On September 19th, 2019, Dominion and the Public Staff filed a joint motion requesting that witnesses Bobby E. McGuire, Bruce E. Petrie, Deanna R. Kesler, Michelle M. Boswell, David M. Williamson, Jeff T. Thomas, and Roxie McCullar be excused from attending the expert witness hearing on September 23rd, 2019.

On September 19th, 2019, the Public Staff filed a motion -- motion requesting that witness Tommy C. Williamson be excused from attending the expert witness hearing.

On September 19th, 2019, the Carolina Industrial Group for Fair Utility Rates I, CIGFUR, filed a motion that -- requesting that witness Nicholas Phillips, Jr. be excused from attending the expert witness hearing.

On September 19th, Nucor Steel-Hertford filed a motion requesting that Jacob M. Thomas and Paul Wielgus be excused from attending the expert witness hearing.

All of the parties' motions to excuse the requested witnesses were granted on September 20th, and the Order was issued on September 23rd, 2019.

Intervention and participation in this docket by the Public Staff is recognized pursuant to North Carolina General Statute 62-15 and Commission Rule R1-19(e). In addition to the Public Staff, Carolina Industrial Group for Fair Utility Rates I and Nucor Steel-Hertford have been allowed to intervene in the proceeding. The Attorney General has also filed a Notice of Intervention pursuant to North Carolina General Statute Section 62-20.

Numerous statements of position from customers have been received and filed in this docket. This brings us to the hearing this afternoon.

In compliance with the requirements of Chapter 163A of the State Government Ethic Act, I remind all members of the Commission of their responsibility to avoid conflicts of interest, and inquire whether any member of the Commission has a known conflict of interest with respect to matters coming before us this afternoon?

(No response.)

CHAIR MITCHELL: Please let the record reflect that no such conflicts have been identified.

I now call upon the parties to announce their appearances, beginning with the Applicant.

MR. KAYLOR: Thank you, Madam Chair, members of the Commission. Robert Kaylor appearing on behalf of Dominion Energy North Carolina.

MS. GRIGG: Good afternoon, Chair Mitchell, members of the Commission. I'm Mary Lynne Grigg with the law firm of McGuireWoods appearing on behalf of the Company.

CHAIR MITCHELL: Good afternoon.

MS. GRIGG: Also here on behalf of Dominion is Mr. Horace Payne, Assistant General Counsel.

MS. KELLS: Madam Chair, Commissioners, Andrea Kells with McGuireWoods appearing on behalf of Dominion Energy North Carolina.

CHAIR MITCHELL: Good afternoon.

MR. SNUKALS: Chair Mitchell and members of the Commission, my name is Dixon Snukals. I'm here with McGuireWoods on behalf of Dominion Energy North Carolina.

CHAIR MITCHELL: Good afternoon.

MR. EASON: May it please the Commission, I'm Joe Eason with Nelson Mullins Riley & Scarborough, appearing here on behalf of Nucor Steel-Hertford, and in addition, appearing with me is Mr. Damon Xenopoulos of the law firm in Washington, DC of Stone Mattheis

Xenopoulos & Brew, P.C. There's a pending motion for pro hac vice admission for the purposes of the hearing for this matter. I just wanted to mention that because we hope we can get a ruling whenever it's necessary for us to respond and participate.

CHAIR MITCHELL: We will address that momentarily. Thank you, Mr. Eason.

MS. HICKS: Good afternoon. Warren Hicks with Bailey & Dixon on behalf of the Carolina Industrial Group for Fair Utility Rates I.

CHAIR MITCHELL: Good afternoon, Ms. Hicks.

MS. HARROD: Madam Chair and Commissioners, Jennifer Harrod, and with me Peggy Force from the Attorney General's Office. We represent the Using and Consuming Public as well as the State and its Citizens in this Matter of Public Interest.

CHAIR MITCHELL: Good afternoon.

MR. DROOZ: Chair and Commissioners, David Drooz with the Public Staff representing ratepayers as a whole. Also appearing in this proceeding on behalf of the Public Staff Lucy Edmondson, Heather Fennell, Gina Holt, and Layla Cummings.

CHAIR MITCHELL: Good afternoon, Mr. Drooz. Okay. That brings us to preliminary matters. I've heard from Mr. Eason regarding the motion pro hac vice for Mr. Xenopoulos, and that motion shall be allowed. Any other preliminary matters?

MR. DROOZ: Just briefly --

COMMISSIONER GRAY: Sir, could you pull the microphone?

MR. DROOZ: I will.

COMMISSIONER GRAY: Some of us have got a little age on us and need a little help.

MR. DROOZ: I've got some of that age, too. So this morning we and the Commission received some of the late-filed exhibits from the Company that had been requested by the Commission. We're still digesting those, and as a result would request that the Public Staff and other Intervenors have an opportunity to file a written comment or response on those exhibits, if needed, before proposed orders are due.

MS. GRIGG: No objection.

CHAIR MITCHELL: Hearing no objection, Mr. Drooz, we will allow that.

MR. DROOZ: Thank you.

CHAIR MITCHELL: Any preliminary matters from the Company?

MR. KAYLOR: Madam Chair, I guess it's not preliminary, but before the first witnesses are called, I would ask the Commission accept the Company's Application into the record, as well as the exhibits and the Form E-1 that go along with the Application, the Supplemental E-1 and the R1-17 filing, and also ask that the Commission accept into evidence the Stipulation between the Company and the Public Staff which was filed on September 17th and the exhibits that go with that Stipulation.

And I do have one correction for the record with regard to Exhibit 1. On Exhibit 1 on line 42, we need to cross -- cross out the number of years and just put two years, and that should be a two year --

CHAIR MITCHELL: Mr. Kaylor, for purposes of the record, Exhibit 1 to which document?

MR. KAYLOR: To the Stipulation.

CHAIR MITCHELL: Okay.

MR. KAYLOR: And line 42 should read two years.

CHAIR MITCHELL: Hearing no objections, Mr. Kaylor, your motion will be allowed. Exhibit 1 to the Stipulation shall be corrected as you've requested.

MR. KAYLOR: Thank you.

(Whereupon, the Application, Exhibits I through X of the Application, Form E-1, Supplemental Form E-1, and the

Agreement and Stipulation of Partial Settlement with Public Staff, as corrected, were admitted into evidence.)

CHAIR MITCHELL: Any additional preliminary matters?

MR. KAYLOR: I think that's all we have.

CHAIR MITCHELL: Okay. Dominion, you may call your first witness.

MS. KELLS: Dominion calls Robert Hevert to the stand.

ROBERT B. HEVERT; Having been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MS. KELLS:

Q Would you please state your name and business address for the record.

A My name is Robert Hevert. Last name is spelled H-E-V, as in Victor, -E-R-T.

Q And by whom are you employed and in what capacity?

A I am a partner with ScottMadden, Incorporated.

Q Did you cause to be prefiled in this docket on March 29th, 2019, 68 pages of direct testimony in question and answer form and Attachment A and nine exhibits?

A Yes, I did.

Q Did you also cause to be filed in this docket on September 12th, 2019, eight pages of rebuttal testimony in question and answer form and one exhibit?

A Yes, I did.

Q Did you also cause to be filed in this docket on September 17th, 2019, seven pages of Stipulation support testimony and one exhibit?

A Yes, I did.

Q And did you also cause to be pre -- to be filed on September 20th, 2019, a corrected Exhibit RBH-8?

A I did, yes.

Q Do you have any changes or corrections to any of your testimonies or exhibits?

A No, I do not.

Q And if I were to ask you the same questions that appear in your testimonies today, would your answers be the same?

A Yes, they would.

MS. KELLS: Chair Mitchell, at this time I'd move that the prefiled direct, rebuttal, and Stipulation testimonies of Mr. Hevert be copied into the record as if given orally from the stand, and his exhibits be marked for identification as prefiled.

CHAIR MITCHELL: Without objection, the motion shall be allowed.

(Whereupon, the prefiled direct, rebuttal, and Stipulation support testimony of Robert B. Hevert were copied into the record as if given given orally from the stand.)

(Whereupon, Company Exhibits RBH-1 through RBH-9, Company Rebuttal Exhibit RBH-1, and Exhibit RBH-S-1 were identified as premarked.)

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DIRECT TESTIMONY

OF

ROBERT B. HEVERT

ON BEHALF OF

DOMINION ENERGY NORTH CAROLINA

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 562

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I. WITNESS IDENTIFICATION AND QUALIFICATIONS

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

A. My name is Robert B. Hevert. I am a Partner at ScottMadden, Inc. ("ScottMadden"). My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts, 01581.

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, doing business in North Carolina as Dominion Energy Carolina ("DENC" or the "Company").

Q. Please describe your educational background.

A. I hold a Bachelor's degree in Business and Economics from the University of Delaware, and a Masters of Business Administration with a concentration in Finance from the University of Massachusetts. I also hold the Chartered Financial Analyst designation.

Q. Please describe your experience in the energy and utility industries.

A. I have worked in regulated industries for over 30 years, having served as an executive and manager with consulting firms, a financial officer of a publicly-traded natural gas utility, and an analyst at a telecommunications utility. In my role as a consultant, I have advised numerous energy and utility clients on a wide range of financial and economic issues, including corporate and asset-based transactions, asset and enterprise valuation, transaction due diligence, and strategic matters. As an expert witness, I have provided testimony in more than 250 proceedings regarding various financial and regulatory matters before numerous state utility regulatory agencies (including this Commission), the Federal Energy Regulatory Commission, U.S. Federal Court, and the Alberta Utilities Commission. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included in Attachment A to my Direct Testimony.

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 return on equity ("ROE").[1] My analysis and conclusions are supported by the data presented in Exhibit RBH-1 through Exhibit RBH-9, which have been prepared by me or under my direction.

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

A. My analyses indicate that the Company's Cost of Equity currently is in the range of 10.00 percent to 11.00 percent. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony, including the

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

risk profile of the Company, it is my view that 10.75 percent is a reasonable and appropriate estimate of DENC's Cost of Equity.

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

A. Because all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. I therefore relied on widely accepted approaches to develop my ROE determination: (1) the Constant Growth Discounted Cash Flow ("DCF") model; (2) the Capital Asset Pricing Model ("CAPM"); (3) the Empirical Capital Asset Pricing Model ("ECAPM"); (4) the Bond Yield Plus Risk Premium approach; and (5) the Expected Earnings Analysis.

In addition to the methods noted above, my recommendation also takes into consideration factors such as DENC's planned capital investment program, the regulatory environment in which DENC operates, flotation costs, and current capital market conditions. Although I did not make explicit adjustments to my ROE estimates for those factors, I did take them into consideration in determining where the Company's Cost of Equity falls within the range of analytical results.

Q. How is the remainder of your Direct Testimony organized?

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

- Section III – provides a summary of issues regarding Cost of Equity estimation in regulatory proceedings and discusses the regulatory guidelines pertinent to the development of the cost of capital;
- Section IV – explains my selection of the proxy group used to develop my analytical results;
- Section V – explains my analyses and the analytical bases for my ROE determination;
- Section VI – provides a discussion of specific business risks and other considerations that have a direct bearing on DENC's Cost of Equity;
- Section VII – discusses the economic conditions in North Carolina;
- Section VIII – highlights the current capital market conditions and their effect on DENC's Cost of Equity; and
- Section IX – summarizes my conclusions.

III. SUMMARY OF ISSUES SURROUNDING COST OF EQUITY ESTIMATION IN REGULATORY PROCEEDINGS

Q. Before addressing the specific aspects of this proceeding, please provide an overview of the issues surrounding the Cost of Equity in regulatory proceedings, generally.

A. In very general terms, the Cost of Equity is the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk. In that important respect, the returns required by debt and equity investors represent a cost to the Company.

Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities.[2] The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders. In that basic sense, equity and debt investors differ: they invest in different securities, face different risks, and require different returns.

Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated or inferred based on market data and various financial models. As discussed throughout my Direct Testimony, each of those models is subject to certain assumptions, which may be more or less applicable under differing market conditions. In addition, since the Cost of Equity is premised on opportunity costs, the models typically are applied to a group of "comparable" or "proxy" companies. The choice of models (including their inputs), the

[2] The observed interest rate may be adjusted to reflect issuance or other directly observable costs.

selection of proxy companies, and the interpretation of the model results all require the application of reasoned judgment. That judgment should consider data and information that is not necessarily included in the models themselves. In the end, the estimated Cost of Equity should reflect the return that investors require in light of the subject company's risks, and the returns available on comparable investments.

Q. Please provide a brief summary of the guidelines established by the United States Supreme Court (the "Court") for the purpose of determining the Return on Equity.

A. The Court established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* ("*Bluefield*");[3] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[4] In *Bluefield*, the 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.[5]

[3] *See Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923).
[4] *See Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
[5] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923).

The Court therefore recognized that: (1) a regulated public utility cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least equal to the Cost of Capital (the principle relating to the demand for capital); and (2) a regulated public utility will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In *Hope*, the Court reiterates the financial integrity and capital attraction principles of the *Bluefield* case:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the 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.[6]

In summary, the Court clearly has recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

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

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.[7]

Q. Aside from those long-held standards, why is it important for a utility to be allowed the opportunity to earn a return adequate to attract capital at reasonable terms?

A. A return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above,

[7] North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, September 24, 2013, at 23; see also State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, Order on Remand, July 23, 2015, at 12-16 (discussing the *Hope* and *Bluefield* decisions) ("DENC Remand Order").

and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. The consequence of the Commission's order in this case, therefore, should be to 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 in enterprises having corresponding risks. To the extent DENC is provided a reasonable opportunity to earn its market-based Cost of Equity, neither customers nor shareholders should be disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables DENC to provide safe, reliable electric utility service while maintaining its financial integrity.

Q. How is the Cost of Equity estimated in regulatory proceedings?

A. As noted earlier (and as discussed in more detail later in my Direct Testimony), the Cost of Equity is estimated by the use of various financial models. By their very nature, those models produce a range of results from which the ROE is determined. That determination therefore must be based on a comprehensive review of relevant data and information; it does not necessarily lend itself to a strict mathematical solution. The key consideration in determining the ROE is to ensure that the overall analysis reasonably reflects investors' view of the financial markets in general, and the subject company (in the context of the proxy companies) in particular. Both practitioners and academics, however, recognize that financial models are simply tools to be used in the ROE estimation process, and that strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions. That position is consistent with the *Hope* and *Bluefield* principle that it is the analytical result, as opposed to the methodology employed, that is controlling in arriving at ROE determinations. Thus, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results in the context of observable, relevant market information.

Q. Did the Commission provide any regulatory conditions in its order approving the Dominion Energy and SCANA merger that are relevant to the Cost of Equity in this proceeding?

A. Yes. Specifically, the Commission noted the following:

> <u>Hold Harmless Commitment</u>. PSNC's Customers shall be held harmless from all current and prospective liabilities of DENC. DENC's Customers shall be held harmless from all current and prospective liabilities of PSNC. DENC, PSNC, Dominion Energy, the other Affiliates, and all of the Nonpublic Utility Operations shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina Customers harmless from the effects of the Merger, including rate increases or foregone opportunities for rate decreases, and other effects otherwise adversely impacting Customers.[8]
>
> ***
>
> The following Regulatory Conditions are intended to ensure (a) that DENC's and PSNC's capital structures and cost of capital are not adversely affected through their affiliation with Dominion Energy, each other, and other Affiliates and (b) that DENC and PSNC have sufficient access to equity and debt

[8] North Carolina Utilities Commission, Docket No. E-22, Sub 551 and G-5, Sub 585, Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, November 19, 2018, Appendix A, at 18.

capital at a reasonable cost to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their Customers.[9]

Q. Does your recommendation adhere to those regulatory conditions?

A. Yes. As discussed below, the analyses on which my recommendation is based are performed with reference to a proxy group. That is, I have considered market-based information that is relevant to DENC, using a comparable group of companies, and the specific risks faced by the Company. This approach and my recommendation do not adversely affect customers due to the merger.

IV. PROXY GROUP SELECTION

Q. As a preliminary matter, why is it necessary to select a group of proxy companies to determine the Cost of Equity for DENC?

A. Since the ROE is a market-based concept and DENC is not a publicly traded entity, it is necessary to establish a group of comparable, publicly traded companies to serve as its "proxy." Even if DENC were a publicly traded entity, short-term events could bias its market value during a given period of time. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

[9] North Carolina Utilities Commission, Docket No. E-22, Sub 551 and G-5, Sub 585, Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, November 19, 2018, Appendix A, at 20.

Q. Does the selection of a proxy group suggest that analytical results will be tightly clustered around average (*i.e.*, mean) results?

A. Not necessarily. For example, the Constant Growth DCF approach defines the Cost of Equity as the sum of the expected dividend yield and projected long-term growth. Despite the care taken to ensure risk comparability, market expectations with respect to future risks and growth opportunities will vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. Consequently, at issue is how to estimate the Cost of Equity from within that range. Such a determination necessarily must consider a wide range of both quantitative and qualitative information.

Q. Please provide a summary profile of DENC.

A. DENC (through Virginia Electric and Power Company) is a wholly-owned subsidiary of Dominion Energy, Inc. ("Dominion") that provides electric generation, transmission and distribution services to almost 2.6 million customers in Virginia and North Carolina.[10] As noted in the Direct Testimony of Company Witness Mitchell, DENC serves approximately 120,000 customers in North Carolina, over a service territory of approximately 2,600 square miles in the northeastern area of the state. DENC's senior unsecured credit ratings

[10] Dominion Energy, Inc., SEC Form 10-K for the fiscal year ended December 31, 2018, at 11.

from Standard & Poor's and Moody's currently are BBB+ and A2, respectively.[11]

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

A. A proxy group should consist of companies with risk profiles comparable to the subject company. In selecting a proxy group, my objective was to balance the competing interests of selecting companies that are highly 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. Based on those two considerations, I began with the universe of companies that Value Line classifies as Electric Utilities, and applied the following screening criteria:

- I excluded companies that do not consistently pay quarterly cash dividends;
- I excluded companies that were not covered by at least two utility industry equity analysts;
- I excluded companies that do not have investment grade senior unsecured bond and/or corporate credit ratings from S&P;
- I excluded companies that were not vertically-integrated, *i.e.* utilities that own and operate regulated generation, transmission and distribution assets;

[11] *Source*: S&P Global Market Intelligence.

- I excluded companies whose regulated operating income over the three most recently reported fiscal years composed less than 60.00 percent of the respective totals for that company;
- I excluded companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 60.00 percent of total regulated operating income; and
- I eliminated companies that are currently known to be party to a merger or other significant transaction.

Q. Did you include Dominion in your analysis?

A. No. To avoid the circular logic that otherwise would occur, it is my practice to exclude the subject company, or its parent holding company, from the proxy group.

Q. What companies met those screening criteria?

A. The criteria discussed above resulted in a proxy group of the following 22 companies:

Table 1: Proxy Group Screening Results

Company	**Ticker**
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avangrid, Inc.	AGR
Black Hills Corporation	BKH
CMS Energy Corporation	CMS
DTE Energy Company	DTE

Duke Energy Corporation	DUK
El Paso Electric Company	EE
Evergy, Inc	EVRG
Hawaiian Electric Industries, Inc.	HE
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Southern Company	SO
WEC Energy Group, Inc.	WEC
Xcel Energy Inc.	XEL

V. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment. The rate of return ("ROR") for a regulated utility is based on its weighted average Cost of Capital, in which the costs of the individual sources of capital are weighted by their respective book values. As noted above, the ROE is market-based and, therefore, must be estimated based on observable market information.

Q. How is the required ROE determined?

A. Because the Cost of Equity is not directly observable it must be estimated based on both quantitative and qualitative information. Although a number of empirical models have been developed for that purpose, all are subject to limiting assumptions or other constraints. Consequently, many finance texts recommend using multiple approaches to estimate the Cost of Equity.[12] When faced with the task of estimating the Cost of Equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed and, therefore, rely on multiple analytical approaches.

As a practical matter, no individual model is more reliable than all others under all market conditions. Therefore, it is both prudent and appropriate to use multiple methodologies in order to mitigate the effects of assumptions and inputs associated with any single approach. As such, I have considered the results of the Constant Growth DCF model, the Capital Asset Pricing Model, Empirical Capital Asset Pricing Model, the Bond Yield Plus Risk Premium approach, and Expected Earnings Analysis.

Constant Growth DCF Model

Q. Please describe the Constant Growth DCF approach.

A. The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In

[12] *See, e.g.*, Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341, and Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd ed., 2000, at 214.

its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + ... + \frac{D_\infty}{(1+k)^\infty} \quad \text{Equation [1]}$$

where P_0 represents the current stock price, $D_1 \ldots D_\infty$ represent expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D(1+g)}{P_0} + g \quad \text{Equation [2]}$$

Equation [2] is often referred to as the "Constant Growth DCF" model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the Constant Growth DCF model?

A. The Constant Growth DCF model assumes: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) the dividend payout ratio remains constant; (3) a Price to Earnings ("P/E") multiple remains constant in perpetuity; and (4) the discount rate is greater than the expected growth rate.

Q. What market data did you use to calculate the dividend yield in your DCF model?

A. The dividend yield is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading day periods as of February 28, 2019.

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

A. I did 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 averaging period should be reasonably representative of expected capital market conditions over the long term. In my view, using 30-, 90-, and 180-day averaging periods reasonably balances those concerns.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Since 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. Given that assumption, it is appropriate to 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 twelve-month period, and does not overstate the dividends to be paid during that time.

Q. Is it important to select appropriate measures of long-term growth in applying the DCF model?

A. Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [2] above) assumes a single growth estimate in perpetuity. Accordingly, in order to reduce the long-term growth rate to a single measure, one must assume a fixed payout ratio, and the same constant growth rate for earnings per share ("EPS"), dividends per share, and book value per share. Since dividend growth can only be sustained by earnings growth, the model should incorporate a variety of measures of long-term earnings growth. That can be accomplished by averaging those measures of long-term growth that tend to be least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Because such decisions may directly affect near-term dividend payout ratios, estimates of earnings growth are more indicative of long-term investor expectations than are dividend growth estimates. For the purposes of the Constant Growth DCF model, therefore, growth in EPS represents the appropriate measure of long-term growth.

Q. Please summarize the findings of academic research on the appropriate measure for estimating equity returns using the DCF model.

A. The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[13] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[14]

Phillips' conclusion continues to hold true. Subsequent academic research has clearly and consistently indicated 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.[15] For example, Vander Weide and Carleton state that "[our] results … are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."[16] Other research specifically notes the importance of analysts' growth estimates in

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[13] *See* Harris, Robert, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

[14] Charles F. Phillips, Jr., The Economics of Regulation, at 285 (Rev. ed. 1969).

[15] *See, e.g.*, Christofi, Christofi, Lori and 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, 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

[16] Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988). The Vander Weide and Carleton study was updated in 2004 under the direction of Dr. Vander Weide. The results of the updated study were consistent with the original study's conclusions.

determining the Cost of Equity, and in the valuation of equity securities. Dr. Robert Harris noted that "a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices." Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based."[17] Similarly, Brigham, Shome, and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts."[18]

To that point, the research of Carleton and Vander Weide demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[19] Those findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Consequently, earnings growth, not dividend growth, is the appropriate estimate for the purpose of the Constant Growth DCF model.

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[17] Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).
[18] Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management (Spring 1985).
[19] *See* Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

Q. Please summarize your inputs to the Constant Growth DCF model.

A. I applied the DCF model to the proxy group of electric utility companies using the following inputs for the price and dividend terms:

- The average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days February 28, 2019, for the term P_0; and
- The annualized dividend per share as of February 28, 2019, for the term D_0.

I then calculated the DCF results using each of the following growth terms:

- The Zack's consensus long-term earnings growth estimates;
- The First Call consensus long-term earnings growth estimates; and
- The Value Line earnings growth estimates.

Q. How did you calculate the DCF results?

A. For each proxy company, I calculated the mean, mean high, and mean low results. For the mean result, I combined the average of the EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. I calculated the high DCF result by combining the maximum EPS growth rate estimate as reported by Value Line, Zacks, and First Call with the subject company's dividend yield. The mean high result simply is the average of those estimates. I used the same approach to calculate the low DCF result, using instead the minimum of the Value Line, Zacks, and First Call estimate for each proxy company, and calculating the average result for those estimates.

Q. What are the results of your DCF analyses?

A. My Constant Growth DCF results are summarized in Table 2 below (*see* also Exhibit RBH-1).

Table 2: Mean DCF Results

	Mean Low	Mean	Mean High
30-Day Average	8.34%	9.24%	10.23%
90-Day Average	8.40%	9.31%	10.30%
180-Day Average	8.48%	9.39%	10.38%

CAPM and ECAPM Analyses

Q. Please briefly 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 must be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad \text{Equation [3]}$$

where:

K_e = the required market ROE;

β = Beta of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In Equation [3], the term $(r_m - r_f)$ represents the Market Risk Premium.[20] According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to investment portfolios, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

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

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 moved in tandem with the overall market. Consequently, if a company has a Beta coefficient of 1.00, it is as risky as the market and does not provide any diversification benefit.

Q. What assumptions did you include in your CAPM analysis?

A. Since utility equity is a long duration investment, I used two different measures of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury

[20] The Market Risk Premium is defined as the incremental return of the market portfolio over the risk-free rate.

bonds (*i.e.*, 3.04 percent); (2) the near-term projected 30-year Treasury yield (*i.e.*, 3.25 percent).

Q. Why have you relied on the 30-year Treasury yield for your CAPM analysis?

A. In determining the security most relevant to the application of the CAPM, it is important to select the term (or maturity) that best matches the life of the underlying investment. Electric utilities typically are long-duration investments and, as such, the 30-year Treasury yield is more suitable for the purpose of calculating the Cost of Equity.

Q. Please describe your *ex-ante* approach to estimating the Market Risk Premium.

A. The approach is based on the market-required return, less the current 30-year Treasury yield. To estimate the market-required return, I calculated the market capitalization weighted average total return based on the Constant Growth DCF model. To do so, I relied on data from two sources: (1) Bloomberg; and (2) Value Line.[21] With respect to Bloomberg-derived growth estimates, I calculated the expected dividend yield (using the same one-half growth rate assumption described earlier), and combined that amount with the projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I performed that calculation for each of the S&P 500 companies for which Bloomberg provided consensus growth rates. I then subtracted the

[21] *See* Exhibit RBH-2.

current 30-year Treasury yield from that amount to arrive at the market DCF-derived *ex-ante* market risk premium estimate. In the case of Value Line, I performed the same calculation, again using all companies for which five-year earnings growth rates were available. The results of those calculations are provided in Exhibit RBH-2.

Q. How did you apply your expected Market Risk Premium and risk-free rate estimates?

A. I relied on the *ex-ante* Market Risk Premia discussed above, together with the current and near-term projected 30-year Treasury yields, as inputs to my CAPM analyses.

Q. What Beta coefficient did you use in your CAPM model?

A. As shown in Exhibit RBH-3, I considered the Beta coefficients reported by two sources: Bloomberg and Value Line. While both of those services adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00, Value Line calculates the Beta coefficient over a five-year period, while Bloomberg's calculation is based on two years of data.

Q. What are the results of your CAPM analyses?

A. The results of the CAPM analyses are shown in Table 3, below (*see* also Exhibit RBH-4).

Table 3: Summary of CAPM Results[22]

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.04%)	8.25%	9.78%
Near-Term Projected 30-Year Treasury (3.25%)	8.47%	10.00%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.04%)	9.29%	11.12%
Near-Term Projected 30-Year Treasury (3.25%)	9.50%	11.34%

Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I also included the Empirical CAPM 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.[23] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad \text{Equation [5]}$$

where:

k_e = the required market ROE.

β = Adjusted Beta coefficient of an individual security.

[22] *See* Exhibit RBH-4.

[23] *See, e.g.*, Roger A. Morin, *New Regulatory Finance* 189-90 (2006).

r_f = the risk-free rate of return.

r_m = the required return on the market as a whole.

Q. What is the benefit of the ECAPM approach?

A. The ECAPM addresses the tendency of the CAPM to under-estimate the Cost of Equity for companies, such as regulated utilities, with low Beta coefficients. As discussed below, the ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM under-estimates the alpha, or the constant return term.[24]

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 Security Market Line (SML) described by the CAPM formula is not as steeply sloped as the predicted SML.[25] Fama and French state that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[26] Similarly, Morin states:

[24] *Ibid.* at 191 ("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.").
[25] *Ibid.* at 175. The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.
[26] 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.

> 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:
>
> $$K = R_F + x\ \beta(R_M - R_F) + (1\text{-}x)\ \beta(R_M - R_F)$$
>
> 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:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [27]

Some analysts claim that using adjusted Beta coefficients addresses the empirical issues with the CAPM by increasing the expected returns for low Beta stocks and decreasing the returns for high Beta stocks, concluding that there is no need for the ECAPM approach. I disagree with that conclusion. 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 states:

> 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.

[27] Roger A. Morin, *New Regulatory Finance* 175, 190 (2006).

> 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. [28]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM. As with the CAPM, my application of the ECAPM uses the Market DCF-derived *ex-ante* Market Risk Premium estimate, the current yield on 30-year Treasury securities as the risk-free rate, and two estimates of the Beta coefficient. The results of my ECAPM analyses shown on Exhibit RBH-4 and summarized in Table 4 below.

Table 4: Summary of ECAPM Results

	Bloomberg Derived Market Risk Premium	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.04%)	9.61%	11.54%
Near-Term Projected 30-Year Treasury (3.25%)	9.83%	11.75%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.04%)	10.39%	12.54%
Near-Term Projected 30-Year Treasury (3.25%)	10.60%	12.76%

[28] *Ibid.*, at 191.

Bond Yield Plus Risk Premium Analysis

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

A. This approach is based on the basic financial tenet that equity investors bear the residual risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, since returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that additional risk. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of the equity risk premium and the yield on a particular class of bonds. As noted in my discussion of the CAPM, since the equity risk premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate *ex-ante*, or forward-looking estimates of the Cost of Equity, and others that consider historical, or *ex-post*, estimates. An alternative approach is to use actual authorized returns for electric utilities to estimate the Equity Risk Premium.

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

A. As suggested above, I first defined the Risk Premium as the difference between the authorized ROE and the then-prevailing level of long-term (*i.e.*, 30-year) Treasury yield. I then gathered data for 1,581 electric utility rate proceedings between January 1980 and February 28, 2019. In addition to the authorized ROE, I also calculated the average period between the filing of the case and the date of the final order (the "lag period"). In order to reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average lag period (approximately 200 days).

Because the data cover a number of economic cycles, the analysis also may be used to assess the stability of the Equity Risk Premium. Prior research, for example, has shown that the Equity Risk Premium is inversely related to the level of interest rates. That analysis is particularly relevant given the relatively low, but increasing level of current Treasury yields.

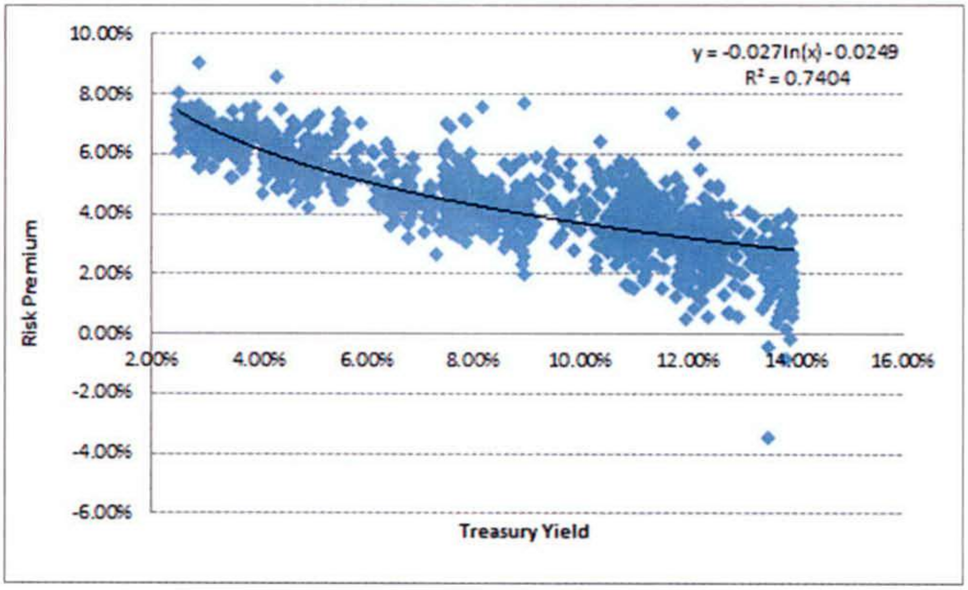
Q. **How did you analyze the relationship between interest rates and the Equity Risk Premium?**

A. The basic method used was regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Relative to the long-term historical average, the analytical period includes interest rates and authorized ROEs that are quite high during one period (*i.e.*, the 1980s) and that are quite low during another (*i.e.*, the post-Lehman bankruptcy period). To account for that variability, I used 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 ("T_{30}"):

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

As shown on Chart 1 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

Chart 1: Equity Risk Premium[29]



As Chart 1 illustrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, simply applying the long-term average Equity Risk Premium of 4.66 percent would significantly understate the Cost of Equity and produce results well below any reasonable estimate. Based on the regression coefficients in Chart 1, however, the implied ROE is between 9.93 percent and 10.17 percent (*see* Table 5 and Exhibit RBH-5).

[29] *See* Exhibit RBH-5.

Table 5: Summary of Bond Yield Plus Risk Premium Results

	Return on Equity
Current 30-Year Treasury (3.04%)	9.93%
Near-Term Projected 30-Year Treasury (3.25%)	9.96%
Long-Term Projected 30-Year Treasury (4.05%)	10.17%

Expected Earnings Analysis

Q. Please describe the Expected Earnings analysis.

A. The Expected Earnings analysis is based on the principle of opportunity costs. Because investors may invest in, and earn returns on alternative investments of similar risk, those rates of return can provide a useful benchmark in determining the appropriate rate of return for a firm. Further, because those results are based solely on the returns expected by investors, exclusive of market-data or models, the Expected Earnings approach provides a direct comparison.

Q. Please explain how the expected earnings analysis is conducted.

A. The Expected Earnings analysis typically takes the actual earnings on book value of investment for each of the members of the proxy group and compares those values to the rate of return in question. Although the traditional approach uses data based on historical accounting records, it is common to use forecasted data in conducting the analysis. Projected returns on book investment are provided by various industry publications (*e.g.*, Value Line), which I have used in my analysis.

I relied on Value Line's projected Return on Common for the period 2021-2023 or 2022-2024, and adjusted those projected returns to account for the fact that they reflect common shares outstanding at the end of the period, rather than the average shares outstanding over the course of the year.[30] The Expected Earnings analysis results in an average value of 10.38 percent and a median value of 10.52 (*see* Exhibit RBH-6).

Q. Has the Commission accepted the use of an Expected Earnings Analysis?

A. Yes, it has. In Duke Energy Carolinas' recent rate case (Docket No. E-7, Sub 1146), the Commission found the Comparable Earnings analysis "credible".[31] The Expected Earnings Analysis described above is similar to the methodology employed by CUCA witness O'Donnell in that case.

VI. <u>BUSINESS RISKS AND OTHER CONSIDERATIONS</u>

Q. Do the mean DCF, CAPM, and Risk Premium results for the proxy group provide an appropriate estimate for the Cost of Equity for DENC?

A. No, the mean results of these models do not necessarily provide an appropriate estimate of DENC's Cost of Equity. In my view, there are additional factors that must be taken into consideration when determining where DENC's Cost of

[30] The rationale for that adjustment is straightforward: Earnings are achieved over the course of a year, and should be related to the equity that was, on average, in place during that year. *See* Leopold A. Bernstein, <u>Financial Statement Analysis: Theory, Application, and Interpretation</u>, Irwin, 4th Ed., 1988, at 630.

[31] North Carolina Utilities Commission, Docket No. E-7, Sub 1146, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, June 22, 2018, at 49.

Equity falls within the range of results. Those factors include: (1) DENC's need to fund its substantial planned capital investment program; (2) the regulatory environment in which the Company operates; (3) flotation costs. Those factors, which are discussed below, should be considered in terms of their overall effect on DENC's risk and, therefore, its Cost of Equity.

Capital Expenditures

Q. Please summarize DENC's capital expenditure plans.

A. The Company's capital expenditure program is significant. As discussed in more detail below, that investment represents a significant increase over its existing net plant. As also discussed below, in the context of existing net plant, the Company's capital investment plans are substantial relative to the proxy companies' projected capital expenditures. DENC currently plans to invest approximately $11.10 billion of additional capital over the period including 2019-2021.[32]

Q. How do DENC's expected capital expenditures compare to the proxy group?

A. To reasonably make that comparison, as shown in Exhibit RBH-7 I calculated the ratio of expected capital expenditures to net plant for each of the companies in the proxy group. For the projected three-year period, I performed that calculation using the Company's projected capital expenditures over this period

[32] *See* Direct Testimony of Mark D. Mitchell.

as compared to its total net plant, property, and equipment as of December 31, 2018. As shown in Exhibit RBH-7, relative to the proxy group, DENC's ratio of projected capital expenditures to net plant is above the proxy group average.

Q. Why is it important for a utility to be allowed the opportunity to earn a return that is adequate to attract capital at reasonable terms?

A. The allowed ROE should enable the subject utility 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 extent a utility is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders should be disadvantaged.

The ratemaking process is predicated on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that since utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of the utility and its ratepayers.

Further, the financial community carefully monitors current and expected financial condition of utility companies, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk. That is especially important during periods in which the utility expects to make significant capital investments and, therefore, may require access to capital markets.

Q. How do these considerations apply to DENC and its capital spending plans?

A. It is clear that DENC's capital expenditure program is significant. It also is clear that the financial community recognizes the need for timely cost recovery for those capital expenditures. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings.

Q. What are your conclusions regarding the effect of DENC's capital investment plan on its risk profile and cost of capital?

A. Relative to the proxy group, DENC's capital expenditure program is above average and will place additional pressure on its cash flows, making regulatory support more important in terms of DENC's ability to finance these expenditures and earn a reasonable return on its planned investments. As such, the Commission's decision in this proceeding will have a direct bearing on

DENC's ability to maintain its financial profile, and its ability to access the capital market at reasonable cost rates.

Regulatory Environment

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to and cost of capital in several ways. The proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. In that regard, the Company's credit rating and outlook depend substantially on the extent to which rating agencies view the regulatory environment as credit supportive, or not. In fact, Moody's finds the regulatory environment to be so important that 50.00 percent of the factors that weigh in the Company's ratings determination are determined by the nature of regulation.[33] Similarly, Standard & Poor's has noted that:

> The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most.[34]

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

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[33] *See* Moody's Investors Service, *Rating Methodology; Regulated Gas and Electric Utilities*, June 23, 2017, at 4.

[34] Standard & Poor's, *Utilities: Assessing U.S. Utility Regulatory Environments*, November 15, 2011.

companies. From the perspective of debt 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.

Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions. From the perspective of equity investors, the authorized return must be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments.

Q. As a point of reference, is North Carolina generally considered a constructive regulatory jurisdiction?

A. Yes, it is. Regulatory Research Associates ("RRA") provides an assessment of the extent to which regulatory jurisdictions are constructive, or not. As RRA explains, less constructive environments are associated with higher levels of risk:

> 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. Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger or more constructive rating from an investor viewpoint;

> 2, a mid-range rating; and, 3, a less constructive rating within each higher-level category. Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."[35]

North Carolina is ranked "Average/1," which places it in the top one-third of the jurisdictions ranked by RRA.[36]

Q. How did you take those rankings into consideration in reviewing recently authorized returns?

A. I applied RRA's rankings to the jurisdictions reported in Exhibit RBH-8 for all vertically integrated electric utility rate cases reported since 2016. My principal observation is that the median ROE for companies operating in jurisdictions that are considered "Above Average," which is only one rank higher than North Carolina, was 10.00 percent; the upper end of the range for those companies was 10.55 percent.[37]

Q. What conclusions do you draw from that data?

A. First, authorized ROEs tend to be correlated with the degree of regulatory supportiveness in that utilities in jurisdictions considered to be more supportive tend to be authorized somewhat higher returns. Similarly, utilities with higher credit ratings tend to be authorized higher returns. Given the need for capital-

[35] Regulatory Research Associates, *Regulatory Focus*, State Regulatory Evaluations - Energy, November 26, 2018, at 3.
[36] Regulatory Research Associates, accessed January 22, 2019.
[37] Of the 16 authorized ROEs in jurisdictions considered "Above Average," 11 were 10.00 percent or higher. The median authorized ROE in jurisdictions ranked Average/1 was 9.90 percent, with a high end of 10.30 percent.

intensive utilities to access external capital when needed, regardless of market conditions, such support is an important consideration to both debt and equity investors.

Second, my recommended range (10.00 percent to 11.00 percent) is well within the range of returns authorized in constructive regulatory jurisdictions. Given the increase in market-based measures of risk discussed in the following section of my Direct Testimony, I believe that my recommendation is consistent with observable data considered by investors as they arrive at their return requirements.

Flotation Costs

Q. What are flotation costs?

A. Flotation costs are the expenses incurred in connection with the sale of new shares of equity. As discussed below, such costs include expenditures for the preparation, filing, and underwriting of common equity offerings.

Q. Why is it important to recognize flotation costs in the allowed ROE?

A. In order to attract and retain new investors, a regulated utility must have the opportunity to earn a return that is both competitive and compensatory. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing its ability to attract adequate capital on reasonable terms.

Q. Are flotation costs part of a utility's invested costs or part of the utility's expenses?

A. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of flotation costs are incurred prior to the test year, remain part of the cost structure that exists during the test year and beyond, and should be recognized for ratemaking purposes. Therefore, recovery of flotation costs is appropriate even if no new issuances are planned in the near future because failure to allow such cost recovery may deny DENC the opportunity to earn its required rate of return in the future.

Q. Is the need to consider flotation costs eliminated because DENC is a wholly-owned subsidiary of Dominion?

A. No. Although the Company is a wholly-owned subsidiary of Dominion, it is appropriate to consider flotation costs because wholly owned subsidiaries receive equity capital from their parents and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based on the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately would penalize the investors that fund the utility operations and would inhibit the utility's ability to obtain new equity capital at a reasonable cost. This is important for companies such as DENC that are planning continued capital expenditures in the near term, and for which access to capital (at reasonable cost rates) to fund such required expenditures will be critical.

Q. Do the DCF and CAPM models already incorporate investor expectations of a return in order to compensate for flotation costs?

A. No. The models used to estimate the appropriate ROE assume no "friction" or transaction costs, as these costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of the CAPM and the Bond Yield Plus Risk Premium model).

Q. Is the need to consider flotation costs recognized by the academic and financial communities?

A. Yes. The need to reimburse investors for equity issuance costs is justified by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair rate of return. As explained by Dr. Shannon Pratt:

> Flotation costs occur when a company issues new stock. The business usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the business. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the business's required returns must be greater to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the net cash flow to discount, or by incorporating the cost into the cost of equity capital. Since

> flotation costs typically are not applied to operating cash flow, they must be incorporated into the cost of equity capital.[38]

Q. Have you estimated the effects of flotation costs?

A. Yes, I modified the DCF calculation to derive the dividend yield that would reimburse investors for direct issuance costs. Based on the weighted average issuance costs shown in Exhibit RBH-9, a reasonable estimate of flotation costs is approximately 0.09 percent (9 basis points).

Q. Are you proposing to adjust your recommended ROE by 9 basis points to reflect the effect of flotation costs on DENC'S ROE?

A. No, I am not. Rather, I have considered the effect of flotation costs, in addition to the Company's other business risks, in determining where the Company's ROE falls within the range of results.

VII. 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. As a preliminary matter, I understand and appreciate that the Commission must balance the interests of investors and customers in setting the Return on Equity. As the Commission has stated, "…the Commission is and must always be mindful of the North Carolina Supreme Court's command that

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[38] Shannon P. Pratt, Roger J. Grabowski, Cost of Capital: Applications and Examples, 4th ed. (John Wiley & Sons, Inc., 2010), at 586.

the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[39] 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 that 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. As the Commission pointed out:

> … 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. This is in accord with the "end result" test of Hope. This the Commission has done.[40]

The Supreme Court agreed, and upheld the Commission's Order on Remand.[41] The Supreme Court has also, however, made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on

[39] State of North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, Sept. 24, 2013 at 24; see also DENC Remand Order at 40 ("the Commission in every case seeks to comply with the North Carolina Supreme Court's mandate that the Commission establish rates as low as possible within Constitutional limits.").
[40] State of North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, October 23, 2013, at 34 – 35; see also DENC Remand Order 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").
[41] State of North Carolina ex rel. Utilities Commission v. Cooper, 766 S.E.2d 827 (2014).

customers when determining the proper ROE for a public utility."[42] In *Cooper II*, which addressed an appeal of the Commission's order on DENC's previous base rate application, the Supreme Court directed the Commission on remand to "make additional findings of fact concerning the impact of changing economic conditions on customers."[43] The Commission made such additional findings of fact in its order on remand.[44] In light of the Cooper II decision and the Supreme Court precedent that preceded it,[45] I appreciate the Commission's need to consider economic conditions in the State and as such, I have undertaken several analyses to provide such a review.

Q. Please now summarize your analyses and conclusions.

A. As to the rate of unemployment, it has fallen substantially in North Carolina, and the U.S. generally since late 2009 and early 2010, when the rates peaked at 10.00 percent and 11.40 percent, respectively. 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. By December 2018, the unemployment rate had fallen to approximately one-third of those peak levels, to 3.90 percent nationally and 3.70 percent in North Carolina. (*see* Chart 2, below).

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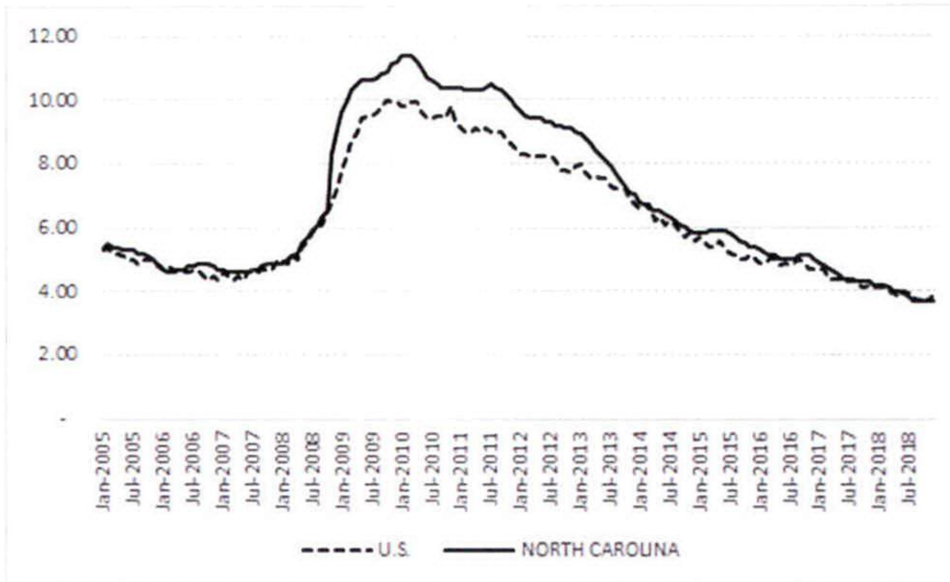
[42] State of North Carolina ex rel. Utilities Commission v. Cooper, 758 S.E.2d 635, 642 (2014) ("Cooper II").
[43] Cooper II, 758 S.E.2d at 643,
[44] State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, Order on Remand, July 23, 2015, at 4-10.
[45] State of North Carolina ex rel. Utilities Commission v. Cooper, 366 N.C. 484, 739 S.E.2d 541 (2013) ("Cooper I").

Chart 2: Unemployment Rate[46]



Since the Company's last rate filing in March 2016, the unemployment rate in North Carolina has fallen from 5.10 percent to 3.70 percent, a reduction of 1.40 percentage points, which is a somewhat greater reduction than the decline in the U.S. unemployment rate (1.10 percentage points). Still, over the entire period of 2005 through 2018, the correlation between North Carolina's unemployment rate and the national rate was approximately 99.00 percent. Furthermore, economic growth at the national level is projected to generate 11.50 million new jobs from 2016-2026 (*i.e.*, 7.40 percent growth over that period).[47]

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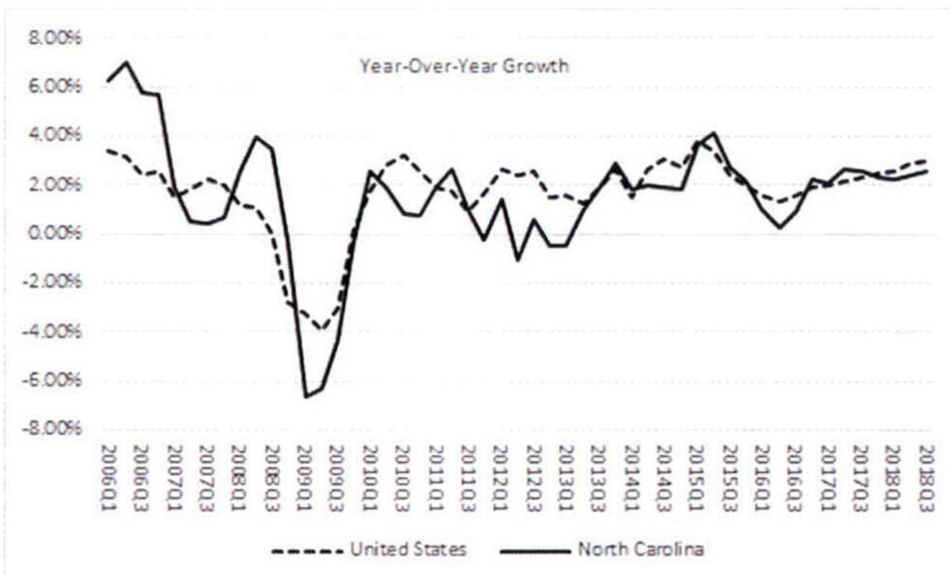
[46] Source: Bureau of Labor Statistics.

[47] U.S. Bureau of Labor Statistics, *Employment Projections: 2016-2026 Summary*, October 24, 2017.

Looking to real Gross Domestic Product growth, again there has been a relatively strong correlation between North Carolina and the national economy (approximately 75.00 percent). After the financial crisis the national rate of growth at times (during portions of 2010 and 2012) outpaced North Carolina. Since the second quarter of 2013 North Carolina and the national Gross Domestic Product have grown at similar rates.

Chart 3: Real Gross Domestic Product Growth Rate[48]

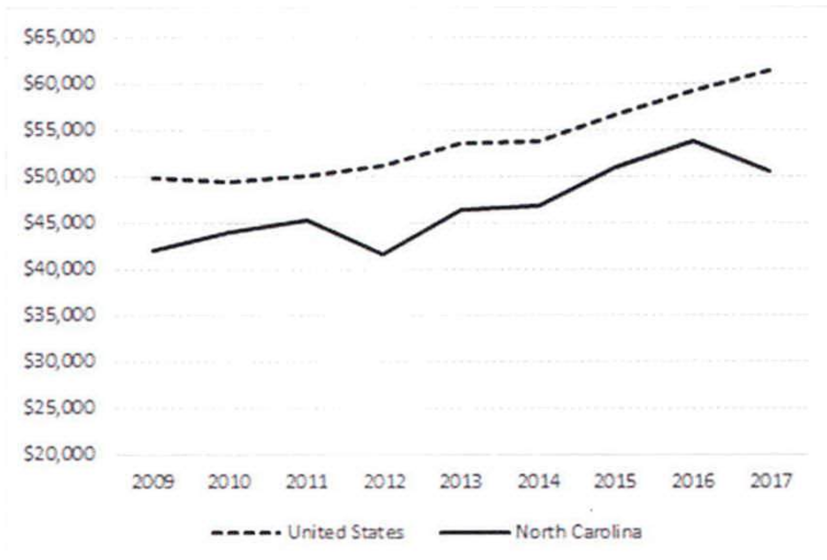


As to median household income, the correlation between North Carolina and the U.S. is relatively strong (nearly 67.00 percent from 2005 through 2017). Since 2009 (that is, the years subsequent to the financial crisis), median household income in North Carolina has grown at a somewhat slower annual rate than the national median income (2.32 percent vs. 2.65 percent; *see* Chart 4,

[48] Source: Bureau of Economic Analysis.

below). To help put household income in perspective, the Missouri Economic Research and Information Center reports that in 2018, North Carolina had the 19th lowest cost of living index of the 50 states and the District of Columbia.[49]

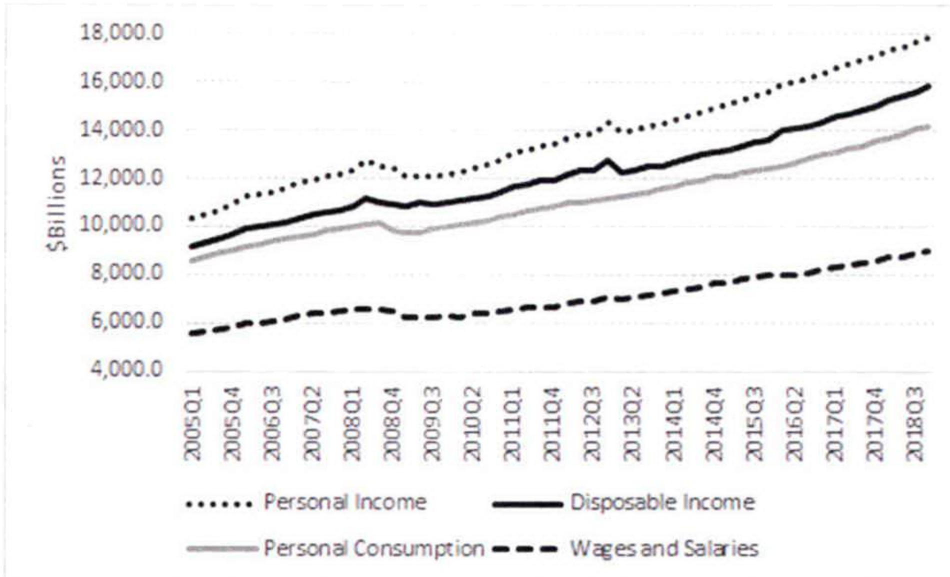
Chart 4: Median Household Income



Similarly, as shown in Chart 5, below, since 2009, total personal income, disposable income, personal consumption, and wages and salaries have generally been on an increasing trend at the national level.

[49] Source: https://www.missourieconomy.org/indicators/cost_of_living/ Accessed February 11, 2019.

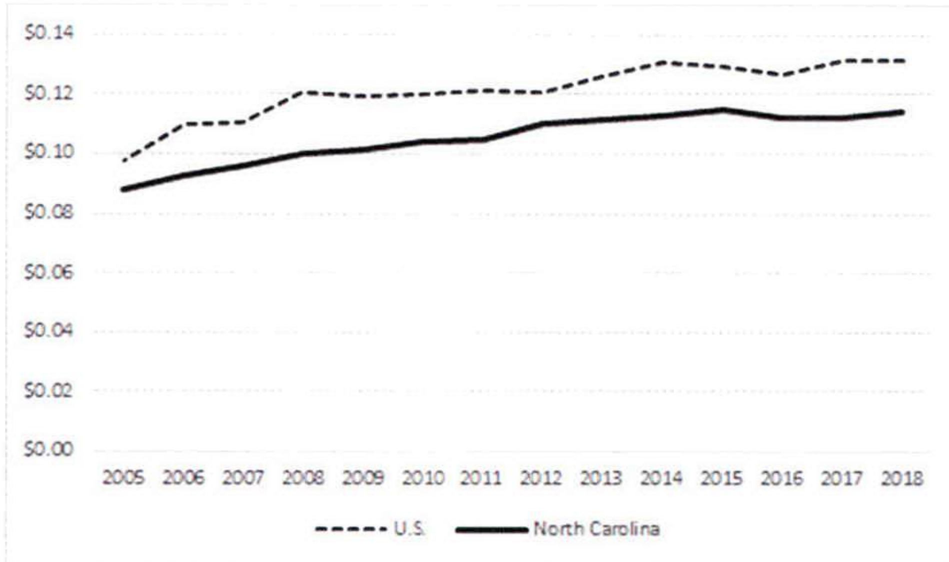
Chart 5: United States Income and Consumption[50]



Since 2018 residential electricity costs (measured in cents/kWh) North Carolina remain approximately 13.00 percent below the national average. Even looking to the years 2009 through 2018, residential rates in North Carolina have been (on average) approximately 12.60 percent below the national average (*see* Chart 6, below). Over the longer period, residential rates grew at a somewhat lower annual rate in North Carolina (2.05 percent versus 2.31 percent nationally), but remained highly correlated with the national average (approximately 95.00 percent).

[50] Source: Bureau of Economic Analysis. Data is seasonally adjusted.

Chart 6: Residential Electricity Rates ($/kWh)[51]



Lastly, I was able to review (seasonally unadjusted) unemployment rates in the counties served by DENC. At its peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 13.41 percent (1.41 percentage points higher than the State-wide average); by December 2018 it had fallen to approximately 4.95 percent (1.25 percentage points higher than the State-wide average). Since the Company's last rate filing in March 2016, the counties' unemployment rate has fallen by 1.83 percentage points. From 2005 through 2018, the correlation in unemployment rates between the counties served by DENC, and the U.S. and North Carolina, respectively, were approximately96.00 percent. In summary, although the unemployment rate

[51] Source: Energy Information Administration. As of July, each year.

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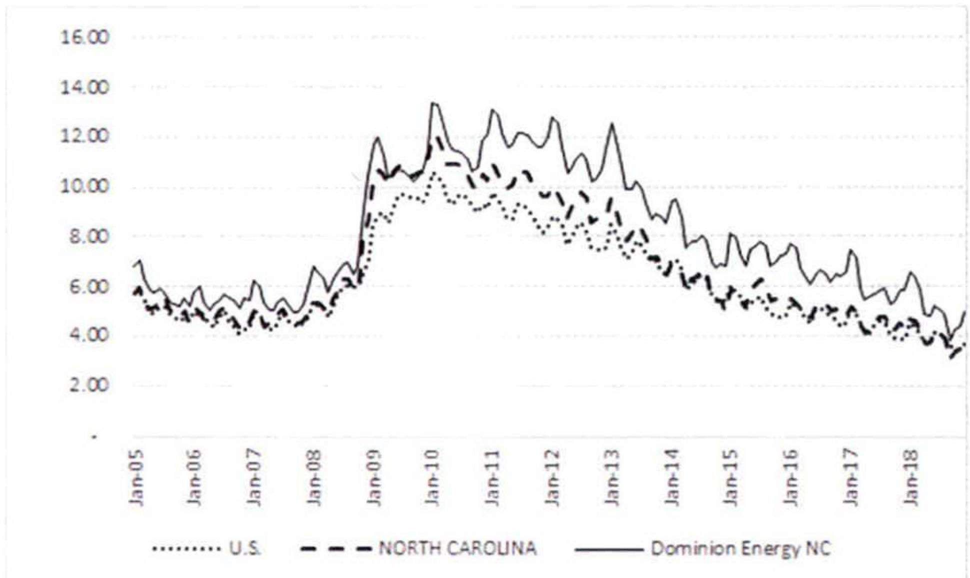
remains higher than the national and State-wide averages, it has fallen considerably since its peak in early 2010.

Chart 7: Seasonally Unadjusted Unemployment Rates[52]



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

- North Carolina's unemployment rate has fallen by one-third since its peak in the 2009-2010 period, such that as of December 2018, it stood at 3.70 percent. Although the current rate is somewhat higher than the national average, it fell by 8.30 percentage points from its peak, whereas the national average rate fell by 6.90 percentage points.

[52] Source: Bureau of Labor Statistics, St. Louis Federal Reserve.

- Although the unemployment rate in the counties served by DENC remains above the national and State-wide averages, it too has fallen considerably since its peak in early 2010.[53]
- The State's Gross Domestic Product remains highly correlated with national GDP, and has grown at a somewhat faster rate than the national economy since the 2009 financial crisis.
- Median household income has grown at a somewhat slower pace in North Carolina than has the national average. Although the median remains below the national average, the overall cost of living in North Carolina also is below the national average. Furthermore, at the national level, income has generally been increasing since the financial crisis.
- Residential electricity rates have grown at a somewhat slower rate in North Carolina than the national average over the past ten years; during that time, the State's residential rates have been approximately 13.00 percent below the national average.

Q. How would you summarize the economic indicators that you have analyzed and discussed in your testimony?

A. It is my opinion that, based on the indicators discussed above, North Carolina and the counties contained within DENC's service area have experienced steady economic improvement since the Company's last rate case. As also discussed above, that improvement is projected to continue.

[53] Seasonally unadjusted. Source: Bureau of Labor Statistics, St. Louis Federal Reserve.

Q. In your opinion, is the proposed ROE fair and reasonable to DENC, its shareholders and its customers, and not unduly burdensome to DENC customers considering the impact of these changing economic conditions?

A. Yes. Based on the factors I have discussed here, I believe that DENC's proposed ROE of 10.75 percent is fair and reasonable to DENC, its shareholders, and its customers in light of the effect of those changing economic conditions.

VIII. CAPITAL MARKET ENVIRONMENT

Q. Do economic conditions influence the required cost of capital and required return on common equity?

A. Yes. As discussed in Section V, the models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. As such, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent a given model's assumptions are misaligned with such data, or its results are inconsistent with basic financial principles, it is appropriate to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

Q. Do you have any general observations regarding the relationship between current capital market conditions and the company's Cost of Equity?

A. Yes, I do. Although the Federal Reserve completed its Quantitative Easing initiative in October 2014, it was not until December 2015 that it raised the Federal Funds rate, and began the process of rate normalization.[54] A significant issue is how investors likely will react as that process continues, and eventually is completed. For example, increasing interest rates may be seen as an indication of expanding macroeconomic growth, in which case we reasonably could expect the growth rate component of the DCF model to increase. At the same time, sectors that historically have included dividend-paying companies have lost value, as increasing interest rates provide investors with alternative sources of current income. A more reasoned approach is to understand the relationships among capital market and macroeconomic variables, and to consider how those factors may affect different models and their results.

Q. Does your recommendation consider the interest rate environment?

A. Yes, it does. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst, and the capital market environment in

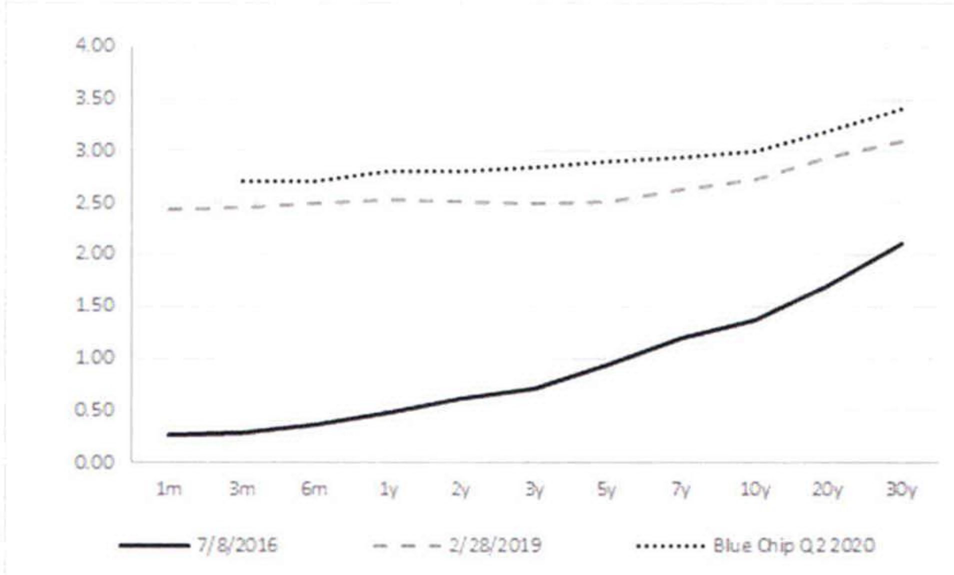
[54] *Federal Reserve Press Release* dated December 16, 2015.

which the analyses were undertaken. Because the Cost of Equity is forward-looking, the salient issue is whether investors see the likelihood of increasing costs of capital during the period in which the rates set in this proceeding will be in effect.

Although the Federal Reserve's market intervention policies have kept interest rates historically low, since July 8, 2016 (when the 30-year Treasury fell to its secular low of 2.11 percent) rates have risen. As the Federal Reserve increased the Federal Funds target rate eight times between December 2016 and December 2018 to 2.25 percent - 2.50 percent, short-term and long-term interest rates also increased (see Chart 8 below).[55]

[55] Federal Reserve Board Schedule H.15. 1-year, 10-year and 30-year Treasury yields increased by 206 basis points, 136 basis points and 98 basis points, respectively, July 8, 2016 to February 28, 2019.

Chart 8: Treasury Yield Curve: 7/8/2016, 2/28/2019 and Projected Q2 2020[56]



In a press conference following the December 2018 Federal Open Market Committee meeting, Chairman Powell discussed the recent increases in the Federal Funds rate and the expectation for some further gradual rate increases, noting a strengthening economy, a strong labor market and rising wages.[57] Lastly, in October 2017, the Federal Reserve also initiated its balance sheet normalization program that includes gradual reductions to its security holdings by decreasing its reinvestment activities.[58] At the same time, the supply of marketable U.S. Treasury securities has increased by approximately $1.14

[56] Sources: Federal Reserve Board Schedule H.15.; Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2018, at 2. 3-year, 7-year and 20-year projected Treasury yields interpolated.
[57] Transcript of Chairman Powell's Press Conference, December 19, 2018.
[58] *See:* https://www.federalreserve.gov/monetarypolicy/policy-normalization.htm and Federal Open Market Committee ("FOMC") Press Release, June 14, 2017.

trillion.[59] The growing supply of Treasury securities from both the Federal Reserve and the U.S. Treasury puts upward pressure on Treasury rates.

Q. Do investors see a probability of increasing interest rates?

A. Yes. Consensus near-term forecasts of the 30-year Treasury yield reported by Blue Chip Financial Forecast indicate the market expects long-term rates to reach 3.40 percent by the second quarter of 2020.[60] Importantly, the potential for rising rates represents risk for utility investors.

Q. Has market volatility changed with the Federal Reserve's move toward monetary policy normalization?

A. Yes, it has. A visible and widely reported measure of expected volatility is the Cboe Options Exchange ("Cboe") Volatility Index, often referred to as the VIX. As Cboe explains, the VIX "is a calculation designed to produce a measure of constant, 30-day expected volatility of the U.S. stock market, derived from real-time, mid-quote prices of S&P 500® Index call and put options."[61] Simply, the VIX is a market-based measure of expected volatility. Because volatility is a measure of risk, increases in the VIX, or in its volatility, are a broad indicator of expected increases in market risk.

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[59] Source: U.S. Treasury, Monthly Statement of the Public Debt. https://www.treasurydirect.gov/govt/reports/pd/mspd/mspd.htm. U.S. marketable securities increased from $14.48 trillion to $15.62 trillion between December 31, 2017 and December 31, 2018.
[60] Blue Chip Financial Forecast, Vol. 39, No. 3, March 1, 2019, at 2.
[61] Source: http://www.cboe.com/vix

Although the VIX is not expressed as a percentage, it should be understood as such. That is, if the VIX stood at 15.00, it would be interpreted as an expected standard deviation in annual market returns of 15.00 percent over the coming 30 days. Since 2000, the VIX has averaged about 19.69, which is highly consistent with the long-term standard deviation on annual market returns (19.80 percent, as reported by Duff & Phelps).

As Chart 9 (below) demonstrates, in 2017 market volatility was well below its long-term average, and moved within a somewhat narrow range; the VIX averaged about 11.09, with a standard deviation of 1.36. Between January 2018 and February 2019, however, the VIX average increased to 16.76 with a standard deviation of 4.84. That is, from 2017 to 2018-2019 both the level and the volatility of market volatility increased.

Chart 9: VIX Since January 2017[62]

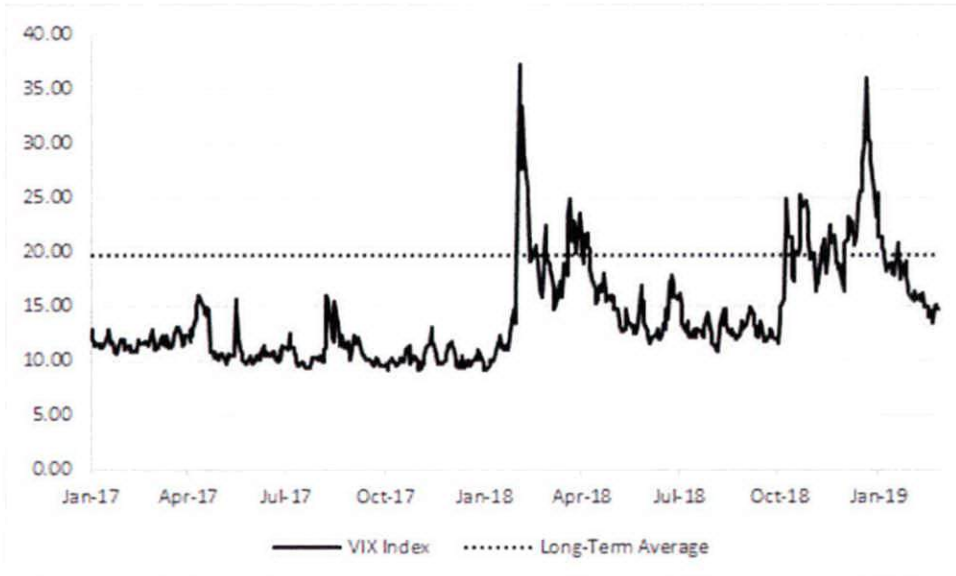

Table 6 (below) further demonstrates the increase in market uncertainty from 2017 to 2018-2019. As that table notes, the standard deviation (that is, the volatility of volatility) in 2018-2019 is about 3.50 times higher than its 2017 level (1.356).

Table 6: VIX Levels and Volatility[63]

Long-Term Average	19.686
2018-2019 Average	16.760
2018-2019 Maximum	37.320
2018-2019 Minimum	9.150
2018-2019 Standard Deviation	4.837
2017 Average	11.090
2017 Maximum	16.040
2017 Minimum	9.140
2017 Standard Deviation	1.356

[62] Source: Bloomberg Professional Services. Data as of February 28, 2019.
[63] Source: Bloomberg Professional Services. Data as of February 28, 2019.

The increase in volatility is not surprising as market participants reassess investment alternatives in light of the Federal Reserve's shift in monetary policy and, as discussed below, the recent passage of new tax legislation.

Q. Is market volatility expected to remain above its 2017 and 2018-2019 average levels?

A. Yes, it is. One means of assessing market expectations regarding the future level of volatility is to review Cboe's "Term Structure of Volatility." As Cboe points out:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of the SPX implied volatility term structure.[64]

The expected VIX value in March 2020 is about 17.74, suggesting investors see a reversion to long-term average volatility over the coming months.[65] The expectation of increased volatility makes intuitive sense, given the Federal Reserve's movement toward normalizing monetary policy. That policy change includes reducing the liquidity provided to the financial markets during the Federal Reserve's Quantitative Easing initiatives. Because that liquidity had the effect of dampening volatility as it was added to the markets, it stands to reason that volatility will increase as liquidity is diminished.

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[64] Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.

[65] Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, accessed February 28, 2019.

Q. Does the Federal Reserve's tightening of monetary policy have other implications for the assessment of capital markets?

A. Yes. Just as the Federal Reserve's monetary policy in the post-financial crisis era was aimed at lowering interest rates and market volatility, its "normalization" will tend to increase both. Because it is at least a directional indicator of investors' return requirements, the elevated uncertainty supports my recommended range.

It is important to recognize that the Federal Reserve's reduction in monetary stimulus is related to expectations of improved economic and financial conditions, and sustained growth in the overall economy. When increasing the Federal Funds rate on December 19, 2018, the Federal Open Market Committee ("FOMC") noted the labor market continued to strengthen and that household spending was rising at a strong rate while business fixed investment had moderated from its rapid pace earlier in the year.[66] Although it did not increase the Federal Funds rate in its January 2019 meeting, the FOMC observed the labor market continued to strengthen, and economic activity continued to rise at a solid rate.[67] At its March 2019 meeting, the FOMC determined it would hold the Federal Funds target rate constant, looking to current and expected economic conditions to determine future rate adjustments.[68]

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[66] *Federal Reserve Press Release* dated December 19, 2018.
[67] *Federal Reserve Press Release* dated January 30, 2019.
[68] *Federal Reserve Press Release* dated March 20, 2019.

Q. What conclusions do you draw from your analyses of the current capital market environment, and how do those conclusions affect your ROE recommendation?

A. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE determination, including assessments of capital market conditions, are consistent with the conclusion itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken. Because the application of financial models and interpretation of their results often is the subject of differences among analysts in regulatory proceedings, it is important to review and consider a variety of data points. That approach enables us to put in context both quantitative analyses and the associated recommendations. Further, because all models produce ranges of results, it is important to consider the type of information discussed above to determine where the Company's ROE falls within those ranges. As discussed throughout my testimony, doing so supports my recommended range of 10.00 percent to 11.00 percent.

IX. CONCLUSIONS

Q. What is your conclusion regarding the ROE and capital structure for DENC?

A. As discussed throughout my testimony, it is important to consider a variety of empirical and qualitative information in reviewing analytical results and arriving at ROE determinations. Based on that review, I believe that an ROE in the range of 10.00 percent to 11.00 percent represents the range of equity investors' required ROE for investment in integrated electric utilities in today's capital markets. Within that range, I conclude that an ROE of 10.75 percent represents the Cost of Equity for DENC. That conclusion considers the current capital market environment, as well as DENC's risk profile relative to the proxy group analytical results with respect to (1) DENC's comparatively high level of capital expenditures; (2) the regulatory environment in which the Company operates; and (3) flotation costs. Based on those factors, it is appropriate to establish an ROE that is above the proxy group mean results. As such, an ROE of 10.75 percent reasonably represents the return required to invest in a company with a risk profile comparable to DENC.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

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MANAGEMENT CONSULTANTS

Attachment A
Resume of:

Robert B. Hevert, Partner
Rates, Regulation & Planning Practice Leader

Summary

Bob Hevert is a financial and economic consultant with more than 30 years of broad experience in the energy and utility industries. He has an extensive background in the areas of corporate finance, mergers and acquisitions, project finance, asset and business unit valuation, rate and regulatory matters, energy market assessment, and corporate strategic planning. He has provided expert testimony on a wide range of financial, strategic, and economic matters on more than 250 occasions at the state, provincial, and federal levels.

Prior to joining ScottMadden, Bob served as managing partner at Sussex Economic Advisors, LLC. Throughout the course of his career, he has worked with numerous leading energy companies and financial institutions throughout North America. He has provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues. Bob earned a B.S. in business and economics from the University of Delaware and an M.B.A. with a concentration in finance from the University of Massachusetts at Amherst. Bob also holds the Chartered Financial Analyst designation.

Areas of Specialization

- Regulation and rates
- Utilities
- Fossil/hydro generation
- Markets and RTOs
- Nuclear generation
- Mergers and acquisitions
- Regulatory strategy and rate case support
- Capital project planning
- Strategic and business planning

Recent Expert Testimony Submission/Appearance

- Federal Energy Regulatory Commission – Return on Equity
- New Jersey Board of Public Utilities – Merger Approval
- New Mexico Public Regulation Commission – Cost of Capital and Financial Integrity
- United States District Court – PURPA and FERC Regulations
- Alberta Utilities Commission – Return on Equity and Capital Structure

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies, the Alberta Utilities Commission, and the Federal Energy Regulatory Commission
- For an independent electric transmission provider in Texas, prepared an expert report on the economic damages with respect to failure to meet guaranteed completion dates. The report was filed as part of an arbitration proceeding and included a review of the ratemaking implications of economic damages
- Advised the board of directors of a publicly traded electric and natural gas combination utility on dividend policy issues, earnings payout trends and related capital market considerations
- Assisted a publicly traded utility with a strategic buy-side evaluation of a gas utility with more than $1 billion in assets. The assignment included operational performance benchmarking, calculation of merger synergies, risk analysis, and review of the regulatory implications of the transaction
- Provided testimony before the Arkansas Public Service Commission in support of the acquisition of SourceGas LLC by Black Hills Corporation. The testimony addressed certain balance sheet capitalization and credit rating issues
- For the State of Maine Public Utility Commission, prepared a report that summarized the Northeast and Atlantic Canada natural gas power markets and analyzed the potential benefits and costs associated with natural gas pipeline expansions. The independent report was filed at the Maine Public Utility Commission

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
Cook Inlet Natural Gas Storage Alaska, LLC	06/18	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. U-18-043	Return on Equity
ENSTAR Natural Gas Company	06/16	ENSTAR Natural Gas Company	Matter No. TA 285-4	Return on Equity
ENSTAR Natural Gas Company	08/14	ENSTAR Natural Gas Company	Matter No. TA 262-4	Return on Equity
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	10/17	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	2018 General Cost of Capital, Proceeding ID. 22570	Rate of Return
EPCOR Energy Alberta G.P. Inc.	01/17	EPCOR Energy Alberta G.P. Inc.	Proceeding 22357	Energy Price Setting Plan
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/16	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2016 General Cost of Capital, Proceeding ID. 20622	Rate of Return
Arizona Corporation Commission				
Southwest Gas Corporation	05/16	Southwest Gas Corporation	Docket No. G-01551A-16-0107	Return on Equity
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
Southwestern Electric Power Company	02/19	Southwestern Electric Power Company	Docket No. 19-008-U	Return on Equity
Oklahoma Gas and Electric Company	09/16	Oklahoma Gas and Electric Company	Docket No. 16-052-U	Return on Equity
SourceGas Arkansas, Inc.	12/15	SourceGas Arkansas, Inc.	Docket No. 15-078-U	Response to Direct Testimony by Arkansas Attorney General related to Compliance Issues
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	11/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 15-098-U	Return on Equity
SourceGas Arkansas, Inc.	04/15	SourceGas Arkansas, Inc.	Docket No. 15-011-U	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	01/07	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
California Public Utilities Commission				
Southwest Gas Corporation	12/12	Southwest Gas Corporation	Docket No. A-12-12-024	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Return on Equity
Xcel Energy, Inc.	03/15	Public Service Company of Colorado	Docket No. 15AL-0135G	Return on Equity (gas)

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Xcel Energy, Inc.	06/14	Public Service Company of Colorado	Docket No. 14AL-0660E	Return on Equity (electric)
Xcel Energy, Inc.	12/12	Public Service Company of Colorado	Docket No. 12AL-1268G	Return on Equity (gas)
Xcel Energy, Inc.	11/11	Public Service Company of Colorado	Docket No. 11AL-947E	Return on Equity (electric)
Xcel Energy, Inc.	12/10	Public Service Company of Colorado	Docket No. 10AL-963G	Return on Equity (electric)
Atmos Energy Corporation	07/09	Atmos Energy Colorado-Kansas Division	Docket No. 09AL-507G	Return on Equity (gas)
Xcel Energy, Inc.	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Xcel Energy, Inc.	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Xcel Energy, Inc.	08/05	Public Service Company of Colorado	Docket No. 05S-369ST	Return on Equity (steam)
Xcel Energy, Inc.	05/05	Public Service Company of Colorado	Docket No. 05S-246G	Return on Equity (gas)
Connecticut Public Utilities Regulatory Authority				
Connecticut Light and Power Company	11/17	Connecticut Light and Power Company	Docket No. 17-10-46	Return on Equity
Connecticut Light and Power Company	06/14	Connecticut Light and Power Company	Docket No. 14-05-06	Return on Equity
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity
Council of the City of New Orleans				
Entergy New Orleans, LLC	09/18	Entergy New Orleans, LLC	Docket No. UD-18-07	Return on Equity
Delaware Public Service Commission				
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0977 (Electric)	Return on Equity
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0978 (Gas)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-649 (Electric)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-650 (Gas)	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 13-115	Return on Equity
Delmarva Power & Light Company	12/12	Delmarva Power & Light Company	Case No. 12-546	Return on Equity
Delmarva Power & Light Company	03/12	Delmarva Power & Light Company	Case No. 11-528	Return on Equity
District of Columbia Public Service Commission				
Potomac Electric Power Company	12/17	Potomac Electric Power Company	Formal Case No. 1150	Return on Equity
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Formal Case No. 1139	Return on Equity

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Washington Gas Light Company	02/16	Washington Gas Light Company	Formal Case No. 1137	Return on Equity
Potomac Electric Power Company	03/13	Potomac Electric Power Company	Formal Case No. 1103-2013-E	Return on Equity
Potomac Electric Power Company	07/11	Potomac Electric Power Company	Formal Case No. 1087	Return on Equity
Federal Energy Regulatory Commission				
Sabine Pipeline, LLC	09/15	Sabine Pipeline, LLC	Docket No. RP15-1322-000	Return on Equity
NextEra Energy Transmission West, LLC	07/15	NextEra Energy Transmission West, LLC	Docket No. ER15-2239-000	Return on Equity
Maritimes & Northeast Pipeline, LLC	05/15	Maritimes & Northeast Pipeline, LLC	Docket No. RP15-1026-000	Return on Equity
Public Service Company of New Mexico	12/12	Public Service Company of New Mexico	Docket No. ER13-685-000	Return on Equity
Public Service Company of New Mexico	10/10	Public Service Company of New Mexico	Docket No. ER11-1915-000	Return on Equity
Portland Natural Gas Transmission System	05/10	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Return on Equity
Florida Gas Transmission Company, LLC	10/09	Florida Gas Transmission Company, LLC	Docket No. RP10-21-000	Return on Equity
Maritimes and Northeast Pipeline, LLC	07/09	Maritimes and Northeast Pipeline, LLC	Docket No. RP09-809-000	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Response to draft policy statement regarding inclusion of MLPs in proxy groups for determination of gas pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Sea Robin Pipeline LLC	06/07	Sea Robin Pipeline LLC	Docket No. RP07-513-000	Return on Equity
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity
GPU International and Aquila	11/00	GPU International	Docket No. EC01-24-000	Market Power Study
Florida Public Service Commission				
Florida Power & Light Company	03/16	Florida Power & Light Company	Docket No. 160021-EI	Return on Equity
Tampa Electric Company	04/13	Tampa Electric Company	Docket No. 130040-EI	Return on Equity
Georgia Public Service Commission				
Atlanta Gas Light Company	05/10	Atlanta Gas Light Company	Docket No. 31647-U	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Hawaii Public Utilities Commission				
Hawai'i Electric Light Company, Inc.	12/18	Hawai'i Electric Light Company, Inc.	Docket No. 2018-0368	Return on Equity
Maui Electric Company, Limited	10/17	Maui Electric Company, Limited	Docket No. 2017-0150	Return on Equity
Hawaiian Electric Company, Inc.	12/16	Hawaiian Electric Company, Inc.	Docket No. 2016-0328	Return on Equity
Hawai'i Electric Light Company, Inc.	09/16	Hawai'i Electric Light Company, Inc.	Docket No. 2015-0170	Return on Equity
Maui Electric Company, Limited	12/14	Maui Electric Company, Limited	Docket No. 2014-0318	Return on Equity
Hawaiian Electric Company, Inc.	06/14	Hawaiian Electric Company, Inc.	Docket No. 2013-0373	Return on Equity
Hawai'i Electric Light Company, Inc.	08/12	Hawai'i Electric Light Company, Inc.	Docket No. 2012-0099	Return on Equity
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/18	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 18-0463	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/15	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 15-0142	Return on Equity
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	04/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Docket No. 14-0371	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/13	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 13-0192	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0279	Return on Equity (electric)
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0282	Return on Equity (gas)
Indiana Utility Regulatory Commission				
Indiana Michigan Power Company	7/17	Indiana Michigan Power Company	Cause No. 44967	Return on Equity
Duke Energy Indiana, Inc.	12/15	Duke Energy Indiana, Inc.	Cause No. 44720	Return on Equity
Duke Energy Indiana, Inc.	12/14	Duke Energy Indiana, Inc.	Cause No. 44526	Return on Equity
Northern Indiana Public Service Company	05/09	Northern Indiana Public Service Company	Cause No. 43894	Assessment of Valuation Approaches

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Kansas Corporation Commission				
Empire District Electric Company	12/18	Empire District Electric Company	Docket No. 19-EPDE-223-RTS	Alternative Ratemaking Mechanisms
Kansas City Power & Light Company	05/18	Kansas City Power & Light Company	Docket No. 18-KCPE-480-RTS	Return on Equity
Westar Energy	02/18	Westar Energy	Docket No. 18-WSEE-328-RTS	Return on Equity
Great Plains Energy, Inc. and Kansas City Power & Light Company	01/17	Great Plains Energy, Inc. and Kansas City Power & Light Company	Docket No. 16-KCPE-593-ACQ	Response to Direct Testimony by Commission Staff related to the ratemaking capital structure processes
Kansas City Power & Light Company	01/15	Kansas City Power & Light Company	Docket No. 15-KCPE-116-RTS	Return on Equity
Maine Public Utilities Commission				
Northern Utilities, Inc.	05/17	Northern Utilities, Inc.	Docket No. 2017-00065	Return on Equity
Central Maine Power Company	06/11	Central Maine Power Company	Docket No. 2010-327	Response to Bench Analysis provided by Commission Staff relating to the Company's credit and collections processes
Maryland Public Service Commission				
Potomac Electric Power Company	01/19	Potomac Electric Power Company	Case No. 9602	Return on Equity
Washington Gas Light Company	05/18	Washington Gas Light Company	Case No. 9481	Return on Equity
Potomac Electric Power Company	01/18	Potomac Electric Power Company	Case No. 9472	Return on Equity
Delmarva Power & Light Company	07/17	Delmarva Power & Light Company	Case No. 9455	Return on Equity
Potomac Electric Power Company	03/17	Potomac Electric Power Company	Case No. 9443	Return on Equity
Delmarva Power & Light Company	06/16	Delmarva Power & Light Company	Case No. 9424	Return on Equity
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Case No. 9418	Return on Equity
Potomac Electric Power Company	12/13	Potomac Electric Power Company	Case No. 9336	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 9317	Return on Equity
Potomac Electric Power Company	11/12	Potomac Electric Power Company	Case No. 9311	Return on Equity
Potomac Electric Power Company	12/11	Potomac Electric Power Company	Case No. 9286	Return on Equity
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 9285	Return on Equity
Delmarva Power & Light Company	12/10	Delmarva Power & Light Company	Case No. 9249	Return on Equity

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Massachusetts Department of Public Utilities				
NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	02/19	NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	DPU 18-64/DPU 18-65/DPU 18-66	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83D
National Grid	11/18	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 18-150	Return on Equity
NSTAR Electric Company d/b/a Eversource Energy	11/18	NSTAR Electric Company d/b/a Eversource Energy	DPU 18-76/DPU 18-77/DPU 18-78	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83C
Boston Gas Company, Colonial Gas Company each d/b/a National Grid	11/17	Boston Gas Company, Colonial Gas Company each d/b/a National Grid	DPU 17-170	Return on Equity
NSTAR Electric Company Western and Massachusetts Electric Company each d/b/a Eversource Energy	01/17	NSTAR Electric Company Western Massachusetts Electric Company each d/b/a Eversource Energy	DPU 17-05	Return on Equity
National Grid	11/15	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 15-155	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	06/15	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 15-80	Return on Equity
NSTAR Gas Company	12/14	NSTAR Gas Company	DPU 14-150	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	07/13	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 13-90	Return on Equity
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	04/12	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	DPU 12-25	Capital Cost Recovery
National Grid	08/09	Massachusetts Electric Company d/b/a National Grid	DPU 09-39	Revenue Decoupling and Return on Equity
National Grid	08/09	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 09-38	Return on Equity – Solar Generation

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Bay State Gas Company	04/09	Bay State Gas Company	DPU 09-30	Return on Equity
NSTAR Electric	09/04	NSTAR Electric	DTE 04-85	Divestiture of Power Purchase Agreement
NSTAR Electric	08/04	NSTAR Electric	DTE 04-78	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-68	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-61	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	DTE 04-60	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Bay State Gas Company	01/93	Bay State Gas Company	DPU 93-14	Divestiture of Shelf Registration
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Divestiture of Shelf Registration
Michigan Public Service Commission				
Indiana Michigan Power Company	05/17	Indiana Michigan Power Company	Case No. U-18370	Return on Equity
Minnesota Public Utilities Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/17	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-17-285	Return on Equity
ALLETE, Inc., d/b/a Minnesota Power Inc.	11/16	ALLETE, Inc., d/b/a Minnesota Power Inc.	Docket No. E015/GR-16-664	Return on Equity
Otter Tail Power Corporation	02/16	Otter Tail Power Company	Docket No. E017/GR-15-1033	Return on Equity
Minnesota Energy Resources Corporation	09/15	Minnesota Energy Resources Corporation	Docket No. G-011/GR-15-736	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-15-424	Return on Equity
Xcel Energy, Inc.	11/13	Northern States Power Company	Docket No. E002/GR-13-868	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/13	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-13-316	Return on Equity
Xcel Energy, Inc.	11/12	Northern States Power Company	Docket No. E002/GR-12-961	Return on Equity
Otter Tail Power Corporation	04/10	Otter Tail Power Company	Docket No. E-017/GR-10-239	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Minnesota Power a division of ALLETE, Inc.	11/09	Minnesota Power	Docket No. E-015/GR-09-1151	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	11/08	CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-08-1075	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E-017/GR-07-1178	Return on Equity
Xcel Energy, Inc.	11/05	Northern States Power Company -Minnesota	Docket No. E-002/GR-05-1428	Return on Equity (electric)
Xcel Energy, Inc.	09/04	Northern States Power Company - Minnesota	Docket No. G-002/GR-04-1511	Return on Equity (gas)
Mississippi Public Service Commission				
CenterPoint Energy Resources, Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Mississippi Gas	07/09	CenterPoint Energy Mississippi Gas	Docket No. 09-UN-334	Return on Equity
Missouri Public Service Commission				
Union Electric Company d/b/a Ameren Missouri	12/18	Union Electric Company d/b/a Ameren Missouri	Case No. GR-2019-0077	Return on Equity
KCP&L Greater Missouri Operations Company	01/18	KCP&L Greater Missouri Operations Company	Case No. ER-2018-0146	Return on Equity
Kansas City Power & Light Company	01/18	Kansas City Power & Light Company	Case No. ER-2018-0145	Return on Equity
Laclede Gas Company and Missouri Gas Energy	11/17	Laclede Gas Company and Missouri Gas Energy	Case No. GR-2017-0215 Case No. GR-2017-0216	Goodwill Adjustment on Capital Structure
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	09/17	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	Case No. GR-2018-0013	New Ratemaking Mechanisms
Union Electric Company d/b/a Ameren Missouri	07/16	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2016-0179	Return on Equity (electric)
Kansas City Power & Light Company	07/16	Kansas City Power & Light Company	Case No. ER-2016-0285	Return on Equity (electric)
Kansas City Power & Light Company	02/16	Kansas City Power & Light Company	Case No. ER-2016-0156	Return on Equity (electric)
Kansas City Power & Light Company	10/14	Kansas City Power & Light Company	Case No. ER-2014-0370	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	07/14	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2014-0258	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	06/14	Union Electric Company d/b/a Ameren Missouri	Case No. EC-2014-0223	Return on Equity (electric)

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MANAGEMENT CONSULTANTS

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	02/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Case No. GR-2014-0152	Return on Equity
Laclede Gas Company	12/12	Laclede Gas Company	Case No. GR-2013-0171	Return on Equity
Union Electric Company d/b/a Ameren Missouri	02/12	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2012-0166	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	09/10	Union Electric Company d/b/a AmerenUE	Case No. ER-2011-0028	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	06/10	Union Electric Company d/b/a AmerenUE	Case No. GR-2010-0363	Return on Equity (gas)
Montana Public Service Commission				
Northwestern Corporation	09/12	Northwestern Corporation d/b/a Northwestern Energy	Docket No. D2012.9.94	Return on Equity (gas)
Nevada Public Utilities Commission				
Southwest Gas Corporation	05/18	Southwest Gas Corporation	Docket No. 18-05031	Return on Equity (gas)
Southwest Gas Corporation	04/12	Southwest Gas Corporation	Docket No. 12-04005	Return on Equity (gas)
Nevada Power Company	06/11	Nevada Power Company	Docket No. 11-06006	Return on Equity (electric)
New Hampshire Public Utilities Commission				
Northern Utilities, Inc.	06/17	Northern Utilities, Inc.	Docket No. DG 17-070	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	04/17	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 17-048	Return on Equity
Unitil Energy Systems, Inc.	04/16	Unitil Energy Systems, Inc.	Docket No. DE 16-384	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	04/16	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 16-383	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	08/14	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 14-180	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	03/13	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 13-063	Return on Equity
EnergyNorth Natural Gas d/b/a National Grid NH	02/10	EnergyNorth Natural Gas d/b/a National Grid NH	Docket No. DG 10-017	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital
New Jersey Board of Public Utilities				
Atlantic City Electric Company	10/18	Atlantic City Electric Company	Docket No. EO18020196	Return on Equity
Atlantic City Electric Company	08/18	Atlantic City Electric Company	Docket No. ER18080925	Return on Equity
Atlantic City Electric Company	06/18	Atlantic City Electric Company	Docket No. ER18060638	Return on Equity
Atlantic City Electric Company	03/17	Atlantic City Electric Company	Docket No. ER17030308	Return on Equity
Pivotal Utility Holdings, Inc.	08/16	Elizabethtown Gas	Docket No. GR16090826	Return on Equity
The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	04/16	The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	BPU Docket No. GM15101196	Merger Approval
Atlantic City Electric Company	03/16	Atlantic City Electric Company	Docket No. ER16030252	Return on Equity
Pepco Holdings, Inc.	03/14	Atlantic City Electric Company	Docket No. ER14030245	Return on Equity
Orange and Rockland Utilities	11/13	Rockland Electric Company	Docket No. ER13111135	Return on Equity
Atlantic City Electric Company	12/12	Atlantic City Electric Company	Docket No. ER12121071	Return on Equity
Atlantic City Electric Company	08/11	Atlantic City Electric Company	Docket No. ER11080469	Return on Equity
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EM06090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process
New Mexico Public Regulation Commission				
Public Service Company of New Mexico	12/16	Public Service Company of New Mexico	Case No. 16-00276-UT	Return on Equity (electric)
Public Service Company of New Mexico	08/15	Public Service Company of New Mexico	Case No. 15-00261-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 14-00332-UT	Return on Equity (electric)

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 13-00390-UT	Cost of Capital and Financial Integrity
Southwestern Public Service Company	02/11	Southwestern Public Service Company	Case No. 10-00395-UT	Return on Equity (electric)
Public Service Company of New Mexico	06/10	Public Service Company of New Mexico	Case No. 10-00086-UT	Return on Equity (electric)
Public Service Company of New Mexico	09/08	Public Service Company of New Mexico	Case No. 08-00273-UT	Return on Equity (electric)
Xcel Energy, Inc.	07/07	Southwestern Public Service Company	Case No. 07-00319-UT	Return on Equity (electric)
New York State Public Service Commission				
Consolidated Edison Company of New York, Inc.	01/15	Consolidated Edison Company of New York, Inc.	Case No. 15-E-0050	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	11/14	Orange and Rockland Utilities, Inc.	Case Nos. 14-E-0493 and 14-G-0494	Return on Equity (electric and gas)
Consolidated Edison Company of New York, Inc.	01/13	Consolidated Edison Company of New York, Inc.	Case No. 13-E-0030	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Electric Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Electric Service	Case No. 12-E-0201	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Gas Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Gas Service	Case No. 12-G-0202	Return on Equity (gas)
Orange and Rockland Utilities, Inc.	07/11	Orange and Rockland Utilities, Inc.	Case No. 11-E-0408	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	07/10	Orange and Rockland Utilities, Inc.	Case No. 10-E-0362	Return on Equity (electric)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-G-0795	Return on Equity (gas)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-S-0794	Return on Equity (steam)
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	Case No. 01-E-1046	Power Purchase and Sale Agreement; Standard Offer Service Agreement
North Carolina Utilities Commission				
Duke Energy Carolinas, LLC	08/17	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1146	Return on Equity
Duke Energy Progress, LLC	06/17	Duke Energy Progress, LLC	Docket No. E-2, Sub 1142	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Public Service Company of North Carolina, Inc.	03/16	Public Service Company of North Carolina, Inc.	Docket No. G-5, Sub 565	Return on Equity
Dominion North Carolina Power	03/16	Dominion North Carolina Power	Docket No. E-22, Sub 532	Return on Equity
Duke Energy Carolinas, LLC	02/13	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1026	Return on Equity
Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	10/12	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	Docket No. E-2, Sub 1023	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/12	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 479	Return on Equity (electric)
Duke Energy Carolinas, LLC	07/11	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 989	Return on Equity (electric)
North Dakota Public Service Commission				
Otter Tail Power Company	11/17	Otter Tail Power Company	Docket No. 17-398	Return on Equity (electric)
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/16	CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	Cause No. PUD201600094	Return on Equity
Oklahoma Gas & Electric Company	12/15	Oklahoma Gas & Electric Company	Cause No. PUD201500273	Return on Equity
Public Service Company of Oklahoma	07/15	Public Service Company of Oklahoma	Cause No. PUD201500208	Return on Equity
Oklahoma Gas & Electric Company	07/11	Oklahoma Gas & Electric Company	Cause No. PUD201100087	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Cause No. PUD200900055	Return on Equity
Pennsylvania Public Utility Commission				
Pike County Light & Power Company	01/14	Pike County Light & Power Company	Docket No. R-2013-2397237	Return on Equity (electric & gas)
Veolia Energy Philadelphia, Inc.	12/13	Veolia Energy Philadelphia, Inc.	Docket No. R-2013-2386293	Return on Equity (steam)
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a National Grid	02/19	The Narragansett Electric Company d/b/a National Grid	Docket No. 4929	Support for financial remuneration under new power purchase agreement
The Narragansett Electric Company d/b/a National Grid	11/17	The Narragansett Electric Company d/b/a National Grid	Docket No. 4770	Return on Equity (electric & gas)

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
The Narragansett Electric Company d/b/a National Grid	04/12	The Narragansett Electric Company d/b/a National Grid	Docket No. 4323	Return on Equity (electric & gas)
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
South Carolina Public Service Commission				
Duke Energy Carolinas, LLC	11/18	Duke Energy Carolinas, LLC	Docket No. 2018-319-E	Return on Equity
Duke Energy Progress, LLC	11/18	Duke Energy Progress, LLC	Docket No. 2018-318-E	Return on Equity
South Carolina Electric & Gas	08/18	South Carolina Electric & Gas	Docket No. 2017-370-E	Return on Equity
South Carolina Electric & Gas	12/17	South Carolina Electric & Gas	Docket No. 2017-305-E	Return on Equity
Duke Energy Progress, LLC	07/16	Duke Energy Progress, LLC	Docket No. 2016-227-E	Return on Equity
Duke Energy Carolinas, LLC	03/13	Duke Energy Carolinas, LLC	Docket No. 2013-59-E	Return on Equity
South Carolina Electric & Gas	06/12	South Carolina Electric & Gas	Docket No. 2012-218-E	Return on Equity
Duke Energy Carolinas, LLC	08/11	Duke Energy Carolinas, LLC	Docket No. 2011-271-E	Return on Equity
South Carolina Electric & Gas	03/10	South Carolina Electric & Gas	Docket No. 2009-489-E	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Company	04/18	Otter Tail Power Company	Docket No. EL18-021	Return on Equity (electric)
Otter Tail Power Company	08/10	Otter Tail Power Company	Docket No. EL10-011	Return on Equity (electric)
Northern States Power Company	06/09	South Dakota Division of Northern States Power	Docket No. EL09-009	Return on Equity (electric)
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)
Texas Public Utility Commission				
Texas-New Mexico Power Company	05/18	Texas-New Mexico Power Company	Docket No. 48401	Return on Equity
Entergy Texas, Inc.	05/18	Entergy Texas, Inc.	Docket No. 48371	Return on Equity
Southwestern Public Service Company	08/17	Southwestern Public Service Company	Docket No. 47527	Return on Equity
Oncor Electric Delivery Company, LLC	03/17	Oncor Electric Delivery Company, LLC	Docket No. 46957	Return on Equity
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Return on Equity
Southwestern Electric Power Company	12/16	Southwestern Electric Power Company	Docket No. 46449	Return on Equity (electric)
Sharyland Utilities, L.P.	04/16	Sharyland Utilities, L.P.	Docket No. 45414	Return on Equity
Southwestern Public Service Company	02/16	Southwestern Public Service Company	Docket No. 44524	Return on Equity (electric)

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Wind Energy Transmission Texas, LLC	05/15	Wind Energy Transmission Texas, LLC	Docket No. 44746	Return on Equity
Cross Texas Transmission	12/14	Cross Texas Transmission	Docket No. 43950	Return on Equity
Southwestern Public Service Company	12/14	Southwestern Public Service Company	Docket No. 43695	Return on Equity (electric)
Sharyland Utilities, L.P.	05/13	Sharyland Utilities, L.P.	Docket No. 41474	Return on Equity
Wind Energy Texas Transmission, LLC	08/12	Wind Energy Texas Transmission, LLC	Docket No. 40606	Return on Equity
Southwestern Electric Power Company	07/12	Southwestern Electric Power Company	Docket No. 40443	Return on Equity
Oncor Electric Delivery Company, LLC	01/11	Oncor Electric Delivery Company, LLC	Docket No. 38929	Return on Equity
Texas-New Mexico Power Company	08/10	Texas-New Mexico Power Company	Docket No. 38480	Return on Equity (electric)
CenterPoint Energy Houston Electric LLC	06/10	CenterPoint Energy Houston Electric LLC	Docket No. 38339	Return on Equity
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				
Atmos Energy Corporation – Mid-Tex Division	10/18	Atmos Energy Corporation – Mid-Tex Division	GUD 10779	Return on Equity
Atmos Energy Corporation – West Texas Division	06/18	Atmos Energy Corporation – West Texas Division	GUD 10743	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/18	Atmos Energy Corporation – Mid-Texas Division	GUD 10742	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	11/17	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10669	Return on Equity
Atmos Pipeline - Texas	01/17	Atmos Pipeline - Texas	GUD 10580	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	12/16	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10567	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	03/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10432	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/12	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10182	Return on Equity
Atmos Energy Corporation – West Texas Division	06/12	Atmos Energy Corporation – West Texas Division	GUD 10174	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/12	Atmos Energy Corporation – Mid-Texas Division	GUD 10170	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	12/10	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline – Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity
Vermont Public Service Board				
Central Vermont Public Service Corporation; Green Mountain Power	02/12	Central Vermont Public Service Corporation; Green Mountain Power	Docket No. 7770	Merger Policy
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)
Virginia State Corporation Commission				
Virginia Electric and Power Company	03/17	Virginia Electric and Power Company	Case No. PUR-2017-00038	Return on Equity
Virginia Natural Gas, Inc.	03/17	Virginia Natural Gas, Inc.	Case No. PUE-2016-00143	Return on Equity
Virginia Electric and Power Company	10/16	Virginia Electric and Power Company	Case No. PUE-2016-00112; PUE-2016-00113; PUE-2016-00136	Return on Equity
Washington Gas Light Company	06/16	Washington Gas Light Company	Case No. PUE-2016-00001	Return on Equity

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MANAGEMENT CONSULTANTS

Attachment A
Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Virginia Electric and Power Company	06/16	Virginia Electric and Power Company	Case Nos. PUE-2016-00063; PUE-2016-00062; PUE-2016-00061; PUE-2016-00060; PUE-2016-00059	Return on Equity
Virginia Electric and Power Company	12/15	Virginia Electric and Power Company	Case Nos. PUE-2015-00058; PUE-2015-00059; PUE-2015-00060; PUE-2015-00061; PUE-2015-00075; PUE-2015-00089; PUE-2015-00102; PUE-2015-00104	Return on Equity
Virginia Electric and Power Company	03/15	Virginia Electric and Power Company	Case No. PUE-2015-00027	Return on Equity
Virginia Electric and Power Company	03/13	Virginia Electric and Power Company	Case No. PUE-2013-00020	Return on Equity
Virginia Natural Gas, Inc.	02/11	Virginia Natural Gas, Inc.	Case No. PUE-2010-00142	Capital Structure
Columbia Gas of Virginia, Inc.	06/06	Columbia Gas of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy

Expert Reports

United States District Court, District of South Carolina, Columbia Division				
South Carolina Electric & Gas Company	07/18	South Carolina Electric & Gas Company	Case No. 3:18-CV-01795-JMC	Return on Equity
United States District Court, Western District of Texas, Austin Division				
Southwestern Public Service Company	02/12	Southwestern Public Service Company	C.A. No. A-09-CA-917-SS	PURPA and FERC regulations
American Arbitration Association				
Confidential Client	11/14	Confidential Client	Confidential	Economic harm related to failure to perform

REBUTTAL TESTIMONY

OF

ROBERT B. HEVERT

ON BEHALF OF

DOMINION ENERGY NORTH CAROLINA

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

DOCKET E-22, SUB 562

TABLE OF CONTENTS

I. INTRODUCTION

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

A. My name is Robert B. Hevert. I am a Partner at ScottMadden, Inc. ("ScottMadden"). My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts, 01581.

Q. Are you the same Robert B. Hevert that submitted Direct Testimony in this proceeding?

A. Yes, I am.

Q. Please state the purpose of your Rebuttal Testimony.

A. The purpose of my rebuttal testimony ("Rebuttal Testimony") is to respond to the Direct Testimony of Mr. Nicholas Phillips, Jr. on behalf of the Carolina Industrial Group for Fair Utility Rates I ("CIGFUR") as his testimony relates to the Virginia Electric and Power Company's (doing business in North Carolina as Dominion Energy North Carolina, also referred to as "DENC" or the "Company") Return on Equity ("ROE" or "Cost of Equity").

II. OVERVIEW OF REBUTTAL TESTIMONY

Q. Please provide a summary overview of the recommendations contained in your Rebuttal Testimony.

A. In my Direct Testimony I found the Company's Cost of Equity falls in a range of 10.00 percent to 11.00 percent. Within that range, I recommended an ROE of 10.75 percent.[1] I continue to believe both my recommendation and range are

[1] Direct Testimony of Robert B. Hevert, at 68.

reasonable and appropriate. As my Direct Testimony discussed, my ROE recommendation considers a variety of factors, including capital market conditions in general, and certain risks faced by DENC. Because the application of financial models and the interpretation of their results are often sources of disagreement among analysts in regulatory proceedings, I believe it is important to review and consider a variety of data points; doing so enables us to put in context both quantitative analyses and the associated recommendations.

Q. How is the remainder of your Rebuttal Testimony organized?

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

- Section III – Contains my response to Mr. Phillips; and
- Section IV – Summarizes my conclusions.

III. RESPONSE TO CIGFUR WITNESS MR. PHILLIPS

Q. Please summarize Mr. Phillips testimony regarding the Company's ROE.

A. Mr. Phillips opposes the Company's proposed ROE based on his review of authorized ROEs, as reported by Regulatory Research Associates ("RRA"), during the first half of 2019. Mr. Phillips reasons that because RRA reports the first half average authorized ROE to be 9.57 percent, the Commission should not authorize an ROE for the Company above that level.[2]

[2] Direct Testimony of Mr. Nicholas Phillips, Jr., at 19-20.

Q. Have you reviewed the 9.57 percent return Mr. Phillips discussed in his testimony?

A. Yes, I have. First, it appears the average return Mr. Phillips observes includes both vertically integrated and distribution-only electric utilities.[3] Because DENC is vertically integrated, the relevant measure is returns authorized for other vertically integrated electric utilities.

Second, because the average is skewed by outlying, or anomalous observations, it is important to consider the median result. From January through August 2019, there were eleven cases reported by RRA in which ROEs were authorized for vertically integrated electric utilities, including the unusually low 8.75 percent return authorized by the South Dakota Public Service Commission for Otter Tail Power.[4] The average return across those eleven cases was 9.61 percent, whereas the median was 9.73 percent. In my view, it is the median return for vertically integrated electric utilities – 9.73 percent – that is the relevant measure in this proceeding.

Q. Are there other distinctions that are important to consider when reviewing authorized returns?

A. Yes, there are. Utility credit ratings and outlooks depend substantially on the extent to which rating agencies view the regulatory environment as credit

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[3] *See*, S&P Global Market Intelligence, *RRA Regulatory Focus, Major Rate Case Decisions – January-June, 2019.*

[4] Please note, there were no reported returns for vertically integrated electric utilities from June through August 2019. In a similar fashion, the 2017 average was skewed upward by the 11.95 percent ROE authorized by the Regulatory Commission of Alaska for Alaska Electric Light and Power. *See*, Company Rebuttal Exhibit RBH-1.

supportive, or not. For example, Moody's finds the regulatory environment to be so important that 50.00 percent of the factors that weigh in its ratings determination are determined by the nature of regulation. Given the Company's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, it is important to consider the extent to which the jurisdictions that recently have authorized ROEs are viewed as having constructive regulatory environments.

Q. Have you reviewed the recently authorized returns as available through RRA?

A. Yes. As shown in Table 1 (below; *see also,* Company Rebuttal Exhibit RBH-1), I analyzed authorized ROEs for vertically integrated electric utilities based on each jurisdiction's ranking by RRA, which explains its ranking convention as follows:

> 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.[5]

North Carolina currently is ranked "Average/1", which falls approximately in the top-third of the 53 jurisdictions ranked by RRA.

[5] Source: Regulatory Research Associates, accessed August 28, 2019.

Across the 81 cases for which RRA reports an authorized ROE since 2016, there was a 45 basis point difference between the median return for jurisdictions ranked in the top third of all jurisdictions and jurisdictions ranked in the bottom third of all jurisdictions (the higher-ranked jurisdictions providing the higher authorized returns, *see* Table 1, below). As Table 1 indicates, authorized ROEs for vertically integrated electric utilities in jurisdictions rated in the top third of all jurisdictions range from 9.37 percent to 10.55 percent, with an average of 9.93 percent, and a median of 9.95 percent.

Table 1: Average Authorized ROE by RRA Ranking (2016 – 2019)[6]

Authorized ROE Vertically Integrated Electric Utilities				
RRA Ranking	**Overall**	**Top Third**	**Middle Third**	**Bottom Third**
Mean	9.74%	9.93%	9.40%	9.66%
Median	9.70%	9.95%	9.50%	9.50%
Maximum	11.95%	10.55%	9.60%	11.95%
Minimum	8.75%	9.37%	8.75%	9.30%
Count	81	41	18	22

Q. Has Mr. Phillips considered the effect of his recommendation on the Company's financial profile?

A. No, he has not. The financial community carefully monitors utilities' current and expected financial profiles, and the regulatory environment in which those companies operate. Here, Mr. Phillips suggests the Commission should reduce the Company's ROE by some unspecified amount without the benefit of

[6] Source: Regulatory Research Associates. "Top Third" includes Above Average/1,2,3 and Average/1; "Middle Third" includes Average/2; "Bottom Third" includes Average/3 and Below Average/1,2,3. Currently, the "Top Third" and "Bottom Third" groups each include 18 (of the 53 total) jurisdictions. The "Middle Third" group includes 17 jurisdictions. *See*, also Company Rebuttal Exhibit RBH-1. Excludes limited issue rider proceedings.

market-based, comparative analyses to support that recommendation. The consequence of doing so would indicate an increased degree of regulatory risk.

IV. CONCLUSIONS

Q. What is your conclusion regarding the ROE for DENC?

A. Mr. Phillips has not undertaken a market-based, comparative analyses to support his recommendation that DENC's ROE should be set no higher than 9.57 percent. Nor has Mr. Phillips considered the range of authorized returns in constructive regulatory jurisdictions similar to North Carolina, the currently unsettled capital market environment, or other factors that affect investors' return requirements. In short, Mr. Phillips' testimony has not caused me to revise my view that the Company's Cost of Equity falls in a range of 10.00 percent to 11.00 percent.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

In the Matter of:	)	
	)	**STIPULATION SUPPORT**
Application of Dominion Energy North	)	**TESTIMONY OF**
Carolina for Adjustment of Rates and	)	**ROBERT B. HEVERT FOR**
Charges Applicable to Electric Service in	)	**DOMINION ENERGY NORTH**
North Carolina		**CAROLINA**

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, AFFILIATION AND BUSINESS ADDRESS.

A. My name is Robert B. Hevert. I am a Partner of ScottMadden, Inc. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. ARE YOU THE SAME ROBERT HEVERT THAT SUBMITTED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted Direct and Rebuttal[1] Testimony before the North Carolina Utilities Commission ("Commission") on behalf of Virginia Electric Power Company, doing business in North Carolina as Dominion Energy North Carolina. ("DENC" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR STIPULATION SUPPORT TESTIMONY?

A. My Stipulation Support testimony supports the 9.75 percent Return on Equity ("ROE")[2] provided for in the Stipulation and Agreement of Partial Settlement dated September 17, 2019 (the "Stipulation") among the Company and Public Staff (together, the "Stipulating Parties"). The conclusions discussed in my Stipulation Support Testimony are supported by the data and analysis presented in Exhibit RBH-S-1 which, for convenience, replicates Company Rebuttal Exhibit RBH-1 to

[1] Rebuttal Testimony filed September 12, 2019 in response to "CIGFUR" Witness Mr. Phillips.
[2] I refer to the 9.75 percent ROE contained in the Stipulation as the "Stipulated ROE."

my Rebuttal Testimony filed in this proceeding on September 12, 2019. Exhibit RBH-S-1 has been prepared under my direction.

II. SUPPORT FOR THE STIPULATED RETURN ON EQUITY

Q. ARE YOU FAMILIAR WITH THE TERMS OF THE STIPULATION AS IT RELATES TO THE COMPANY'S RETURN ON EQUITY?

A. Yes, I am familiar with certain terms underlying the Stipulation. In particular, I understand the Stipulating Parties have agreed to the Stipulated ROE of 9.75 percent.

Q. IN GENERAL, DO YOU SUPPORT THE COMPANY'S DECISION TO AGREE TO THE STIPULATED ROE?

A. Yes, I do. In my Direct and Rebuttal Testimonies, I recommend an ROE within the range of 10.00 percent to 11.00 percent.[3] Although the 9.75 percent Stipulated ROE is somewhat below the lower bound of my recommended range, I understand the Stipulation reflects negotiations among the Stipulating Parties regarding multiple issues. I further understand the Company believes the terms of the Stipulation, taken as a whole, would be viewed by the financial community as constructive and equitable. I appreciate and respect that determination.

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[3] See, Direct Testimony of Robert B. Hevert, at 4; Rebuttal Testimony of Robert B. Hevert dated September 12, 2019, at 3.

Q. PLEASE NOW SUMMARIZE YOUR ASSESSMENT OF THE STIPULATED ROE.

A. Although it falls somewhat below my recommended range, the Stipulated ROE generally is within the ranges of analytical results presented in my Direct and Rebuttal Testimonies. As discussed in those Testimonies, the unsettled capital market environment adds considerable complexity to estimating the Cost of Equity. Given that complexity and uncertainty, it remains my position that in a fully litigated proceeding, 10.00 percent to 11.00 percent represents an appropriate and defensible range of the Company's Cost of Equity. Nonetheless, I recognize the benefits associated with the Company's decision to enter into the Stipulation. On balance, it is my view that the Stipulated ROE is a reasonable resolution of a complex and frequently contentious issue.

Q. HAVE YOU CONSIDERED THE STIPULATED ROE IN THE CONTEXT OF AUTHORIZED RETURNS FOR OTHER VERTICALLY INTEGRATED ELECTRIC UTILITIES?

A. Yes, I have. As shown in Exhibit RBH-S-1, since January 2016 the average authorized ROE for vertically integrated electric utilities was 9.74 percent, only one basis point from the Stipulated ROE.[4] More recently, the median ROE authorized in 2019 has been 9.73 percent, just two basis points from the Stipulated ROE. From a somewhat different perspective, Regulatory Research Associates ("RRA"), which

[4] Please note, RRA reports no cases for vertically integrated electric utilities between June and August 2019.

is a widely referenced source of rate case data, provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not. As RRA explains:

> 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.[5]

Within that ranking system, North Carolina is rated "Average/1", which falls in the approximate top one-third of the 53 regulatory commissions ranked by RRA.[6] Across the 81 electric rate cases summarized in Exhibit RBH-S-1, the mean and median authorized ROEs were 9.93 percent and 9.95 percent, respectively, in jurisdictions that, like North Carolina, are rated at least Average/1. Those results are consistent with, although somewhat higher than, the Stipulated ROE.

Q. DOES THE STIPULATED ROE GENERALLY FALL WITHIN THE RANGE OF YOUR MODEL RESULTS?

A. Yes. Although it falls below the Risk Premium model results, the Stipulated ROE percent falls at about:

[5] Source: Regulatory Research Associates.

[6] Source: Regulatory Research Associates. Of the 53 jurisdictions, 18 are ranked "Average/1" or higher.

- The 69th percentile of the mean and median Constant Growth Discounted Cash Flow ("DCF") results provided in Exhibit RBH-1;[7]
- The 32th percentile of the Capital Asset Pricing Model ("CAPM"), and Empirical CAPM results provided in Exhibit RBH-4; and
- The 40th percentile of Expected Earnings analysis results provided in Exhibit RBH-6.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THOSE ANALYSES AND RESULTS?

A. First, the Stipulated ROE is supported by returns authorized in other jurisdictions, including those whose regulatory climates are comparable to North Carolina. That finding is important, given the Company's need to compete for capital with other electric utilities. Second, although it is toward the lower end, 9.75 percent generally falls within the range of my model results. Together, those observations support my conclusion that the Stipulated ROE, in the context of the overall Stipulation, is a reasonable outcome. As noted earlier, however, in a fully litigated proceeding I would continue to support my recommended range.

[7] Based on the mean and median results presented in columns 10, 11, and 12 for the 30, 90, and 180-day average stock price calculations. The cited exhibits refer to my Direct Testimony filed March 29, 2019.

Q. LASTLY, DOES YOUR TESTIMONY IN THIS PROCEEDING, INCLUDING YOUR SUPPORT FOR THE STIPULATED ROE, CONSIDER ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. Yes, it does. As explained in my Direct Testimony, I understand and appreciate the Commission's need to balance the interests of investors and ratepayers, and to consider economic conditions in the State, as it sets rates. I therefore reviewed several measures of economic conditions and found that North Carolina, and the counties contained in the Company's service area, have experienced significant improvement over the past several years, with further improvement expected in the future.[8] From that perspective as well, I believe the Stipulated ROE is a reasonable outcome.

Q. DOES THIS CONCLUDE YOUR STIPULATION SUPPORT TESTIMONY?

A. Yes, it does.

[8] Direct Testimony of Robert B. Hevert, at 48-58.

BY MS. KELLS:

Q Mr. Hevert, do you have a summary of your testimonies with you today?

A Yes, I do.

Q Would you please now present that for the Commission?

A Yes. Thank you. Chair Mitchell, members of the Commission, the purpose of my direct testimony is to estimate and provide a recommendation regarding the Company's return on equity, sometimes referred to as the ROE or cost of equity. My testimony discusses the financial models used to estimate the cost of equity and addresses other often qualitative issues that are important in developing ROE recommendations. In particular, I discuss capital market conditions and the effect of those conditions on the return that investors require to accept the risk of equity ownership. My testimony also addresses business risks facing utilities such as Dominion Energy North Carolina and the importance of maintaining a financial profile, enabling access to long-term capital during both accommodating and constrained markets. Based on those analyses and considerations, I initially recommended a range of 10 percent to 11 percent, with a specific ROE recommendation of 10.75 percent.

As my direct testimony explains, every model used to estimate the cost of equity is subject to limiting assumptions and constraints. I note that no single method best approximates investor behavior at all times and under all market conditions. It therefore remains important to apply multiple models and to assess the extent to which their fundamental assumptions align with prevailing and expected market conditions.

My rebuttal testimony -- excuse me -- responds to the testimony of CIGFUR Witness Phillips. I note that the median authorized ROE in 2019 for electric utilities that own and operate electric generating assets, as Dominion Energy North Carolina does, has been 9.73 percent. I also explain that since 2016, the mean and median ROE authorized in jurisdictions considered to have relatively constructive regulatory environments similar to North Carolina has been about 9.95 percent.

My Stipulation testimony discusses my support for the 9.75 percent stipulated ROE. My testimony recognizes that the Stipulation with Public Staff represents the give and take regarding multiple otherwise contested issues, and that the Company believes the Stipulation, taken as a whole, would be viewed by the financial community as constructive and equitable. I appreciate and respect that determination.

As did my rebuttal testimony, my Stipulation support testimony noted that in 2019, the median authorized ROE for vertically integrated electric utilities has been 9.73 percent, and returns authorized by relatively constructive jurisdictions since 2016 has been about 9.95 percent. My testimony also explains that the stipulated ROE generally falls within the range of my analytical results, although toward the low end.

I also support the Stipulation entered into by the Company and CIGFUR filed today in this proceeding for the same reasons discussed in my Stipulation support testimony in support of the Stipulation with Public Staff.

Lastly, I appreciate that in setting the Company's rates, the Commission must balance the interests of customers and investors. I understand that in doing so the Commission considers the effect of changing economic conditions on customers. My direct testimony therefore provided several analyses reviewing economic conditions in the U.S. generally, in North Carolina specifically, and where possible in the Company's service territory. Those analyses indicate that North Carolina and the counties contained in the Company's service territory have experienced significant economic improvement over the past several years.

Thank you, and that concludes that my summary.

MS. KELLS: The witness is available for cross exam.

MS. HARROD: Chair Mitchell, I think the Attorney General's Office may be the only party asking questions of this witness; is that correct? Okay.

CROSS EXAMINATION BY MS. HARROD:

Q Good afternoon, Mr. Hevert. Jennifer Harrod on behalf of the Attorney General's Office. How are you?

A I'm -- I'm well. It's nice to see you.

Q Nice to see you. I would like to talk to you about some of your analytical models that you've used in this case, and let's start with the capital asset pricing model which is often referred to as the CAPM. And your testimony begins the analysis of that model on page 26. I'm also going to make use of your Exhibit RBH-4 and RBH-2, as I recall.

MS. HARROD: Actually, if -- if I can, I've got our -- our documents fairly well organized, so if Ms. Force can go ahead and distribute those, Chair.

CHAIR MITCHELL: She may.

MS. HARROD: Thank you.

Q All right. While Ms. Force distributes that, I'm just going to start setting the table to make sure you and I have a shared understanding of what we're talking about. So the CAPM model measures how much return an investor would require for the risk associated with a particular investment. Is that a pretty fair summary?

A That -- that is a fair summary, yes.

Q Okay. Thank you. And there are, as I understand it, three inputs to that model, that a person who wishes to make that estimate needs to decide what values they're going to use for those inputs. So there's -- there's a risk-free return that we all must face when we invest in the equities market. There is a market risk premium that is designed to measure the overall risk of the -- in this case, the United States equities market, correct, and then there's a -- a beta coefficient that's designed to capture the risk of the particular investment that we're trying to measure; is that fair?

A I think that's generally fair. The risk-free rate, I think we're saying the same thing, is just the return available absent any risk, absent default risk or equity risk or anything else. So, yes, I think we generally agree.

Q Thank you. So the arithmetic on that, if we would turn to your Exhibit RBH-4 to just talk about how we put those three factors together, you've got your chart which has a lot of numbers on it, and so I'm going to pull out three of the numbers just to go through the basic arithmetic.

So I'm going to -- I'm going to pull out from the -- from RBH-4. Are you there?

A I'm sorry. Yes. I'm there.

Q No problem. I'm going to pull out your Ex-Ante Market Bloomberg -- Mark--- sorry -- Ex-Ante Market Risk Bloomberg Market DCF derived number which is 10.65 percent. So that is one of your values for the market risk, correct?

A Yes. That is one estimate of the market risk premium, yes.

Q Okay. And I'm going to stick with that top line in your chart there, so I'm going to then note that you have an average beta coefficient -- one of the average beta coefficients used in your modeling is .90 (sic), and that's the measure of the risk of the particular investment we're looking at, correct?

A I don't think that's right. It's .490?

Q So sorry.
A That's okay.
Q .490. That's why we have to have the paper in front of us. Okay. So then we have the risk-free rate which we were just talking about of, again, using this first line, 3.04 percent.
A Correct.
Q Okay. So the arithmetic on that is that we're going to multiply the market-risk premium of 10.65 percent by the beta coefficient of .49 perc--- .49, and that gives us a number of 5.21. Glad you have your calculator.
A Yes.
Q And then we're going to add that to the risk-free rate that you're using in this particular iteration of the model of 3.04 percent, and we're going to walk across the chart under the Bloomberg Market DCF Derived CAPM result, and we're going to see that the answer is 8.25 percent, correct?
A Correct.
Q Okay. I just wanted to get the arithmetic out of the way. So let's talk about the beta and how you derive the beta a little bit. An asset that has the same risk as the market overall would have a beta of 1.0,

right?

A It would, yes.

Q Okay. So a stock that's more risky than the market overall has a beta of greater than 1, and a stock that's less risky than the market overall has a beta of less than 1, correct?

A Correct. That is where we define risk by reference to the variability of returns, but, yes, that's right.

Q Okay. So in order to derive the beta values that you use in your CAPM analysis, that's summarized on the chart, the Exhibit RBH-3, correct?

A It is, yes.

Q Okay. And in your testimony it states that you use two data sources. You used Bloomberg and you used Value Line as your -- as your sources for the beta, correct?

A That's right.

Q And you have a chart there that shows the betas from those two sources for the 22 companies that are in your proxy group.

A Exhibit 3.

Q On Exhibit 3, correct. And you didn't -- you didn't derive these individual beta numbers that are on this chart. These were somebody else's analysis, correct?

A I'm not sure what you mean by someone else's analyses. These were from two sources, Bloomberg and Value Line, but if your question is did Bloomberg and Value Line respectfully calculate the beta coefficients, then, yes, that's -- that's what happens.

Q That was my question. Thank you.

A Okay.

Q So, for instance, if we take the beta for Duke Energy Corporation, Bloomberg's beta for that is .437, and that's not -- that's not a number you -- that's not your analysis; that's a number you took from Bloomberg?

A Right. Bloomberg -- and I should say this is Bloomberg's default calculation. You can calculate beta coefficients any number of ways, but Bloomberg typically provides a default calculation, and that's what we use for this purpose.

Q Okay. And in your testimony it states that Bloomberg uses two years of data in its analysis and Value Line uses five years of data in its analysis, correct?

A It does. That's right.

Q Okay. And so I notice that the Bloomberg number is 10 percentage points lower than the Value Line number, for instance.

A It -- it is lower, .49 relative to .59, yes.

Q Okay. Now, in your -- in your models you used the mean of those numbers rather than the median. Can you explain why you made that choice?

A I do. It's a fairly large data set, and when you look at the data itself, there's not a lot of variability within them. We certainly could look at the median if we wanted to, but for this purpose we've typically used the mean.

The other point is, of course, we're looking at two data sources, and as you correctly pointed out they're two different calculations. They calculate beta coefficients over two and five years respectively. So we think using the average here, using the mean is a good measure of central tendency for that purpose.

Q Okay. And so as I understand it, a person would often choose to use the median when there are outliers and you want to pick the number in the middle rather than necessarily having the outliers bring your total either up or down?

A You could. That's right. And in other areas of my testimony I do focus on the median for exactly that purpose. Here I think we have an interesting situation with the calculation of beta coefficients simply because of the way the utility sector traded relative to the overall market. Around the time that the Tax Cut and Jobs Act was enacted, the utility sector started trading considerably differently than the overall market. And one of the two things that beta coefficients measures is the correlation in return, so when that correlation falls off, the beta coefficients become lower. That effect was unusual. And so you could use a median, but in my view I think it's important to recognize the difference in beta coefficients between Bloomberg and Value Line and to understand why that happened. So in my view, the mean was proper for that purpose.

Q All right. Well, let me just -- let me just make an observation that if we just take the Value Line numbers, leaving the Bloomberg numbers out, most of those numbers are .5, .6 range. There were three numbers that are pretty far outside of that range. I think it's 175, 185 -- 1.75, 1.85, and 1.75. I cal--- I did -- looks to me like the median of those, just taking the Value Line numbers as .55 rather than .59. Does that look right to you?

A That could be. I think you were talking about outliers. I don't think you talked about the .4 outlier to the downside.

Q Sure.

A But that's right. It would be a .55. This is the other issue with Value Line. They round their beta coefficients, as you can see, to the nearest .05.

Q And so given that your market-risk premiums are 10.65 and 13.77, when you use .55 as opposed to .59, it reduces the basis points -- and you've got your calculator up there so don't take my word for it -- but if you use 10.65 in the calculation, causes the CAPM analysis to drop by 43 basis points. Do you agree with me?

A I'm sure you are right.

Q Well, I --

A Let me check.

Q -- I would never presume to tell you how to do math.

A That's very close, yes.

Q Okay. And, likewise, using your 13.77 market-risk premium, if you use the median of the -- just taking the Value Line numbers and not the mean, it reduces the CAPM result by 55 basis points.

A I'll take that.

Q Okay. Okay. So now let's talk about how you derived your market risk premium. This is, in general, a concept, it measures the overall risk of the market in question. Here we're talking about the United States stock market. And would you agree that this is -- no, we're not -- I'm sorry -- your -- your facial expression suggests maybe you don't agree with me.

A No, no, no --

Q It's the S&P 500.

A I'm sorry. Can you start over?

Q Sure. What I said was, is that the effort here in this market risk premium is to estimate the overall risk of the U.S. stock market.

A I would put it slightly differently. It's to measure the return required in excess of the risk-free return to invest in the stock market.

Q Okay. Thank you. So this is a -- this is a number that's, in general, of interest to investors; is that correct?

A I would agree with that, yes.

Q And so accordingly, there are multiple analysts that develop market risk premium analysis?

A There are. There certainly are analysts, there are academics. There are all sorts of approaches.

That's correct.

Q Okay. And, for instance, Dr. Woolridge, who submitted prefiled testimony on behalf of the Public Staff in this matter, he relied -- he found credible an analysis by Duff & Phelps and their investment advisors, correct?

A Yes. I think that's right. And the reason I'm hesitating is because Duff & Phelps has a number of different methods for calculating risk premia, but Dr. Woolridge typically does look at one of those.

Q Okay. And so have you -- you've reviewed Dr. Woolridge's testimony and exhibits in this -- in this matter?

A I have, yes.

Q Okay. And so you're aware that his market risk premium is quite a bit different from yours?

A I am aware of that, yes.

Q Okay. We're not going to spend a lot of time with Dr. Woolridge's testimony, but I just -- he -- if we look at page 76 in his testimony -- do you have it with you?

A His full testimony?

Q Yes.

A I do --

Q His prefiled?
A No. I do not.
Q Okay. I don't -- sorry to say I don't have --
MS. KELLS: I have a copy if I can approach.
CHAIR MITCHELL: Yes.
MS. HARROD: Thank you.
A That was page 76?
Q Correct. So over the preceding several pages he discusses in general what types of studies and surveys are available on the market risk premium, and then he says that -- at the top of page 76. Are you with me?
A Yes. I'm there.
Q Okay. So he says that after looking at all -- at all of these studies, he -- they suggest that the appropriate market risk premium in the U.S. is in the 4 to 6 percent range, and then he says that he's going to use a market risk premium of 5.5 percent in the upper end of his range.
A Right. And --
Q Okay.
A Yes. I'm sorry. Yes.
Q No, no. That's --
A And he produced cost of equiny (ph.) -- excuse me -- cost of equity estimates of 7.3 percent and 7.2

percent which are -- I'll call it 150 basis points below his recommended return of 8.75 percent, so it's difficult for me to see how much weight Dr. Woolridge gave those estimates.

Q So if you -- in the top of your packet just for reference we've included something that's already in evidence. It's JRW-8, one of Dr. Woolridge's exhibits. And it provides a chart of the different analyses that he looked at and provides the -- the median for those different categories of analysis.

A It does.

Q Okay. So Dr. Woolridge used a 5.5 percent market risk premium after reviewing a number of studies that were done by others. What market risk premium did you use in your model?

A Well, you -- I think we went over them a minute ago -- 10.65 percent and 13.77 percent.

Q Okay. So one of them almost double, and the other one more than double. How --

A Double Dr. Woolridge's --

Q Correct.

A -- that he didn't seem to use? Yes. That's right.

Q So let's talk about how you -- how you arrived at those two numbers. If we turn to your Exhibit RBH-2 --

A RBH-2?

Q Yes.

A Yes. I'm there.

Q So you performed your own study in order to determine the market risk premium, correct?

A That's right.

Q Okay. And this is not a study that's published anywhere or is available to investors, correct?

A I'm not sure I fully agree with that. The data certainly is available to investors. The methodology is well known by investors. Investors certainly can undertake this type of analysis. So if your question is is my study readily available to investors, I -- I don't suppose everybody looks at my study for that -- I don't suppose that's true, but the data underlying it and the method underlying it certainly is available.

Q Okay. But you haven't relied on anybody else's calculation using DCF and expected earnings in your testimony. You've relied on the study that you, yourself, performed?

A Right. And that's correct, based on the data provided by Bloomberg and Value Line respectively.

Q Okay. So looking at RBH-2, it looks like for the growth -- for the growth term in the DCF analysis that you performed you relied on -- on growth of earnings, correct?

A Yes. That's correct.

Q And those are projected earnings growth; they're not historical values?

A Yes. That's correct.

Q Okay. And there's no other growth -- there's no other estimate of growth other than the projected growth in earnings in your analysis, correct?

A Yes. That's correct. I should say growth rates from Bloomberg are earnings only. Of course, Value Line provides other measures as well.

Q Is that right? I don't think you provided your Value Line calculation.

A Oh, I didn't do a calculation based on other measures. I just said Value Line does provide other growth rates. I don't use them.

Q I see. So -- yeah. So right now we're just talking about your CAPM analysis. So -- and for the moment I'm looking at the one that you used with the Bloomberg data which is represented by RBH Exhibit 2, okay?

A Okay.

Q All right. So as I understand it, you performed a discounted cash flow analysis and made an estimate for -- to -- for every company for which long-term earnings per share growth was available, you estimated that earnings per -- that projected earnings per share growth, and then you weighted it based on market capitalization?

A Correct.

Q Okay. And at the top of the very first page of RBH-2 there's -- it says "S&P 500 estimated required market return 13.68 percent," correct?

A Correct.

Q Okay. So if I understand what this -- what this model is capturing, you're saying that for an investor to invest in the market in the S&P 500, they're going to require 13.68 percent return over the long term?

A That -- that's right. And if you look at that 13.68 percent, the historical arithmetic average return on the market is about 12 percent. The standard deviation is about 19 percent. So 13.68 is well within the range of historical experience.

Q And so then in order to get to that actual market risk premium you back out the risk-free rate that you're using in that particular instance of 3.04 and you get to the implied market risk premium of 10.65, correct?

A Yes. That's correct.

Q And that's what gets plugged into your RBH-4 that we were looking at?

A It is.

Q Okay. And if we look at RBH-4, your Value Line -- the analysis you did using Value Line's expected earnings growth rate information is a market risk premium of 13.77 percent, correct?

A Correct.

Q So at the low end, if we take the Bloomberg results and the current 30-year Treasury yield of 3.04 percent, your analysis is saying that -- it's predicting market returns of 13.68 long term?

A I'm sorry. So I think we're saying the same thing --

Q Uh-huh.

A -- that based on the Bloomberg data, the expected market return is 13.68 percent?

Q Okay.

A Yes.

Q And then at the high end, if we take your -- your market risk premium that you derived using the Value

Line expected earnings and the projected 30-year Treasury of 3.25 percent, if we add those two numbers together at the high end, that is 17.02 percent; is that right? You could feel free to calculate it.

A Yes. Correct.

Q Okay. Is this the same or similar method that you used in the -- in other testimony that you have given here, the recent -- most recent case being the Piedmont rate case?

A It is.

Q But also the Duke Energy Progress rate case from a couple years back?

A Correct.

Q Okay. And this has been disregarded by this Commission in the past as being upwardly biased and unreliable, correct?

A In each case has it been dismissed? Is that your question?

Q Well, specifically, I was speaking about the Duke Energy Progress general rate case.

A I don't recall that. I'm sure you're -- do you have that with you?

Q I don't have a copy -- I don't have a copy of it here with me, but I -- but I would like to ask the

Commission to take judicial notice of its order in that case, that is E-2, Sub 1131, 1142, 1103, and 1153.

MS. KELLS: So are we actually talking about how many?

MS. HARROD: Sorry. Let me be more specific.

MS. KELLS: You said the most recent which was --

MS. HARROD: Yes, yes, yes.

MS. KELLS: -- 1142, so...

MS. HARROD: What I -- let me be more specific. What I'm asking the Commission to take judicial notice of is its Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, and it's got all those docket numbers at the top of it. It's -- okay. It's the -- yeah. Ms. Force is helping me out here. It's the 11 -- it's E-2, Sub 1142, is the -- is the rate case docket number.

CHAIR MITCHELL: Hearing no objection, judicial notice shall be taken.

Q Okay. So I would quote from that Order. See if this sounds familiar to you, Mr. Hevert. It says "Witness Hevert's risk premium component of this CAPM uses a constant growth DCF for the S&P companies, using analyst projected earnings per share forecast as the growth component. Witness Hevert's DCF dividend growth component based solely on analyst earning per share growth projections, without consideration of any historical results, is upwardly biased and unreliable."

MS. KELLS: Well, object. If you -- do you have a copy that he can look at?

MS. HARROD: I don't have a copy for everybody, but I do have a copy.

MS. KELLS: That would be good. Thank you.

MS. HARROD: May I approach?

CHAIR MITCHELL: You may.

Q Let's see. Let me find you that page reference. It's on page 85.

A I almost guessed it. So as I look at page 85, the Commission gave no weight to any of the witnesses' CAPM analyses. Is that the paragraph you were on?

Q Correct. Yes. That is true.

A Okay.

Q And so you notice that the Commission found the use of a DCF analysis with only using dividend growth based on earnings per share projections, without consideration of any historical results, being upwardly biased and unreliable?

A I do, and I do think when we look at the entirety of that paragraph, we were talking a little bit earlier about the 9, excuse me, 7.2 and 7.3 percent estimates based on the historical data that you are discussing. That seems to have fallen in the range of about the 7.56 percent which the Commission found to be an outlier and unrealistically low as well.

Q And so in addition, if you look at that same paragraph of the Order, it also notes that the use of near-term projected 30-year interest rates caused the CAPM rates to be upwardly biased as well; isn't that correct?

A Yes. Now, that's an interesting point. I think if we were to go back to Exhibit 4, here we see about a 21 basis point difference between the current and projected Treasury yields. There's not a material difference between the two.

Secondly, I think in this case, as in the last, the Capital asset pricing mode results and looking only at the current yield tend to be within the range of my recommendation. So it's true the projected yield is part of the analysis, but the current yield also -- excuse me -- the CAPM results based on the current yield also support my recommendation.

Q Let me ask you to turn to the next document in that short stack I handed you. It's --

MS. HARROD: Chair Mitchell, if -- it's -- if we could ask to have this marked AGO Hevert Cross Examination Exhibit Number 1. This is the -- this is the Final Order entered in -- by the Commonwealth of Virginia State Corporation Commission, Application of Virginia Electric and Power Company for a Determination of the Fair Rate of Return on Common Equity to be Applied to its Rate Adjustment Clauses.

CHAIR MITCHELL: The document shall be so marked.

MS. HARROD: Thank you.

(Whereupon, AGO Hevert Cross Examination Exhibit Number 1 was marked for identification.)

Q Mr. Hevert, I believe you testified on behalf of Virginia Electric and Power Company as to the return on equity in this matter, did you not?

A I did, yes.

Q Okay. Just going to turn to page 5 of the Order --

A Okay.

Q -- where at the top of the page above the footnotes, the Virginia Commission stated that "The

Company's capital asset pricing model is also flawed. For example, the Company's highest ROE estimates result from the use of a 2019 projected 30-year Treasury bond yield of 4.2 percent and a 2021 projected 30-year Treasury bond yield of 4.4 percent." And then they go on to say -- I'm going to skip a sentence -- and say "In addition, the Company exclusively used earnings per share as the measure of long-term growth to develop the market risk premium component of its CAPM analysis which results in an overstatement of the cost of equity." Is that a similar analysis to the analysis you used on behalf of Dominion in this case?

A It did. Excuse me. It is. I think we have to keep in mind the differences between the market in 2017 and this market right now. Here we have a market where the 30-year Treasury yield fell 71 basis points in 34 trading days. In over 3,000 observations that's happened 50 times. And so I think using projected yields, especially in this case where there's a 24 -- excuse me -- 21 basis point difference between the current and projected yields, gives an important perspective. I don't think anyone would look at a Treasury yield that fell by 71 basis points in such a short period of time and say that that is the Treasury yield we ought to use for the forward looking cost of equity.

So I agree that's what the Commission said in 2017. 2019 is a fundamentally different market, and I do think the projected Treasury yields here give us some very important information.

Q Well, you submitted your testimony in this case in March of 2019. Are the projected Treasury yields higher or lower than they were at the time you submitted your testimony?

A I'm sorry. What was your question?

Q Today as we sit here --

A Yeah.

Q -- compared to when you submitted your testimony in March, did you look to see whether the Treasury yields are lower or higher?

A Oh. I thought you said the projected Treasury yields, so I -- I'm not quite sure.

Q I may have.

A Okay. The -- that's exactly my point. The Treasury yields are much lower now, and I think at this point, since you brought up this Order from 2017, I think it's important for us to consider that the market is extraordinarily volatile right now and that the use of projected yields are important.

In March of 2019 did anyone think that the Treasury yield would go from 3 percent to 1.94 percent? No. That was event driven. And I don't think investors established their forward-looking cost of equity based on events.

Q So in addition to the criticism of the use of projected Treasury bond yields, you see the Virginia Commission also finds that the use of earnings per share as the measure of long-term growth results in an overstatement of the cost of equity?

A It does, and I think this Commission also has found that even when you use earnings growth rates only, the constant growth discounted cash flow model can produce unrealistically low estimates. So, yes, I agree that's what the Commission in Virginia has said. I think this Commission has found that the constant growth discounted cash flow model, even using only earnings estimates, can produce unreasonably low ROE calculations.

Q Actually, when you look at -- if you look back at that order by this Commission in the DEP case that I handed you, page 85 again, the last sentence of the first full paragraph --

A Yes.

Q -- it says "Witness Hevert's DCF dividend growth" -- I think there's a -- "dividend growth component based solely on analyst earnings per share growth projections, without consideration of any historical results, is upwardly biased and unreliable."

A Right. And if you go to the preceding paragraph, the last sentence there, it reads "The Commission determines that all of these DCF analyses in the current market produce unrealistic low results."

Q Uh-huh. So let's talk about your -- you also use a variant of CAPM that you call the ECAPM.

A Yeah.

Q Let's talk about that just for a minute.

A Sure.

Q So for low cost -- sorry -- low risk stocks, such as utilities that have a beta of less than one, your ECAPM analysis is mathematically guaranteed to always be higher than your CAPM analysis, correct?

A Right. The -- what the model does is it recognizes the fact that historically, the capital asset pricing model tends to underestimate returns for low beta companies and overestimate returns for high beta companies.

Q So your model takes 25 percent of the market risk component and does not apply a beta to that, so it's just your straight up either 10.65 market risk premium or your 13.77 market risk premium without -- without multiplying it by that -- by that beta coefficient?

A And it takes a portion of that, correct.

Q I think -- yes. Twenty-five (25) percent, correct?

A Twenty-five percent, correct.

Q Yes. So if the Commission were to find in this case that your CAPM model which uses only projected earnings per share growth for the growth factor were upwardly biased, that finding would apply equally to your ECAPM model as well?

A Well, if your question is would -- if the Commission were to find that the method by which the market risk premium is calculated under the capital asset pricing model isn't appropriate, would that finding apply to the empirical capital asset pricing model, then, yes, I suppose that's true.

I think what this model does is two things. It sort of shifts up the intercept, so it says that if beta is zero, the required return is somewhat higher than the risk-free rate, but as you move out, as you become more risk, as you add more risk, as -- through higher beta coefficients the incremental return required is less. So if you can imagine a line, it sort of shifts up the intercept, but it makes the line flatter. And we've shown empirically that that's, in fact, true for low beta coefficient companies.

Q But it's -- but the point -- the question on the table, though, is that it -- it's essentially the same analysis except just guaranteed to be higher?

A I -- I'm not sure I -- for low beta coefficient companies the result would be higher. The premise of the model is that the result would be more accurate, and it would be more accurate because of the capital asset pricing model's propensity to underestimate the return for low beta coefficient companies.

Q Okay. But it -- but it presumes -- it uses the same market risk premium that you derived on your own using the Bloomberg and the Value Line data?

A That's right, it does.

Q Okay.

A Yes.

Q Okay. So let's turn to the discounted cash flow model --

A Okay.

Q -- that you used, and it has two primary inputs for it, also. There's the dividend yield which is adjusted by a multiplier to account for the fact that Companies issue dividends at different points in the year, and then there's a growth factor.

A Correct.

Q And we've -- we've already more or less been talking around that because your CAPM model has a DCF calculation built into it.

A It does.

Q Okay. And so as with your CAPM model, the growth factor that you use in just the plain straight-up DCF model represents long-term growth, correct?

A It does.

Q Okay. And, again, for that model you chose to use only earnings per share growth as your only growth factor, correct?

A I do under the model, but the way the model works is that the growth rate, if you hold all the model's assumptions true, the growth rate equals the rate of capital appreciation, that is, it equals the rate at which the stock price will grow in value over time. So if we look at what is the most common measure that investors use to look at the value of stock, things like price-to-earnings ratios, we can understand that earnings are important to investors and that growth in earnings is what drives growth in the stock price, so that's why I believe the earnings growth rate is the proper measure.

Q And as we've seen, that's been criticized both by this Commission in the DEP Order and also by the Virginia Commission in the Order that's represented by Attorney General Exhibit Number 1. And the next exhibit in your stack is a Final Decision and Order entered in -- entered by the Public Utilities Commission of the State of South Dakota in the Matter of the Application of Otter Tail Power Company for Authority to Increase its Electric Rates.

A Right.

MS. HARROD: Chair Mitchell, can we have that marked as Attorney General Hevert Cross Examination Exhibit 2?

CHAIR MITCHELL: The document shall be so marked.

(Whereupon, AGO Hevert Cross Examination Exhibit Number 2 was marked for identification.)

Q So did you perform a similar analysis in this rate case as you performed in the present rate case that we're -- sorry. That was too many -- too many pronouns.

A That's okay.

Q In the Otter Tail rate case did you perform a similar discounted cash flow analysis that you performed here for Dominion North Carolina?

A Well, the Otter Tail case had -- had a lot of issues that have not arisen in this -- in this case and quite frankly, that have not arisen in cases in North Carolina with which I am familiar, but the general approach of using earnings growth rates is, yes, that's exactly what I did.

Q Right. I'm just focused on your DCF analysis, not the other issues in the case at this time.

A Okay.

Q Okay. So with respect to your analysis, if we turn to page 6, paragraph 20, of Attorney General Hevert Cross Examination Exhibit 2, the Commission --

A I'm sorry. Is this -- that's the Order from South Dakota?

Q Correct.

A Okay.

Q Page -- I'm looking at page 6, paragraph 20.

A Yes. I'm there.

Q Okay. And the Commission notes that the primary difference between your DCF methodology and the one that was used by the Public Staff, the South Dakota

Public Staff, was Otter Tail's exclusive use in its DCF model of forecasted growth and earnings per share and the Staff's use in its DCF model of an average of four different expected growth rate indicators?

A Correct.

Q Okay. And then down in paragraph 23 the Commission finds that "The Staff's model is a more reliable methodology for projecting growth rates, and the Commission adopts the Staff's DCF model approach and its conclusions"?

A It did.

Q Okay. And then you also perform a projected earnings analysis. This is -- this analysis, I don't think you need to go there, but it's on page 37 of your testimony, and it also uses exclusively forecasted data and in that case projected returns on book investment, correct?

A That's correct. The expected earnings analysis is forward looking by definition and based on earnings by definition, so, yes, that's right.

Q Okay. Just to -- as a final point and as -- to give us something to talk about, I've handed out just for reference -- Dr. Woolridge had an exhibit that collected the different analyses that you performed, and I've handed it out for reference. It's Exhibit JRW-9.

A Yes.

Q Okay. And it does not have your expected earnings analysis on it, but it has your DCF results, and there's nine different values there for your DCF results, the mean low and the mean and the mean high.

A Yes. It does.

Q And then it's got your CAPM results and your ECAPM results, and each one of those has eight different values.

A It does.

Q Okay. And then your risk premium results has three different -- three different numbers, depending on what Treasury -- how you -- how you calculated the risk-free rate there.

A Correct.

Q And then, of course, the two for the expected earnings, you provided the mean and the median for those two values. So when I add all that up together, you've got 30 different values that you've provided in your different models, and your different analyses have 30 different values there.

A Right.

Q And they range between -- the lowest one is

8.25 percent and -- which is the Bloomberg derived market-risk premium using the current 30-year Treasury, correct?

A Yes.

Q That's the lowest one?

A Yes. That's correct.

Q Okay. And then your highest one is your ECAPM analysis using the Value Line derived market-risk premium and the projected 30-year Treasury rates, and that's -- that's 12.76 percent?

A Correct.

Q And then in your testimony you were asked whether it would be appropriate to take an average of all these numbers to give guidance to the Commission. That's on page 38 of your testimony.

A Yes.

Q Okay. And you said -- your answer was "The mean results of these models did not necessarily provide an appropriate estimate of DENC's cost of equity."

A Right.

Q And then you go on. For the remainder of your testimony you mention various qualitative factors that the Commission should also consider, such as Dominion's capital expenditure plans, the regulatory environment, correct?

A That's correct. Yes.

Q But those are qualitative factors. You don't quantify those factors at all?

A I think it would be very, very difficult to attribute basis points to them, so correct.

Q Okay. So at the end of your testimony your ultimate recommendation to the Commission, based on your initial testimony --

A Yes.

Q -- is a recommended range of 10.0 to 11.0, and within that range you suggest an ROE of 10.75?

A Correct.

Q Now, of the 30 data points that we looked at, most of them are on JRW-9, plus the two for expected earnings, by my count 24 of them are less than your ultimate recommended ROE.

A Are you talking about 10.75?

Q Correct.

A That's probably right.

Q Okay.

A Of course, more are within the recommended range, right, so when you say -- if you were to look at the results on Dr. Woolridge's Exhibit 9, you've got three estimates from the discounted cash flow result that are over 10 percent, three from the capital asset pricing model -- one, two, three, four, five -- six from the empirical capital asset pricing model, one from the risk premium result, and I think both from the expected earnings approach would be above 10 percent.

Q Okay. And you -- and that's your -- that's your opinion of what an ROE to -- to borrow from your -- to borrow from your testimony summary -- well, no. Forget that.

So do you take into account anywhere in your testimony the fact that the Commission has an obligation to set the rate of return at the lowest point that's constitutionally permissible?

A Of course. I discuss that throughout my testimony. I'm fully aware of the Commission's need and obligation to balance the interest of investors and ratepayers.

Q Okay.

MS. HARROD: No further questions.

CHAIR MITCHELL: Any additional cross examination for this witness?

(No response.)

CHAIR MITCHELL: Redirect?

MS. KELLS: Yes. A few. Thank you.

REDIRECT EXAMINATION BY MS. KELLS:

Q Mr. Hevert, Ms. Harrod asked you some questions about the most recent Duke Energy Progress case from Docket Number E-2, Sub 1142. Do you recall --

A Yes, I do.

Q -- those questions? In that case the ROE was stipulated in the end, was it not?

A Yes, it was.

Q And did the Commission approve that Stipulation?

A Yes, it did.

Q And so that was not your originally-proposed ROE, was it?

A It was not, no.

Q What year -- do you recall, was that the -- would you accept that the Final Order in that case was issued -- I recall it was in the February 2018 time frame?

A Yes.

Q All right. And are market conditions the same now as they were then such that your analyses would be the same when you consider all the factors that go into your analyses?

A No. The market simply is just far more volatile, far more unsettled now than it was then.

Q And would you agree with me that it's especially important in such a volatile environment for a utility to receive a constructive, you know, return on equity such that it can operate in the market?

A I would agree with that. I think from the investment community's perspective we look at the ability to maintain financial integrity, the ability to raise capital, both during accommodating and constrained markets. When you have a market, again, where a 30-year Treasury yield moves by 71 basis points about 27 percent, it's very unusual, it's very volatile, so I think providing investors comfort that the regulatory support remains in place is important.

Q Thank you. And do you recall the stipulated ROE in those -- in that Duke case?

A 9.9 percent.

Q All right. And that's above the stipulated ROE in this case, is it not?

A It is.

Q Ms. Harrod also asked you about the Virginia Order from 2017, I believe?

A Yes.

Q Would you consider that case and decision particularly useful for this proceeding?

A No. The -- quite often, for example, when witnesses look at authorized returns, they will exclude returns from cases that involve limited issue rate riders. Those are cases where there's a base return set and then an incentive added to it for the purpose of, in this case, building in-state generation. So typically when we look at average or median authorized ROEs, those cases are excluded because they just differ from basic rate cases. So putting aside differences in markets, just that difference itself often distinguishes that case from other types of general base rate cases.

Q And is this Commission bound by the analysis or determinations of the Virginia State Corporation Commission?

A No.

Q Ms. Harrod also asked you about the Otter Tail case in South Dakota?

A Yes.

Q Do you recall that line of questioning?

A I do.

Q Would you speak to the relevancy of that outcome to this proceeding?

A Well, first off, it is an outlier; 8.75 percent is an outlying low estimate. There's not been another case of which I'm aware where the return was set that low. When you look at what happened to Otter Tail Power stock price around the time of that Order, the Company meaningfully underperformed the utility sector. That Order came out at about May 30th. My recollection is that the market -- Otter Tail underperformed the Dow Jones Utility Average by about a little bit over 5 percent. So the import of that is that South Dakota is less than 10 percent of Otter Tail's overall operations, and so you have an Order that is an outlier, historically low, for a very small portion of the Company's operations, yet the Company underperformed the market around the time the Order came out. So I will say as the witness I was very disappointed in that Order, and I think the market also reacted to the Order as well.

Q Ms. Harrod also asked you about Witness Woolridge's Exhibit 9. I think it's the last document in the packet that -- it's his exhibit that had all the numbers.

A Yes.

Q And she discussed with you some -- the relevance of -- or the relationship between your originally proposed ROE and the numbers in this document; is that right?

A Yes.

Q Your stipulated -- your recom--- pardon. In your Stipulation testimony you support the stipulated ROE of 9.75; is that right?

A I do.

Q And where would 9.75 fall in this, generally speaking?

A 9.75 generally falls toward the bottom end of my estimates.

Q But taken together, in your opinion is the stipulated ROE a fair and reasonable result here?

A I think it is, and as I say in my Stipulation support testimony, when you look at any stipulation taken as a whole, that's the important perspective. So I do believe that the Stipulation is fair and reasonable.

MS. KELLS: That's all I have.

CHAIR MITCHELL: Questions from the Commission for this witness?

(No response.)

CHAIR MITCHELL: Okay. Mr. Hevert, you may step down. Thank you.

THE WITNESS: Thank you.

(Witness excused.)

CHAIR MITCHELL: And I will entertain motions.

MS. HARROD: Oh. Yes. Chair Mitchell, we would like to have Attorney General Hevert Cross Examination Exhibits 1 and 2 entered into the record, please.

CHAIR MITCHELL: Hearing no objection, the motion will be allowed.

(Whereupon, AGO Hevert Cross Examination Exhibits 1 and 2 were admitted into evidence.)

MS. HARROD: And I think the motion for taking judicial notice of the DEP Rate Order, was that -- did you rule on that?

CHAIR MITCHELL: I did. The motion was allowed.

MS. HARROD: Hmm?

CHAIR MITCHELL: The motion was allowed.

MS. KELLS: May we also move Mr. Hevert's exhibits into the record?

CHAIR MITCHELL: That motion will be allowed.

MS. KELLS: Thank you.

(Thereupon, Company Exhibits RBH-1 through RBH-9, Company Rebuttal

Exhibit RBH-1, and Company Exhibit
RBH-S-1 were admitted into evidence.)

CHAIR MITCHELL: Okay. Dominion, please call your next witness.

MS. GRIGG: Thank you. Mr. Mitchell is here. If the Commission or the parties have any questions of him, he's happy to testify. Thank you. The Company calls Mr. Mark Mitchell.

MARK D. MITCHELL; Having been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MS. GRIGG:

Q Good afternoon, Mr. Mitchell.

A Good afternoon.

Q Would you please state your name and business address for the record.

A My name is Mark D. Mitchell, and I reside at 600 East Canal Street, Richmond, Virginia.

Q By whom are you employed and in what capacity?

A Dominion Energy, and I'm Vice President - Generation Construction.

Q Did you cause to be prefiled in this docket in March 29th, 2019, 20 pages of direct testimony in question and answer form, an Appendix consisting of two pages, and one exhibit consisting of two pages?

A Yes, I did.

Q Do you have any changes or corrections to your testimony you'd like to make at this time?

A Just one minor correction. My address in the direct testimony was listed as 5000 Dominion Boulevard, Glen Allen, Virginia, and as I just stated, now it's 600 East Canal Street, Richmond, 22219.

Q If I were to ask you the questions -- the same questions that appear in your direct testimony today, would your answers be the same?

A Yes, I would.

MS. GRIGG: Madam Chair, at this time I would move the prefiled direct testimony of Mr. Mitchell. We ask that it be copied into the record as if given orally from the stand.

CHAIR MITCHELL: That motion will be allowed.

MS. GRIGG: And his exhibits be premarked for identification -- I mean, exhibits be marked for identification as prefiled.

CHAIR MITCHELL: They will be so marked.

MS. GRIGG: Thank you.

(Whereupon, the prefiled direct testimony of Mark D. Mitchell, as corrected, was copied into the the record as if given orally from the stand.)

(Whereupon, Company Exhibit MDM-1 was identified as premarked.)

**DIRECT TESTIMONY
OF
MARK D. MITCHELL
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562**

Q. **Please state your name, business address and position of employment with Virginia Electric and Power Company.**

A. My name is Mark D. Mitchell, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am Vice President, Generation Construction for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). A statement of my background and qualifications is attached as Appendix A.

Q. **Please summarize your testimony in this proceeding.**

A. My testimony presents an overview of DENC's request for an increase in its base rates and charges, provides information on the Company's recent performance delivering reliable, cost-effective, and environmentally responsible electric service to its North Carolina customers. I also explain the need to obtain the rate relief and the authorized return requested in DENC's Application to increase its rates and charges ("Application"). I also briefly introduce the other Company witnesses who sponsor testimony supporting the Company's Application.

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

A. DENC provides electric service to over 120,000 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 major industrial facilities like Nucor Steel, KapStone, Enviva, and Hospira, as well as commercial and residential customers. During the 2018 test year, the Company's North Carolina jurisdictional sales totaled 4.4 million megawatt-hours ("MWh"). Additionally, the Company provides power and/or transmission services to the North Carolina Eastern Municipal Power Agency and the Town of Windsor.

Q. Do you have any initial comments about the Application?

A. Yes. 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. This commitment requires DENC's constant attention to efficient operations, customer service, and updating and maintaining our infrastructure. Achieving this commitment in the recent past has been challenging, as new environmental regulations, electric reliability standards, and other mandates have placed increasing, and often costly, demands on the electric utility industry and have required unprecedented levels of capital investments.

The Company has continued to experience new load growth, as well as unprecedented demand on its system. To meet all of these challenges, DENC has invested in key infrastructure for the benefit of its North Carolina customers, and continues to do so. These infrastructure investments, such as the Greensville combined cycle generating facility, have improved the efficiency and operational performance of the Company's generation fleet. The Company has also continued to invest in its electric delivery system, which provides reliable power to DENC's North Carolina customers. The Company's belief has been, and remains, that providing reliable and cost-effective electric service is important to its customers' quality of life and to North Carolina's economy over the long term.

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

A. The Company's Application is necessitated by its recent, and continuing, significant investment in generation, transmission, and distribution infrastructure for the benefit of DENC's customers, as well as in response to recent 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 2016 in Docket No. E-22, Sub 532 ("2016 Rate Case"). 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.

Q. Please describe the major recent investments in electric generation plants.

A. After completion of the Brunswick County Generating Station combined cycle facility ("Brunswick County CC"), which was placed in service in April 2016, the Company has over the past three years continued to transform its generation fleet by investing $1.3 billion for the Greensville County Generating Station ("Greensville County CC") bringing approximately 1,588 megawatts ("MW") of increasingly clean and highly-efficient new baseload combined cycle generating capacity online. The Greensville County CC was placed in service in December 2018 and is the most efficient fossil-fueled unit in Dominion Energy's fleet, producing enough clean burning natural gas fired generation to power 400,000 homes while providing a projected customer value greater than $1.5 billion over the 36-year operating life. The Greensville County and Brunswick County CC facilities are state-of-the-art 3x1 baseload gas-fired generating facilities have the capability to create substantial fuel savings for DENC's customers by leveraging very favorable current natural gas commodity prices.

Additionally, in December 2016, the Company invested approximately $132 million to bring on-line three regulated solar facilities totaling 56 MW in aggregate. The Company continues to invest in renewable energy, and views new utility scale solar resources as an increasingly important component of DENC's generation mix. Between 2019 and 2020, the Company plans to invest approximately $410 million to bring on-line two major new solar facilities with a total of 240 MW of additional nameplate capacity. Finally, the Company has received a certificate of public convenience and necessity from the State Corporation Commission of Virginia to construct the 12 MW Coastal Virginia Offshore Wind Project which is expected to enter service in late 2020. This project will provide valuable permitting, construction, and operations experience which will inform of potential deployment of over 2,000 MW of wind turbines in the adjacent 112,000 acre lease area, which the Company controls under the Bureau of Ocean Energy Management Lease Program (BOEM lease program).

Q. Please provide additional information on the Company's future plans for developing new generating resources.

A. DENC's most recent biennial Integrated Resource Plan ("IRP") filed with the Commission in 2018 addresses the Company's continued need to increase generation to meet new load demand and to replace less efficient infrastructure for economic and environmental reasons. Additionally, the Virginia Grid Modernization and Security Act (SB-966) specified that up to 5,000 MW of solar and wind generation facilities constructed by a utility are in the public interest. Of this amount, the Company has committed to have approximately 3,000 MW placed in service or under development by the end of 2022. As the costs of installing utility-scale solar and other renewable energy technologies have declined, the Company has determined that increasing its portfolio of renewable energy resources as part of a diversified generation fleet makes both environmental and economic sense in providing customers cleaner power with zero fuel cost.

Q. Please also provide an update on Subsequent License Renewal ("SLR") for the Company's nuclear fleet.

A. In November 2015, the Company notified the Nuclear Regulatory Commission ("NRC") of its intent to file an application for SLR for its two nuclear units at Surry Power Station ("Surry") in order to operate an additional 20 years. As with the Company's other nuclear units, Surry's units were originally licensed to operate for 40 years and then were renewed for an additional 20 years. The licenses for Surry's two units will expire in 2032 and 2033. The Company submitted the SLR application for the Surry units to the NRC on October 15, 2018. The Company also notified the NRC in November 2017 of its plans to file an application for SLR for its two nuclear units at North Anna Station in 2020. The existing licenses for those units will expire in 2038 and 2040.

Q. Please explain how the Company has invested in other areas of its system in North Carolina since 2016.

A. As discussed by Company Witness Bobby E. McGuire, since 2016, 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 2016 through 2018, the Company spent approximately $268 million on transmission improvements in North Carolina. Over the next five years, the Company plans to invest an additional $200 million in improvements to its North Carolina transmission system. These transmission-related improvement projects include new or upgraded transmission lines, as well as new or upgraded substations.

Likewise, the Company has invested over $29 million in its North Carolina distribution system since its last rate case in 2016 to support load growth and improve reliability. The completed and planned efforts to improve the Company's distribution system since 2016 include 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. Please discuss the Company's decision to retire certain units at a number of DENC facilities.

A. In an effort to reduce costs, uneconomical units that were previously placed in a cold reserve state and are not currently operating will be retired by the end of March 2019. These older, less efficient units are unable to compete in the current energy market and have been displaced by cleaner burning natural gas facilities, as well as utility-scale solar. See Company Witness Bruce E. Petrie's testimony for details on the units being retired.

Q. Please briefly describe the impact of current environmental regulations on the Company's business.

A. Over the past decade, the electric utility industry has been confronted with a suite of new U.S. Environmental Protection Agency ("EPA") standards for traditionally regulated emissions from fossil-fueled power generating facilities, including sulfur dioxide, nitrogen oxide, and mercury, amongst others. Achieving compliance with these new, more stringent EPA regulations has directly impacted the continued operation of the Company's coal-fired generating fleet. For example, the Mercury Air Toxics Standards Rule ("MATS") requirements, and the projected cost to comply with those requirements, was a primary driver of the Company's decision to retire over 900 MW of coal-fired generating capacity, including four units at Chesapeake Energy Center, which were retired in 2014, and two units at Yorktown Power Station, which were retired in March of this year.

Consideration of current and potential future environmental requirements also contributed to the Company's resource planning decisions to construct the Brunswick County and Greensville County CC facilities. These new generation facilities are prudent investments that are contributing to the Company's emission reduction strategy to comply with these new EPA regulations and are, as I have noted, in the long-term best interests of DENC customers.

Another environmental regulation impacting the Company's business is the EPA's final rule regulating the management and disposal of coal combustion residuals ("CCR") at the Company's coal-fired power plants (the "CCR Final Rule"). The CCR Final Rule regulates CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store, CCRs. As discussed by Company Witness Jason E. Williams, the

Company currently operates inactive ash ponds and CCR landfills subject to the CCR Rule. The enactment of the CCR Final Rule in April 2015 created a legal obligation for the Company to retrofit or close all of its inactive and existing ash ponds, as well as perform required monitoring, corrective action, and post-closure activities as necessary. Recent legislation in Virginia, signed by Governor Ralph Northam on March 20, 2019, requires the Company to impound ash at lined landfills either on station property, or at a nearby lined landfill. This new law also requires that the Company recycle 6.8 million cubic yards of coal ash from no fewer than two sites. Company Witness Paul M. McLeod provides additional information on the Company's accounting for the major new costs that it is incurring to comply with the CCR Rule and Company Witness Williams provides details on the facilities affected by the legislation.

Q. **What CCR compliance expenditures has the Company incurred that are included in this case?**

A. In Company Exhibit MDM-1, I have detailed the CCR-related asset retirement obligation expenditures to execute the compliance actions described in Company Witness Williams' testimony. In detailing these costs, I have also provided narrative summaries explaining the make-up of the costs and the regulatory drivers for these costs. The compliance cost expenditures from July 1, 2016 through June 30, 2019, are estimated to be $390.4 million.

Q. Please describe the Company's capital investment program for generation resources over the next several years.

A. Looking ahead, for the three-year period 2019-2021, the Company is planning overall capital investments of approximately $11.1 billion, which includes $5.3 billion for generation investments, $3.2 billion for distribution investments, and $2.6 billion in transmission level investments. These investments are substantial, but they are necessary in order for the Company to continue to fulfill its obligation of providing reliable, cost-effective service in an environmentally responsible manner for DENC's customers.

Importantly, in order to attract the capital needed to meet these substantial future capital needs, the Company must achieve an adequate authorized return on equity ("ROE") in this proceeding. The 10.75% 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 also ensures 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, and to do so without eroding its shareholders' interests. Company Witness Richard M. Davis discusses the Company's capital needs in detail in his testimony, while Company Witness Robert B. Hevert 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.

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.

In the area of generation performance, the Company's fleet has consistently delivered exceptional value for its customers since 2016. One critical benchmark of generation performance is the Equivalent Forced Outage Rate on demand ("EFORd"). Over the past three years, the Company's EFORd results have compared very favorably to its peers, with fleet performance levels of 5.3% for period 2016-2018. This performance is significantly better than the PJM region's average of 6.8% during 2015-2017, which represents the most current data available.

The Company's nuclear fleet has also maintained its record of industry leading performance over the past few years. The Company's nuclear units at North Anna and Surry delivered an average capacity factor greater than 95% for the years 2017 and 2018, exceeding both the 2017 and 2018 U.S. Industry averages, respectively, as well the peer group averages. This strong generating plant performance is important as it equates to operational efficiency and, along with optimal dispatch of the Company's generation fleet, achieves both capacity- and energy-related savings for customers.

In addition to DENC's excellent generation performance results, the Company continues to provide excellent levels of customer service. DENC believes that its customers deserve dependable and consistent service reliability. An industry-accepted measure of reliability performance is System Average Interruption Duration Index ("SAIDI"), excluding major storms. The Company's investments have improved North Carolina SAIDI performance (excluding major storms) by over 20% since 2007 and maintained consistent performance below 120 minutes since 2016.

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 2018, DENC's customers completed more than 16 million online transactions, which represents an increase of 12% from the previous year, and the enrollment and usage of online services continues to grow.

DENC is also promoting social media interactions with its customers. Social media is an important communication channel because it offers customers an alternative way to reach the Company and allows the Company to quickly communicate with large segments of customers at one time. Customers also can contact the Company via social media and inquire about outages from any device – desktop, laptop, tablet or smart phone. DENC also publishes messages 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. Over the past several years, the Company's parent, Dominion Energy, Inc. ("Dominion") has been recognized as either No. 1 or No. 2 on *Fortune's* list of "Most Admired" electric and gas utilities. Dominion has also been lauded as an excellent corporate citizen with its inclusion among *Forbes'* "Just 100," which recognizes a variety of factors, including producing quality goods, treating customers well, minimizing environmental impact, supporting the communities served, and treating workers well. Part of that ethos as a good corporate citizen includes how Dominion treats military veterans. Dominion has received the highest honor from the U.S. Department of Defense for its support of employees who serve in the National Guard or Reserve – the Employer Support Freedom Award. Dominion is routinely ranked among the top utilities by *Military Times Edge* as "Best for Vets" for the energy sector, and each year *GI Jobs* places Dominion as one of the top "Military-Friendly

Employers" and "Spouse-Friendly Employers" in the U.S. In addition, Dominion was recognized as one of Forbes' "Best Employers for Diversity" and "Best Employers for Women" in 2018.

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

A. The Company believes 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 and Operation Fan Heat Relief programs provide further examples of DENC's commitment to the communities it serves. EnergyShare helps people who need assistance in paying any type of home heating bill, particularly helping lower-income customers stay warm in the winter months, while Operation Fan Heat Relief provides fans and/or air conditioners to help seniors stay cool in the summer. From 2016 to 2018, more than $2,000,000 has been donated and more than 6,120 families in DENC's service territory have benefitted from these programs.

Additionally, over the past three years, the Company and the Dominion Foundation have awarded over $600,000 in grants to various North Carolina organizations, schools and universities, food banks and other disaster relief funds. Dominion employees donated more than 351,761 hours of volunteer service to their communities. The costs of these philanthropic activities are not recovered from customers, but represent a voluntary commitment by the Company and Dominion shareholders to the North Carolina service area.

Q. Will you please summarize the proposed rate impact of the Company's Application?

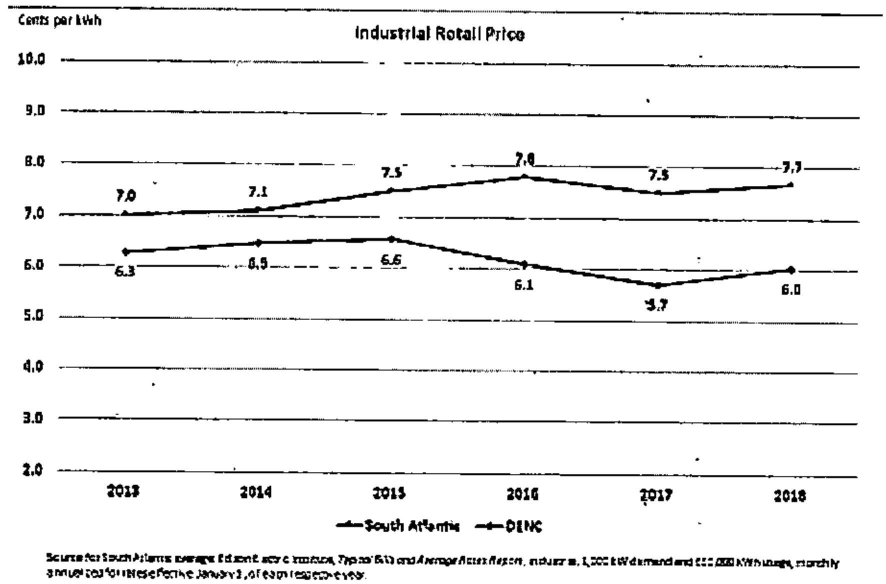
A. The Company's Application and pre-filed testimony request and support an incremental base non-fuel revenue requirement of approximately $27 million. Company Witness McLeod provides more detailed information and support for the Company's requested base non-fuel revenue requirement.

As Company Witness Paul B. Haynes describes, the overall increase, including the non-fuel base rate increase, the Rider EDIT (decrement), and the projected fuel decrease anticipated in the Company's August 2019 fuel factor adjustment filing, results in a projected overall rate increase of approximately 5.96% for the average residential customer compared to rates currently in effect. Using the widely accepted 1,000 kWh monthly usage measurement for a "typical residential bill," the average residential customer's bill will increase from $113.13 to $120.08, which remains very competitive with other electric service providers in the region.

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. The following chart compares DENC's industrial rates during the last five years with the rates of other electric utilities in the Edison Electric Institute's ("EEI") South Atlantic region, as most recently reported by EEI in its *Typical Bills and Average*

Rates Report:[1]

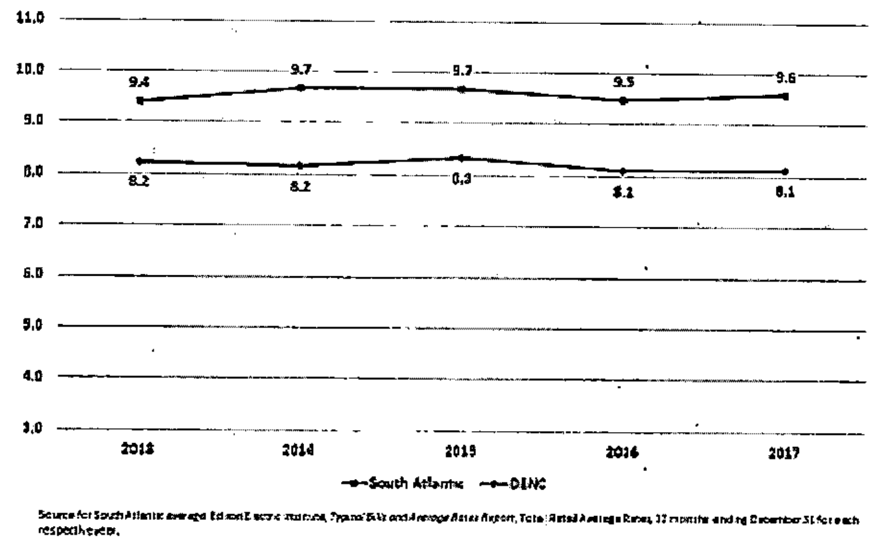
DENC vs. EEI South Atlantic – Industrial Retail Price



Finally, overall, the Company's North Carolina rates have historically been lower than, and continue to be very competitive compared to, other utilities and electric service providers in North Carolina and throughout the South Atlantic region. As shown in the following chart, the Company's average total retail rates in 2018 were more than 15% below the average retail price in the region. After the proposed base rate increase, DENC's average rates remain very competitive with the average rates for investor-owned utilities in the South Atlantic region.

[1] The EEI South Atlantic Region includes investor-owned electric utilities serving retail customers in Delaware, the District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia.

DENC vs. EEI South Atlantic - Average Retail Price[2]



Q. Is the Company requesting any deferred accounting authority in conjunction with this Application?

A. Yes. First, as described in the Application and by Company Witness McLeod, DENC intends to file a companion application for Commission approval to defer the post-in-service costs of the Greensville County CC from its commercial operation date to the date new base rates become effective through this proceeding.

The Company's application shows DENC earning well below the Company's authorized ROE of 9.9% under existing rates and, therefore, not adequately

[2] Source for EEI South Atlantic: Edison Electric Institute, Typical Bills and Average Rates Report, Total Average Retail Price for each respective calendar year. DENC and EEI South Atlantic for 2015 reflects rates in effect July 1, 2015 – latest data available from EEI. DENC proposed November 1, 2016 is based on the Application.

recovering the Company's cost of service and a fair and reasonable rate of return for its investors.

The Company believes that the significance of placing this major new generating facility into service, coupled with its degraded financial condition under current rates, supports deferral and the Company has therefore included these deferred post-in-service costs in the Company's revenue requirement, as supported by Company Witness McLeod. Absent Commission approval to defer and recover these costs through new base rates, these prudently-incurred costs will go unrecovered. The Company emphasizes that the Greensville County CC will provide substantial fuel savings for its customers.

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.**, Director – Corporate Finance and Assistant Treasurer, 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.

- **Robert B. Hevert**, Managing Partner, ScottMadden, Inc., testifies as to his assessment of the Company's cost of common equity and the ROE that is appropriate in this case.

- **Bobby E. McGuire**, Director – Electric Transmission Project Development & Execution, describes the Company's major investments in its transmission and North Carolina distribution electric system from 2016 through 2018.

- **Bruce E. Petrie**, Manager – Generation System Planning, presents the Company's adjusted actual and forecasted total system fuel expense levels, which will be used to calculate the base fuel rate. Mr. Petrie also provides an estimate of the system fuel expense for July 1, 2018 to June 30, 2019, and an estimate of the deferred fuel balance as of June 30, 2019.

- **Jason E. Williams**, Director – Environmental Services, describes the Company's request to recover deferred CCR expenses incurred from July 1, 2016 through June 30, 2019 related to compliance with applicable regulatory requirements.

- **Paul M. McLeod**, Regulatory Specialist, presents 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 2018 test year. Mr. McLeod also supports the Company adjustments to cost of service and the establishment of Rider EDIT to refund federal corporate excess deferred income taxes associated with recent federal tax changes enacted by the Tax Cuts and Jobs Act of 2017.

- **Robert E. Miller,** Regulatory Analyst, describes the cost of service studies filed in support of the Company's application and describes the studies along with the minimum system analysis and distribution cost allocation factors used to develop them.

- **Paul B. Haynes**, Director – Regulation, describes the allocation methods used to allocate Production and Transmission fixed costs and related expenses in the cost of service studies. Mr. Haynes also describes the Company's proposed apportionment of the non-fuel base rate revenue increase and the revisions to the Company's non-fuel base rates and Terms and Conditions changes. Mr. Haynes also discusses the update of the base fuel rate and provides a projection of this rate and the anticipated Experience Modification Factor for the Company's August 2019 fuel proceeding. Finally, Mr. Haynes' testimony supports Rider EDIT, which refunds excess deferred federal income taxes to the Company's customers over one year.

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 public service obligation 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 2016 Rate Case have enabled significant improvements in the reliability and efficiency of service to the Company's North Carolina customers, 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 MARK D. MITCHELL

As Vice President of Generation Construction for Dominion Energy Services, Inc. ("Dominion"), Mr. Mitchell is responsible for the engineering and construction of existing and planned power station capital projects for Virginia Electric and Power Company (the "Company") and its affiliates. Since 2000, he has been responsible for the installation of numerous generation projects for the Company, including major plant retrofits, new combined-cycle gas turbines, new simple-cycle gas turbines, wind turbines, solar, new nuclear development, and the VCHEC Project.

Mr. Mitchell joined Dominion in June 2000 as a project manager in charge of a 750 MW gas turbine project in Illinois. From 2001 through 2004, he was in charge of the 1200 MW Fairless Energy Combined Cycle project near Philadelphia, Pennsylvania. During this project, he was promoted to Project Director. In 2004, he was named Director, Fossil & Hydro Projects, and from 2004 through 2007 was in charge of projects performed across the fossil generation fleet, as well as new generation project development. In 2007, he assumed management of the VCHEC construction project as Director of Fossil and Hydro Projects – Generation Construction. Mr. Mitchell was promoted to his current position in January 2014.

A native of Ashland, Virginia, Mr. Mitchell received a Bachelor of Applied Science degree from the University of Delaware in 1991 and a Master's degree in business administration from Wilmington College in 1993. He is a registered professional engineer in Virginia and Pennsylvania in the electrical engineering field. He also attended the Reactor Technology Course for utility executives at MIT and The Executive Program at the Darden School of Business at the University of Virginia.

Prior to joining Dominion, Mr. Mitchell worked for Reynolds Metals from 1995 to 2000 on various projects in the United States, Europe, and Africa. From 1982 to 1995, he worked in the utility industry on various projects for large utilities, including construction and startups for four nuclear plants.

BY MS. GRIGG:

Q Mr. Mitchell, do you have a summary of your testimony?

A Yes, I do.

Q Would you please give it at this time?

A Yes, I will. Good afternoon, Commissioners. I am Mark Mitchell, Vice President - Generation Construction for Dominion Energy North Carolina. I am pleased to be here today to support the Company's Application, as well as the proposed Agreement and Stipulation of Partial Settlement which the Company entered into with the Public Staff and Stipulation with Carolina Industrial Group for Fair Utility Rates.

As described in my testimony and the testimony of other Dominion witnesses in the case, Dominion has made significant investments on behalf of our customers, both in North Carolina and throughout our electric systems since our last rate case before the Commission in 2016. These investments, including placing into service our new Greensville combined cycle generating facility, which has improved the efficiency and operational performance of the Company's generation fleet, and other significant benefits to our customers today. They also include upgrades and rebuilds of transmission and distribution lines throughout our system to ensure we have the infrastructure in place to deliver on our commitment of providing highly reliable power to our customers.

As I describe in my direct testimony, these investments have been largely driven by new environmental regulations related to emissions and coal combustion residual-related asset retirement obligation expenditures, replacements of less efficient infrastructure, and to increase the Company's renewable energy resources going forward. They have also been driven by new load growth in North Carolina. Through these investments and the dedication of our employees, our generating fleet and electric delivery system are providing reliable electric service to all of our customers including our customers in North Carolina.

The customer's (sic) application is driven by the fact that our recent current rates have not kept pace with increases in our costs and our Company's need to recover the significant new capital investments we have made to serve customers since 2016. As highlighted by Company Witness Paul McLeod, the Company's fully adjusted return on equity, or ROE, has declined to only 7.81 percent as of June 30th, 2019, which is far below our currently authorized 9.9 percent ROE and well below the 9.75 -- 9.75 percent ROE agreed to in the Stipulation.

Commission approval of the revenue increase and proposed rates presented in the Stipulation will allow Dominion to recover our cost of service and to earn a reasonable return which will be critical over the next few years as the Company is projecting more significant capital investments.

The Company believes that providing reliable and cost-effective electric service is vitally important to both our customers' quality of life and to North Carolina's economy over the long term. As we have heard from some of our customers and their representatives, some customers continue to experience challenging economic circumstances even as North Carolina's economy overall, including in our service territory, has steadily improved since our last rate case in 2016. Given these considerations, the Company is pleased to have reached a partial settlement with the Public Staff, and we believe successfully balances our customers' interest in the lowest rate impact possible with the Company's need to recover our cost of providing reliable service to our customers and also provide a reasonable and competitive return for the investors that fund our capital requirements.

I believe that the evidence presented in this case will demonstrate that the Company has acted responsibly and prudently with respect to new capital investments, operation and maintenance programs, and financing, and the provisions of the Stipulation are reasonable and should be approved.

I thank the Commission for its time and consideration in reviewing Dominion's case and Stipulations, and I look forward to answering your questions.

Q Thank you, Mr. Mitchell.

MS. GRIGG: He is available for cross examination.

CHAIR MITCHELL: Thank you. Any cross examination for the witness?

(No response.)

CHAIR MITCHELL: Questions from the Commission?

COMMISSIONER CLODFELTER: Ms. Grigg, the questions I have for Mr. Mitchell arise from the late-filed exhibits, and those have not yet been introduced, so how -- how do you want to proceed with that? And I will be asking him some questions about Late-Filed Exhibits 5 and 6, but the non-confidential portions.

I'll only be asking about the publicly available portions of those exhibits.

MS. GRIGG: Okay. Thank you, sir. Why don't I go ahead and move, without objection, all six of the Company's late-filed exhibits that were filed today into evidence.

CHAIR MITCHELL: Hearing no objection, your motion will be allowed.

MS. GRIGG: Thank you.

(Whereupon, Company Late-Filed Exhibits 1 through 6 were identified as premarked and admitted into evidence. The confidential versions were filed under seal.)

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Mitchell, I put these questions to you because in a summary -- a helpful summary that your counsel provided, you were designated as someone who might have knowledge about a couple of the questions that the Commission posed prior to the hearing, and specifically questions 4 and 5 which relate to Late-Filed Exhibits 5 and 6. Do you have those two exhibits available to you?

A Yes, I do.

Q Okay. I'm not -- I thank you for Late-Filed Exhibit 6. It responds to the Commission's question completely and fully, and so I don't really have any particular questions about it, but I'm going to refer to it to help me frame the questions about Exhibit 5.

So I'm -- let's take Late-Filed Exhibit 5. And, again, I'm not asking about any of the confidential portions. I just want to look at the portions of the -- of the exhibit that designate the activities under each of the projects. The first one would be -- on the first page is Bremo CCR Project.

A Yes.

Q Yes. And what I'm -- what I'm really trying to tease out here is some understanding of which of these various activities might be considered capital in nature and which are more in the nature of ongoing operating activities or maintenance or repair or preconstruction activities. I see, for example, the category Water Management Activities includes analytical sampling. Well, I understand analytical sampling, but I'm not sure what else is embraced in that category Water Management Activities. What kind of tasks at a more -- can you give me a more granular description of it, is really what I'm asking for?

A Sure. Many of these ponds, including the ones at Bremo, they -- Company Witness Williams can answer questions in more detail about the scope, but at a very high level many of these ponds included water that had to be removed in order to remove the ash out of them, so --

Q You had to dewater the ash?

A Dewater the ash.

Q Okay.

A And, of course --

Q All right.

A -- there was permit requirements which required treatment of that.

Q If -- because Witnesses McLeod and Williams are also designated for these two questions, you just happen to be up first on the --

A Yes.

Q -- in the pecking order, so I ask them of you, but if they're -- if they are better equipped to answer them, that's fine for you -- fine with me if you want to refer to them. I was looking, though, at page 5 of the Late-Filed Exhibit 6, and really what I was getting at with my question is that is a discussion of the closure project for Chesapeake Energy Center, and it has a column titled Description of Tasks which is a much more detailed and specific description of the activities that are summarized in that table. Is there something like that that also is available for each of the other projects that's discussed in Late-Filed Exhibit 5?

A MDM-1, in response to question 4 --

Q Right.

A -- and it did provide some break -- some further breakout of cost, I believe.

Q There -- there is a further detailed breakdown?

A Yeah. I believe it's redacted and it's confidential, but, for instance, it's on Late-Filed Exhibit 5 response to waste coal ash -- ash question number 4. And if you look at, for instance, like page 1 is an example that happens to be Bremo, I believe, but -- yeah, it's Bremo -- but we did file further breakdown of cost in that exhibit.

MS. GRIGG: Just for clarification, the pages that you have here, Mr. Mitchell, which are Late-Filed Exhibit 5, confidential pages 1 through 4, were what were filed today with the Commission.

THE WITNESS: Correct.

Q Is there more supporting detail that backs up those four pages? Is that what I'm understanding?

A No. These are the more detailed cost breakdowns. The original -- my original direct testimony had some description of what work was done at each facility, as well as Witness Williams can discuss details.

MS. GRIGG: That's right. This is additional information on top of Mitchell Exhibit 1 to his direct testimony.

COMMISSIONER CLODFELTER: Correct. And, again, I don't want to make this difficult. I'm really just trying to -- to get the most granular information I can --

MS. GRIGG: Sure.

COMMISSIONER CLODFELTER: -- so when I look at Late-Filed Exhibit 6, page 5, though, I've got, for example, it's detailed down as demolition contractor expenses, groundwater monitoring, erosion maintenance, and grass mowing. That's the level of detail that I don't see on Late-Filed Exhibit 5.

MS. GRIGG: I have not seen that level of detail from the Company.

THE WITNESS: Yes. We've got individual entries, but they rolled up into these broad categories that we filed.

COMMISSIONER CLODFELTER: Let me let you go on this, and I'll talk some more with Witness McLeod about what it would take to get that same level of detail in Exhibit 5 as the level of detail we've got in Exhibit 6. If it's possible to do that, I'll ask Witness McLeod.

THE WITNESS: Okay. Thank you.

COMMISSIONER CLODFELTER: Great. That's all I have. And by the way, thank you for the Late-Filed Exhibits, especially Number 6. It was a thorough answer.

MS. GRIGG: You're welcome.

CHAIR MITCHELL: Questions on the Commissioner's questions?

MS. GRIGG: No questions.

CHAIR MITCHELL: Thank you, Mr. Mitchell. You may step down.

THE WITNESS: Thank you.

(Witness excused.)

MS. GRIGG: We'd like to move Mr. Mitchell's exhibit and appendix into evidence.

CHAIR MITCHELL: Hearing no objection, your motion will be allowed.

(Whereupon, Company Exhibit MDM-1 was admitted into evidence. The confidential version was filed under seal.)

CHAIR MITCHELL: Call your next witness.

MS. KELLS: Dominion calls Richard Davis.

RICHARD M. DAVIS, JR.; Having been duly sworn, Testified as follows:

DIRECT EXAMINATION BY MS. KELLS:

Q Would you please state your name and business address for the record?

A Yes. My name is Richard M. Davis, Jr., and my business address is 120 Tredegar Street, Richmond, Virginia, 23219.

MS. KELLS: One moment while I locate his summary which I had just a moment ago. Apologies.

Q All right. We'll continue with this while that's getting passed out. Did I ask you by whom you're employed in what -- and in what capacity?

A Not yet.

Q Okay. By whom are you employed and in what capacity?

A I'm employed by Dominion Energy, Incorporated. I'm the Assistant Treasurer and Director of Corporate Finance.

Q Did you cause to be prefiled in this docket on March 29th, 2019, 14 pages of direct testimony in question and answer form and Appendix A and one exhibit?

A I did.

Q And did you cause to be prefiled in this docket on August 5th, 2019, two pages of supplemental testimony and one exhibit?

A I did.

Q And did you cause to be prefiled in this docket on September 12th, 2019, nine pages of rebuttal testimony and one exhibit?

A I did.

Q Finally, did you cause to be filed in this docket on September 17th, 2019, four pages of Stipulation testimony?

A Yes, I did.

Q Do you have any changes or corrections to any of your testimonies or exhibits?

A I do. I have two small changes. First, in my rebuttal, page 4, in the table at the top of the page in the second column titled Actual -- Actual Equity Ratio, the third number down, which in that exhibit reads 53.3006 percent, it should be revised to read 53.006 percent. There was an extra three accidentally included in the exhibit.

And second correction, on page 3 of my

Stipulation testimony, in Figure 1 at the top of the page, the third line down in the title should read Actual June 30th, 2019 Balances with Stipulated Capital Structure and ROE.

Q And with the exception of those corrections, if I were to ask you the same questions that appear in your testimonies today, would your answers be the same?

A Yes, they would.

MS. KELLS: Chair Mitchell, at this time I move the prefiled direct, supplemental, rebuttal, and Stipulation testimonies of Mr. Davis be copied into the record as if given orally from the stand, and that his exhibits be marked for identification as prefiled.

CHAIR MITCHELL: Hearing no objection, your motion is allowed.

(Whereupon, the prefiled direct, supplemental, rebuttal, as corrected, and Stipulation testimony, as corrected, of Richard M. Davis, Jr. were copied into the record as if given orally from the stand.)

(Whereupon, Company Exhibit RMD-1, Company Supplemental Exhibit RMD-1, and Company Rebuttal Exhibit RMD-1 were identified as premarked.)

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 562

Q. Please state your name, position, business address and professional background.

A. My name is Richard M. Davis, Jr., and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am the Director – Corporate Finance and Assistant Treasurer for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). A statement of my background and qualifications is attached as Appendix A.

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

A. My testimony presents DENC's actual year-end regulated capital structure, calculated in line with the North Carolina Utilities Commission's ("Commission") approved format, as of December 31, 2018, 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 Mark D. Mitchell explains in his Direct Testimony, this includes investments in new combined cycle natural-gas fired generation facilities, new solar and offshore wind facilities, subsequent license renewals for its existing nuclear fleet, new and upgraded transmission lines, and new distribution substations. In total, the Company has spent over $4 billion of capital investments in the three 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 actual year-end regulatory capital structure as of December 31, 2018. This schedule is in accordance with the Commission's approved format. 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, 2018. The capital structure presented follows the Commission's approved format 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, 2018 capital structure is 46.99%, and the equity component is 53.01%.

Q. Why is the Company's actually-experienced capital structure as of December 31, 2018, appropriate for use in this proceeding?

A. The Company's December 31, 2018, 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. Since the Commission most recently set DENC's base rates in Docket No. E-22, Sub 532 ("2016 Rate Case"), the Company's year-end equity component was 53.19% as of December 31, 2016, and 52.11% for the year ending December 31, 2017. DENC's December 31, 2018, equity component of 53.01% 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 7.79%, which is composed of a long-term debt cost rate of 4.45% and a cost of common equity rate of 10.75%. The long-term debt cost rate is based upon debt issued, via the capital markets, and still outstanding at December 31, 2018. The cost of common equity cost rate is supported by Company Witness Robert B. Hevert in his testimony and supporting schedules.

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

A. Since the 2016 Rate Case, the Company has and continues to make significant investments to maintain and improve the sustainability and reliability of the service it provides to its North Carolina customers. As Company Witness Mitchell explains in more detail, the Company plans continued capital investments approximating $11.1 billion during the three-year period 2019-2021, including $5.3 billion for generation – including approximately $2.2 billion for new generation construction projects, $3.2 billion for distribution investments, and $2.6 billion in transmission level investments. 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. Importantly, 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 its capital needs while also managing its credit profile with a focus on maintaining access to a wide range of financial markets on reasonable terms. A large part of this effort relates to maintaining credit metrics that are supportive of DENC's target credit ratings in order to enable the Company to maintain such market access 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 and continue to enable the Company to access a number of 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 in order 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 crafting 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 2019, the Edison Electric Institute ("EEI") estimated that more than one-third 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 $100 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.

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, efficiency of tariff setting procedures, 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, and 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, all with stable outlooks. S&P's rating is below our internal target of A-. This is not an indicator of the credit strength of the subsidiary, but is, instead, a result of the overall group or consolidated family methodology used at S&P. This is a methodology that investors and others are very accustomed to, and as such, investors will rely less on the S&P methodology and instead rely on Moody's, Fitch's or on their own credit analysis. 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, DENC 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 Hevert's testimony demonstrates, the Company's current market cost of equity is in the range of 10% to 11%. Granting the Company an authorized return of 10.75% 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 Hevert also addresses the impact of changing economic conditions in setting the Company's authorized return on equity.

Q. Will the Company's capital structure and cost of capital be impacted by the recent merger with SCANA Corporation?

A. No. There will be no impacts, positive or negative, to the Company's capital structure and cost of capital from the merger with SCANA. In fact, the Regulatory Conditions contained in the Commission's order approving the merger prohibit any such adverse impact. The Regulatory Conditions require that North Carolina customers be held harmless from the effects of the merger. More specific to my testimony, one of the stated purposes of the Regulatory Conditions is to ensure that DENC's capital structure and cost of capital are not adversely affected through affiliation with SCANA.

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, which is discussed more completely by Company Witness Mitchell in his testimony. As discussed further by Company Witness Hevert, capital markets appear to be more volatile now than they were even during the Company's 2016 North Carolina 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 reasonable 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, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF RICHARD M. DAVIS, JR.

Richard M. Davis, Jr. is the Director of Corporate Finance and Assistant Treasurer. He joined Dominion in April 2005 and was named to his current post in August 2015. Davis has nearly 14 years of experience in accounting and finance at Dominion with various roles, including leadership, during that time. Prior to joining Dominion, Davis primarily worked in public accounting as an auditor serving various industries, including power and utilities. Davis serves on multiple committees within the Company including the Environmental Social and Governance (ESG) Steering Committee and the Diverse Ability Employee Resource Group. Davis also 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. 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.

SUPPLEMENTAL DIRECT TESTIMONY
OF
RICHARD M. DAVIS, JR.
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

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

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

Q. Are you the same Richard M. Davis, Jr. who filed direct testimony in this case on March 29, 2019?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my supplemental testimony is to update Company Exhibit RMD-1, Schedule 1 filed with my direct testimony to reflect the actual capital structure for ratemaking purposes at June 30, 2019. This Schedule 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 updated proposed capital structure and cost of capital to be used in this proceeding.

A. The Company's actual capital structure and cost of capital, presented in the same manner as presented on Company Exhibit RMD-1, Schedule 1 to my pre-filed direct testimony is attached to this supplemental testimony as Company Supplemental Exhibit RMD-1, Schedule 1. As shown on my Supplemental Schedule 1, the long-term debt component of the Company's capital structure as of June 30, 2019, is 46.351% of the total, while the equity component is 53.649%. The overall weighted-average cost of capital is 7.826%, composed of a debt cost of 4.442%, and a cost of common equity of 10.750%.

Q. Please briefly describe the factors underlying the change from the originally filed capital structure at December 31, 2018, and the actual capital structure at June 30, 2019.

A. The amount of long-term debt decreased by approximately $382 million, driven by $390 million of long-term debt maturities and amortization of debt costs and other items. The decrease in common equity was primarily due to common stock dividends paid in the first half of 2019, offset by results of actual operations on retained earnings for the first half of 2019.

Q. Does this conclude your supplemental direct testimony?

A. Yes, it does.

REBUTTAL TESTIMONY
OF
RICHARD M. DAVIS, JR.
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

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

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

Q. **Are you the same Richard Davis who filed direct and supplemental testimony in this proceeding?**

A. Yes, I am.

Q. **What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to address certain aspects of the testimony of Nicholas Phillips, Jr. on behalf of the Carolina Industrial Group for Fair Utility Rates I ("CIGFUR"), specifically those sections of Mr. Phillips' testimony that relate to the capital structure to be employed in establishing rates in this proceeding.

Q. **Are you sponsoring any exhibits or schedules with your testimony?**

A. Yes. I am sponsoring Company Rebuttal Exhibit RMD-1. 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. Consistent with previous filings and as described in my Supplemental Direct Testimony and shown on Company Supplemental Exhibit RMD-1, Schedule 1, page 1 of 1, the Company's proposed capital structure to be used in this proceeding is the Company's actual capital structure as defined in North Carolina for regulatory proceedings as of June 30, 2019. This proposed capital structure reflects an equity component of 53.649% and a long-term debt component of 46.351%.

Q. What capital structure has Mr. Phillips recommended?

A. Mr. Phillips has recommended a capital structure not to exceed 52.000% common equity and 48.000% long-term debt.

Q. Is his recommendation reasonable as it relates to capital structure?

A. No. Mr. Phillips has chosen to ignore the Company's actual capital structure as of June 30, 2019, as well as DENC's actual capital structure at year-end of each of the previous three years in favor of arbitrarily developed structures. Utilizing the period-end capital structure, as the Company promotes, represents a consistent and well-supported framework for ratemaking procedures. As I discuss below, the actual capital structure is the relevant structure for this case because it is the prudent and reasonable structure that continues to support the Company's target credit ratings, which in turn allows the Company to continue attracting debt investment at an attractive cost basis.

Q. How does the equity component of DENC's actual capital structure as of June 30, 2019, compare to the equity component of the Company's year-end capital structure for the previous three years and to the forecasted capital structure as of December 31, 2019?

A. It is very similar. As discussed in my pre-filed direct testimony, since the Commission most recently set DENC's base rates in Docket No. E-22, Sub 532 ("2016 Rate Case"), the Company's year-end and forecasted 2019 year-end capital structures fall within a narrow band between 52.1% and 53.6% and are as follows:

	Actual Equity Ratio	Actual Debt Ratio
12/31/16	53.192%	46.808%
12/31/17	52.106%	47.894%
12/31/18	53.3006%	46.994%
6/30/19	53.649%	46.351%
12/31/19 (projected)	53.089%	46.911%

Q. **Do you have a forecast for the capital structure at year-end of 2019?**

A. Yes. As shown above DENC projects that its capital structure at year-end will consist of approximately 53.089% equity. Please see Company Rebuttal Exhibit RMD-1, Schedule 2 for a summary of this projected capital structure. The equity percentage in the year-end forecast decreases slightly from the June 30, 2019 actual capital structure. This is primarily due to a long-term bond issuance that was completed on July 10, 2019 ($500 million, 10-yr Bond) and an expected issuance later in 2019.

Q. **What does this forecast tell you about the Company's proposed capital structure in this case?**

A. The forecast tells me that DENC's proposed capital structure of 53.649% equity and 46.351% long-term debt is not only reasonable because it is in line with historical results but also because it is consistent with the Company's structure as it is projected for the end of this year.

Q. **Why is it important that the Company's actual capital structure be considered in determining the appropriate capital structure for purposes of this case?**

A. It is important to use the Company's actual capital structure, and not an arbitrarily imputed structure, for several reasons. First, the suggestion of an imputed structure reflecting a proxy group of peer utilities in differing jurisdictions (with differing jurisdictional definitions for capital structure) can lead to erroneous conclusions. For example, when the capital structure of the proxy group is not properly adjusted to reflect the jurisdictional definition of the target entity, comparative capital structures can appear significantly higher or lower than the target and can appear out of line.

Second, the Company's financing plan is constructed with an eye towards maintaining current ratings, which DENC believes benefit customers in the long-term by allowing the Company consistent access to the capital markets at attractive rates. One component of DENC's current ratings is, for each agency, an analysis of the regulatory environments within which the Company operates. Each of the agency rating methodologies for regulated utilities differentiates between supportive frameworks and less supportive frameworks and, if the Commission assigns an arbitrarily derived capital structure in setting the Company's rates, the rating agencies could view this negatively in assigning DENC's credit ratings, potentially leading to consideration for a downgrade.

Finally, it is the Company's view that it is important to utilize the actual capital structure to support the significant capital spending program that the Company has and continues to undertake to enhance and improve DENC's generation and transmission infrastructure. These significant investments will require frequent capital market access. As discussed above, maintaining DENC's credit ratings will continue to allow the Company the capital market access that will be required during this period of continued capital expansion projects.

Q. Does Mr. Phillips rely on any proxy groups in support of his recommended capital structures?

A. Yes. Mr. Phillips offers in support of his recommended capital structure peer "proxy groups" that he claims exhibit the various jurisdictional regulatory capital structures of a comparable group of electric utility companies. He references groups that consist of all electric utilities nationwide with equity ratios determined in the first half of 2019 and North Carolina gas and electric utilities that have had authorized ROEs approved in recent years.

Q. Do you agree with Mr. Phillips' reliance on these proxy groups?

A. No. Although Mr. Phillips presents his final recommended capital structure for DENC in line with the Commission's policy of excluding short-term debt from electric utility capital structures, it is not clear that that is the case for all of the peer companies that he selected for the proxy groups used in his analysis. It is difficult to determine a truly comparable capital structure within a proxy group of peer utilities that operate in different regulatory jurisdictions due to the fact that not all regulatory jurisdictions define capital structures in the same manner. Some jurisdictions include and/or exclude different balance sheet items such as short-term debt, income tax items, customer deposits, Accumulated Other Comprehensive Income ("AOCI"), average balances versus period end balances, etc. Due to the variable nature of the equity ratio calculation across regulatory jurisdictions and the resultant capital structures of the representative peer groups, it is important to make appropriate adjustments in order to be able to view different capital structures on an equal basis.

Additionally, while Mr. Phillips states that DENC's requested capital structure is inconsistent with those authorized by the Commission in recent general rate cases, the Company believes that its actual capital structure is the most reasonable and appropriate structure because it fairly reflects DENC's actual operating experience, capital markets activity and is also, as I have explained, consistent with the Company's year-end capital structure over the past few years.

Q. What is the most problematic common concern you have with Mr. Phillips' recommendations?

A. My biggest concern is that no reasonable and appropriate rationale is given, and no framework provided, for his recommendations regarding an alternative capital structure to the Company's June 30, 2019 actual capital structure. He simply relies upon the average of his "proxy groups" to conclude that because the proposed period-end capital structure is higher than the averages of the proxy groups, it is too high.

In my direct testimony, I discuss how the Company, through a well-defined, consistent, and disciplined approach, determines the mix of debt and equity capital in DENC's capital structure. DENC develops the capital structure with an objective of achieving and maintaining credit metrics that are supportive of its credit ratings, which will allow the Company continued access to the capital and money markets on terms and conditions that will provide a long-run benefit for its customers. The amount of equity (not necessarily the percentage of equity in the capital structure) necessary to achieve those objectives is a <u>result</u> of the process, and represents the one element that is within DENC's control as a means to achieve these objectives. It is absolutely critical that the Company achieve these objectives so that DENC can maintain access to the capital markets.

Mr. Phillips offers no criticism or objection to the Company's approach to meeting its financial objectives, or the appropriateness of those objectives. Nor does he question whether the resultant capital structure is, or is not, supportive of those objectives. He simply observes that the equity capitalization ratio, which happens to be the actual ratio as of a point in time, is higher than an average that he has calculated from a broad group of companies, and cite that fact as evidence that the Company's actual capital structure is somehow inappropriate. Without any additional support for his alternative capital structure proposals, Mr. Phillips' proposal should not be considered a valid alternative to the Company's actual capital structure.

Q. **Would you please summarize your rebuttal testimony?**

A. The Company's proposed capital structure of an equity component of 53.649% and a long-term debt component of 46.351% is appropriate for use in establishing the Company's rates in this case, because it is based on the Company's actual capital structure as of June 30, 2019, and because it will enable the Company to access capital markets on reasonable terms during the ongoing intensive capital investment efforts that the Company is undertaking. Mr. Phillips' proposed capital structure should not be accepted for the reasons I have discussed in this testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

TESTIMONY
OF
RICHARD M. DAVIS, JR.
IN SUPPORT OF AGREEMENT AND STIPULATION OF SETTLEMENT
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

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

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

Q. Are you the same Richard Davis who filed direct, supplemental, and rebuttal testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to support the Agreement and Stipulation of Settlement the Company reached with the North Carolina Utilities Commission Public Staff ("Public Staff") (together, the "Stipulating Parties"), and filed with the Commission on September 17, 2019, in this docket (the "Stipulation") as it relates to the capital structure to be used in setting rates in this proceeding.

Q. What capital structure is reflected in the Stipulation?

A. The Stipulation provides for a capital structure consisting of an equity component of 52.00% and a long-term debt component of 48.00%. This capital structure represents a compromise by both parties in an effort to reach agreement. The settlement recommendation of 52.00% for the equity ratio is 165 basis points lower than the Company's request of 53.649% (which represents DENC's actual June 30, 2019, equity ratio when short-term debt is removed from the capital structure). This equity ratio is also 200 basis points higher than the Public Staff's initial recommendation as presented in the testimony of Public Staff Witness J. Randall Woolridge,[1] and 25 basis points higher than the Commission-authorized equity ratio in the 2016 DENC rate case.

Q. What is the Company's overall cost of capital when this capital structure and the cost of capital are accounted for?

A. Taken together with the return on equity of 9.75% presented by Company Witness Hevert and the 4.442% debt cost rate, which was not contested, the capital structure reflected in the Stipulation results in an overall cost of capital of 7.202%, as shown in Figure 1 below.

[1] Dr. Woolridge also presented an alternative rate of return recommendation that used DENC's actual June 30, 2019, equity ratio of 53.649%, combined with a recommended return on equity of 8.75%.

VIRGINIA ELECTRIC AND POWER COMPANY

Cost of Capital and Capital Structure

Actual June 30, 2019 Balances with Proposed ROE

Description	Q2 2019 Amount	Q2 2019 Percent	EOP Q2 2019 Annualized Cost Rate	Q2 2019 Weighted Cost
Total Long-Term Debt	$11,192,889,951	46.351%	4.442%	2.059%
Total Debt	11,192,889,951	48.000%	4.442%	2.132%
Common Equity:				
Common Stock & Other Paid-in Capital	6,850,277,118	28.368%		
Retained Earnings	6,104,778,627	25.281%		
Total Common Equity	12,955,055,745	52.000%	9.750%	5.070%
Total Capitalization	$24,147,945,696	100.000%		7.202%

Q. Is the 52.00% equity ratio a reasonable result?

A. Yes. While I continue to believe that the Company's actual capital structure is the most relevant capital structure to use in establishing the Company's rates in this proceeding, I also believe that the stipulated capital structure of 52% equity and 48% long-term debt represents a reasonable compromise when considered within the context of the Stipulation taken as whole, including the stipulated ROE of 9.75%. When considered within the larger negotiation on all non-CCR issues in this proceeding, I believe this result to be fair and reasonable with respect to customers and shareholders. While the equity component of the settled capital structure is less than the 53.649% I supported in my earlier testimony in this proceeding, I believe an equity component of 52.00% will still allow DENC to maintain reasonable access to financing in the capital markets in order to fund the significant investments it has planned for the next several years. I believe this level of equity component will when combined with the stipulated cost of equity of 9.75% enable 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.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MS. KELLS:

Q Mr. Davis do you have a summary of your testimonies?

A Yes, I do.

Q Would you please present it for the Commission?

A Sure. My direct testimony presents the Company's capital structure as of December 31st, 2018, and the Company's cost of debt and proposed weighted average cost of capital for use in establishing rates in this case. I discuss the Company's credit profile and the importance of maintaining strong credit ratings as we continue to make significant capital investments for the benefits of our customers. I also address how DENC's significant capital needs should be considered in setting the overall cost of capital and proposed return on equity, or ROE, in order to balance the Company's capital requirements with the interests of customers. I echo the testimony of Company Witness Mark Mitchell as to the significant capital investments of over $4 billion DENC has made system-wide since its 2016 rate case and the planned investments going forward. These investments will strengthen DENC's entire interconnected system, benefiting our North Carolina customers with a more stable, reliable system for years to come. However, the

Company will need reasonable access to financing in the capital markets in order to fund these significant investments.

In my supplemental testimony I update the Company's actual capital structure as of June 30th, 2019, to 53.649 percent equity and 46.351 percent long-term debt. I also update the Company's cost of debt to 4.442 percent and the overall weighted average cost of capital to 7.826 percent.

My rebuttal testimony addresses the testimony of CIGFUR Witness Nicholas Phillips, Jr. as his testimony relates to the capital structure to be employed in establishing rates in this proceeding. I continue to support the proposed capital structure presented in my supplemental testimony as appropriate for use in establishing the Company's rates in this proceeding.

In my testimony in support of the Agreement and Stipulation of Settlement I explain the Company's support of the Stipulation as it relates to the capital structure to be used in setting rates in this proceeding. The Stipulation between the Company and the Public Staff provides for a capital structure consisting of 52.00 percent common equity and 48.00 percent of long-term debt. The Stipulating Parties also agreed to the

Company's cost of debt of 4.442 percent, which when combined with the stipulated ROE of 9.75 percent results in an overall weighted cost of capital of 7.202 percent. While the equity component of the stipulated capital structure is below that reflected in the Company's actual capital structure as of June 30th, 2019, it is my opinion that the stipulated capital structure and overall weighted average rate of return will still allow the Company to access capital markets on reasonable terms in order to secure the capital required to make the significant investments DENC is planning and will therefore benefit our North Carolina customers.

I also support the Stipulation entered into by the Company and CIGFUR filed today in this proceeding for the same reasons discussed in my testimony in support of the Stipulation with Public Staff. Thank you.

MS. KELLS: The witness is available for cross exam.

CHAIR MITCHELL: Thank you. At this point we're going to take a break. We will come back into the hearing room, go back on the record at 3:50. Let's go off the record, please.

(Recess taken from 3:35 p.m. to 3:50 p.m.)

CHAIR MITCHELL: Okay. Let's go back on the record, please.

MS. KELLS: I think the witness was available for cross.

MS. HARROD: No questions.

MS. KELLS: I think that's a change, right?

MS. HARROD: The Attorney General did have some time reserved, but we don't have any questions.

CHAIR MITCHELL: Is there any additional cross examination for this witness?

(No response.)

CHAIR MITCHELL: Questions from the Commission for this witness?

(No response.)

CHAIR MITCHELL: Okay. Mr. Davis, you may step down. Thank you.

THE WITNESS: Thank you.

MS. KELLS: May he be excused as well?

CHAIR MITCHELL: He may be excused.

MS. KELLS: Thank you.

THE WITNESS: Thank you.

(Witness excused.)

CHAIR MITCHELL: Okay. Dominion, call your next witness, please.

MS. GRIGG: Thank you, ma'am. Dominion calls

Mr. Paul McLeod.

PAUL M. McLEOD; Having been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MS. GRIGG:

Q Good afternoon, Mr. McLeod.

A Good afternoon.

Q Would you please state your name and business address for the record.

A My name is Paul McLeod. My address -- my business address is 120 Tredegar Street, Richmond, Virginia, 23219. I'm a Regulatory Consultant with the Regulatory Accounting Group for the Company.

Q Did you cause to be prefiled in this docket on March 29th, 2019, 53 pages of direct testimony in question and answer form and Appendix A and two exhibits?

A Yes.

Q Did you also cause to be filed in this docket on August 5th, 2019 32 pages of supplemental testimony in question and answer form, two exhibits, and an Appendix A?

A Yes.

Q Did you also cause to be filed in this docket on September 12th, 2019, seven pages of second supplemental testimony in question and answer form and one exhibit?

A Yes.

Q Did you also cause to be prefiled in this docket on September 27th, 2019, eight pages of Stipulation testimony in question and answer form and one exhibit?

A Yes.

Q Do you have any changes or corrections to your testimonies that you would like to make at this time?

A Yes. I do have a couple of corrections.

COMMISSIONER GRAY: Please pull the microphone towards you, please.

THE WITNESS: Oh. Sorry.

A I do have a couple of corrections to make. First, in my direct testimony on page 2, line 4, where it says 20-month period, that should say 22-month period. Similarly, on page 52 of my direct testimony, line 3, that should also say 22-month period rather than 20.

Q Any further corrections?

A Yes. I do have a correction to my Stipulation testimony. On page 7, line 15, where it says as discussed further, you can strike out that whole line 15 and then on line 16 through the end of that sentence.

Q Thank you. And with those corrections, if I were to ask you the same questions that appear in your testimonies today, would you answers be the same?

A Yes, they would.

MS. GRIGG: Chair Mitchell, at this time I would move that the prefiled direct, supplemental, second supplemental, and Stipulation testimony of Mr. McLeod be copied into the record as if given orally from the stand and his exhibits be marked for identification as prefiled.

CHAIR MITCHELL: Hearing no objection, your motion will be allowed.

MS. GRIGG: Thank you.

(Whereupon, the prefiled direct, as corrected, supplemental, second supplemental, and Stipulation testimony, as corrected, of Paul M. McLeod were copied into the record as if given orally from the stand.)

(Whereupon, Company Exhibits PMM-1 and PMM-2, Company Supplemental Exhibits PMM-1 and PMM-2, Company Second Supplemental Exhibit PMM-1, and Company Stipulation Exhibit PMM-1 were identified as premarked.)

**DIRECT TESTIMONY
OF
PAUL M. MCLEOD
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562**

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

A. My name is Paul M. McLeod, and my business address is 701 East Cary Street, Richmond, Virginia 23219. I am a Regulatory Specialist with the Regulatory Accounting Group for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). A statement of my background and qualifications is attached as Appendix A.

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

A. The purpose of my testimony is to support the Company's proposed increase to North Carolina retail annual non-fuel revenue of approximately $27.0 million. My testimony includes an overview of the significant issues involved in developing the revenue requirement, an explanation of my sponsored 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").

I also discuss the impact of the federal Tax Cuts and Jobs Act of 2017 ("TCJA"), including the Company's methodology for addressing excess deferred federal corporate income taxes ("federal EDIT") for ratemaking purposes. Specifically, the Company proposes to begin amortizing federal EDIT on January 1, 2018. Since the Company is proposing new base rates to go into effect on November 1, 2019, federal EDIT amortization attributable to the 20-month period January 1, 2018 through October 31, 2019, will be credited to customers through a one-year decrement rider, Rider EDIT, with a total proposed credit of $6,909,000. Company Witness Paul D. Haynes further describes the Company's planned implementation of Rider EDIT. For periods after October 31, 2019, the Company's revenue requirement in the instant case includes a $3.6 million reduction which is reflective of the income tax benefit arising from annual amortization during the Test Year, thereby incorporating a going-level of federal EDIT amortization in base non-fuel rates.

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

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

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Company Exhibit PMM-1 which supports the revenue requirement and requested revenue increase and Company Exhibit PMM-2 which supports the calculation of EDIT and related amortization allocable to the North Carolina jurisdiction. Company Exhibit PMM-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

Company Exhibit PMM-2 consists of the follow schedules, which are discussed later in my testimony.

Schedule 1 – EDIT Balances as of December 31, 2017

Schedule 2 – North Carolina Jurisdictional EDIT Amortization

Schedule 3 – Rider EDIT Total Revenue Credit

These Exhibits were prepared under my supervision and direction, and are accurate and complete to the best of my knowledge and belief.

Q. 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, 2019, with new permanent rates requested to become effective on and after January 1, 2020. My analysis shows the Company is currently earning a return on common equity capital of 7.52% during the fully-adjusted test period presented in my Schedule 1.

Q. Does the revenue requirement presented in this proceeding incorporate an updated base fuel component?

A. As further described by Company Witness Haynes, the Company is proposing a "placeholder" base fuel rate in the Application based on the current base fuel rates plus Fuel Rider A approved by the North Carolina Utilities Commission ("NCUC" or "Commission") in the Company's most recent fuel proceeding, Docket No. E-22, Sub 558 ("2018 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 2019. 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 532 ("2016 Rate Case").

Q. Have you made 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. While the Company's direct case reflects a placeholder base fuel rate based on the current base fuel rates plus Fuel Rider A, I incorporated certain changes in the composition of costs recovered through non-fuel rates. As discussed by Company Witness Bruce E. Petrie, due to the enactment of North Carolina House Bill 589 on July 27, 2017, and House Bill 374 on June 27, 2018, the Company can now recover the total delivered costs, including capacity and non-capacity costs, associated with certain purchases of power from qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 ("PURPA") that are not subject to economic dispatch or curtailment. My accounting adjustments to purchased power capacity and energy expenses have removed such costs from the base non-fuel rate revenue requirement. Additionally, the adjustments to purchased energy expenses reflect an updated marketer percentage of 71% supported by Company Witness Petrie. The base fuel rate revenue requirement in the supplemental filing will reflect the 71% marketer percentage.

I. OVERVIEW OF BASE RATE REVENUE REQUIREMENT

Q. Please define the term "revenue requirement" as discussed in your 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. My 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 Robert B. Hevert. This revenue requirement is compared to the operating revenues under existing rates in order to determine the increase in revenue required by the Company.

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 ending December 31, 2018 ("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, 2019 ("Update Period"), based on budgetary information. These adjustments will be updated with actual information in a supplemental filing in August 2019.

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 7.52%. The Company is requesting a base non-fuel revenue increase of approximately approximately $27.0 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 7.79%. The overall rate of return is based on the Company's capital structure and cost of debt supported by Company Witness Richard M. Davis, and an ROE of 10.75% supported by Company Witness Hevert.

Q. Before you discuss the significant factors contributing to the Company's need for a revenue increase, please briefly discuss the Company's most recent base rate case.

A. On March 31, 2016, the Company filed an application initiating its 2016 Rate Case. The test period in the 2016 Rate Case was calendar year 2015 with general updates through June 30, 2016. The Commission's *Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions* issued on December 22, 2016 ("2016 Rate Order") authorized an overall increase of $25.8 million, consisting of an increase of $34.7 million in base non-fuel revenues. The Commission approved an ROE of 9.90% in its determination of the revenue requirement. The base non-fuel revenue increase was partially offset by a decrease of $8.9 million in base fuel revenues, with new base non-fuel and fuel rate becoming effective on a permanent basis on January 1, 2017.[1] The 2016 Rate Order also approved implementation of a decrement rider to flow $16.8 million of EDIT benefits associated with reductions in the North Carolina corporate tax rate to customers over a 2-year period ending in October 2018.

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 during the past three years since the 2016 Rate Case. As discussed by Company Witness Mark D. Mitchell, the Company has

[1] 2016 Rate Order, page 147.

continued investing in new generating facilities in order to meet load growth and respond to plant closures driven by environmental regulations. The Greensville County Power Station ("Greensville County CC"), a 1,588 MW (nominal) natural gas-fired combined cycle electric generating facility, began commercial operations in December 2018. The total system level costs for the Greensville County CC were approximately $1.3 billion (excluding financing costs).

The Company has also made substantial investments in its transmission and distribution systems since the 2016 Rate Case. Company Witness Bobby E. McGuire describes the Company's transmission investments to meet federal reliability standards, and provides details on the Company's efforts to expand and strengthen both its transmission and distribution 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.

My Figure 1 depicts the approximate revenue requirement impact of total projected growth in net plant in service as of the end of the Update Period (June 30, 2019) as compared to the amount approved in the 2016 Rate Case. The Company updated rate base through June 30, 2016 in the 2016 Rate Case.

FIGURE 1

Dominion Energy North Carolina
Projected Growth In Net Plant In Service By Function - North Carolina Jurisdiction
Revenue Requirement Effect
(Millions of Dollars)

Line	Description	(1) 2019 Base Rate Case		(2) 2016 Base Rate Case		(3) Total Growth	
		Note 1		Note 2		(1) - (2)	
1	Generation	$	634.6	$	601.9	$	32.7
2	Transmission	$	340.5	$	278.8	$	61.7
3	Distribution	$	356.1	$	316.6	$	39.5
4	Other	$	32.5	$	33.0	$	(0.6)
5	Total	$	1,363.6	$	1,230.4	$	133.2
6	Accumulated Deferred Income Taxes (ADIT)	$	279.6	$	250.8	$	28.8
7	Net Plant Including ADIT (Line 5 - Line 6)	$	1,084.0	$	979.6	$	104.4
8	Pre-Tax Weighted Cost of Capital (Note 3)						9.75%
9	Revenue Requirement					$	10.2
10	Depreciation Expense	$	63.7	$	53.2	$	10.5
11	Approximate Revenue Requirement Impact of Projected Growth in Net Plant (Line 9 + Line 10)					$	20.7

Note 1: Projected North Carolina jurisdictional net plant in service as of June 30, 2019
Note 2: North Carolina jurisdictional net plant in service approved in the 2016 Base Rate Case
Note 3: DENC's approved weighted cost of capital from the 2016 Base Rate Case

The table shows projected growth in net plant in service including accumulated deferred income taxes ("ADIT") since the 2016 Rate Case of $104.4 million. The revenue requirement associated with this considerable increase in plant investment is $20.7 million ($10.2 million of financing costs and $10.5 million annual depreciation expense), which represents 77% of the total requested base non-fuel rate increase.

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, 2016 through June 30, 2019 in continued compliance with federal and state environmental regulations associated with managing coal combustion residuals ("CCR") at several of DENC's generating stations. The CCR regulations requiring these CCR remediation activities are discussed by Company Witness Jason E. Williams, and the Company's CCR-related costs are discussed by Company Witness Mitchell.

II. RATE OF RETURN STATEMENT – ADJUSTED

Q. Please describe Schedule I of Company Exhibit PMM-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").[2] The rate base section in Column 1 is a summary of rate base for

[2] 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.

the total VEPCO system. Schedule 2 of Company Exhibit PMM-1 contains the Rate Base Statement – Adjusted that includes more details on the Company's rate base. I discuss Schedule 2 later in my 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 PMM-1 provides an itemized listing of each accounting adjustment in Column 4 of Schedule 1.

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 7.52%.

This return is lower than the Company's current cost of common equity of 10.75% as supported by Company Witness Hevert 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 incremental revenue requirement of approximately $27.0** million. **What does this incremental revenue requirement represent?**

A. The incremental revenue requirement on Line 6, Column 6 of Schedule 1 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 incremental revenue requirement in Column 6 of Schedule 1 calculated?**

A. The incremental revenue requirement is 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 10.75%. 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 incremental operating income requirement to the incremental revenue requirement of approximately approximately $27.0 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. Please describe Schedule 2 of Company Exhibit PMM-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 PMM-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. What is the purpose of Schedule 3 of Company Exhibit PMM-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 (referred to as regulatory accounting adjustments), 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 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, 2019	19
NC-2 and NC-9 – Eliminate DSM and REPS Rider Revenues and Costs	19
NC-3, NC-7, NC-8 and NC-31 – Annualize Fuel Revenues and Expenses at Current Rates	20
NC-5 – Normalization of Ancillary Services Margins	20
NC-10, NC-35, NC-56, NC-64, NC-67, NC-73 and NC-79 – Eliminate the Effects of ASC 410-20 – Asset Retirement Obligations	21
NC-11 – Update Purchased Power Capacity	22
NC-12 – Update Purchased Power Energy	23
NC-13 – Normalize Fossil & Hydro Planned Outage Expense	23
NC-14 – Levelize Nuclear Refueling and Maintenance Outage Expense	24
NC-15 – Eliminate Yorktown Unit 1 and 2 Net Operating Expense	25

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, 2019.

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 acts to mitigate 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 2019 that updates the estimates with actual June 30, 2019 results. This approach is also consistent with the Company's approach in prior rate cases.

Q. Why did the Company select June 30, 2019 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, 2019, or amounts based on the level included in the twelve months ending June 30, 2019.

Q. 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, 2019

The Company annualized base non-fuel tariff revenues based on projected customer levels and weather normalized usage as of June 30, 2019. In this proceeding, this adjustment is a net reduction to revenue, primarily reflecting the annualized impact of a return to normal weather on customer usage. Company Witness Haynes 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-31 – 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, 2019. In conjunction with this adjustment to fuel clause revenue, an adjustment is made to duel clause expense to make fuel clause expense equal to fuel clause revenue, net of the regulatory fee.

Adjustment NC-5 – Adjust Ancillary Services 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 2019. 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 was 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 2019.

Adjustments NC-10, NC-35, NC-56, NC-64, NC-67, NC-73 and NC-79 – Eliminate the Effects of ASC 410-20 – Asset Retirement Obligations ("ARO")

Statement of Financial Accounting Standard ("SFAS") No. 143 (now codified as Accounting Standard Codification ("ASC") 410) 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. In Docket No. E-22, Sub 420, the Commission stated the following regarding the ratemaking treatment of AROs:

> That the adoption of SFAS 143 shall have no impact upon [DCNP]'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 [DCNP]'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.[3]

Each of these regulatory accounting adjustments is necessary to eliminate the effects of ARO accounting pursuant to ASC 410-20 from the North Carolina jurisdictional cost of service. The Commission has historically provided for

[3] *Order Allowing Utilization of Certain Accounts,* Docket No. E-22, Sub 420, (Aug. 06, 2004) ("2004 ARO Accounting Order"), Ordering paragraph 2.

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. During the Test Year, the Company also recognized ARO-related expenses in accordance with ASC 410-20 related to future CCR ash pond and landfill closure costs, the effects of which have been eliminated as part of this adjustment.

Adjustment NC-11 – Update Purchased Power Capacity

The change in capacity costs for the twelve months ending June 30, 2019, reflects the ongoing level of costs of capacity purchased from the PJM capacity market, non-utility generators ("NUG"), 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, 2019. 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, including the Greensville County CC. The normalized PJM purchased capacity rate was based on the average of the 10 years from June 1, 2013 through May 31, 2022. This period of time represents both a historical range and three forward delivery years.

The NUG capacity purchases are based on an estimate for the twelve months ended June 30, 2019 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 QFs under PURPA that are not subject to economic dispatch or curtailment. The Company will reflect these costs as recoverable through the fuel clause in its 2019 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, 2019. As discussed by Company Witness Petrie, the Company proposes to use an updated marketer percentage of 71% for purchased energy costs from PJM for recovery through the base fuel component. Company Witness Petrie also discusses that all energy purchases from NUGs will be reflected as a component of the fuel clause when the Company files its 2019 fuel case. As such, this adjustment eliminates 71% of the Company's energy costs purchased from PJM from the purchased power energy estimate and recognizes the impact of moving all NUG energy purchases to base fuel rates.

Adjustment NC-13 – Normalize Fossil & Hydro Planned Outage Expense

The Company has a diverse portfolio of fossil and hydro generating units. These units use different fuel sources and technologies, are dispatched at different rates, and are of different ages. All of these factors contribute to the frequency and level of maintenance required on any given unit and can influence or alter the timing of planned outages. As a result, there is not a consistent pattern of maintenance expenses from year to year, or even over various cycles of years.

Due to the variability of expense year to year, it is appropriate to normalize these expense for ratemaking purposes to smooth out variability and the impact on the North Carolina retail cost of service. Further, over the next several years, there are significant outages scheduled for the Company's newer combined-cycle natural gas units. This adjustment utilizes a five-year historical average of fossil and hydro maintenance outage expenses, adjusted for inflation, to calculate an appropriate level of expenses for ratemaking purposes in this case.

Adjustment NC-14 – 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-15 – Eliminate Yorktown Power Station ("Yorktown") Units 1 and 2 Net Operating Expense

The Company ceased operations of Yorktown units 1 and 2 on March 8, 2019. This adjustment eliminates all net operating expenses attributable to units 1 and 2 during the Test Year in order to remove the impact of such operating expenses from the revenue requirement going forward. The amortization of previously deferred impairment costs and the Company's proposal to defer closure costs are discussed later in my testimony.

Adjustment NC-16 – Annualize Greensville County CC O&M

As previously discussed, the Greensville County CC began commercial operation in December 2018. Once operations commenced, the Company began incurring ongoing O&M expenses associated with running the facility. This adjustment includes an annualized level of non-labor O&M expense based on projected average monthly expenses during 2019.

Adjustment NC-17 – Annualize Salary and Wages as of June 30, 2019 – 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 2018 including the budgeted merit increase of 3% in March 2019.

Adjustment NC-18 – Annualize Salary and Wages as of June 30, 2019 – 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 2018 including the actual merit increase of 2.75% in March 2019.

Adjustment NC-19 – Annualize Salary and Wages as of June 30, 2019 – Services Company

Salaries and wages for Dominion Energy Service, Inc. ("DES") employees are annualized based on the Test Year ending headcount and actual average rate during the month of December 2018 including the budgeted merit increase of 3% in March 2019.

Adjustment NC-20 – Adjust Employee Benefits Costs to June 30, 2019

Employee benefit costs are adjusted based on the six months of actual benefits costs for July through December 2018 and six months of projected benefits costs for January through June 2019. 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-21 – Normalize Employee Severance Program Costs

This adjustment includes a normalized level of employee severance costs in the cost of service based on the Company's historical experience over the past 24 years. During the period 1994 through 2018, there were 5 major corporate-wide severance programs instituted by the Company, resulting in an average of approximately one every five years.

Adjustment NC-22 – 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-23 – 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-24 – DES Office Building Adjustment

During the second quarter of 2019, the Company plans to begin occupying a new office building, 600 Canal Place, which is currently under construction in Richmond, Virginia. The Company currently forecasts that DES will begin making payments under its lease agreement in May 2019 for use of the new building by and employees of DENC and DES. This adjustment incorporates an annualized amount of costs for DENC's direct occupancy of the new building (based on headcount), as well as DENC's billable portion of expenses from DES based on DES's existing methodology to bill its office space and equipment expenses to affiliates. Additionally, the Company expects to cease occupying and leasing from Dominion Energy Inc. its existing office space in One James River Plaza by June 2019. This adjustment reflects the net effect of increased annual expenses related to 600 Canal Place and removal of existing costs related to the expiring lease of One James River Plaza.

Adjustment NC-25 – 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 2010-2018 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-26 and NC-88 –Transmission Rate Design Settlement

Since November 2016, the Company's transmission cost of service has included net credits associated with major new transmission enhancement projects developed in accordance with PJM's Regional Transmission Expansion Plan ("RTEP"). In its invoices from PJM, DENC receives credits for the Company's own RTEP projects and charges for the allocated portion of total RTEP program for which the Company is responsible.

In August 2018, DENC began making payments pursuant to a FERC-approved settlement resolving issues associated with rate design for the allocation of transmission enhancement costs among PJM transmission customers. The majority of these payments relate to RTEP charges and credits from periods prior to November 2016, and therefore, are excluded from the cost of service developed in this proceeding. Adjustment NC-26 eliminates the impact of these settlement payments. Additionally, Adjustment NC-26 annualizes the net RTEP credits received during the six month period from July through December 2018 as representative of DENC's going-forward level of RTEP credits for ratemaking purposes in this proceeding. Adjustment NC-88 removes ADIT associated with the accrued liability for the FERC-approved settlement.

Adjustment NC-27 – Eliminate Promotional Advertising Expenses

This adjustment eliminates all promotional advertising expenses from the Test Year.

Adjustment NC-28 – Adjust Uncollectible Expense

The Company adjusts uncollectible expense based on an historical average uncollectible expense rate. This rate is applied to the fully-adjusted North Carolina jurisdictional operating revenues to derive the ratemaking level of uncollectible expense.

Adjustment NC-29 – Reclassify Certain Non-Operating Expenses

This adjustment eliminates certain expenses associated with ongoing maintenance of a beneficial use site that are considered non-operating.

Adjustment NC-30 – 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-32 – Amortize Chesapeake Energy Center ("CEC") Closure Cost Regulatory Asset

CEC was retired from service in December 2014. The Company began incurring decommissioning costs and other site costs in connection with the closure in 2013 prior to retirement. Consistent with the 2016 Rate Order for costs deferred through June 30, 2016, this adjustment includes amortization of costs deferred from July 1, 2016 through June 30, 2019, to be recovered over a three year period.

Adjustment NC-33 – Amortize CCR Expenditures Regulatory Asset

In April 2015, the Environmental Protection Agency's ("EPA") final rule regulating the management of CCR stored in impoundments (ash ponds) and landfills was published in the Federal Register ("CCR Rule"). As discussed by Company Witness Williams, the CCR Rule obligates the Company to perform ash pond closure activities at affected generating stations. Witness Williams provides additional detail on DENC's ongoing efforts to close such ash ponds, as required under the CCR Rule.

Pursuant to the 2016 Rate Order, the Company was permitted to recover CCR ARO-related cash expenditures incurred through June 30, 2016 over a five year amortization period and to defer subsequent costs to be evaluated for recovery in future rate cases.[4]

From the period July 1, 2016 through the end of the Test Year, the Company's CCR-related cash expenditures totaled $334.7 million, and the Company anticipates spending an additional $55.7 million during the Update Period, resulting in total projected cash expenditures of $390.4 million. The North Carolina jurisdictional portion of these expenditures is $19.9 million which the Company proposes to recover over a three-year amortization period. This accounting adjustment also reflects the financing cost associated with these expenditures incurred during the July 1, 2016 through June 30, 2019 spending period totaling $2.8 million based on the weighted-average cost of capital approved in the 2016 Rate Case.

Adjustment NC-34, NC-42, NC-61, NC-66 and NC-90 – Adjust Existing Regulatory Assets

These adjustments address the amortization and rate base balances associated with the following existing regulatory assets:

Warren County CC and Brunswick County CC Deferrals – These regulatory assets will be fully-amortized before the date permanent rates in this

[4] 2016 Rate Order, at 63, 149.

proceeding become effective (January 1, 2020). This adjustment eliminates the amortization and rate base associated with these regulatory assets.

Yorktown Impairment Deferral –Yorktown Units 1 and 2 and the associated common assets were impaired for financial reporting purposes in 2011, the test period in the Company's 2012 Rate Case.[5] The Commission allowed for the impairment losses to be deferred for financial reporting purposes in the 2012 Rate Case.[6] However, the Commission deferred contemplation of the retirement of CEC and Yorktown until the facilities are physically retired from service.[7] Costs associated with the Yorktown impaired assets are incorporated into the cost of service through a separate accounting adjustment discussed later in my testimony. As such, the amortization and balances of the regulatory assets net of ADIT per books are eliminated.

North Branch Power Station ("North Branch") and CEC Impairments – North Branch and CEC were also impaired for financial reporting purposes in 2011, the test period in the Company's 2012 Rate Case. The Commission allowed for recovery of the North Branch and CEC impairments on a levelized basis over a ten-year period.[8] 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

[5] *See Order Granting General Rate Increase*, Docket No. E-22, Sub 532 (Dec. 21, 2012) ("2012 Rate Order").
[6] 2012 Rate Order, Finding of Fact No. 26.
[7] 2012 Rate Order, Finding of Fact No. 25.
[8] For North Branch see 2012 Rate Order, Finding of Fact No. 17. For CEC see 2012 Rate Order, Finding of Fact No. 20.

requirement level which includes both the principal and return 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.

Other Expiring Regulatory Deferrals – The regulatory deferrals associated with the Department of Energy Settlement, Bear Garden Deferral, certain NUG Buyouts and prior CEC closure costs will be fully-amortized before the date permanent new base rates are proposed to become effective (January 1, 2020). This adjustment eliminates the amortization and rate base associated with these expiring regulatory assets.

CCR Expenditures Regulatory Asset – Costs associated with CCR Expenditures being proposed for recovery in this proceeding are incorporated into the cost of service through a separate accounting adjustment as discussed previously in my testimony. As such, the amortization and balances of the regulatory assets net of ADIT per books are eliminated.

Adjustments NC-36, NC-71, NC-78 and NC-80 – Eliminate Acquisition Adjustments

These adjustments eliminate acquisition amortization and net balances from rate base.

Adjustments NC-37, NC-75, and NC-82 – Annualize Depreciation Expense

Adjustment NC-37 annualizes depreciation expense based on projected plant in service as of June 30, 2019 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-75 and NC-82 reflect the impact of annualizing depreciation expense on accumulated depreciation and ADIT, respectively.

Adjustments NC-38, NC-46, NC-69, NC-76 and NC 89 – 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.[9] 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.

Adjustments NC-39, NC-47, NC-70, NC-77 and NC-83 – 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.

[9] 2012 Rate Order, Finding of Fact No. 27.

This ensures that the program has no effect on the North Carolina jurisdictional base rate cost of service.

Adjustment NC-40 – Amortize Yorktown Impairment Regulatory Asset

Yorktown units 1 and 2 ceased operations on March 8, 2019.[10] Consistent with the recovery of the CEC impairment loss approved by the Commission in its 2016 Rate Order, the Company proposes to recover the previously deferred impairment loss on a levelized basis over a 10-year amortization period. The Company estimated the Yorktown impairment loss based on the North Carolina jurisdictional net book value as of the March 2019 retirement date, which is derived based on the net plant balances as of December 2011 prior to impairment adjusted for additional capital projects and depreciation expense during the interim years.

As discussed in the letter submitted on March 27, 2019, in Docket No. E-22, Sub 532, the Company estimates spending approximately $1 million in decommissioning expenses on Yorktown units 1 and 2. The Company will evaluate for the August 2019 supplemental filing, and, if necessary, make appropriate adjustments or recommendations regarding ratemaking treatment of such costs.

[10] As required by the 2016 Rate Order, DENC filed a letter with the Commission on March 27, 2019, notifying the Commission of Yorktown's closure and providing estimates of the generating station's undepreciated value and closure costs projected to be incurred. *See* 2016 Rate Order, at Ordering Paragraph 12.

Adjustment NC-41 – Amortize Greensville County CC Deferral

This adjustment amortizes the deferred costs, including a return on investment, associated with the Greensville County CC as requested in the Company's petition filed on March 29, 2019 in Docket No. E-22, Sub 566. The Company is requesting that the incremental costs incurred from the time this major new generating facility was placed into service in December 2018 until such time as the costs will be reflected in the base non-fuel rates approved in this proceeding be deferred and amortized over a three-year period beginning with the effective date the Commission approves new rates in this proceeding.

Adjustments NC-43 and NC-50 – 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-44 and NC-51 – 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-45 and NC-52 – 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 – Amortize Non-Plant Unprotected Federal EDIT

As discussed in Section V of my testimony, the Company did not amortize any non-plant, unprotected federal EDIT during the Test Year. This adjustment reflects an annual level of amortization. See Section VI of my testimony for additional discussion of federal EDIT.

Adjustment NC-49 and NC-53 – Adjust North Carolina State Income Tax for Lower Rate

In 2017, North Carolina Session Law 2017-57 reduced the corporate tax rate from 3% to 2.5% effective January 1, 2019. This adjustment reduces the Test Year state income tax expense to reflect this lower tax rate.

Adjustment NC-54 – Annualize Property Taxes Based on Plant in Service as of June 30, 2019

Property taxes are annualized based on the projected level of plant in service as of June 30, 2019. Property taxes are calculated by applying the ratio of 2018 property tax expense and the December 31, 2018 plant in service balance. This ratio is then applied to the projected level of plant in service as of June 30, 2019.

Adjustment NC-55 – 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-57 – Eliminate AFUDC Income;

Adjustment NC-65 – Eliminate CWIP Accounts Payable and Accrued Payroll; and

Adjustment NC-72 – 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-58 – 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-59 – 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-60 – CWC Effect of Lead/Lag Study and Accounting Adjustments

This adjustment to CWC is based on a lead/lag study prepared using calendar year 2017 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 calculation of the adjusted CWC requirement is included in Schedule 4 of Company Exhibit PMM-1. See Form E-1 Item 14 for workpapers supporting the Company's 2017 lead/lag study.

Adjustment NC-62 and NC--91 – 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-63 and NC-86 – 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-68, NC-74, and NC-81 – Update Plant in Service, Accumulated Depreciation, and ADIT to June 30, 2019

These adjustments update plant in service, accumulated depreciation, and plant-related ADIT to the end of the Update Period (June 30, 2019) based on budgetary information.

Adjustment NC 84 – Eliminate ADIT Related to TCJA Regulatory Liabilities

This adjustment removes ADIT related to regulatory liabilities to be credited to customers for TCJA impacts through mechanisms other than the non-fuel base rates established in this proceeding. These include the one-time bill credit for amounts provisionally collected for the "income tax gross-up" component of rates as well amounts to be credited through a separate decrement rider for the amortization of federal EDIT for the period January 1, 2018, through October 31, 2019. Each of these separate rate mechanisms are discussed later in Section V of my testimony.

Adjustment NC-85 – 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-87 – 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-92 – Eliminate ADIT Related to State Rider EDIT

This adjustment eliminates an ADIT balance associated with the prior Rider EDIT established in the 2016 Rate Case.

Q. **Do you have any additional comments about items that will be addressed in the supplemental filing?**

A. Yes. First, as discussed by Company Witness Mitchell, the Company recently announced that several coal units that were previously placed in a cold reserve state will be retired. Second, in March 2019, Dominion Energy announced it is offering a corporate-wide Voluntary Retirement Program for eligible, non-union employees until April 16, 2019. I will address these items and incorporate the appropriate revenue requirement impacts in the supplemental filing in August 2019.

V. TCJA - FEDERAL EDIT

Q. Mr. McLeod, please provide some background on the TCJA.

A. On December 22, 2017, President Donald J. Trump signed federal tax reform legislation known as the Tax Cuts and Jobs Act of 2017 ("TCJA") into law. Generally speaking, the primary elements of the TCJA that impact DENC include: (i) a reduction in the federal corporate income tax rate from 35% to 21% effective January 1, 2018; (ii) the elimination of Internal Revenue Code Section 199 domestic production activities deduction ("DPAD") effective January 1, 2018; and (iii) a modification to tax depreciation by no longer allowing 50% bonus depreciation in the first year of an asset's tax depreciable life post-September 27, 2017, unless the utility had a written binding contract for the capital expenditure as of that date.

Q. Has the Commission provided specific direction regarding the implementation of rate reductions in response to the TCJA?

A. Yes. On January 3, 2018, the Commission initiated a new proceeding, Docket M-100, Sub 148, to address how the Company and other North Carolina utilities should adjust their North Carolina jurisdictional cost of service and rates in response to the TCJA. The Commission's initial order establishing Docket No. M-100, Sub 148 directed the Company and other utilities to collect the federal corporate income tax expense component of rates on a provisional basis beginning January 1, 2018, pending final disposition of the matter by the Commission. The Commission further directed the utilities, the Public Staff and other interested parties to advise the Commission on how it should proceed in response to the TCJA, specifically including how to account for and treat federal EDIT. The Company initially responded to this order on February 1, 2018, and filed reply comments on February 20, 2019.

After receiving comments from DENC, the Public Staff, as well as numerous other utilities and interested parties, the Commission issued its *Order Addressing the Impacts of the Federal Tax Cuts and Jobs Act on Public Utilities* on October 5, 2018, (the "TCJA Order"), requiring DENC to adjust its non-fuel base rates through a single-issue rate reduction to reflect the lower federal corporate income tax expense. Additionally, the Commission established a new docket, Docket No. E-22, Sub 560, and directed the Company to submit a proposal regarding how it would flow back to customers any amounts provisionally collected since January 1, 2018. The TCJA Order also directed DENC to hold federal EDIT in a regulatory liability account until they can be addressed for ratemaking purposes in the Company's next general rate case proceeding or in three years, whichever is sooner.

Q. Please provide a summary and status of the Company's compliance with the TCJA Order.

A. In response to the TCJA Order, the Company implemented a Commission-approved rate reduction to address certain aspects of the TCJA.[11] Specifically, the adjustments to the Company's rates and charges were designed to provide an overall annual revenue reduction of $14.3 million due to the net reduction in DENC's retail revenue requirement (*i.e.,* the income tax expense component in base rates). Additionally, the Commission approved the Company's proposal to issue to customers a one-time bill credit to reflect a return of amounts collected provisionally for income taxes at the higher tax rate through existing base rates since January 1, 2018. This one-time bill credit will be delivered to customers beginning in April 2019 billing period representing amounts collected on a provisional basis from January 1, 2018 through March 2019.

As for federal EDIT, the Company established an overall regulatory liability position (comprised of regulatory liability and asset accounts, as applicable) at a system level. Hereafter, I will refer to this net regulatory liability position as "federal EDIT". The Company began amortizing plant-related federal EDIT on its books and records at a system level as a reduction to income tax expense with an effective date of January 1, 2018. Such amortization is being deferred to a regulatory liability account in accordance with the TCJA Order.

[11] *Order Approving Proposal and Requiring Filing of Revised Tariffs and Customer Notice*, Docket Nos. M-100 Sub 138, E-22, Sub 532, E-22, Sub 560 (March 4, 2019).

I will discuss herein the Company's proposal for addressing federal EDIT for ratemaking purposes, which will apply to the new rates being requested in this proceeding.

Q. Mr. McLeod, how did the Company's federal EDIT arise?

A. Stated simply, excess accumulated deferred federal income taxes, or EDIT, represent a cumulative reduction in the balance of federal accumulated deferred income taxes, or ADIT, resulting from a change in tax rates – in this case, the reduction in federal corporate income tax rates under the TCJA. Federal ADIT arises in connection with "timing differences" between when costs are recorded for "book" purposes and recovered in rates and when they are deducted in the Company's federal income tax returns. The largest and most common example of such timing differences relates to depreciation expense. While DENC recovers depreciation expense in rates on a straight-line basis, it is able to deduct such depreciation expense on an accelerated basis for federal income tax purposes. This increases cash flow (or reduces cash outflows) and effectively represents a "zero-cost" capital resource from the federal government. These cash flow benefits will be "repaid" in the later years of the asset's life when taxable income reflects continued straight-line depreciation expense recovery with a lower corresponding depreciation deduction for tax purposes. This taxable timing difference is recorded as a liability, reflecting the future taxes to be paid, and a reduction to rate base, reflecting the "zero-cost" nature of federal ADIT.

Turning to federal EDIT, as it relates to this depreciation expense example, the Company benefits from the reduction in the tax rate as accelerated depreciation deductions originally taken at 35% will now be "repaid" through future tax payments at 21%. When required, this benefit is passed along to customers as a reduction in the revenue requirement via an annual amortization amount.

Q. Is there a limitation on how the Company can pass along the benefit of federal EDIT to customers in rates?

A. Yes, the predominant amount of federal EDIT are associated with utility property depreciation and related book-tax timing differences, which are subject to the Internal Revenue Code's normalization rules. The Company is required to use the average rate assumption method ("ARAM") for purposes of amortizing federal EDIT over the remaining regulatory lives of the property that gave rise to the original reserve for deferred taxes. The consequence of violating the normalization rules is significant and would result in the loss of accelerated depreciation for tax purposes. This EDIT is referred to as "protected." All other federal EDIT balances are termed "unprotected" and are not subject to the normalization requirements.

Q. Please summarize the federal EDIT balances for the VEPCO system and the portion allocable to the North Carolina retail jurisdiction.

A. Figure 2 below presents the federal EDIT at a system level and the portion allocable to the North Carolina retail jurisdiction. The balances are categorized as: (i) plant-protected; (ii) plant-unprotected; and (iii) non-plant unprotected. Schedule 1 of Company Exhibit PMM-2 presents this information and shows the allocation of the specific EDIT balance to the North Carolina retail jurisdiction.

FIGURE 2

Dominion Energy North Carolina
Federal EDIT Balances as of December 31, 2017
(Millions of Dollars)

	(1) System	(2) Non-Jurisdictional	(3) North Carolina Jurisdiction (1) - (2)
Plant - Protected	$ 2,120.2	$ 2,020.2	$ 100.0
Plant - Unprotected	$ (75.6)	$ (73.8)	$ (1.8)
Non-Plant and Unprotected	$ (65.0)	$ (60.8)	$ (4.2)
Total	**$ 1,979.6**	**$ 1,885.5**	**$ 94.1**

As depicted above in Figure 2, the system-level EDIT balance as of December 31, 2017 was $2.0 billion of which $94.1 million was allocable to the North Carolina retail jurisdiction.

Q. Please describe your methodology for allocating the federal EDIT beginning balances to the North Carolina jurisdiction.

A. As presented in Schedule 1 of Company Exhibit PMM-2, federal EDIT beginning balances were allocated to North Carolina in the same manner as the underlying federal ADIT balances are allocated in Schedule 23 of the 2018 cost of service study. The system-level federal EDIT, as prepared by the Company's Tax Department, are shown in Column 1. Using Schedule 23 of the 2018 cost of service study, I matched each federal EDIT line item to its corresponding federal ADIT line item and used the applicable jurisdictional allocation factors (Column 2 and 3) for those federal ADIT line items in order to allocate each federal EDIT line item to the North Carolina jurisdiction.

The AFUDC-related deferred taxes relate to multiple lines in the cost of service study with various allocation factors. I allocated the federal EDIT based on a ratio of the total North Carolina jurisdictional balances in Schedule 23 of the cost of service study to the system level balance. Similarly, the book depreciation federal EDIT relates to multiple federal ADIT lines in the cost of service study. The balance was allocated to the North Carolina jurisdiction based on a ratio of North Carolina jurisdictional accumulated depreciation in Schedule 11 of the cost of service study to the system level balance. Finally, the deferred fuel related federal EDIT was allocated based on a detailed analysis of deferred fuel for the Company's various jurisdictions and contractual customers.

Q. How does the Company propose to address federal EDIT for ratemaking purposes in this proceeding?

A. The Company proposes for the effective date of federal EDIT amortization to begin on January 1, 2018. Since the Company is proposing for new rates to go in effect on November 1, 2019, federal EDIT amortization attributable to the 20-month period January 1, 2018 through October 31, 2019, will be credited to customers through a one-year decrement rider, Rider EDIT. For periods thereafter, the Company's fully adjusted cost of service in this instant case includes the income tax benefit arising from the annual amortization during the Test Year, thereby incorporating a going-level of federal EDIT amortization in base non-fuel rates.

Q. What method and amortization periods does the Company propose for federal EDIT?

A. For plant-related federal EDIT (both protected and unprotected), the Company proposes to use ARAM, which follows the same treatment of the related ADIT balances. This is the method that the Tax Department is currently using to amortize plant-related federal EDIT on the Company's books and records. For non-plant, unprotected federal EDIT, the Company proposes a 30-year amortization period. The Company determined this to be reasonable as the largest non-plant EDIT relates to pension benefits, which is a long-term obligation. The 30-year period is also in line with the remaining recovery period for plant-related EDIT and long-term tenure of bonds issued in support of operations and investments.

Q. Are there other reasons why the Commission should accept the Company's proposed methods and amortization periods for federal EDIT?

A. Yes. The methods and amortization periods for federal EDIT are identical to that approved by the Virginia State Corporation Commission, including the amortization effective date of January 1, 2018. The Company's accounting systems are setup to track ARAM for plant-related EDIT at a system-level, not by state regulatory jurisdiction. There are efficiencies gained in both financial reporting and regulatory reporting in allowing the Company's Tax Department to account for plant-related EDIT at a system-level. From a regulatory standpoint, the amortization can be reported in the established ADIT line items in the Company's cost of service study and follow the jurisdictional allocation process that the Company has used in the North Carolina jurisdiction for many years and in several rate cases. Having federal EDIT amortization begin on January 1, 2018 aligns with the change federal tax law pursuant to the TCJA and with the effective date of rates that the Commission approved for the Company's recent rate change pursuant to the TCJA Order.

Q. **Please summarize the proposed federal EDIT amortization for the North Carolina retail jurisdiction.**

A. Figure 3 below presents the federal EDIT amortization for the North Carolina retail jurisdiction. Schedule 2 of Exhibit PMM-2 presents this information and shows the allocation of the plant-related federal EDIT amortization balance to the North Carolina jurisdiction.

FIGURE 3

Dominion Energy North Carolina
Proposed Federal EDIT Amortization - North Carolina Jurisdiction
(Millions of Dollars)

Plant - Protected	$ 2.8
Plant - Unprotected	included above
Non-Plant and Unprotected	$ (0.1)
Total	2.7

As depicted above in Figure 3, the annual total North Carolina jurisdictional federal EDIT amortization proposed herein is $2.7 million. The Company's base non-fuel rate revenue requirement in this case reflects this amortization providing the customers with an annual revenue benefit of approximately $3.6 million ($2.7 million / 74% retention factor).

Q. **Please describe the methodology for allocating federal EDIT amortization to the North Carolina jurisdiction.**

A. As presented in my Company Exhibit PMM-2 Schedule 2, for plant protected and unprotected federal EDIT amortization, I used the system-level 2018 federal EDIT amortization provided by the Company's Tax Department. I used applicable jurisdictional allocation factors from the 2018 cost of service study to allocate this system-level amortization to the North Carolina jurisdiction.

For non-plant – unprotected federal EDIT, a regulatory asset, I calculated the 2018 federal EDIT amortization by dividing the unprotected EDIT beginning balance by the proposed long-term 30-year amortization period to arrive at an annual amortization estimate.

Q. **Please summarize the Company's proposal for passing along the amortization of federal EDIT attributable to the period January 1, 2018 through October 31, 2019 to North Carolina jurisdictional customers.**

A. As noted previously in my testimony, DENC began amortizing plant-related federal EDIT in January 2018 at the system level. DENC is proposing a one-year decrement rider in this proceeding, Rider EDIT, to pass along to North Carolina retail customers their share of amortization benefit attributable to the 20-month period January 1, 2018 through October 31, 2019 (the ending of the month prior to the implementation of interim rates in connection with this proceeding). In my Company Exhibit PMM-2 Schedule 3, I present the Company current estimate of the overall Rider EDIT rate credit of approximately $6.9 million at the revenue level. This 20-month estimate is based upon the North Carolina jurisdictional share of actual amortization for calendar year 2018 of $3.6 million at the revenue level. The Company also proposes to include capital savings of $0.2 million associated with the regulatory liability until the liability is fully returned to customers at the cost of capital requested in this proceeding. In total, Rider EDIT will credit an estimated $6.9 million to customers over the one-year period ($6.7 million EDIT regulatory liability plus $0.2 million of capital savings). The actual total Rider EDIT credit amount will be based on the North Carolina amortization amounts and capital savings approved by the Commission in this case. Company Witness Haynes further describes the Company's planned implementation of Rider EDIT.

VI. 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 PMM-1. As shown in Column 6 of Schedule 1 of Company Exhibit PMM-1, the Company requires additional base non-fuel revenues of approximately $27.0 million in order to achieve the Company's total base rate revenue requirement of $380.9 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's proposals regarding the ratemaking treatment of federal EDIT including:

   a. The jurisdictional allocation of federal EDIT balance and amortization to the North Carolina jurisdiction,
   b. The proposed methods and amortization periods,
   c. An effective start date for federal EDIT amortization of January 1, 2018, and
   d. The total credit of $6.9 million to the North Carolina jurisdictional customers for federal EDIT amortization attributable to the period January 1, 2018 through October 31, 2019 through a decrement rider, Rider EDIT, over a one-year period as shown in Schedule 3 of Company Exhibit PMM-2.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF PAUL M. MCLEOD

Paul M. McLeod joined the Company's Regulatory Accounting Group in February 2015 as a Regulatory Analyst III. In January 2016, Mr. McLeod was promoted to his current position as Regulatory Specialist. His responsibilities include analyzing and calculating revenue requirements for Dominion Energy North Carolina.

Mr. McLeod graduated from Virginia Commonwealth University in 2010 with a Bachelor of Science Degree with a major 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. He has previously presented testimony before the Virginia State Corporation Commission and the North Carolina Utilities Commission.

SUPPLEMENTAL DIRECT TESTIMONY
OF
PAUL M. MCLEOD
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

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

A. My name is Paul M. McLeod, and my business address is 701 East Cary Street, Richmond, Virginia 23219. I am a Regulatory Consultant with the Regulatory Accounting Group for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted pre-filed direct testimony on behalf of the Company in support of DENC's application for authority to adjust and increase its retail electric rates and charges filed on March 29, 2019 ("Application"). In my direct testimony, I presented the Company's proposed increase to the North Carolina retail annual non-fuel revenue of approximately $27.0 million, as well as DENC's proposed methodology for addressing excess deferred federal corporate income taxes ("federal EDIT") for ratemaking purposes, including a credit to customers through a one-year decrement rider representing federal EDIT amortization attributable to the 22-month period January 1, 2018 through October 31, 2019 ("Rider EDIT").

I also supported the Company's proposed deferral accounting treatment and associated amortization periods for certain new and existing North Carolina jurisdictional regulatory assets.

Q. Mr. McLeod, what is the purpose of your supplemental direct testimony in this proceeding?

A. The purpose of this supplemental direct testimony is to present the Company's revised proposed increase to its base non-fuel revenue of $24.9 million, which is $2.1 million less than the $27.0 million increase requested in the Company's original Application and my direct testimony. The Company's ratemaking test period in this proceeding is the twelve months ended December 31, 2018 ("Test Year"). In support of the Application, the Company proposed several accounting adjustments to certain revenues, expenses, and investments based on estimates through June 30, 2019 ("Update Period"). Through this supplemental filing, these adjustments are being updated or revised to incorporate actual revenue, expense, and investment information during the Update Period. I also discuss several new accounting adjustments that have arisen due to new information or subsequent events that occurred during the Update Period.

Finally, I discuss certain corrections to the allocation of system-level federal EDIT balances and amortization to the North Carolina jurisdiction, and present a revised Rider EDIT credit. These corrections reflect revisions to DENC's cost of service study presented by Company witness Robert E. Miller. The total proposed Rider EDIT credit is $6,910,000, which is a slight increase from the $6,909,000 Rider EDIT credit presented in the Company's original Application.

Q. Are you sponsoring any exhibits with your supplemental direct testimony?

A. Yes. I am sponsoring Company Supplemental Exhibit PMM-1, which supports the revenue requirement and requested revenue increase and Company Supplemental Exhibit PMM-2 which supports the calculation of EDIT and related amortization allocable to the North Carolina jurisdiction. Company Supplemental Exhibit PMM-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
- Schedule 6 – Reconciliation of Change in Revenue Requirement from Direct Case to Supplemental Filing
- Appendix A – Listing of Revisions to Accounting Adjustments

Company Supplemental Exhibit PMM-2 consists of the follow schedules, which have been updated to reflect revisions to DENC's cost of service study as discussed by Company Witness Miller in his supplemental direct testimony.

- Schedule 1 – EDIT Balances as of December 31, 2017
- Schedule 2 – North Carolina Jurisdictional EDIT Amortization

Schedule 3 – Rider EDIT Total Revenue Credit

In addition, I support supplemental schedules R1-17(b)(9)(a) through (e) in Appendix A of the supplemental filing. These exhibits and schedules were prepared by me or under my supervision and direction and are accurate and complete to the best of my knowledge and belief.

Q. Please summarize the results of your base non-fuel rate revenue requirement analysis presented in this supplemental filing.

A. As presented in Column 5 of Supplemental Exhibit PMM-1, Schedule 1 – Rate of Return Statement – Adjusted, the Company's fully-adjusted Test Year reflects a return on equity ("ROE") of 7.81%. To fully recover DENC's cost of service, the Company is requesting an updated base non-fuel revenue increase of $24.9 million as shown on Column 6 of Supplemental Exhibit PMM-1, Schedule 1. This will provide for the recovery of the North Carolina jurisdictional fully-adjusted cost of service, including an overall rate of return on rate base of 7.83% supported by Company Witness Richard M. Davis and an ROE of 10.75% supported by Company Witness Robert B. Hevert. A detailed reconciliation of changes in the base non-fuel rate revenue requirement from the Application to the supplemental filing is included in Schedule 6 of Company Supplemental Exhibit PMM-1.

Q. Please summarize the updates and revisions to the accounting adjustments presented in the supplemental filing.

A. The updated accounting adjustments presented in the supplemental filing can be categorized as follows:

1. Rate Base Update through Update Period

   Updates to certain rate base items such as utility plant in service, accumulated depreciation, and accumulated deferred income taxes ("ADIT") based on balances as of June 30, 2019.

2. Operating Revenues and Expenses Due to Rate Base, Customer Levels, Employee Counts, Rate of Return, and Tariff Revenues

   Updates to Test Year operating revenues and expenses that are a function of plant in service, number of employees, number of customers, and revenues are synchronized to match the rate base update identified above in category 1. Examples of costs updated using this method include depreciation and amortization expense, property taxes, salaries and wages, and the operation and maintenance ("O&M") expense inflation adjustment.

3. Actual Cost Information During the Update Period

   Updates to Test Year operating expenses based on actual costs experienced during the Update Period. Examples include purchased capacity costs, purchased energy costs, and employee benefits. Additionally, salary, wages and benefits expenses were adjusted to reflect anticipated savings arising from the Company's recent Voluntary Retirement Program ("VRP").

4. Subsequent Events or New Information Since the Application Filing Date

Revisions to accounting adjustments in the Application and new accounting adjustments identified as the result of subsequent events or new information obtained after the Application filing date and during extensive discovery conducted during this proceeding.

5. Revisions to Schedules and Adjustments Based on a Revised Cost of Service Study

As discussed further by Company Witness Miller, the Company has filed a revised cost of service study as part of this supplemental filing to incorporate several revisions, including certain allocation factors and revenue assignments. While these revisions did not result in a significant overall change to DENC's North Carolina's cost of service, they did involve small changes to numerous per books operating revenue, expense, and rate base line item amounts. Accounting adjustments associated with these line items were likewise impacted. As the impacts are individually insignificant, I do not address them specifically or individually in my supplemental direct testimony. These impacts are included in the reconciling item amounts presented in my Schedule 6 of Company Supplemental Exhibit PMM-1.

Q. Does the revenue requirement in this supplemental filing incorporate an update to the capital structure proposed in the Application?

A. Yes. Company Witness Davis is supporting an update to the actual capital structure for ratemaking purposes as of the end of the Update Period, June 30, 2019. This proposed update to the Company's capital structure to reflect changes occurring during the Update Period is consistent with the rate base update as well as other updated costs in this supplemental filing. The overall weighted average cost of capital is 7.83% based on the actual June 30, 2019 capital structure, an increase of four basis points as compared to the 7.79% weighted average cost of capital included in the original Application.

Q. Please explain why the adjustments proposed by the Company in this supplemental filing are appropriate.

A. N.C. Gen. Stat. § 62-133(c) allows the North Carolina Utilities Commission ("NCUC" or "Commission") to consider relevant, material, and competent evidence tending to show actual changes in costs, revenues, and cost of property within a reasonable time after the test period. Likewise, Commission Rule R1-17(c) provides that the Commission will consider relevant evidence showing actual changes in costs, revenues, and utility property that is used and useful, or to be used and useful within a reasonable time after the test period. Through this supplemental filing, the Company is requesting to update certain costs, revenues, and investments to June 30, 2019. The proposed update adjustments are consistent with the Company's previous base rate cases and comply with N.C. Gen. Stat. § 62-133.

Q. Is the Company planning to make additional updates closer in time to the hearing scheduled in this proceeding?

A. Yes. As I explain in my discussion of Adjustment NC-24 below, the Company anticipates making certain additional updates to DENC's cost of service prior to the evidentiary hearing scheduled in this proceeding.

Q. Please summarize notable updates that are being incorporated in the Company's revenue requirement in the supplemental filing.

A. There are two significant events that occurred in March 2019 that are now being incorporated in the revenue requirement: (1) the Company's decision to retire several generating units, most of which were in a "cold reserve" state during the test year, and (2) the announcement of the Voluntary Retirement Program (previously defined as "VRP"). Given the timing of when these events occurred, the Company was unable to incorporate the impacts into the cost of service presented in the original Application. They are now being incorporated through this supplemental filing either through new accounting adjustments or updates to accounting adjustments presented in the original Application.

Q. Please elaborate on how the early plant retirements are incorporated into the revenue requirement.

A. In March 2019, the Company announced the planned retirement of eleven units at six stations before the end of their useful lives. As discussed in the direct testimony of Company Witness Bruce E. Petrie, ten of the units were older, less efficient units that had been placed in a "cold reserve" state in

2018. These units include Bellemeade Power Station, Bremo Power Station ("Bremo") units 3 and 4, Chesterfield Power Station units 3 and 4, Mecklenburg Power Station units 1 and 2, Pittsylvania Power Station, and Possum Point Power Station ("Possum Point") units 3 and 4. The ten units formerly in cold reserve were retired from service effective March 31, 2019. In addition, the Company plans to retire Possum Point unit 5 on May 31, 2021. As a result of these early retirements, DENC recorded an impairment charge $307.1 million, which represents the remaining net book value of the units. Related balances in construction work in progress ("CWIP") and materials and supplies inventory were written-off as well.

The supplemental filing reflects new accounting adjustments for the following items to reflect the Company's proposed ratemaking treatment of the impaired assets and to adjust operating expenses and rate base to reflect current operations:

- Amortize the plant impairments for the ten units formerly in cold reserve that were retired from service on March 31, 2019 over a ten-year period, on a levelized basis,
- Amortize the materials and supplies inventory for the retired plants over a three-year period,
- Eliminate O&M expense and materials and supplies inventory for the ten units formerly in cold reserve that were retired from service on March 31, 2019,

- Reestablish the Possum Point unit 5 net book value and depreciation expense for ratemaking purposes since the unit has not been physically retired from service.

I provide a more detailed discussion of each adjustment later in my testimony.

Q. **How does the Company propose to recover decommissioning costs associated with the retired generating units?**

A. The Company has not incurred any decommissioning costs as of the end of the Update Period for any of the retired generating units, and no such decommissioning costs are reflected in the cost of service in this proceeding. The Company may, however, incur significant decommissioning costs in the next few years. The Company requests that the Commission allow the Company to defer the North Carolina jurisdictional portion of any decommissioning costs incurred after the Update Period in this proceeding for review in the Company's next base rate case. This ratemaking treatment is consistent with how the Commission has allowed for recovery of decommissioning costs associated with the Chesapeake Energy Center ("CEC") in the Company's most recent general rate case, Docket E-22, Sub 532 ("2016 Rate Case").[1]

[1] *See Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions,* Docket No. E-22, Sub 532 (Dec. 22, 2016) ("2016 Rate Case Order"), Finding of Fact No. 20.

Q. Please elaborate on the VRP and how it has been incorporated into the revenue requirement presented in this supplemental filing.

A. In March 2019, Dominion Energy, Inc. ("DEI") announced the VRP for employees that meet certain age and service requirements. The VRP was extended to employees of nearly all affiliates of DEI, including DENC and Dominion Energy Services, Inc. ("DES"), and is expected to reduce total workforces during the balance of 2019 and early 2020. The program provides severance incentives for eligible employees to retire and is expected to result in cost savings due to efficiencies gained in transforming the Company's departments and work processes that provide utility service to North Carolina.

The revenue requirement presented in the Company's supplemental filing has comprehensively incorporated the severance costs and savings associated with the VRP. The savings are incorporated through accounting adjustments for employee salaries and wages, benefits, and the annual incentive plan costs. Severance costs associated with VRP have been incorporated in the adjustment to normalize major employee severance program costs.

Q. Before discussing each of your accounting adjustments, were there any other corrections to the calculation of the revenue requirement presented in the supplemental filing?

A. Rule R1-17(b)(9) is a statement showing, among other things, the calculation of the additional revenue requirement being requested in this proceeding. Additional calculations have been included in Columns 6 and 7 of this statement to properly calculate the additional revenue requirement associated with the debt and equity portions of changes in required net operating income.

Q. Do you have any other general organizational comments concerning your exhibits before discussing each of the new and updated adjustments?

A. Yes. New accounting adjustments presented in this supplemental filing contain the prefix "SUPP" in the adjustment number. Accounting adjustments proposed in the original direct case filing on March 29, 2019, contain the prefix "NC" in the adjustment number. Schedule 3 in my Supplemental Exhibit PMM-1 contains a comparison of the adjustment amounts in the supplemental filing and original Application.

Section IV – Explanation of Accounting Adjustments on pages 15 – 41 of my direct testimony discussed all proposed accounting adjustments to DENC's cost of service. My supplemental direct testimony will only discuss accounting adjustments that: (1) have been *updated* using actual information during the Update Period, (2) have been *revised* to reflect corrections that have a significant impact on the revenue requirement, and (3) are *newly identified*. These updated, revised, and new accounting adjustments arose generally due to subsequent events or new information obtained since the Application filing date and during the discovery process. Unless otherwise addressed in my supplemental direct testimony, the original purposes of and methodologies used for accounting adjustments, including updated or revised accounting adjustments, are addressed in my direct testimony. Appendix A to

Supplemental Exhibit PMM-1 contains an itemized listing of all revisions to accounting adjustments presented in the Company's supplemental filing.

Q. Please proceed with your explanation of the updated accounting adjustments and revisions that have a material impact on the revenue requirement as presented in Schedule 3.

A. I will discuss each of these 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 order. The detailed work papers supporting all accounting adjustments are included in supplemental NCUC Form E-1, Item 10.

Adjustments NC-1, NC-4, and NC-6 – Annualize Revenue for Usage, Weather, and Customer Growth as of June 30, 2019

This adjustment to the Company's annualized base non-fuel tariff revenues has been updated to reflect actual customer levels and weather normalized usage as of June 30, 2019. Company Witness Paul B. Haynes discusses this adjustment in his supplemental direct testimony.

Adjustments NC-3, NC-8 and NC-31 – 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. This adjustment has been updated to reflect the annualized and normalized customer usage information as of June 30, 2019 as also used in Adjustments NC-1, NC-4 and NC-6. Adjustment NC-31 has been updated to reflect the regulatory fee percentage rate of 0.13% effective July 1, 2019.

Adjustment NC-5 – Adjust Ancillary Services Margins

The going-level of ancillary services revenue has been updated to include net revenues received by the Company from the PJM Interconnection, L.L.C. ("PJM") markets during the twelve months ended June 30, 2019. Certain operating reserve charges recorded during the twelve months ended June 30, 2019, relating to activity in the 2nd quarter of 2018 are removed.

Adjustment NC-11 – Update Purchased Power Capacity Expense

This adjustment addresses DENC's net capacity expenses associated with capacity purchased from the PJM market, from non-utility generators ("NUG"), and other capacity purchases. This adjustment has been updated to reflect DENC's net load position for the PJM delivery year beginning June 1, 2019, as well as updated price assumptions. Annual NUG capacity purchases have been reduced by over $50 million (system-level) to reflect the early termination of a capacity contract for a 218 MW (summer rating) coal-fired NUG facility, which occurred during the Update Period. The cost associated with terminating this capacity contract are addressed in a new accounting adjustment, Adjustment SUPP-2, discussed later in my testimony. All other NUG capacity expenses are for purchases from qualifying facilities ("QF") under the Public Utility Regulatory Policies Act of 1978 that are not subject to economic dispatch or curtailment. The costs of these QF NUG purchases are recoverable through the fuel adjustment clause, and therefore, are excluded from the base non-fuel cost of service.

Adjustment NC-11 in the supplemental filing also reflects a revision to remove credits to a wholesale customer, the Virginia Municipal Electric Association ("VMEA") from the Other Capacity Expense section. The June 1, 2019 net load position discussed above excludes VMEA's generation so it is appropriate to also exclude the credits paid to VMEA. After the updates and revisions discussed herein, Adjustment NC-11 only includes net purchased capacity from PJM.

Adjustment NC-12 – Update Purchased Power Energy Expense

The purpose of this adjustment is to adjust the Test Year non-fuel purchased power energy expenses recovered through base non-fuel rates and has been updated to reflect actual purchased energy activity during the twelve months ended June 30, 2019.

Adjustment NC-16 – Annualize Greensville County CC O&M

This adjustment includes an annualized level of non-labor O&M expense for the Greensville County CC which began operations in the December 2018. This annualized expense has been updated to reflect the actual average costs incurred during the six months ended June 30, 2019.

Adjustment NC-17 – Annualize Salary and Wages as of June 30, 2019 – Salaried Payroll;

Adjustment NC-18 – Annualize Salary and Wages as of June 30, 2019 – Hourly Payroll; and

Adjustment NC-19 – Annualize Salary and Wages as of June 30, 2019 – Services Company

These adjustments annualize salaries and wages expense and have been updated to reflect an annualization of actual expenses incurred during the month of June 2019. These adjustments have been updated to reflect expected salary and wage savings resulting from the VRP. Salaries and wages for employees that voluntarily retired under the VRP are calculated based on the annual salary of each employee. The total annualized amount is eliminated from the going-level of salaries and wages.

Adjustment NC-20 – Adjust Employee Benefits Costs to June 30, 2019

Employee benefit costs are adjusted based on actual benefit cost information available during the update period. In the second quarter of 2019, DEI remeasured its pension and other postretirement employee benefit ("OPEB") plans because of the VRP. Pension and OPEB expenses have been updated to reflect actual benefit costs for calendar year 2019 based on the latest actuarial reports. The Company has excluded one-time charges for VRP-related plan curtailments from the calendar year 2019 pension and OPEB costs. These costs have been included with the VRP severance expenses in Adjustment NC-21. Other employee benefit costs other than pension and OPEB have been updated based on the twelve months of actual benefits costs through June 2019 including a reduction to remove an annualized level of benefit costs due to the VRP.

Adjustment NC-21 – Normalize Employee Severance Program Costs

This adjustment has been updated to include the VRP and therefore now includes a normalized level of employee severance costs in the cost of service based on the Company's historical experience over the past 25 years. During the period 1994 through 2019, there were six major corporate-wide severance programs instituted by the Company, resulting in an average of approximately one every 4.17 years. As previously discussed, this adjustment includes charges incurred during the Update Period for VRP-related pension and OPEB plan curtailments.

Adjustment NC-22 – Normalize Annual Incentive Plan Costs

This adjustment provides for 100% of the Annual Incentive Plan ("AIP") target based on employees meeting all operational and financial goals during the year. The adjustment has been updated to provide an average AIP expense level per employee applied to the actual number of employees at June 30, 2019, and to remove an annualized level of AIP expenses due to the VRP.

Adjustment NC-23 – 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. This adjustment was revised to reflect a direct identification and measurement of amounts allocated to DENC during the Test Year rather than the previous estimation approach used in the Company's original Application.

Adjustment NC-24 – DES Office Building Adjustment

This adjustment reflects the net effect of increased annual expenses related to 600 Canal Place and removal of existing costs related to the expiring lease of One James River Plaza. At the time of the Application, occupation of 600 Canal Place by DENC and DES employees was expected to begin during the second quarter of 2019. DES and the Company began occupying Canal Place in July 2019 and DES will begin making lease payments in August 2019. Additionally, the Company now expects to cease occupying and leasing from DEI its existing office space in One James River Plaza by September 2019. This accounting adjustment was updated to reflect the new lease expense budget for calendar year 2019 and, as I mention above, will be updated again in September 2019 based on the actual lease payment incurred for August 2019.

Adjustment NC-26 –Transmission Rate Design Settlement

This adjustment has been updated to reflect net transmission enhancement credits received during the twelve months ended June 30, 2019.

Adjustment NC-28 – Adjust Uncollectible Expense

The Company adjusts uncollectible expense based on an historical average uncollectible expense rate. This rate is applied to the fully-adjusted North

Carolina jurisdictional operating revenues, as updated in the supplemental filing, to derive the ratemaking level of uncollectible expense.

Adjustment NC-30 – Adjust Certain Operation and Maintenance Expenses for Inflation

The Company adjusts O&M expenses in the cost of service not adjusted elsewhere using an inflation factor. The inflation factor is measured as the difference of the Producer Price Index – Finished Goods less Food and Energy ("PPI") between the midpoint of the Test Year and the end of the Update Period and was updated to reflect the actual PPI for June 2019.

Adjustment NC-32 – Amortize Chesapeake Energy Center Closure Cost Regulatory Asset

This adjustment amortizes CEC deferred closure costs incurred from July 1, 2016 through the end of the Update Period to be recovered over a proposed three-year period and has been updated to reflect actual costs incurred through June 30, 2019.

Adjustment NC-33 – Amortize Coal Combustion Residual Expenditures Regulatory Asset

This adjustment amortizes the Company's cash expenditures made to manage coal combustion residuals from July 1, 2016 through the end of the Update Period over a proposed three-year period. The adjustment has been updated to reflect actual cash expenditures and the associated financing costs through June 30, 2019.

Adjustment NC-42 – Adjust Existing Regulatory Assets

Among these existing regulatory assets, the North Branch Power Station ("North Branch") and CEC impairments are being recovered on a levelized basis over a ten-year period based on an annuity factor. The Company adjusts the amortization in the cost of service to this levelized basis and the underlying annuity factor has been updated to reflect the rate of return proposed in this supplemental filing.

Adjustment SUPP-1 – Eliminate Cold Reserve Plant O&M Expense

As discussed in the direct testimony of Company Witness Petrie, the Company retired ten older, less efficient generating units that had been in a "cold reserve" state in 2018. This adjustment eliminates test year non-labor O&M expenses for these units that are no longer operational.

Adjustment SUPP-2 – Amortize NUG Contract Termination Expense Regulatory Asset

As introduced in the updated Adjustment NC-11 above, the Company had a long-term power and capacity contract with one coal-fired NUG with an aggregate summer generation capacity of approximately 218 MW. The plant had been, and was expected to remain, generally uneconomical in the PJM energy market, and therefore, ran infrequently and was not a key resource for DENC nor does it continue fit within DENC's portfolio of increasingly cleaner generation resources. In May 2019, the Company entered into an agreement and paid $135.0 million to terminate the contract, effective April 2019. As noted earlier in my testimony, the termination of this contract significantly reduces the Company's capacity expenses for ratemaking purposes in this proceeding. Given the magnitude of the termination fee and the significant capacity savings going-forward, the Company proposes to defer the North Carolina jurisdictional portion of the termination fee to be amortized over the original remaining term of the contract (32 months—April 2019 through November 2021).

Adjustment SUPP-3 – Bremo Fixed Transportation Contract

In connection with the early retirement of Bremo, the Company ceased utilizing natural gas service under a fixed transportation contract that expires in July 2026. The North Carolina jurisdictional fixed contract costs had previously been recovered through North Carolina retail fuel rates. However, as the payments no longer relate to gas transportation services being utilized, the Company is now proposing to recover the costs through base non-fuel rates. This adjustment includes an annual level of contract payments in the cost of service.

Adjustment SUPP-4 – Amortize Retired Plant Inventory Regulatory Asset; and

Adjustment SUPP-11 – Eliminate Cold Reserve Plant Materials & Supplies Inventory

DENC identified and wrote-off obsolete material and supplies inventories totaling $20.9 million in connection with the plant impairments recorded in March 2019. This adjustment also includes inventory previously written-off related to the retired units at Yorktown Power Station ("Yorktown"). The

Company is requesting to defer these charges as a regulatory asset to be amortized over a three-year period. This ratemaking treatment is consistent with the treatment approved by the Commission for obsolete inventory at North Branch[2] and CEC[3] in the 2016 Rate Case. Adjustment SUPP-11 reflects the removal of obsolete inventory balance for the cold reserve plants from the Material and Supplies Inventory component of rate base.

Adjustment SUPP-5 – Amortize Mt. Storm Fuel Flexibility Project Impairment Regulatory Asset

In 2011, the Company began developing a coal yard fuel flexibility project at its Mount Storm Power Station ("Mt. Storm") that was intended to achieve lower fuel costs by improving rail receiving capabilities and expanding coal sourcing and blending options. However, in recent years, market conditions have decreased power prices resulting in a declining capacity factor and reduced coal consumption at Mt. Storm. Additionally, bids for construction of the project from general contractors have steadily increased, making the project uneconomical to complete. In May 2019, the Company abandoned the project resulting in an impairment of construction costs incurred on the project totaling $62.4 million (system-level). The Company is proposing to defer the North Carolina jurisdictional portion of the project costs as a regulatory asset to be amortized over a three-year period.

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[2] *See* 2016 Rate Case Order, at Ordering Paragraphs 1-2. NCUC Form E-1, Item No. 10 – Supplemental Filing, Page 298, Line 13 filed August 12, 2016 in Docket No. E-22, Sub 532.
[3] *See* 2016 Rate Order, Finding of Fact No. 20.

Adjustment SUPP-6 – 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, 2019, the regulatory fee percentage rate decreased to 0.13%. This adjustment recalculates the Test Year regulatory fee expense based on this new, lower rate. The Retention Factor used to calculate the incremental revenue requirement was also adjusted to account for the change in the regulatory fee.

Adjustment SUPP-7 – VRP Employee Backfills

This adjustment offsets a portion of the VRP savings incorporated in the employee labor and benefits adjustments with a calculated value of salaries and wages for backfilled positions.

Adjustments NC-37, NC-75, and NC-82 – Annualize Depreciation Expense

These adjustments annualize depreciation expense based on actual plant in service as of the end of the Update Period as well as capture the impact of annualizing depreciation expense on accumulated depreciation and ADIT. These adjustments have been updated to reflect actual balances as of June 30, 2019. The annualized depreciation expense has been reduced due to the early retirement of eleven generating units, as discussed previously in my testimony.

Adjustments NC-38, NC-46, NC-69, NC-76 and NC 89 – Eliminate Incremental Costs for Certain Underground Transmission Projects

These adjustments update the incremental plant in service, accumulated depreciation, and ADIT associated with certain undergrounding projects excluded from cost of service by the Commission in its 2012 *Order Granting General Rate Increase.*[4] The Company also eliminates an annualized level of depreciation expense for these projects. The adjustments have been updated to eliminate actual balances at June 30, 2019, consistent with the plant in service update.

Adjustments NC-39, NC-47, NC-70, NC-77 and NC-83 – Eliminate AC Cycling Program Costs

These adjustments eliminate costs associated with the Company's AC Cycling Program that are recovered through the DSM Rider. These adjustments have been updated to reflect actual balances through and as of June 30, 2019.

Adjustment NC-40 – Amortize Yorktown Impairment Regulatory Asset

This adjustment proposes to amortize the impairment loss on Yorktown units 1 and 2 on a levelized basis over a 10-year amortization period using an annuity factor. The annuity factor has been updated to reflect the Company's updated overall cost of capital proposed in this supplemental filing.

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[4] *Order Granting General Rate Increase*, Docket No. E-22, Sub 479 at Finding of Fact No. 27. (Dec. 21, 2012) ("2012 Rate Order").

Adjustment NC-41 – Amortize Greensville County CC Deferral

This adjustment amortizes the deferred costs, including a return on investment, associated with the Greensville County CC as requested in the Company's petition filed on March 29, 2019 in Docket No. E-22, Sub 566. The Company is requesting that the incremental costs incurred from the time this major new generating facility was placed into service in December 2018 until the costs will be reflected in the base non-fuel rates approved in this proceeding be deferred and amortized over a three-year period beginning with the effective date the Commission approves new rates in this proceeding. This adjustment has been updated to reflect actual financing and operating costs through June 30, 2019. The actual operating and financing costs for June 2019 are used as a proxy for the months subsequent to the Update Period.

Adjustment SUPP-8 – Amortize Cold Reserve Plant Impairment Regulatory Asset

As I introduce above, in March 2019, DENC made the decision to retire early ten units at six generating stations. The Company proposes to defer the North Carolina jurisdictional portion of the impairment charge for recovery through base non-fuel rates. The Company proposes to amortize the regulatory asset over a ten-year period on a levelized basis using an annuity factor. While the Company believes a shorter amortization period may be appropriate in this case, the methodology and amortization period proposed in Adjustment SUPP-8 is consistent with the Commission's authorized ratemaking and regulatory accounting treatment for the North Branch plant impairment in the 2012 Rate Order[5] as well as for the CEC plant impairment in the 2016 Rate Order.[6]

Adjustment SUPP-9, SUPP-12, SUPP-13, and SUPP-14 – Reestablish Possum Point Unit 5 Impairment

As previously discussed in my testimony, DENC committed to retire Possum Point Unit 5 after it meets its capacity obligation to PJM in 2021. Under generally accepted accounting principles, this unit is accounted for as an abandoned plant and the Company recognized an impairment charge of $73.4 million (system-level) for the remaining net book value of the plant and ceased recording depreciation expense. Therefore, Possum Point unit 5 was not included in June 30, 2019, per books plant balances used to update plant in service and depreciation expense.

The Company proposes a series of adjustments to reestablish the depreciation expense and rate base associated with Possum Point unit 5 in the cost of service. This is necessary since the assets were impaired for financial reporting purposes during the Update Period, and therefore, are not included in the Company's plant in service update through June 30, 2019. Furthermore, this proposed ratemaking treatment is consistent with the Commission's authorized accounting treatment for Yorktown units 1 and 2

[5] 2012 Rate Order, Findings of Fact No. 17-18.
[6] 2016 Rate Order, Finding of Fact No. 20.

and CEC in the 2012 Rate Order,[7] and again for Yorktown units 1 and 2 in the 2016 Rate Order.[8]

The adjustments calculate the balances of plant in service, accumulated depreciation, and ADIT as of June 30, 2016. These balances are derived based on the net plant balances as of March 2019 prior to impairment, adjusted for additional depreciation expense during the interim period of time. The depreciation expense is calculated by applying the composite depreciation rate for the unit to the average plant in service balance during the year. The depreciation expense adjustment is derived by annualizing the depreciation expense during the three months ending June 30, 2016.

The Company also requests that the Commission allow the Company to defer the Possum Point unit 5 impairment loss for financial reporting purposes. The Commission granted similar authority for impairment losses associated with CEC and Yorktown units 1 and 2 in the 2012 Rate Case.[9]

Adjustments NC-43 and NC-50 – Interest Synchronization Adjustment

These adjustments reflect the federal and state income tax impacts of adjusting interest expense based the Company's updated weighted average cost of capital and fully-adjusted rate base included in the supplemental filing.

[7] 2012 Rate Order, Finding of Fact No. 26.
[8] 2016 Rate Order, Finding of Fact No. 25.
[9] 2012 Rate Order, Finding of Fact No. 26.

Adjustments NC-44 and NC-51 – Federal and State Income Tax Effect of Adjustments

These adjustments reflect the change in federal income tax expense produced by aggregating all 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.

Adjustment SUPP-10 – Federal Income Tax Expense Correction

This adjustment reflects a correction to per books current income tax expense for the Test Year. During the Test Period, certain current income tax expense journal entries were inadvertently not recorded related to the cost of removal component of book depreciation for the distribution function. This component of the book depreciation accrual is not tax deductible on the Company's tax return until actual cash expenditures occur resulting in a book/tax timing difference. As such, for income tax purposes, the cost of removal component of book depreciation is added back to taxable income resulting in an increase to current income tax expense for financial and regulatory reporting purposes. However, these current tax expense entries associated with distribution plant were not recorded during the Test Year resulting in an understatement of per books current income tax expense. This adjustment corrects the per books current income tax expense resulting in an increase to the North Carolina jurisdictional overall income tax expense.

Adjustment NC-54 – Annualize Property Taxes Based on Plant in Service as of June 30, 2019

Property taxes are annualized based on the plant in service as of June 30, 2019. Property taxes are calculated by applying the ratio of 2018 property tax expense and the December 31, 2018 plant in service balance. This ratio is then applied to the incremental increase in North Carolina jurisdictional plant in service through June 30, 2019.

Adjustment NC-55 – Adjust Payroll Tax for Incremental Payroll

This adjustment incorporates incremental payroll tax expense associated with the ratemaking adjustments to salaries and wage expenses. This adjustment incorporates incremental payroll tax expense associated with the accounting adjustments to salaries and wage expenses.

Adjustment NC-59 – 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 updated capital structure, debt costs, and rate base proposed in the Company's supplemental filing.

Adjustment NC-60 – CWC Effect of Lead/Lag Study and Accounting Adjustments

The CWC rate base component included in the cost of service per books is adjusted based on the adjusted CWC requirement as determined for regulatory purposes and has been updated to reflect the lead/lag days reflected in

Supplemental Form E-1 Item 14, and the impacts of the various accounting adjustment revisions and updates discussed elsewhere in my supplemental direct testimony.

Adjustment NC-62 and NC-91 – Adjust Rate Base for New Regulatory Assets

These adjustments incorporate in rate base the balances of new North Carolina jurisdictional regulatory assets being requested in this proceeding. The adjustments have been updated to capture actual costs through June 30, 2019, as well as incorporating newly identified regulatory assets arising subsequent to the Application filing date. The Company deducted one year of amortization from the balance of each new regulatory asset, and the remaining balance is included net of ADIT.

Adjustments NC-68, NC-74, and NC-81 – Update Plant in Service, Accumulated Depreciation, and ADIT to June 30, 2019

These adjustments update plant in service, accumulated depreciation, and plant-related ADIT to the end of the Update Period based on actual June 30, 2019 balances.

Q. Does this conclude your explanation of the accounting adjustments in your supplemental direct testimony?

A. Yes, it does.

Q. Please summarize the corrections reflected in your Supplemental Exhibit PMM-2 and the updated Rider EDIT credit being presented in the supplemental filing.

A. My Supplemental Exhibit PMM-2 reflects corrections to the allocation of system-level federal EDIT balances and amortization to the North Carolina jurisdiction, and presents a revised Rider EDIT credit. These corrections reflect revisions to DENC's cost of service study presented by Company Witness Miller. My direct testimony included a table, Figure 2 on page 46, which presented the federal EDIT at a system-level and the portion allocable to the North Carolina jurisdiction. Below is an updated Figure 2 (from page 47 of my direct testimony) summarizing Schedule 1 of Supplemental Exhibit PMM-2:

FIGURE 2 – REVISED
Dominion Energy North Carolina
Federal EDIT Balances as of December 31, 2017
(Millions of Dollars)

	(1) System	(2) Non-Jurisdictional	(3) North Carolina Jurisdiction (1) - (2)
Plant - Protected	$ 2,120.2	$ 2,019.6	$ 100.6
Plant - Unprotected	$ (75.6)	$ (73.8)	$ (1.8)
Non-Plant and Unprotected	$ (65.0)	$ (60.8)	$ (4.2)
Total	**$ 1,979.6**	**$ 1,884.9**	**$ 94.7**

As depicted above in updated Figure 2 - Revised, the North Carolina jurisdictional federal EDIT balance was $94.7 million, which is $0.6 million greater than the amount in my direct testimony of $94.1 million. The allocable portion of North Carolina jurisdictional EDIT amortization presented in Schedule 2 of Exhibit PMM-2 changed slightly but was less than $1,000; therefore, Figure 3 in my direct testimony is still accurate. Schedule 3 of Supplemental Exhibit PMM-2 presents the Rider EDIT rate credit, as corrected, of $6,910,000, which reflects a slight $1,000 increase from the $6,909,000 Rider EDIT credit presented in the Company's original Application.

Q. **Does this conclude your supplemental direct testimony?**

A. Yes, it does.

SECOND SUPPLEMENTAL DIRECT TESTIMONY
OF
PAUL M. MCLEOD
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

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

A. My name is Paul M. McLeod, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am a Regulatory Consultant with the Regulatory Accounting Group for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. **Did you provide pre-filed direct testimony in this case?**

A. Yes. I submitted direct testimony on behalf of the Company ("Direct Testimony") in support of DENC's application for authority to adjust and increase its retail electric rates and charges filed in this docket on March 29, 2019 ("Application"). My Direct Testimony supported the Company's proposed increase to North Carolina retail annual non-fuel revenue of approximately $27.0 million.

Q. **Did you also provide pre-filed supplemental testimony in this case?**

A. Yes. My supplemental testimony, filed on August 5, 2019 ("Supplemental Testimony"), presented the Company's revised proposed increase to its base non-fuel revenue of $24.9 million, which is $2.1 million less than the $27.0 million increase requested in the Company's original Application. My supplemental testimony proposed several accounting adjustments to certain revenues, expenses, and investments based on estimates through June 30, 2019 ("Update Period"), and my Supplemental Testimony updated and revised these estimates to incorporate actual revenue, expense, and investment information during the Update period. I also proposed several new accounting adjustments that arose due to new information or events that occurred during the Update Period.

Q. What is the purpose of your second supplemental testimony?

A. The purpose of this second supplemental direct testimony is to reflect certain updates to the Company's proposed changes to base fuel and base non-fuel revenues. The Application included a "placeholder" base fuel rate based on the current base fuel rates plus Fuel Rider A approved by the North Carolina Utilities Commission ("NCUC" or "Commission") in the Company's most 2018 fuel proceeding, Docket No. E-22, Sub 558 ("2018 Fuel Case"). I propose to update the calculation of fuel factor revenue and expense to reflect the base fuel factor and Rider A presented in the second supplemental testimony of Company Witness Paul B. Haynes. These adjustments reduce base fuel revenue by $2.2 million. I also update the calculation of the base non-fuel revenue annualization to reflect the revised customer growth and usage presented in the Company Witness Haynes second supplemental testimony. Finally, as discussed in my supplemental testimony, I am updating an accounting adjustment relating to the Dominion Energy Services, Inc's ("DES") new office building. After making these updates and changes, the

Company's proposed base non-fuel revenue increase is $24.2 million, which is $0.7 million less than the $24.9 million increase requested in the Company's Supplemental Testimony.

Q. **Are you sponsoring any exhibits with your second supplemental testimony?**

A. Yes. I am sponsoring Company Second Supplemental Exhibit PMM-1, which supports the revenue requirement and requested fuel and non-fuel base revenue increases. Company Second Supplemental Exhibit PMM-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

Schedule 6 – Reconciliation of Change in Revenue Requirement from Supplemental Filing to Second Supplemental Filing

Schedule 7 – Workpapers Supporting New Accounting Adjustment Presented in Second Supplemental Filing

I have also prepared updates to affected sections of the Company E-1, Item 10, as well as an updated Rule R1-17(b)(9) statement showing, among other things, the calculation of the additional base fuel and base non-fuel revenue changes being requested in this proceeding.

Q. **Do you have any other general organizational comments concerning your exhibits before discussing each of the new and updated adjustments?**

A. Yes. The new accounting adjustments presented in this Second Supplemental Filing contain the prefix "2SUPP" in the adjustment number.

Q. **Please proceed with your explanation of the updated accounting adjustments and revisions that have a material impact on the revenue requirement as presented in Schedule 3.**

A. I will discuss each of these 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 order. I have attached to my testimony replacement pages for the Form E-1, Item 10 for the accounting adjustments being updated. I also attach the workpaper supporting the proposed decrease in fuel factor expense discussed above.

Adjustment NC-1 – Annualize Revenue for Usage, Weather, and Customer Growth as of June, 30, 2019

The calculation of annualized base non-fuel rate revenues in this adjustment was updated based on the annualized level of revenue presented in Company Witness Haynes second supplemental testimony filed on August 14, 2019.

Adjustments NC-3, NC-8 and NC-31 – Annualize Fuel Revenues and Expenses at Current Rates

The calculation of annualized fuel clause revenues in this adjustment was updated based on the annualized level of customer usage presented in Company Witness Haynes' second supplemental testimony filed on August 14, 2019.

Adjustment 2SUPP-1 – Adjustment to Fuel Expense to Reflect Proposed Base Fuel Factor

The Company agrees with Public Staff Witness Johnson's proposed adjustment to fuel clause expense to reflect the base fuel rate and Rider A set forth in the Second Supplemental Testimony of Company Witness Haynes and recommended by Public Staff Witness Floyd, subject to approval by the Commission in the Company's ongoing fuel proceeding (Docket No. E-22, Sub 579).

Adjustment NC-24 – DES Office Building Adjustment

The calculation of an annualized level of expenses for the new DES office building, 600 Canal Place, has been updated based on the actual corporate-level costs for the month of August 2019, the month in which the lease payments commenced.

Adjustments NC-43 and NC-50 – Interest Synchronization Adjustment

These adjustments reflect the federal and state income tax impacts of adjusting interest expense based the Company's updated weighted average cost of capital and fully-adjusted rate base included in the supplemental filing.

Adjustments NC-44 and NC-51 – Federal and State Income Tax Effect of Adjustments

These adjustments reflect the change in federal income tax expense produced by aggregating all 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.

Adjustment NC-59 – 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 updated capital structure, debt costs, and rate base proposed in the Company's second supplemental filing.

Adjustment NC-60 – CWC Effect of Lead/Lag Study and Accounting Adjustments

The CWC rate base component included in the cost of service per books is adjusted based on the adjusted CWC requirement as determined for regulatory purposes and has been updated to reflect the lead/lag days reflected in Supplemental Form E-1 Item 14, and the impacts of the various accounting adjustment revisions and updates discussed elsewhere in my supplemental direct testimony.

Q. Mr. McLeod, does this conclude your second supplemental testimony?

A. Yes, it does.

TESTIMONY
OF
PAUL M. MCLEOD
IN SUPPORT OF AGREEMENT AND STIPULATION OF SETTLEMENT
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

Q. **Please state your name, business address, and position with Virginia Electric and Power Company.**

A. My name is Paul M. McLeod, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am a Regulatory Consultant with the Regulatory Accounting Group for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. **Have you previously submitted testimony in this proceeding?**

A. Yes. I have previously submitted testimony in this proceeding. I have sponsored pre-filed direct, supplemental, second supplemental, and rebuttal testimony, supporting the Company's proposed changes to base fuel and non-fuel revenue requirements, as has been updated in this case.

Q. **Mr. McLeod, what is the purpose of your testimony today?**

A. My testimony supports the Agreement and Stipulation of Settlement ("Stipulation") as filed today by the North Carolina Public Staff ("Public Staff") and agreed to between DENC and the Public Staff ("the Stipulating

Parties"). Specifically, my testimony in support of the Stipulation addresses certain accounting and ratemaking adjustments agreed upon in the Stipulation.

Q. **Are you sponsoring any exhibits with your rebuttal testimony?**

A. Yes. I am sponsoring Company Settlement Exhibit PMM-1, which supports a base non-fuel revenue increase of $8.6 million. This revenue increase reflects all of the agreed-upon settlement adjustments to the revenue requirement and the Company's position on unresolved issues, specifically the ratemaking treatment of coal combustion residual ("CCR") costs. Company Supplemental Exhibit PMM-1 consists of the follow schedules:

<u>Schedule 1</u> – Rate of Return Statement – Adjusted

<u>Schedule 2</u> – Rate Base Statement – Adjusted

I have also prepared an updated Rule R1-17(b)(9) statement showing, among other things, the calculation of the additional base non-fuel revenue change of $8.6 million.

Q. **Has the Company reviewed Settlement Exhibits I & II sponsored by Public Staff Witness Sonja R. Johnson?**

A. Yes. The Company has reviewed and agrees with Settlement Exhibits I & II sponsored by Public Staff Witness Johnson. My Settlement Exhibit PMM-1 reflects the adjustments in the "Company" column of Settlement Exhibit I.

Q. Please describe the events that led to the filing of a stipulation in this proceeding.

A. After the filing of the Company's Application in this docket, DENC, the Public Staff, and intervenors engaged in substantial discovery regarding the matters contained therein. All parties filed testimony in the case asserting their respective positions, and the Company also filed rebuttal testimony responding to certain positions taken by the Public Staff and intervenors.

After lengthy negotiations but before the Company filed its rebuttal testimony, DENC and the Public Staff arrived at a settlement of all issues in the case other than the appropriate mechanism for recovery of DENC's previously-incurred CCR costs, specifically the recovery amortization period and return during the amortization period. These extensive negotiations between the Stipulating Parties culminated in the Stipulation being filed today in this proceeding.

Q. What was the outcome of the negotiations among the Stipulating Parties?

A. The agreement reflected in the Stipulation was the result of the give-and-take negotiations in which each party made substantial compromises on individual issues in order to obtain a compromise from the other parties on other issues. In the end, each party believes that the results reached, in the aggregate, are fair to the Company and its customers.

Q. Please describe the effect of the Stipulation on DENC's requested revenue increase.

A. The Stipulation provides for an adjustment to the Company's North Carolina retail base rates and tariffs to produce a total increase in annual non-fuel base revenues of $8.6 million from DENC's North Carolina retail electric operations, which represents a decrease of $15.6 million from DENC's requested revenue increase of $24.2 million, as presented in my second supplemental direct filing (filed on September 12, 2019). Public Staff Witness Johnson Settlement Exhibit 1 contains a detailed reconciliation between DENC's requested base non-fuel rate revenue increase and the stipulated revenue increase.

Q. You note that the Stipulating Parties did not reach an agreement regarding CCR Costs. How is that reflected in the revenue requirement described above?

A. The Public Staff continues to support the "equitable sharing" methodology for the Company's previously-incurred CCR costs sought for recovery in this proceeding, as described in the direct testimony of Public Staff Witness Michael C. Maness. This methodology amortizes the costs over a 19-year period with the unamortized balance excluded from rate base and reduces the Company's base non-fuel revenue requirement by $7.2 million. The Company disagrees with the Public Staff's recommended partial disallowance of CCR costs.

As most recently addressed in my rebuttal testimony, the Company's Application recommended recovery of DENC's previously-incurred CCR costs over a three year amortization period; however, the Company has now modified its position in this Stipulation to amortize such CCR costs over a five-year period rather than a three-year period as originally requested in its direct filing, with the unamortized balance included in rate base. Moving from a three-year amortization to a five-year amortization results in a $2.8 million downward adjustment to the Company's revenue requirement. As this amount falls within the Public Staff's adjustment amount, it has been reflected in Public Staff Witness Johnson Settlement Exhibit 1, notwithstanding the fact that the Stipulating Parties intend to litigate the appropriate ratemaking treatment for CCR costs as part of this proceeding. The disposition of the remaining difference of $4.3 million between the adjustments proposed by the Public Staff and the Company will be resolved outside of the Stipulation.

Q. Please provide an overview of the major components of the Stipulation.

A. The key features of the Stipulation are as follows:

- The Stipulation provides for an annual non-fuel base revenue increase of $8.6 million. As the Company originally requested a $24.2 million increase in revenues, as presented in my second supplemental direct testimony, the Stipulation represents a reduction of approximately 64% from the Company's original request;
- The Stipulation is based upon a return on equity ("ROE") of 9.75% and a capital structure for ratemaking purposes consisting of 52% common equity and 48% long-term debt. As further addressed by Company Witness Hevert, the stipulated ROE is below the Company's

currently allowed ROE of 9.9% as well as the Company's originally requested 10.75% ROE. The Stipulating Parties agreed to an embedded cost of debt of 4.442% as appropriate and reasonable for purposes of this proceeding. The overall rate of return resulting from the above inputs is 7.20%, which is 17 basis points below the Company's currently authorized overall rate of return of 7.37%;

- The Stipulating Parties agree that an average base fuel factor of $0.02092 per kWh, including regulatory fee, is appropriate to be included in the Company's base rates, and that the appropriate experience modification factor to be included in the Company's annual fuel factor to be effective February 1, 2020, shall be determined by the Commission in the Company's 2019 fuel factor proceeding, Docket No. E-22, Sub-579 ("2019 Fuel Case");
- The Stipulating Parties agree that decrement Rider A1, equal to ($0.00375) per kWh on a jurisdictional basis, calculated as the difference between the currently approved Rider B EMF of $0.00388 per kWh and the proposed Rider B EMF in the Company's 2019 Fuel Case Docket, E-22, Sub 579 of $0.00013 per kWh, is appropriate to become effective November 1, 2019, to coincide with the effective date of interim rates in this proceeding. The Company has stated in the 2019 Fuel Case that it is anticipating over-recovering fuel expenses in the second half of 2019.

- The Stipulating Parties agree that the Company shall implement Rider EDIT to allow for recovery of federal EDIT of $1.2 million (on a pre-income tax basis). The $1.2 million is comprised of 1) the amortization of all unprotected federal EDIT totaling $8.0 million partially offset by 2) the refund of $6.8 million associated with federal EDIT amortization attributable to the 22-month period January 1, 2018 through October 31, 2019. The Stipulating Parties agree that the Company shall implement Rider EDIT as described in the stipulation testimony of Company witnesses McLeod and Haynes.
- The Stipulating Parties' dispute regarding the inclusion of certain wet-to-dry conversion costs at the Chesterfield Power Station ("Chesterfield") has been resolved for purposes of this proceeding by including these costs in the stipulated revenue requirement, pending resolution of a similar dispute in the Company's Virginia jurisdiction, as discussed further in the stipulation testimony of Company Witness Mark D. Mitchell. If the final resolution in the Virginia jurisdiction results in such costs being removed from the Virginia Rider E revenue requirement, the Company will establish a regulatory liability for estimated amounts recovered from North Carolina jurisdictional customers associated with Chesterfield wet-to-dry conversion costs beginning November 1, 2019 and ending on the effective date of rates established in the Company's next general rate case. The amortization

of the regulatory liability balance will be incorporated into the revenue requirement developed in the Company's next general rate case.

Q. In your opinion, does the Stipulation reflect a fair, just, and reasonable resolution of the issues it addresses?

A. Yes. The Stipulation is the result of negotiations between the Stipulating Parties who, collectively, represent both residential and industrial customer interests impacted by this rate case. It resolves all but one contested issue in the case between the Stipulating Parties without the necessity of contentious litigation. Therefore, we respectfully request that the Commission approve the Stipulation in its entirety.

Q. Does that conclude your testimony in support of the stipulation?

A. Yes.

BY MS. GRIGG:

Q Mr. McLeod, do you have a summary of your testimonies with you?

A I do.

Q Would you please present your summary for the Commission at this time.

A My direct testimony presents an overview of the reasons for the Company's original requested increase to its non-fuel base revenue requirement of approximately $27 million. First, Dominion's current base rates are not sufficient to recover our prudently incurred costs of providing electric service. This is demonstrated in part by the return on equity of 7.52 percent that the Company experienced during the fully adjusted test period.

In addition, the Company's proposed incremental revenue requirement is driven by the substantial capital investment that the Company has made to its system since the 2016 rate case, including the addition of the Greensville County Power Station, as well as significant investments in our transmission and distribution systems, as discussed by Company Witnesses Mark Mitchell and Bob McGuire. In my direct testimony I also discuss the Company's adjustment to amortize the deferred costs for the Greensville County Power Station, as requested in

Docket Number E-22, Sub 566. Finally, I present the Company's proposed methodology for addressing excess deferred federal corporate income taxes, "federal EDIT," including a credit to customers through a one-year decrement rider representing federal EDIT amortization.

My supplemental testimony updates the Company's net plant based on actual balances as of June 30th, 2019, and includes several new accounting adjustments that arose due to new information or subsequent events that occurred during the update period. I also present a revised incremental base non-fuel revenue requirement of 24.9 million. Finally, I discuss certain corrections made to the Company's allocation of the federal EDIT rider.

My second supplemental testimony provides additional adjustments to reflect certain updates the Company's proposed changes to base fuel and base non-fuel revenues. I also present an updated calculation of the base non-fuel revenue annualization to reflect the revised customer growth and usage presented in Company Witness Paul Haynes' second supplemental testimony. Finally, I update an accounting adjustment related to a new office building. After these updates and adjustments, the Company's proposed base non-fuel revenue increase is 24.2 million, which is 0.7 million less than what was requested in my supplemental testimony.

My testimony in support of Agreement and Stipulation of Settlement addresses certain accounting and ratemaking adjustments agreed upon in the Stipulation between the Company and the Public Staff which recommends a base non-fuel revenue increase of 8.6 million. I explain that this revenue increase reflects all of the agreed-upon settlement adjustments to the revenue requirements in the Company's position on the unresolved issue of the ratemaking treatment of coal combustion residual costs. I also explain that the agreement reflected in the Stipulation is a result of a give and take negotiation between the Public Staff and DENC where both parties made substantial compromise. This Stipulation represents a decrease of 15.6 million from the Company's requested revenue increase of 24.2 million as presented in my second supplemental testimony. In my opinion, the Stipulation reflects a fair, just, and reasonable resolution of the issues it addresses and should be approved in its entirety. Thank you.

Q Thank you.

MS. GRIGG: Mr. McLeod is available for cross examination.

CROSS EXAMINATION BY MS. FORCE:

Q Good afternoon, Mr. McLeod. My name is Margaret Force or Peggy Force with the Attorney General's Office.

A Hi. Good afternoon.

Q I just have a few questions for you. On your -- in your direct testimony, if you'd please turn to page 21. And at that point in your testimony on 21 and 22 you refer to accounting for asset retirement obligations and quote from the North Carolina Utilities Commission Order for Dominion in 2004; is that right?

A That's right.

Q Okay. And on page 31 you state that the Company is seeking 19.9 million, including 2.8 million in financing cost related to coal ash closure cost; is that right?

A In my direct testimony, that's correct.

Q Well, and when you say -- let's ask this question first and then we'll get to the -- I think you were going to follow up on what you said in rebuttal. If you want to just clarify the record now, that would be fine with me. I think -- did you change that -- increase that number or adjust it?

A The 19.9 million?

Q That's right. Is it now 21.9 million or is there another adjustment since then?

A The 19.9 million stayed the same. In the Stipulation it's the $2.8 million of financing costs. I believe that --

Q So 21.9 million includes -- ahh, I -- is that made up of 19. -- my notes aren't very good -- 19.2 million of coal ash cost and then 2.7 million is the amount of financing costs?

A Are you looking at the Stipulation testimony?

Q At the time of your rebuttal. I don't think the -- did the Stipulation address this?

A I believe I -- I changed --

Q I'm asking you questions. I don't -- I don't need to -- we can -- we can look at that in rebuttal. I don't mean to put you on the spot on testimony --

A Oh, no. Just --

Q -- outside of your direct.

A Just quickly, I think I did change the financing costs in the rebuttal.

Q That makes sense. And so you said financing costs. Did that -- do you mean by that, that's an amount that was booked at the time that these costs accumulated for rate of return as the costs accumulate? Is that what you're talking about?

A Yeah. These financing costs represent financing costs on the deferral that we had for the cash expenditures from the last rate case from July 1 of 2016, up through when rates go into effect in this case, which is October 31st, 2019.

Q So you're going through the time that the rates would go into effect and including what you're calling financing costs?

A Yes. That's correct.

Q And so is it Dominion's position that the Commission is required to include financing costs if it approves these coal ash cost recovery amounts?

A I'm -- I don't know if I want to speak to, you know, saying what the Commission must do, but this proposal was based on how the Commission addressed coal ash cost recovery in the recent Duke cases, where they were allowed to recover financing cost on the deferred balances in between rate cases.

Q Okay.

A And we're simply following that Commission precedent.

Q Okay. I'm going to pass out some exhibits, and I have a question first. I had exhibits -- well, I'll come to that at the end.

Mr. McLeod, you mentioned in your testimony -- you referred to an Order that was issued concerning ARO or asset retirement obligations; is that right?

A Are you referring back to --

Q We talked about that earlier.

A -- in my direct testimony?

Q In your direct testimony.

A Yeah. That's correct.

Q And you talked about an Order in two thousand -- excuse me -- in 2004. And if you'd look at the top -- I better get a copy myself. If you'd look at the second handout in the stack that you've got, could you look at that and verify for me, is that the Order that you're referring to in E-22, Sub 420, when the Commission issued an Order allowing use of certain accounts?

A Yes. That's right.

Q Okay.

MS. FORCE: And I'd ask that this be marked AGO Cross -- McLeod Cross Examination Exhibit 1.

CHAIR MITCHELL: The exhibit shall be so marked.

MS. FORCE: Thank you.

(Whereupon, AGO McLeod Cross

Examination Exhibit 1 was marked
for identification.)

Q And then if you would look at the page just below that, and it has Dominion North Carolina Power on it, filed April 8th, 2004. Take a look at that. I found this in the same docket as Dominion's request for an Order in that docket.

A Is this -- this is in this packet here?

Q Yes. This -- I think it's the third one.

A Okay.

Q Do you see the one? Dominion North Carolina Power, filed April 8th, 2004, a copy --

A Yes. I see that.

Q -- in E-22, Sub 420. Can you look at that briefly and see whether you would agree with me that that was a request that was filed by Dominion, or a filing, anyway, regarding asset retirement obligation cost?

A Yeah. It appears to be.

Q Okay.

MS. FORCE: And I'd ask that that be identified as AGO McLeod Cross Examination Exhibit 2.

Q And the third item that I've passed out is from the -- it has October 3rd, 2016, and it has McGuireWoods at the top, and it refers to Docket Numbers E-22, Sub

532, and others. Do you see that?

A Yes.

Q And I'd submit to you, if you can double check, that that is a copy of the filing of Agreement and Stipulation of Settlement between Dominion and the Public Staff and CIGFUR in the last Dominion rate case in 2016.

A Yes. I agree.

Q You'd agree to that?

A Yes.

MS. FORCE: And I'd ask that that be identified as AGO McLeod Cross Examination Exhibit 3, please.

CHAIR MITCHELL: The exhibits will be so marked.

(Whereupon, McLeod AGO Cross Examination Exhibits 2 and 3 were marked for identification.)

Q And I have some questions, but they're not going to refer directly to those. I just wanted to get them into the record, so I --

A Okay.

Q -- appreciate your --

A Yeah.

Q -- help with that.

MS. FORCE: I'd also ask the Commission, before

I forget, to take judicial notice of the rate case Order in E-22, Sub 532, that's dated December 22nd, 2016, and it's 150 pages.

CHAIR MITCHELL: Hearing no objection, we will take judicial notice of that Order.

MS. FORCE: Thank you. I do have -- I wanted to introduce something else into the record, and I appreciate it. These are things that we can take up separately so we don't take up time at the hearing. But I want to get some clarification. There was a -- I think at the beginning Mr. Kaylor asked that the filings that were made by the Company, including the E-1 filings, be admitted into this record; is that right? And that includes confidential --

MR. KAYLOR: Correct.

MS. FORCE: -- filings. I'd just like to note that there was an NCUC Form E-1, Item 10, pages 162 through 169, that refer to coal ash costs in this, and I want to make sure that's in the record.

And with that, I don't have any other questions. Thank you.

CHAIR MITCHELL: Any additional cross examination for the witness?

MR. XENOPOULOS: No, thank you.

MS. GRIGG: No redirect.

CHAIR MITCHELL: No redirect. Questions from the Commission?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. McLeod, according to your counsel, you have some familiarity with Late-Filed Exhibit Number 3 which responded to a question the Commission asked before the hearing about recovery of cost of removal and depreciation.

A Yes. That's correct.

Q That sounds familiar to you?

A Yes.

Q I have -- do you have access to that?

A I have it here.

Q Right. I have read the Company's response, and I think I understand it, so I just want to be sure I understand it. And as I read it, what I'm being told here is that before the Company began to report under SFAS 143, it was not recovering cost of removal or closure of any of its ash waste facilities as part of depreciation. Do I read it correctly?

A Prior to ARO, the SFAS --

Q Right.

A -- 143, and still now, the Company does not include terminal net salvage in its depreciation rates, including the cost of removal.

Q And that's true for all components of a coal-fired generating plant; it does not recognize net salvage as part of depreciation?

A Terminal net salvage. That's correct.

Q Terminal net salvage. Has -- historically has not done so?

A Correct.

COMMISSIONER CLODFELTER: That's all I have. Thank you.

THE WITNESS: Okay.

EXAMINATION BY CHAIR MITCHELL:

Q Mr. McLeod, I have one question for you. This relates to DES allocation factors to DENC. You did not provide any testimony on this issue, but I want to ask you the question in the hopes that you may be able to answer it. If you can't, just please let me know.

Public Staff has provided testimony noting that as a result of Dominion Energy's acquisition of the SCANA Corporation that the allocations to DENC have decreased on a going-forward basis, but that the Companies have not been able to complete a full investigation of the allocation factors. Are you -- do you recall this testimony that's been provided in this case, and can you -- can you speak to the issue for us as to why the Company hasn't been able to provide -- to conduct a full investigation at this point?

A Are you referring to Witness -- Public Staff Witness Johnson's --

Q I am, yes.

A -- testimony? If I recall, we did receive a question of that nature in discovery and, you know, at this time for the test period and the update period, there were -- there were minimal savings that were resulting in the allocation factor process. I believe that the question asked for -- also asked for forecasted savings, which the Company did not have that information available.

Q Do you know when the Company will be able to provide -- will be in a position to provide that type of information?

A I don't know, but I can follow up with you on that.

Q Okay. Thank you.

CHAIR MITCHELL: Any additional questions from the Commission? Commissioner Brown-Bland.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Mr. McLeod, just a follow up. Do you know why there hasn't been a Company investigation on those allocation factors?

A I don't.

Q Do you know in terms of going forward when the next -- the next review of the DES allocation factors are due to be filed with the Commission?

A I don't know. Sorry.

Q That's -- if you don't. All right. Thank you.

CHAIR MITCHELL: Questions on Commission questions?

MS. GRIGG: I just have one.

EXAMINATION BY MS. GRIGG:

Q Mr. McLeod, Chair Mitchell and Commissioner Brown-Bland asked you about the effects of the SCANA merger on the jurisdictional allocations. Do you -- is it fair to say that the Company is very early in the process of its integration with SCANA?

A Yes. That's my understanding. At this point the SCANA services company is still separate. They still have their own separate and distinct services company. And I believe there's been some changes to allocation factors which would allocate less cost to VEPCO, but it's, at this point, as you said, not significant.

Q Thank you.

MS. GRIGG: That's all I have.

MR. DROOZ: And I have one follow-up question on Commissioner Clodfelter's question with regard to the coal-fired power plants and their ash basins.

EXAMINATION BY MR. DROOZ:

Q Before the effective date of SFAS 143, what was the accounting practice regarding terminal net salvage value?

A I believe they would be -- to the extent they weren't through depreciation, I assume that they would be operating expenses.

Q Are you not sure at this time?

A I haven't researched at this time, no.

Q Okay. Is that something the Company could follow up and provide a response, file it with the Commission as a further late-filed exhibit?

A Yes.

Q Thank you.

CHAIR MITCHELL: Any additional questions on Commissioner's questions? Okay. Mr. McLeod -- Ms. Harrod?

MS. HARROD: If I may. Just a quick question to make sure I understand.

EXAMINATION BY MS. HARROD:

Q And ARO accounting -- and I think this is reflected in the answer to waste coal ash question number 1 that's represented in this Late-Filed Exhibit Number 3. ARO accounting relates to a Company's legal obligations in connection with closure of plant, correct?

A Yeah. That's correct.

Q Okay. So it doesn't relate to any other plans that the Company might have for closing a plant, where it might voluntarily take some action with respect to coal ash, correct?

A To the extent that the Company does not have a legal obligation, then these activities would not he covered by ARO capital.

Q Correct.

A Right.

MS. HARROD: And so just to clarify, when you're -- following up on Mr. Drooz's question, prior to the point in time when the Company would have said it had a legal obligation to remove coal ash or to somehow treat coal ash, the -- I think the question that we would be interested in knowing is how was the Company accounting for any removal plans that it did have that may not -- that it may not have thought it had a legal obligation to do, but it may have wanted to undertake for some reason.

THE WITNESS: Okay.

MS. HARROD: Thank you.

CHAIR MITCHELL: Okay, Mr. McLeod, you may step down. Thank you.

(Witness excused.)

MS. GRIGG: May we move Mr. McLeod's exhibits and appendices into evidence at this time?

CHAIR MITCHELL: Hearing no objection, your motion is allowed.

(Whereupon, Company Exhibits PMM-1 and PMM-2, Company Supplemental Exhibits PMM-1 and PMM-2, Company Second Supplemental Exhibit PMM-1, and Company Stipulation Exhibit PMM-1 were admitted into evidence.)

MR. KAYLOR: And one -- one more cleanup item. I forgot to mention that the Stipulation between the Company and CIGFUR, we would ask that that also be entered into the evidentiary record in this case.

CHAIR MITCHELL: The motion is allowed.

(Whereupon, the Agreement and Stipulation of Partial Settlement with CIGFUR I was admitted into evidence.)

MS. FORCE: And I'd move the introduction of AGO McLeod Cross Examination Exhibits 1, 2, and 3.

CHAIR MITCHELL: Hearing no objection, your motion is allowed.

MS. FORCE: Thank you.

(Whereupon, AGO McLeod Cross Examination Exhibits 1-3 were admitted into evidence.)

MS. KELLS: May I have one more cleanup motion? I believe I forgot to move Mr. Davis' exhibits into the record as well. We'd move that we do that at this time.

CHAIR MITCHELL: Okay. Hearing no objection, that motion will be allowed.

MS. KELLS: Thank you.

(Whereupon, Company Exhibit RMD-1, Company Supplemental Exhibit RMD-1, and Company Rebuttal Exhibit RMD-1 were admitted into evidence.)

CHAIR MITCHELL: Dominion, you may call your next witnesses.

MS. KELLS: All right. Dominion calls Paul Haynes and Robert Miller as a Panel.

ROBERT E. MILLER;
PAUL B. HAYNES: Having been duly sworn,
Testified as follows:
DIRECT EXAMINATION BY MS. KELLS:
Q All right. I will start with Mr. Haynes. Would you please state your name and business address for the record.
A (Haynes) My name is Paul B. Haynes. My business --
COMMISSIONER GRAY: Mr. Haynes, y'all are going to have to sort of share that microphone, and I appreciate so much your respecting the ability of everybody to hear in the -- in the room. Thank you.
A My name is Paul B. Haynes. My business address is 120 Tredegar Street, Richmond, Virginia.
Q And by whom are you employed and in what capacity?
A I'm employed by Dominion Energy North Carolina, and my title is Director - Regulation.
Q Did you cause to be prefiled in this docket on March 29th, 2019, 49 pages of direct testimony in question and answer form, an Appendix A, and three (sic) exhibits?
A Yes.

Q Did you also cause to be prefiled in this docket on August 5th, 2019, 10 pages of supplemental testimony in question and answer form and one exhibit?

A Yes.

Q Did you cause to be prefiled on August 14th, 2019, 10 pages of additional supplemental testimony and one exhibit?

A Yes.

Q Did you cause to be prefiled in this docket on September 12th, 2019, 50 pages of rebuttal testimony and one exhibit?

A Yes.

Q And, finally, did you cause to be filed in this docket on September 17th, 2019, seven pages of Stipulation testimony and one exhibit?

A Yes.

Q Do you have any changes or corrections to any of your testimonies or exhibits?

A Yes, I do. First, on page 1 of my direct testimony, my business address has changed to 120 Tredegar Street, Richmond, Virginia. In my direct testimony on page 24, footnote 5, the -- there is a correction in the sentence that begins with "As discussed earlier." The correction is after the word recognizes.

The word "that" should be removed, and "Nucor" should be revised to be "Nucor's" with an apostrophe s. Also in my direct testimony on page 35, line 12 should read page 1 of 6. Also in my direct testimony on page 41, line 19, which states "The typical bill amount for Rate Schedule 6L currently says the bill would decrease from $378,661.96 to $377,179.29, or by 5.67 percent," those numbers should be revised so that the line reads "from $378,661.96 to $357,179.29." The percentage change is the same.

In my supplemental testimony, page 1, line 1, my business address has changed to 120 Tredegar Street, Richmond, Virginia. The same is true in my additional supplemental testimony, page 1. The business address should be 120 Tredegar Street, Richmond, Virginia.

In my rebuttal testimony, page 34, footnote 26, the page number referenced in that footnote -- actually, the line number referenced in that footnote should be line 59 rather than line 49.

And then finally, in my Stipulation testimony there are references to Section V of the Stipulation that appear on page 2, line 17; page 3, lines 5 and 18; and page 4, line 11. These should be revised to reference Section VI of the Stipulation.

Q And considering those corrections, if I were to ask you the same questions that appear in your testimonies today, would you answers be the same?

A Yes.

MS. KELLS: Chair Mitchell, at this time I move the prefiled direct, supplemental, additional supplemental, rebuttal, and Stipulation testimonies of Mr. Haynes be copied into the record as if given orally from the stand and his exhibits be marked for identification as prefiled.

CHAIR MITCHELL: Hearing no objection, that motion will be allowed.

(Whereupon, the prefiled direct testimony, as corrected, supplemental testimony, as corrected, additional supplemental testimony, as corrected, rebuttal testimony, as corrected, and Stipulation testimony, as corrected, of Paul B. Haynes were copied into the record as if given orally from the stand. The confidential version of the rebuttal testimony was filed under seal.)

(Whereupon, Company Exhibit PBH-1, Company Supplemental Exhibit PBH-1, Company Additional Supplemental Exhibit PBH-1, Company Rebuttal Exhibit PBH-1, and Company Stipulation Exhibit PBH-1 were identified as premarked.)

DIRECT TESTIMONY
OF
PAUL B. HAYNES
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

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

A. My name is Paul B. Haynes, and my business address is 701 East Cary Street, Richmond, Virginia 23219. My title is Director-Regulation for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). A statement of my background and qualifications is attached as Appendix A.

Q. **Mr. Haynes, what is the purpose of your testimony in this case?**

A. The primary purpose of my testimony is to address i) the allocation method(s) used to allocate Production and Transmission fixed costs and related expenses in the cost of service studies, ii) the Company's proposed apportionment of the non-fuel base rate revenue increase among the customer classes, and iii) then to revise DENC's non-fuel base rates 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.

In addition, I 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 2019 fuel proceeding. My testimony also supports Rider EDIT, which is designed to refund excess deferred Federal income taxes ("EDIT") to our customers over one year.

Finally, I address how the Company's proposed non-fuel base, base fuel and the projected EMF fuel adjustments will impact customers' rates.

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

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

	Section
I.	**ALLOCATION OF PRODUCTION AND TRANSMISSION FIXED COSTS AND RELATED EXPENSES**
II.	**BASE RATES**
III.	**APPORTIONMENT OF NON-FUEL BASE RATE INCREASE AND RATE DESIGN**
IV.	**PLACEHOLDER BASE FUEL RATE**
V.	**PROJECTED BASE FUEL RATE AND EMF**
VI.	**RIDER EDIT**
VII.	**SUMMARY SHEET AND TYPICAL BILLS**
VIII.	**RATE SCHEDULES**
IX.	**TERMS AND CONDITIONS AND EXISTING RIDERS**
X.	**RULE R1-17 AND E-1 REQUIREMENTS**

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

A. Yes. I am sponsoring Company Exhibits PBH-1, PBH-2, and PBH-3. Company Exhibit PBH-1, consisting of Schedules 1 through 8, was prepared

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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, pages 1 through 4 provide the Company's calculation of Factor 1 (production demand) and Factor 2 (transmission demand) for the Company's four jurisdictions and for the North Carolina jurisdiction's customer classes using the Summer Winter Peak and Average ("SWPA") allocation method. My Schedule 1, pages 5 through 8 provide the Company's calculation of Factor 1 and Factor 2 for the Company's four jurisdictions and for the North Carolina Jurisdiction's customer classes using the Average and Excess Demand ("A&E") allocation method.
- Page 1 of my Schedule 2 shows the proposed non-fuel base rate revenue increase, in both revenues and percentage increase, for each of the customer classes compared to the overall North Carolina jurisdictional percentage non-fuel base rate revenue increase. Page 2 of 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 shows the calculation of the revised base fuel component by customer class equal to the sum of the existing class' 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, 2019, as discussed later in my testimony.

- My Schedule 4 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, 2019, using eight months of actual fuel expense data for the months of July 2018 through February 2019 and four months of forecasted fuel expense data for the months of March through June 2019.
- My Schedule 5 shows the rate design for the Company's proposed Rider EDIT. The Company is proposing that federal EDIT amortization attributable to the 20 month period January 1, 2018 through October 31, 2019 be credited to customers through a one year decrement rider, Rider EDIT, as explained in more detail by Company Witness Paul M. McLeod.
- My Schedule 6 is a summary sheet showing the increase in non-fuel base rate revenue or basic revenue amounts and the proposed rate decrement Rider EDIT compared to total current revenues and their corresponding percent changes.
- My Schedule 7 is a summary sheet showing the increase in non-fuel base rate revenue amounts, the proposed rate decrement Rider EDIT,

and the projected decrease in fuel revenue compared to total current revenues and their corresponding percent changes.

- My Schedule 8 provides a list of charges in the Terms and Conditions that the Company is proposing to update in this docket.

I am also filing Company Exhibits PBH-2 and PBH-3, which provide supplemental information and rate analyses that I further identify and explain in my testimony. 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. ALLOCATION OF PRODUCTION AND TRANSMISSION FIXED COSTS AND RELATED EXPENSES

Q. What methodology has DENC used to allocate production and transmission fixed costs in the Company's jurisdictional cost of service and customer class cost of service studies 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 six general rate cases, Docket Nos. E-22, Sub 273 (1983), Sub 314 (1990), Sub 333 (1992), Sub 459 (2010), Sub 479 (2012), and Sub 532 (2016) and in the Commission's 2004 general rate investigation, Docket No.

E-22, Sub 412. Most recently, the Commission determined in its final order in the Company's previous general rate case, Docket No. E-22, Sub 532,[1] that "DNCP's continued use of the SWPA methodology in this proceeding properly assigns plant production costs to all customer classes, including the Schedule NS Class in recognition of its significant use of the Company's generation throughout the year." [2]

Q. Please explain the fundamental concepts of 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 and the winter months.

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 next recognizes that these two components (peak demand and average demand) should be weighted before determining the resulting

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[1] *Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions*, Docket No. E-22, Sub 532 (Dec. 22, 2016) ("2016 Rate Order").
[2] 2016 Rate Order, Page 16, Finding of Fact #40.

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

Q. Why is the Company continuing to support the use of the SWPA method in this proceeding?

A. The Company is continuing to support 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 at a lower cost 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 invest in new baseload generation that can serve customers' electricity needs throughout the year. For example, the Company's recent addition of the high capacity factor Greensville Power Station, as well as other advanced combined cycle facilities and historical investments in its baseload nuclear fleet, will operate throughout the year to provide baseload energy to the Company's customers. These recent baseload generating plant investments support the view that DENC's resource planning is driven by both the need to serve load at the peak hour as well as throughout the year. These recent plant decisions align with the SWPA's approach of allocating plant costs and related expenses considering both the peak demand component and the average demand, or energy consumption, component of service.

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 106 MW. The average of Nucor's summer (July 2, 2018) and winter (January 7, 2018) coincident peak demands is approximately 42 MW. Without recognizing an average component in the cost allocation, this customer class would "pay" for only 42 MW and would escape cost responsibility for an average of 64 MW for the rest of the year (*i.e.,* the average demand of 106 MW less allocated demand of 42 MW). In sum, use of a peak-only methodology would allow the NS Class to avoid cost responsibility for 64 MW of power – equal to approximately 560,000 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 six rate cases – that SWPA provides the appropriate jurisdictional and inter-class 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. Can you explain the adjustment the Company made to the summer and winter peak demands to recognize generation from certain non-utility generators ("NUGs")?

A. Yes. In the 2016 rate case, the Company proposed to adjust 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 concluded in the 2016 Rate Order that "DNCP's adjustment to the peak component of SWPA appropriately recognizes the impact non-utility generators have on DNCP's utility system and is appropriate for use in this proceeding."[3]

The Company is proposing to apply the same adjustment in this proceeding to recognize the impact that certain non-utility generators have on the Company's system.

Q. Has the Company considered other adjustments related to DENC's industrial customers' demand reductions associated with available load curtailment programs that were made in previous rate case proceedings?

A. Yes. In the Company's 2012 rate case, Docket No. E-22, Sub 479, the Commission determined that a Company-proposed administrative adjustment to the SWPA winter peak was appropriate because not all load management

[3] 2016 Rate Order, Page 16, Finding of Fact No. 16.

pricing programs were called to achieve load reductions on that day. The load response programs were not actually called on the winter peak day (all programs were called on the summer peak day). This adjustment recognized that industrial customers' ability to curtail their loads in response to the Company's price signals is an appropriate consideration to take into account in setting the SWPA peak allocation factors. The Company considered the same adjustment in the 2016 rate case but all load management programs and pricing signals within the rate schedules to signal peak load conditions that were eligible to be called were called on the winter and summer peak days. In this proceeding, all programs that were eligible at that time were called upon for both the winter and summer peak days; therefore, no adjustments are necessary.

Q. Are there any new adjustments that are appropriate for the purpose of establishing rates that will be in effect during 2020 and beyond?

A. Yes. As discussed in the testimony of Company Witness Bruce E. Petrie, the Company's power supply contract with the North Carolina Electric Membership Corporation ("NCEMC"), which is a wholesale customer with a capacity requirement of 150 MW, is not being renewed and will terminate at the end of 2019. Also, the Company learned in the first quarter of 2019 of two large industrial customers with non-coincident peak demands totaling just over approximately 100 MW in the Virginia jurisdiction that are no longer taking generation service from the Company.

The Company proposes to adjust the test year demand and energy used in the calculation of the SWPA production demand allocation factor (Factor 1) to remove the impact associated with these customers.

The Company is not proposing to adjust the transmission demand allocation factor.

Q. **Based upon the adjustments you just described, 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.

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.

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' 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' 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. Is the Company also filing the Average and Excess ("A&E") cost allocation methodology in this proceeding?

A. Yes. In the 2016 rate case, the Commission stated "that the Company shall file an Average and Excess cost allocation methodology in its next North

Carolina general rate case, in addition to the cost allocation methodology proposed by the Company."[4]

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.

[4] 2016 Rate Order, page 150, Ordering Paragraph No. 22.

	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)	Kilowatt-hours (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 kilowatt-hours 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 also filed the A&E method in a North Carolina rate case in 1992 in Docket No. E-22, Sub 333.

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. These are:

i) 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;

ii) adjustments related to DENC's industrial customers' demand reductions associated with available load curtailment programs; none were required; and

iii) adjustments to demand and energy to recognize the loss in 2019 of a wholesale power supply contract and the loss of two large industrial customers in the Virginia jurisdiction that no longer require generation service.

Q. In the calculation of the A&E factor has the Company considered whether an additional adjustment may be appropriate for the demand and energy associated with the Schedule NS class on the jurisdictional class peak hour for use in calculating the jurisdictional allocation factor?

A. Yes. On the day and hour of the jurisdictional class peak, the Schedule NS class was not provided a price signal to curtail. As a result, both the load for this customer class and for the North Carolina jurisdiction were higher than what would have occurred had the load management price signal been provided to the Schedule NS class. Consistent with item (ii) from the previous answer and for the purpose of considering this allocation factor for use in ratemaking, the Company has adjusted the Schedule NS load, the North Carolina jurisdictional load and the total system load down to reflect the demand curtailment level experienced on the system peak. Without this additional adjustment, the calculation of the A&E factor would have resulted in a higher jurisdictional allocation factor.

Q. Based upon the adjustments you just described, can you provide the A&E factor for the Company's four jurisdictions and the North Carolina customer classes?

A. This information is provided in my Schedule 1, pages 5-8.

Q. For the development of the cost of service studies contained in Form E-1, Item 45 prepared by Company Witness Robert E. Miller, what allocation methodology and set of factors are you providing to him to allocate system production and transmission plant costs and related expenses?

A. For use in the cost of service studies, I am providing the allocation factors calculated according to the SWPA methodology, which reflect the adjustments I have described in this testimony that are appropriate for this method.

II. 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 McLeod's Schedule 1, the Company is requesting to increase total annual non-fuel base rate revenues by $27.0 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 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 (approximately $202,059) from the proposed annual non-fuel base rate revenue increase of $27.0 million. The remainder of the non-fuel base rate revenue increase of $26.76 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.

III 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 taking into account 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.

To achieve the goal of moving toward parity, we first reviewed the existing class rates of return, which are shown in Company Witness Miller's Schedule 4. Page 2 of my Schedule 2 duplicates this information and provides the customer class rates of return, and their respective indices, from the

Company's class cost of service study. 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 return with annualized revenues. The next block shows the class rates of return and indices after all ratemaking adjustments, but prior to any revenue increase. At this point, 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.

As can be seen in this section of my Schedule 2, there are six classes that have existing rates of returns/indices that are significantly different from the rates of return of the overall North Carolina jurisdiction. On the low end, the Outdoor and Street Lighting class has a ROR of 2.0963% and an index of 0.35. Two other classes have RORs below the jurisdictional ROR. The residential class has a ROR of 5.2713% and an index of 0.87. The NS Class has a ROR of 5.1061% and an index of 0.84. On the upper end, the Large General Service ("LGS") class has a ROR of 8.3710%, and an index of 1.38. Two other classes have rates of return and resulting indices that may be considered high relative to the jurisdiction. The Small General Service ("SGS") and Public Authority class has a ROR of 7.6671% and an index of 1.26.The 6VP class has a ROR of 7.6492% and an index of 1.26. The

Traffic lighting has a ROR that is closer to the jurisdictional ROR and has an index of 1.08.

Q. 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 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, I then apply the following general and class-specific principles to equitably distribute the base rate revenue increase:

- All 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 customers pay with their responsibility for cost, even if the index achieved after apportionment still 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 being given to the appropriate increase for these customer classes based upon certain non-cost factors that support a lesser increase for large industrial customers with high load factors within these classes. And 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 our largest and most energy-intensive customer, Nucor and how that arrangement benefits the system and the customers in the North Carolina jurisdiction.

Q. Please elaborate on the other 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 a number of factors, including the quantity of our 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.

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, eight of the large, high load factor industrial customers in our LGS (four customers), Schedule 6VP (three customers), and Schedule NS classes employ approximately 7,800 people.[5]

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 table presents information on i) allocated rate base, ii) class rates of return and 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 indices after apportionment.

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[5] Specifically, in terms of the NS class, the Company has an arrangement with Nucor that partially interrupts load related to its electric arc furnace 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 earlier, the SWPA allocation method used in the cost of service that establishes the Company's requested revenue requirement in this proceeding recognizes that 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 by having a lower allocation of production and transmission demand plant and related costs that used as a basis for establishing a revenue requirement.

TABLE 1

	Res	SGS / PA	LGS	NS	6VP	Out Lts	Traffic
Rate Base	$614,757,351	$208,595,666	$125,297,474	$123,703,740	$48,643,229	$20,521,579	$161,988
% of Jurisdictional Rate Base	53.85%	18.27%	10.97%	10.84%	4.26%	1.80%	0.01%
Fully Adjusted COS ROR	5.27%	7.67%	8.37%	5.11%	7.65%	2.10%	6.54%
ROR Index Before Change	0.87	1.26	1.38	0.84	1.26	0.35	1.08
Non-fuel Increase - All Charges	$19,397,612	$3,745,940	$807,024	$2,003,792	$296,603	$703,388	$3,641
ROR After Non-fuel Base Increase	7.06%	8.96%	8.80%	6.26%	8.06%	4.63%	8.19%
ROR Index After Change	0.97	1.15	1.13	0.8	1.03	0.59	1.05

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 1, in terms of cost responsibility for rate base, the residential class is the largest with an allocation of $614.7 million or 53.85% of the jurisdictional total rate base. The class ROR on this allocated rate base is 5.27% with an index of 0.87 before any apportionment of the non-fuel base rate increase and below the desired Parity Index Range. The large size of this class in terms of responsibility for rate base and related expenses, and having an index of 0.87, means that it will be responsible for the greatest portion of the non-fuel base rate increase, with a target percentage increase of 14.66% (jurisdictional increase is 10.51%) as its rates are not fully aligned with cost. The index after the increase of 0.97 shows that the residential class will have rates that are aligned more closely with its responsibility for cost.

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 1, the SGS and Public Authority class is the second largest in the jurisdiction with an allocation of almost $208.6 million or 18.27% of the jurisdictional total rate base. The class ROR on this allocated rate base is 7.67% with an index of 1.26 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. However, this amount has been tempered by the fact that this class is currently paying rates that are not aligned with its responsibility for cost as evidenced by its index of 1.26. 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 7.36%, which is less than the non-fuel base percentage increase for the jurisdiction of 10.51%. While the Company is endeavoring through this apportionment to bring this class toward the Parity Index Range, the index after the increase of 1.15 shows that the class will still pay rates that are above cost leave this class's ROR above the desired Parity Index Range, albeit closer to this range than prior to the apportionment of the revenue increase.

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 department stores, grocery stores, large hardware stores, colleges, health care facilities, governmental facilities and industrial manufacturers - some small and some large. As shown in Table 1, this is the third largest class with an allocation of rate base of $125.3 million or approximately 10.97% of the jurisdictional rate base. Its ROR is 8.37% resulting in an index of 1.38.

The 6VP class is composed of large industrial customers engaged in manufacturing. As shown in Table 1, this class has been allocated responsibility for $48.6 million or about 4.3% of the jurisdictional rate base. Its ROR is 7.65% resulting in an index of 1.26.

Both the LGS and 6VP classes have a ROR that is well above 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 of 2.63% in non-fuel base revenue to these combined classes, which is less than the overall jurisdictional increase of 10.51%. The apportioned increase results in an 8.80% ROR for the LGS class and in a 8.06% ROR for the 6VP class after the increase. After receiving the increase, the LGS class has an index of 1.13 which is slightly above the Parity Index Range but significantly improved from its index prior to the increase. Meanwhile, the increase for the 6VP class brings its index to within the Parity Index Range at 1.03.

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 $123.7 million or 10.84% of jurisdictional rate base. The fully adjusted cost of service shows that the Schedule NS class has a ROR of 5.11% with an index of 0.84. In the 2016 case, this class received a non-fuel base rate increase that moved its ROR index from 0.44 to 0.75. This moved the NS class two-thirds of the way toward the low end (90% of jurisdictional ROR) of the Parity Index Range. Prior to the 2016 rate case, a deficiency had existed for a number of years, as reported in the Company's past rate cases and annual jurisdictional cost of service studies filed with the Commission. For example, in 2011, which was the year following the Company's 2010 base rate case in Docket No. E-22, Sub 459, Nucor's ROR index was negative. In 2013, which was the year following DENC's 2012 base rate case in Docket No. E-22, Sub 479, Nucor's jurisdictional ROR index had increased to only 0.51.

With an ROR Index of 0.84 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 to an index that is approximately 10 basis points below the Parity Index Range. Therefore, I have apportioned a target percentage increase in non-fuel base rate revenue for the NS class of 7.88%.

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, 2019. The Company will work with Nucor regarding the renewal or amendment of that 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 1, the Outdoor / Street Lighting and Traffic Lights classes are the two smallest customer classes in terms of responsibility for rate base with an allocation of $20.5 million, 1.80% of rate base and $0.16 million, 0.01% of rate base, respectively. The ROR before the non-fuel base rate increase for the Outdoor / Street Lighting class is 2.10% with an index of 0.35. The rates the Outdoor 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 target increase of 14.66%, the Outdoor / Street Lighting class has an index of 0.59.

The ROR for the Traffic Lighting class is 6.54% with an index of 1.08, which is in the high end of the Parity Index Range. After the apportioned increase of 6.36%, the Traffic Lights class has an index of 1.05.

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 1 of my Schedule 2. The last section on Page 2 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, but 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 VII below, while our customer classes will experience an increase in non-fuel base rates, their total bill will be substantially moderated when the proposed rate decrement Rider EDIT and projected fuel components of our rate structure are taken into consideration.

III B. 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 2018 billing determinants as of December 31, 2018. This calculation is by each rate component or "block" in the rate schedule. For purposes of reference, the rates recently placed in effect as of January 1, 2018 as a result of Docket No. E-22, Sub 560 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 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 on page 3 in Columns (7) through Column (14). 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 6. In total, the final change in revenue equals the revenue increase of $27.0 million provided to me by Company Witness McLeod.

Q. For each rate schedule, does the final change in revenue for each function equal the target revenue increase?

A. No. There are 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 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 did review the study and noted the fully supported customer charges for the customer classes. As described above in explaining the rate design, I applied the same factor to adjust the present customer charges as I did other components in the rate schedule. 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. The exception is 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.

IV. 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 re-establishing the base fuel rate approved in the 2016 Rate Case, the Company is proposing a Placeholder Base Fuel Rate to be updated through the 2019 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 2016 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 558 (the "2018 Fuel Case"). To support this proposal, Company Witness Bruce E. Petrie presents the June 30, 2018, test period adjusted system fuel expense of $1.824 billion (as provided in Schedule 1 of Company Exhibit BEP-1), which was approved by the Commission in the 2018 Fuel Case.

In my Schedule 3, Page 1 of 3, I show the calculation of the normalized North Carolina jurisdictional average fuel factor of $21.42 per MWh, as approved in the 2018 Fuel Case, for the 12-month period ending June 30, 2018. The calculation used to differentiate the approved North Carolina jurisdictional average fuel factor by class is shown in Schedule 3, Page 2 of 3. The Company proposes to set Rider A – Fuel Cost Rider to zero and use the $21.42 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, 2019, as shown on my Schedule 3, 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 2019, 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 2019 annual fuel filing ("August 2019 Base Fuel Rate").

V. PROJECTED BASE FUEL RATE AND EMF

Q. Does the Company have any projections for the August 2019 Base Fuel Rate at the present time?

A. Yes. As stated in Company Witness Petrie's direct testimony in this proceeding, the Company anticipates an increase in the base fuel factor given current projections for fuel expenses for the 12-month period ended June 30, 2019, which is the test period in the Company's annual fuel proceeding to be filed in August 2019, for fuel rates to become effective for usage on and after February 1, 2020, and due to the reflection of total delivered costs associated with certain purchases of power from qualifying facilities under the Public Utility Regulatory Policies Act of 1978 ("PURPA") pursuant to NC House Bill 589. Since the system fuel expenses for March 2019 through June 2019 are currently unavailable, Company Witness Petrie provided estimated total system fuel expenses of $1.803 billion, using eight months of actual data for the months of July 2018 through February 2019 and four months of forecasted data for the months of March through June 2019 (provided in Company Exhibit BEP-1, Schedule 2, which is attached to Company Witness Petrie's direct testimony in this proceeding).

As shown in my Schedule 4, Page 1 of 5, I calculate the projected normalized North Carolina jurisdictional average fuel factor of $21.72 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 4, Page 2 of 6. The calculations shown in my Schedule 4 are consistent with the methodologies used in the Company's 2018 Fuel Case, except I have updated the class expansion factors for 2018. The Projected Base Fuel Rate of $21.72 per MWh is an increase of $0.30 per MWh from the Placeholder Base Fuel Rate of $21.42 per MWh.

Q. Does the Company have any projections for the EMF that will be filed in its annual fuel proceeding in August 2019?

A. The current period fuel under-recovery through June 30, 2019 will be the basis for the EMF to become effective on February 1, 2020. As stated in Company Witness Petrie's direct testimony in this proceeding, the Company expects the EMF balance to be in an under-recovery position of approximately $1-3 million, which will be a significant decrease from the under-recovery balance as of June 30, 2018 of $16,162,154 that is being recovered through the EMF Rider B currently in effect. Assuming an under-recovery of $1 million, this projection will result in a projected EMF of about $0.23 per MWh, shown in my Schedule 4 page 3, from the current EMF of $3.88 per MWh for the overall North Carolina jurisdiction. This is a reduction of $3.65 per MWh.[6] My Schedule 4 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 2019?

A. The Company currently projects a total decrease in the fuel factor of approximately $3.35 per MWh for the overall North Carolina jurisdiction from $25.30 per MWh to $21.95 per MWh. Refer to page 5 of my Schedule 4.

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[6] For an under-recovery of $3 million on June 30, 2019, the projected EMF would be $0.70 per MWh. Compared to the present EMF of $3.88 per MWh, this represents a decrease of $3.18 per MWh.

VI. RIDER EDIT

Q. Please address the Company's proposal to refund excess deferred income taxes ("EDIT") to North Carolina jurisdictional customers?

A. As explained in Company Witness McLeod's testimony, the Company is proposing that federal EDIT amortization attributable to the 20 month period January 1, 2018 through October 31, 2019 be credited to customers through a one year decrement rider, Rider EDIT. The total credit proposed is $6,909,000.

Q. How do you propose to allocate the EDIT credit of $6,909,000 to the customer classes and to develop the decrement rider rate?

A. I propose to allocate the credit to customer classes based upon North Carolina basic (non-fuel) rate revenue annualized based upon current rates for 2018. I developed a decrement rate based upon booked 2018 kWh sales adjusted for weather, growth, and increased usage. My Schedule 5 shows the rate design for the proposed Rider EDIT to refund customers EDIT and the proposed Rider EDIT tariff.

The decrement rate will be applied to customer usage beginning with the effective date of the rider and will be in effect for 12 months. Prior to the tenth month from the effective date of the rider, the Company will provide an analysis to the Public Staff to evaluate if the total rider credit will be provided at the end of the 12 months. If there is a deviation between the total rider credit and the projected credit provided to customers, the Company and the Public Staff will work together to develop an adjustment to the Rider EDIT to minimize the deviation over the remaining months of Rider EDIT being in effect.

VII. 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 6, Column 11 shows the increase in the non-fuel base rate revenues by rate schedule. Column 15 shows the percent change in non-fuel base rate revenue compared to existing non-fuel base rate revenues. Column 18 shows the percent change in total revenue (*i.e.* non-fuel base rate revenue plus rider revenue including the proposed Rider EDIT, fuel revenue associated with the Placeholder Base Fuel Rate, and the currently approved EMF).

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, 2019, 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. Haynes, assuming the proposed change in non-fuel base rates, combined with the Placeholder Base Fuel Rate and the existing EMF, become effective May 1, 2019, 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 and the proposed Rider EDIT, to become effective for usage on and after May 1, 2019, when combined with the Placeholder Base Fuel Rate and the currently approved Fuel Rider B – Experience Modification Factor, 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 $113.13 to $123.46, or by 9.13%;
- 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 $1,134.85 to $1,170.78, or by 3.17%;
- 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 $40,909.77 to $40,867.30, or by (0.10)%; 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 $378,661.96 to $377,339.29, or by (0.35)%.

Q. Mr. Haynes, do you anticipate the foregoing increase in the Company's non-fuel base rates will be allowed to become effective on May 1, 2019, as proposed?

A. No. Consistent with past rate cases, I anticipate that the Commission will suspend the non-fuel base rates proposed in the Company's Application to become effective on May 1, 2019. This suspension, and the timing of the effective date of new rates on January 1, 2020, is important, as it allows DENC to generally synchronize the adjustment to non-fuel base rates with the Company's 2019 fuel factor during the early part of 2020. As shown in my Schedule 7, the overall effect of the proposed non-fuel base rate increase, current non-fuel riders, and the proposed Rider EDIT when combined with the projected fuel rate reduction to be filed in August 2019, 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 $113.13 to $120.08, or by 6.14%;

- 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 $1,134.85 to $1,128.52, or by (0.56)%;
- 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 $40,909.77 to $38,931.94, or by (4.83)%; 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 $378,661.96 to $377,179.29, or by (5.67)%.

VIII. RATE SCHEDULES

Q. Is the Company filing proposed rate schedules that will be changed to collect the proposed revenue requirement of $27.0 million?

A. Yes. The rate schedules that the Company proposes to become effective for usage on and after May 1, 2019, to be used in collecting the proposed $27.0 million revenue requirement, are presented as Item 39 of the Company's Form E-1. The rates to be changed in those May 1, 2019, rate schedules are struck through and the new proposed rates added and shown in italics.

Q. With regard to Rate Schedule 26 Outdoor Lighting Service, is the Company proposing to close to new customers the applicability of rates related to high-pressure sodium vapor ("HPS") lighting?

A. Yes. Over the course of the last year, the Company has found that since this technology has become outdated, it has become difficult to source as lighting manufacturers have largely switched to the newer LED technology. As a result, the Company is facing challenges in maintaining a sufficient inventory of HPS lighting fixtures to meet customers' needs when fixtures fail and need to be replaced. Due to the sourcing problems associated with continued provision of HPS fixtures under existing Rate Schedule 26 and the anticipated benefits of utilizing LED fixtures which were approved by the Commission as part of this rate schedule during 2018, the Company is filing to close to new customers installations of HPS lighting.

Q. When is the Company requesting to place permanent base rates into effect, upon Commission approval?

A. The fuel rates proposed in the Company's August 2019 annual fuel factor proceeding will go into effect on February 1, 2020, with Commission approval. There are synergies produced by implementing the proposed base rates (included in the May 1, 2019, rate schedules) in this proceeding as close as possible to the August 2019 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 January 1, 2020, on a permanent basis.[7]

Q. Is the Company considering putting the non-fuel base rate increase into effect on a temporary basis?

A. Yes. The Company intends to accelerate implementing base rates for usage on and after November 1, 2019, 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 2016 Rate Case.

[7] This would be one month prior to the projected reduction in the fuel rate, which will take effect on February 1, 2020.

Q. Regarding the rates being placed into effect on a temporary basis, will the provision to close the HPS portion of Schedule 26 to new customers also take effect on November 1, 2019?

A. No. The Company proposes that the HPS portion of Schedule 26 be closed to new customers effective January 1, 2020.

IX. 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, Rider D – Tax Effect Recovery, Fuel Rider A, and Rider EDIT. 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. Accompanying each revised section of the Terms and Conditions is a "Comments" page(s) that will provide a brief description of each proposed change. The Company proposes an effective date of May 1, 2019, 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 8, page 1 contains a list the charges being updated based upon the costs of providing such services.

Q. What change does the Company propose to Fuel Rider A?

A. As I mentioned earlier, the Company proposes to set the existing rates by class in Fuel Rider A to zero, after adding the rates to the existing class base fuel rate to calculate the Placeholder Base Fuel Rate. The Base Fuel Rate will be updated when the Company files its fuel case in August 2019.

X. 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, and other riders including the proposed Rider EDIT. Summary sheet 2 presents the impact of proposed changes to the non-fuel base rates, the Projected Base Fuel Rate and projected EMF, and other riders including the proposed Rider EDIT.

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.

<u>Item 40</u>

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 kilowatt-hour 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 2016 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 our 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 in May 2015,[8] 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 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 2016 Rate Case, I will make an adjustment in our August 2019 supplemental filing to "recognize" the kWh sales reductions associated with measures installed through June 30, 2019, as being recovered through the non-fuel base rates. The Company anticipates supporting this adjustment using its most current Evaluation, Measurement, and Verification Report.

[8] *Order Approving Revised Cost Recovery and Incentive Mechanism And Granting Waiver*, Docket No. E-22, Sub 464 (May 7, 2015).

Q. Mr. Haynes, does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF PAUL B. HAYNES

Paul B. Haynes received a Bachelor of Science degree in Business Administration from the University of Richmond in 1984 and a Master of Business Administration with a Concentration in Quantitative Methods from Virginia Commonwealth University in 1989.

Mr. Haynes started his career with the Company as a meter reader. He went through the Company's Customer Service Representative training program for three-and-one-half years, during which time he designed distribution facilities to serve residential and non-residential customers. In 1990, Mr. Haynes joined the Rate Department to work in the Rate Design section, where he assisted with regulatory filings and the design of rates, and performed analysis related to the Company's Virginia and North Carolina service territories. He has held various staff analyst positions within the Customer Rates Department, formerly the Cost Allocation and Pricing Department. In 2006, Mr. Haynes became Project Manager of Regulatory Research and Analysis, and then became Manager of Regulatory Analysis, Research and Support in 2007. On June 1, 2009, Mr. Haynes became Manager – Regulation with responsibility for cost allocation and cost of service studies, and on January 1, 2013, he assumed his current position as Director – Regulation with responsibility for Cost of Service and Rate Design.

Mr. Haynes has previously provided testimony before the State Corporation Commission of Virginia and the North Carolina Utilities Commission.

SUPPLEMENTAL DIRECT TESTIMONY
OF
PAUL B. HAYNES
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

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

A. My name is Paul B. Haynes, and my business address is 701 East Cary Street, Richmond, Virginia 23219. My title is Director-Regulation for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Did you provide pre-filed direct testimony in this case?

A. Yes. I submitted direct testimony on behalf of the Company ("Direct Testimony") in support of DENC's application for authority to adjust and increase its retail electric rates and charges filed on March 29, 2019 ("Application"). My Direct Testimony presented the Company's proposed revenue apportionment and rate design using the Cost-of-Service Study ("COSS") supported by Company Witness Robert E. Miller. My Direct Testimony also supported the Company's proposed tariffs, discussion of the update to the base fuel rate, and a projection of the Experience Modification Factor ("EMF"), Rider B, anticipated in the Company's August 2019 fuel proceeding. My Direct Testimony also supported the calculation of Rider EDIT, which is designed to refund excess deferred Federal corporate income taxes ("Federal EDIT") to our customers over one year.

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

A. The purpose of my supplemental testimony is, first, to address a correction to Factor 2 used to allocate transmission plant costs and related expenses. Second, I will update the weather, growth, and increased usage adjustment to annualize revenue based on actual information through June 30, 2019, and explain changes in the calculation of this adjustment's impact on annualized revenue. Third, I calculate the energy efficiency program ("EE Program") lost revenues adjustment identified in my Direct Testimony based upon information provided by Company Witness Deanna R. Kesler. Finally, I address an update to the Base Fuel Rate, included as the Placeholder Base Fuel Rate in my Direct Testimony and also explain Rider A1, a decrement rider, to be filed in the Company's Fuel Factor filing on August 13, 2019.

Q. In your supplemental testimony, will you be introducing any exhibits?

A. Yes. Company Supplemental Exhibit PBH-1 was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief. As described further below, Company Supplemental Exhibit PBH-1 is intended to update and replace affected Schedules included in Company Exhibit PBH-1, as filed on March 29, 2019, in support of the Application.

Q. Please introduce the updates included in your Supplemental Schedules included in Company Supplemental Exhibit PBH-1.

A. My Supplemental Schedules correct or supplement information presented in my Direct Testimony Schedules as follows:

- Supplemental Schedule 1 replaces all eight pages included in my Direct Testimony Schedule 1. My Supplemental Schedule 1 pages 1, 3, 5, 6, 7, and 8 are identical to my Direct Testimony Schedule 1 pages 1, 3, 5, 6, 7, and 8 which present the calculation of Factor 1 (Production Demand) for the Company's four jurisdictions and the North Carolina Jurisdiction's customer classes using the Summer Winter Peak and Average ("SWPA") and the Average and Excess Demand ("A&E") allocation methods. My Supplemental Schedule 1 pages 2 and 4 present a corrected calculation of Factor 2 (Transmission Demand) using the SWPA method.
- Supplemental Schedule 2 presents updated information for the present annualized revenue presented in columns 1-6 of my Direct Testimony Schedule 6. The updated information reflects an update to the weather, growth, and increased usage calculation based upon actual customers through June 30, 2019. In addition, the updated information includes the lost revenue adjustment associated with EE programs.
- Supplemental Schedule 3 provides the calculation of the EE Program Lost Revenue Adjustment by class. The information that summarizes this impact by customer class is included in my Supplemental Schedule 2.

I am also sponsoring an updated Item 42a.2 of the Form E-1.

Q. Mr. Haynes, how is your supplemental testimony organized?

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

I. EXPLANATION OF CORRECTION TO ALLOCATION FACTOR 2

Q. Please explain Allocation Factor 2 and why it needs to be corrected.

A. Factor 2 is used to allocate transmission plant costs and related expenses to the Company's jurisdictions and customer classes in the COSS. In my Direct Testimony Schedule 1 on page 2, I showed the North Carolina Jurisdiction Factor 2 calculated using the SWPA method to be 4.2024%. In reviewing COSS information and allocation factors in preparation for this supplemental filing, I discovered an error in the calculation of Factor 2. The error relates to an adjustment made to remove the demand and energy associated with a large industrial customer in the Company's Virginia Jurisdiction that no longer takes generation service from the Company. Such an adjustment should not impact the calculation of Factor 2 for the Company's North Carolina Jurisdiction. However, because the demand for this large industrial customer at the time of the summer and winter system peaks and its energy had not been properly placed in the FERC Jurisdiction, the total system loads were understated causing the North Carolina Jurisdiction's share of Factor 2 to be 4.2024%. The corrected North Carolina Jurisdiction Factor 2 should be 4.2009%. I show the corrected calculation of Factor 2 for the Company's four jurisdictions in my Supplemental Schedule 1 page 2.

Also, Factor 2 calculated using the SWPA method for the North Carolina customer classes has an error that needs to be corrected. While the energy and demand amounts are correct, because of the error in the calculation of Factor 2 for the Company's four jurisdictions, the system load factor applied in the calculation of Factor 2 for the North Carolina classes was not correct. With the system load factor corrected, I show the corrected calculation of Factor 2 for the North Carolina classes in my Supplemental Schedule 1, page 4. For the residential class, Factor 2 as presented in my Direct Testimony Schedule 1 was 49.5599%. The corrected Factor 2 is 49.5576%.

In my Direct Testimony Schedule 1, I also presented calculations of Factor 2 using the A&E method. The calculations of Factor 2 using the A&E method do not need to be corrected. The calculations of Factors 1 and 2 using the A&E method in my Supplemental Schedule 1 are identical to those included in my Direct Testimony Schedule 1.

II. UPDATE TO WEATHER, GROWTH, AND INCREASED USAGE ADJUSTMENT TO ANNUALIZED REVENUE

Q. Has the Company updated the calculation of annualized revenue to reflect the weather, growth, and increased usage adjustment based upon actual information through June 30, 2019?

A. Yes. The calculation is provided in my updated Supplemental Schedule 2 on page 2 and included in the updated summary of annualized revenue on page 1 of Supplemental Schedule 2.

Q. Have you made a change to the calculation of the annualized revenue impact associated with the updated weather, growth, and increased usage calculation?

A. Yes. In the response to Public Staff Set 131 question 3 shown in my Supplemental Schedule 2 page 3, I state "the Weather Normalization and Usage Adjustments should not include Basic Customer Charge revenues in the calculation of the average revenue per kWh applied to the sum of these kWh adjustments." I have made this change in the calculation of the annualized revenue impact related to the weather normalization and usage portions of the adjustment. I continue to include Basic Customer Charge revenue in the calculation of the average revenue per kWh applied to the customer growth portion of the adjustment.

III. CALCULATION OF EE PROGRAM LOST REVENUE ADJUSTMENT TO ANNUALIZED REVENUE

Q. Please explain the EE Program Lost Revenue Adjustment that you have calculated.

A. As described by Company Witness Kesler, DENC has obtained approval to deploy 17 EE Programs in North Carolina, as of the close of the Update Period on June 30, 2019. Pursuant to Commission Rule R8-69 and the revised Demand Side Management and Energy Efficiency Cost Recovery and Incentive Mechanism ("Mechanism") approved by the Commission on May 22, 2017, in Docket No. E-22, Sub 464, DENC is authorized to recover net lost revenues for decreases in kWh sales attributable to customer participation in the Company's approved EE Programs for a period of 36 months after installation of a measure causing the kWh savings. Notwithstanding the 36 month net lost revenue allowance period, Paragraph 46 of the Mechanism provides that installed measurement units shall cease being eligible for use in calculating recoverable net lost revenues upon implementation of new base rates approved by the Commission that are explicitly or implicitly designed to recover net lost revenues associated with the kWh sales reductions of the installed measurement units. Consistent with the Mechanism, DENC is making an adjustment to "recognize" EE Program kWh sales reductions associated with measures installed through June 30, 2019, as being recovered through the non-fuel base rate proposed in this Filing.

Q. Mr. Haynes, do you have an exhibit that shows the proposed EE Program Lost Revenue Adjustment? If so, please explain the exhibit.

A. Yes. My Supplemental Schedule 3, Pages 1 through 3, shows the calculations for the annualized EE Program Lost Revenue Adjustment by program and by class. My calculations take the kWh energy savings (kWh reductions), by EE program, from Company Witness Kesler's Schedule 1, that occurred during the test period of January through December 2018 in this proceeding, adjusts those values based on the level of energy savings for the month of June 2019, also from Company Witness Kesler's Schedule 1, and annualizes that level of kWh reduction over the January 1 through December 31, 2018 test period in this Filing. Note, I only include those programs for which a different amount of energy savings is recognized than what has been included in the test period.

Next, I apply the applicable present and proposed average non-fuel base rates, excluding the Basic Customer Charges and all fuel rates, to the adjusted annualized energy savings to calculate a dollar adjustment for each program. Page 3 of my Supplemental Schedule 3 summarizes the EE Program Lost Revenue Adjustment by program and shows the allocation of this adjustment to the appropriate customer class.

I incorporated the EE Program Lost Revenue Adjustment, by class, into the adjusted annualized revenue exhibit, shown on Page 3 of my Supplemental Schedule 3. The Summary Sheet, shown in my Supplemental Schedule 2, includes the EE Program Lost Revenue Adjustment by customer class. I provided this revenue adjustment to Company Witness McLeod.

IV. UPDATE TO BASE FUEL RATE

Q. Is the Company updating the Base Fuel Rate in your supplemental testimony?

A. No. I provided the calculation of the Placeholder Base Fuel Rate in my Direct Testimony Schedule 3. I stated in my Direct Testimony that "the Base Fuel Rate will be updated when the Company files its fuel case in August 2019."

Q. Is the Company planning to make an additional supplemental update once the Company's fuel case is filed to update the base fuel rate in this proceeding?

A. Yes. The Company anticipates making an additional supplemental update to calculate revised base fuel rates by customer class based on the Company's 2019 fuel factor filing on August 13, 2019. Such filing will be made within one day of the fuel factor filing.

Q. Currently, the Company's Rider B EMF of $3.88 per MWh is in effect until February 1, 2020. Is the Company still projecting a decrease in this rider?

A. Yes. The Company still anticipates that Rider B EMF will decrease, and will include the calculation in its upcoming fuel factor filing. In addition, as the Company prepares its fuel factor filing, it is anticipated that there will be an over-recovery of fuel expenses for the period of July 2019 – December 2019.

Q. Is the Company considering implementing a decrement rider to implement a reduction in the fuel cost recovery prior to February 1, 2020?

A. Yes. In order to further mitigate the effect of the November 1, 2019 non-fuel base rate increase on customer rates, the Company anticipates proposing in its fuel case to implement a three-month decrement rider, Rider A1, for each class to be effective November 1, 2019. If approved by the Commission, Rider A1 will allow for a seamless, no impact, transition of total fuel rates ($/kWh) between November 1, 2019 and February 1, 2020, based on the Company's anticipated fuel factor filing.

Q. Mr. Haynes, does this conclude your supplemental testimony?

A. Yes, it does.

**ADDITIONAL SUPPLEMENTAL DIRECT TESTIMONY
OF
PAUL B. HAYNES
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562**

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

A. My name is Paul B. Haynes, and my business address is 701 East Cary Street, Richmond, Virginia 23219. My title is Director-Regulation for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Did you provide pre-filed direct testimony in this case?

A. Yes. I submitted direct testimony on behalf of the Company ("Direct Testimony") in support of DENC's application for authority to adjust and increase its retail electric rates and charges filed in this docket on March 29, 2019 ("Application"). My Direct Testimony presented the Company's proposed revenue apportionment and rate design using the Cost-of-Service Study ("COSS") supported by Company Witness Robert E. Miller. My Direct Testimony also supported the Company's proposed tariffs, discussion of the update to the base fuel rate, and a projection of the Experience Modification Factor ("EMF"), Rider B, anticipated in the Company's August 2019 fuel proceeding. My Direct Testimony also supported the calculation of Rider EDIT, which is designed to refund excess deferred Federal corporate income taxes ("Federal EDIT") to customers over one year.

Q. Did you also provide pre-filed supplemental testimony in this case?

A. Yes. My supplemental testimony, filed on August 5, 2019, first addressed a correction to Factor 2 used to allocate transmission plant costs and related expenses. Second, I updated the weather, growth, and increased usage adjustment to annualize revenue based on actual information through June 30, 2019, and explained changes in the calculation of this adjustment's impact on annualized revenue. Third, I calculated the energy efficiency program ("EE Program") lost revenues adjustment identified in my Direct Testimony based upon information provided by Company Witness Deanna R. Kesler. Finally, I addressed an update to the Base Fuel Rate, included as the Placeholder Base Fuel Rate in my Direct Testimony and also explained Rider A1, a decrement rider, to be filed in the Company's Fuel Factor filing on August 13, 2019.

Q. What is the purpose of your additional supplemental testimony?

A. This additional supplemental testimony supports the Company's updated base fuel rate, proposed Rider A1, and updated presentation of present and proposed fuel cost recovery by customer class. I am also revising the growth and usage adjustments and the calculation of annualized revenue filed on August 5, 2019, in Form E-1, Item 42.a.2 and in my Supplemental Schedule 2, as the calculations I prepared for the August 5, 2019 filing did not conform with the methodology used in the Company's 2016 base rate case (Docket No. E-22, Sub 532).

Q. In your additional supplemental testimony, will you be introducing any exhibits?

A. Yes. Company Additional Supplemental Exhibit PBH-1 was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief. As described further below, Company Additional Supplemental Exhibit PBH-1 is intended to update and replace affected Schedules included in Company Exhibit PBH-1, as filed on March 29, 2019, and Company Supplemental Exhibit PBH-1, as filed on August 5, 2019, in support of the Application.

Q. Please introduce the updates reflected in your Additional Supplemental Schedules included in Company Additional Supplemental Exhibit PBH-1.

A. My Supplemental Schedules correct or supplement information presented in my Direct Testimony Schedules as follows:

- Additional Supplemental Schedule 1 pages 1 through 3 presents a calculation of the system fuel factor as filed in the Company's fuel case on August 13, 2019, and develops a new placeholder base fuel rate. These pages replace the following: i) my Direct Testimony Schedule 3 pages 1 through 3, which calculated the placeholder base fuel rate; and ii) my Direct Testimony Schedule 4 pages 1 and 2, which calculated the projected system average fuel factor. Additional Supplemental Schedule 1 pages 4 and 5 presents a calculation of EMF Rider B and replaces my Direct Testimony Schedule 4 pages 3 and 4. Additional Supplemental Schedule 2 presents a decrement rider, Rider A1, being proposed in the Company's fuel proceeding, Docket E-22, Sub 579 ("2019 Fuel Case"), which the Company is proposing to mitigate the effect of the November 1, 2019 non-fuel base rate increase on customer rates.

- Additional Supplemental Schedule 3 replaces my Direct Testimony Schedule 4 pages 5 and 6 showing present and proposed fuel cost recovery for the jurisdiction and by customer class.
- Additional Supplemental Schedule 4 presents updated information for the present annualized revenue presented in columns 1 through 6 of my Direct Testimony Schedule 6 and revises my Supplemental Schedule 2.

I am also filing a revised Form E-1, Item 42.a.2 pages 1 and 2 to replace Form E-1, Item 42.a.2 pages 1 and 2 filed on August 5, 2019.

Q. Please explain the Company's plans regarding the proposed base fuel rate.

A. Consistent with Section IV of my Direct Testimony, the Company is updating the base fuel factor for each class based upon the test period ending June 30, 2019. This is shown in my Additional Supplemental Schedule 1, which provides detailed development of the jurisdictional fuel factor for the North Carolina Jurisdiction and by customer class. To support this proposal, Company Witness Bruce E. Petrie presented supplemental direct testimony in this proceeding showing the forecasted normalized and adjusted system fuel expense based on the historical period of July 1, 2018, through June 30, 2019, of $1.78 billion (as provided in Schedule 1 of Company Supplemental Exhibit BEP-1). This was the same fuel expense level as filed in the Company's 2019 Fuel Case in the testimony of Company Witness Katherine E. Farmer at Schedule 4 of Company Exhibit KEF-1.

In my Additional Supplemental Schedule 1, page 1, I show the calculation of the normalized North Carolina Jurisdictional average fuel factor of $0.02092/kWh, as presented in the Company's 2019 Fuel Case by Company Witness George G. Beasley. The calculations used to differentiate the proposed North Carolina Jurisdictional average fuel factor by voltage, and Rider A (set to $0.00000/kWh) are shown in Additional Schedule 1, Page 2. The 2019 Fuel Case requests an average base fuel factor of $0.02092/kWh. I present the proposed base fuel factor by customer class in my Additional Supplemental Schedule 1 page 3.

In the 2019 Fuel Case, Company Witness Beasley also proposes Fuel Rider B – EMF (as presented in pages 4 and 5 in my Additional Supplemental Schedule 1), to become effective for usage on and after February 1, 2020, as it normally would.

To implement the average base fuel factor of $0.02092/kWh on November 1, 2019, the Company proposes to replace the approved Fuel Rider A class rates that became effective for usage on and after February 1, 2019, with proposed Fuel Rider A class rates equal to zero ($0.00000/kWh). This proposed base fuel rate would become effective for usage on and after November 1, 2019, through and including January 31, 2020 (or such other date as the Commission places permanent rates in effect), on a temporary basis, subject to refund.

Q. Please explain the Company's reasoning for proposing Rider A1 to become effective on November 1, 2019.

A. In order to further mitigate the effect of the November 1, 2019 non-fuel base rate increase on customer rates, the Company has proposed in its 2019 Fuel Case in the testimony of Company Witness Beasley to implement a three-month decrement rider, Rider A1, for each class to be effective November 1, 2019. Company Witness Farmer presented direct testimony in the 2019 Fuel Case estimating that the Company will over-recover fuel expenses for July through December 2019 by approximately $11.8 million. As a result, the Company voluntarily proposes to reduce this over-recovery to customers by implementing a three-month decrement rider, Rider A1. Rider A1 is calculated to be equal to the difference between the proposed February 1, 2020 Fuel Rider B EMF rate for each customer class, as calculated on page 1 in my Additional Supplemental Schedule 2, and the current EMF Rider B rates that became effective on February 1, 2019. The Rider A1 tariff is shown on page 2 in my Additional Supplemental Schedule 2. As proposed by Company Witness Beasley in the 2019 Fuel Case, the Rider A1 tariff would become effective for usage on and after November 1, 2019 through and including January 31, 2020. The implementation of Rider A1 will serve to a) lower the estimated over-recovery balance as of December 31, 2019, as

Witness Farmer explained, and b) reduce further the impact of the proposed November 1, 2019 non-fuel base rate increase on customers.

In summary, the Company proposes to implement a total jurisdictional average fuel rate of $0.02105/kWh on November 1, 2019, which includes the proposed base fuel rate, the proposed Fuel Rider A rates re-set to $0.00000/kWh, the proposed Rider A1 rates, and the present EMF Rider B, differentiated by customer class by voltage. This would be a decrease of $0.00425 as compared to the present total jurisdictional average fuel rate of $0.02530/kWh.

Q. What is the Company's proposal for the total jurisdictional average fuel rate to become effective for usage on and after February 1, 2020?

A. Subject to Commission approval, the Company proposes to continue billing the proposed jurisdictional average base fuel rate of $0.02092/kWh on February 1, 2020, and to implement the proposed EMF rate of $0.00013/kWh effective for usage on and after February 1, 2020. The resulting total jurisdictional average fuel rate on February 1, 2020, of $0.02105/kWh will be equal to the total fuel rate, including Rider A1, that the Company proposes to implement on November 1, 2019. This will allow the proposed reduction in the North Carolina Jurisdictional total average fuel factor of approximately $0.00425/kWh that DENC proposes to take effect three months early and to continue on and after February 1, 2020. As a result, customers will see no change in the approved total fuel rates on February 1, 2020, compared to the November 1, 2019 total fuel rates.

Q. Do you have a table that shows by class and rate component the present total fuel rate compared to the proposed total fuel rates on November 1, 2019, and February 1, 2020?

A. Yes. The following table compares the present North Carolina Jurisdictional total fuel rate to the proposed North Carolina Jurisdictional total fuel rates on November 1, 2019, and February 1, 2020, respectively:

Table 5: Fuel Factor Comparison by Customer Class

NC Jurisdiction	As of 2/1/2019	As Proposed For 5/01/2019[1]	As Proposed For 11/1/2019	As Proposed For 2/1/2020
Base Fuel	$0.02073	$0.02142	$0.02092	$0.02092
Rider A	$0.00069	$0.00000	$0.00000	$0.00000
Rider A1	$0.00000	$0.00000	($0.00375)	N/A
Rider B	$0.00388	$0.00388	$0.00388	$0.00013
Total	$0.02530	$0.02530	$0.02105	$0.02105

[1] The Company's proposed base rates were suspended by the Commission pursuant to G.S. 62-134.

In summary, the proposed fuel factor changes will reduce the total North Carolina jurisdictional average fuel factor to $0.02105/kWh from $0.02530/kWh, or by $0.00425/kWh. My Additional Supplemental Schedule 3, pages 1 and 2 presents the comparison shown by Company Witness Beasley in the 2019 Fuel Case of the total fuel rate proposed to take effect February 1, 2020, by class and rate component, to the current total fuel rate effective for usage on and after February 1, 2019. The differences in the total fuel factor by customer class as proposed for February 1, 2020, will be the same for November 1, 2019, if the Company's proposal is approved.

Q. Are you presenting any other updates with your Additional Supplemental Testimony?

A. Yes. Since the submission of the Company's Supplemental Testimony on August 5, 2019, the Company reviewed its calculation of the customer growth and usage adjustments and compared them to those made in the 2016 rate case. The Company found that in the 2016 case, the end-of-period ("EOP") level of customers was determined by calculating a predicted customer level based upon the most recent 36 months of historical customer data for the period ending June 2016. In its supplemental filing in this proceeding on August 5, 2019, the Company used the actual level of customers at the end of June 2019.

The Company discussed this deviation from the 2016 approach with the Public Staff on August 9, 2019. In that discussion, it was decided that the Company would resubmit the customer growth and usage adjustments using predicted customers based upon the most recent 36 months of historical customer data for the period ending June 30, 2019.

Q. Has the Company updated the calculation of annualized revenue to reflect these changes to the growth and usage adjustment?

A. Yes. The calculation is provided in my Additional Supplemental Schedule 4. The revised calculation of the growth and usage adjustment is included on page 2. The updated summary of annualized revenue is provided on page 1.

In addition, I am providing an updated Item 42.a.2 of the Form E-1 showing this same information.

Q. Mr. Haynes, does this conclude your additional supplemental testimony?

A. Yes, it does.

**REBUTTAL TESTIMONY
OF
PAUL B. HAYNES
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562**

Q. Please state your name, business address and position with Virginia Electric and Power Company.

A. My name is Paul B. Haynes and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am Director – Regulation testifying on behalf of Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Have you previously submitted testimony in this proceeding?

A. Yes. My pre-filed Direct Testimony on behalf of DENC was submitted to the North Carolina Utilities Commission (the "Commission" or "NCUC") in this matter on March 29, 2019, my pre-filed Supplemental Direct Testimony was submitted on August 5, 2019, and my pre-filed Additional Supplemental Direct Testimony was submitted on August 14, 2019.

Q. What is the purpose of your rebuttal testimony?

A. My Rebuttal Testimony will address the testimonies of Public Staff Witness Jack L. Floyd, Carolina Industrial Group for Fair Utility Rates I ("CIGFUR") Witness Nicholas Phillips, Jr., Nucor Steel-Hertford ("Nucor") Witness Paul J. Wielgus, and Nucor Witness Jacob M. Thomas, regarding issues related to cost allocation in the cost of service ("COS"). I also address the testimonies of CIGFUR Witness

Phillips and Nucor Witness Wielgus regarding apportionment of the revenue requirement to the customer classes and rate design.

Q. How is your rebuttal testimony organized?

A. I have divided my Rebuttal Testimony into the following sections:

I. Use of SWPA Cost Allocation Method With Weighting Based on System Load Factor

- Discussion of Support of Public Staff
- Addressing Criticism of Use of SWPA By CIGFUR and Nucor

II. Rebuttal of Cost Allocation Proposals

- CIGFUR Proposal of S/W CP
- Nucor Proposal Related to 1CP
  - If not decided in this docket, the Commission should commit to examine via a formal docket whether requiring 1CP or 5CP instead of SWPA would be most appropriate
- Nucor Proposal to Use SWPA with weighting modified to 60% Peak Demand and 40% Average

III. Addressing the Targeted ROR Index for Nucor

IV. Addressing Comments from CIGFUR and Nucor on Revenue Apportionment and Rate Design

Q. Will you be introducing an exhibit in your rebuttal testimony?

A. Yes. I am sponsoring Company Rebuttal Exhibit PBH-1, which consists of Rebuttal Schedules 1 through 5. This Company Rebuttal Exhibit PBH-1 was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief.

Q. With regard to cost allocation in the cost of service, please identify and summarize the issues raised by Public Staff, CIGFUR and Nucor that you will address in your rebuttal testimony.

A. My Rebuttal Testimony responds to the comments and recommendations of the Public Staff, CIGFUR, and Nucor, as follows:

1) Consistent with DENC's past rate cases, dating back to 1983, the Company and the Public Staff agree that the Summer/Winter Peak and Average ("SWPA") methodology continues to properly recognize DENC's generation planning and operations and continues to be the most appropriate cost allocation methodology for allocating DENC's production and transmission plant costs and related expenses in the Company's cost of service;

2) The use of DENC's actual System Load Factor during the test year is a reasonable, reliable and consistent method for establishing the "weighting" of the peak and average components of the SWPA COS method in this case;

3) Public Staff Witness Floyd accepts two adjustments made in the course of calculating the SWPA allocation factors: i) an adjustment to the summer and winter peak demands to recognize non-utility generation connected to the distribution system, and ii) an adjustment to remove the demand and energy requirements of three large customers that will no longer be served by the Company after 2019;

4) The Commission found in the 2016 Rate Case that the Company's "continued use of the SWPA methodology in this proceeding properly assigns production plant costs to all customer classes, including the

Schedule NS Class in recognition of its significant use of the Company's generation throughout the year;"[1]

5) The Summer/Winter Coincident Peak ("S/W CP") methodology advocated by CIGFUR Witness Phillips is not reasonable or appropriate for DENC because its reliance on only the two hours of DENC's summer and winter peaks is inconsistent with the way DENC plans and operates its system to both meet the system peaks as well as to deliver low cost energy throughout the year. Use of S/W CP would also result in a significant shift of costs to the residential class;

6) While not recommending the 1 CP methodology be used in the cost of service study in this proceeding, Nucor Witness Wielgus is recommending the Commission examine in a formal proceeding whether using a 1 CP or 5CP method instead of SWPA would be most appropriate for the Company given the way PJM uses coincident peaks and the "Commission's practice in the Duke Energy cases (where allocation is based on 1CP)." Based on information in this case, such a method would increase the total North Carolina jurisdictional revenue requirement and significantly shift costs to the residential class while benefitting Nucor and the LGS and 6VP classes. Also, with regard to the Commission determining that the 1 CP allocation method is appropriate in Duke Energy's proceedings, I believe it is appropriate for the Commission to consider the usage characteristics of customers and the generation system's planning and operation for each utility to determine an appropriate allocation method and to not uniformly apply a particular method to all utilities; and

7) Nucor Witness Wielgus recommends a modification to the weighting of the peak demand and average components in the SWPA method as proposed by the Company and supported by Public Staff Witness Floyd. Such modification is not consistent with the way customers use the Company's production and transmission systems and would result in a shift in cost responsibility from Nucor and other non-residential classes to the residential class resulting in a higher increase in rates for residential customers than proposed by the Company.

[1] Docket No. E-22, Sub 532, Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, December 22, 2016, Page 16, Finding of Fact #40.

Q. With regard to revenue apportionment and rate design, please identify and summarize the issues raised by CIGFUR and Nucor that you will address in your rebuttal testimony.

A. My rebuttal testimony responds to the comments and recommendations of CIGFUR and Nucor, as follows:

1) Nucor Witness Wielgus contends that the higher assigned ROR index of 0.80 that I proposed in my Direct testimony does not adequately acknowledge the benefits of the Company's arrangement with Nucor or the benefits it provides to the Company's system and customers. He later contends that the ROR index should be closer to the index for Street Lights and recommends it be set 20 points below the low end of the Parity Index Range ("PIR") of 0.90. I strongly disagree with an approach that attempts to set Nucor's ROR Index on the basis of a position relative to the Street Lighting class as the Street Lighting class rates are currently far below its responsibility for costs and the rate increase I proposed for this class was limited by gradualism. However, I have an updated analysis that leads me to support a lower ROR index for Nucor than I proposed initially of 0.80, which is not based on the index for the Street Lighting class;

2) Nucor Witness Wielgus recommends that the percentage increase in base rates to Schedule NS should not exceed the percentage increases applied to rate schedules LGS and 6VP. I disagree;

3) CIGFUR Witness Phillips cites "excessive returns" for the 6VP class, and recognizes that the Company's proposed method of distributing the requested increase moves rates closer to cost in a meaningful manner. He recommends that it should be implemented as proposed;

4) In response to CIGFUR Witness Phillips' recommendation, I discuss revenue apportionment and rate design in the context of the principles, including consideration of ROR indexes and non-cost factors, I provided in my Direct Testimony. When establishing rates in this proceeding, it is reasonable to address the "excessive returns" for the LGS and 6VP classes. It is also reasonable to determine a ROR index that recognizes the Company's service arrangement with Nucor considering its value to the system and benefit to the North Carolina jurisdiction;

I. Use of SWPA Cost Allocation Method With Weighting Based on System Load Factor

Q. Please reintroduce the Company's proposed COS allocation methodology.

A. Consistent with Commission orders in DENC general rate cases dating back to 1983, the Company has again used the SWPA allocation methodology as the most reasonable and appropriate methodology for allocating DENC's production and transmission plant costs and related expenses in the Company's COS.[2]

Q. Does the Public Staff agree with the Company's continued use of the SWPA allocation methodology in this case?

A. Yes. On page 3 of his testimony, Public Staff Witness Floyd states "the Public Staff believes that the SWPA cost-of-service methodology is the most appropriate methodology because it appropriately allocates production plant costs in a way that most accurately reflects both the Company's generation planning and operation."

At page 4 of his testimony, Mr. Floyd states that "[u]nlike many other methodologies that allocate all of the production plant costs based on the single coincident peak or on a series of monthly peaks, the SWPA methodology recognizes that a portion of plant costs, particularly those incurred for base load generation, is incurred to meet annual energy requirements throughout the year

[2] The Commission has approved the SWPA methodology for allocating DENC's fixed production costs in numerous prior DENC base rate proceedings, including Docket Nos. E-22 Sub 265 (1983), Sub 273 (1984), Sub 314 (1990), Sub 333 (1993), Sub 412 (2005), Sub 459 (2010), Sub 479 (2012) and, most recently, Sub 532 (2016).

and not solely to meet peak demand at a particular time."

Q. Do you agree with Mr. Floyd's assessment that the SWPA appropriately allocates production plant costs in a way that most accurately reflects the Company's generation planning and operation?

A. Yes. As discussed in my pre-filed Direct Testimony, the SWPA method recognizes the two components of providing service to customers, peak demand, and average demand, and weights them before determining the allocation factor. The weight is based on the system load factor, which is calculated by taking the Company's actually-experienced average demand divided by peak demand. In the calculation of the SWPA allocation factor, the average demand is weighted by the system load factor and the peak demand is weighted by (1 minus the system load factor). I further discuss the reasonableness of using the system load factor below.

As I explained in my direct testimony, 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, as well as transmission plant, would be allocated based on the jurisdictional and customer class contribution to the demands at the summer and winter peak hours. In terms of their operation, the Company's system of generating plants (and its transmission system) are operated throughout the year, every hour of each day, and must perform reliably to meet the obligation to serve all customers throughout the Company's service territory in North Carolina and Virginia. Capital costs for generation plants differ by the type of generation. Base load and intermediate plants have higher capital costs than peaking plants but can operate over a longer duration of hours to provide the system with low cost energy. Using the system load factor to weight the average demand in the calculation of the SWPA factor is appropriate considering the need for low cost energy and system operation that dispatches generating units to serve customers each hour of the year. The system load factor approach to weighting has been used in the Company's last three North Carolina general rate cases (Docket No. E-22, Subs 459, 479, and 532) and in the required annual cost of service studies filed with the Commission.

Q. **Please continue with your discussion of why it is appropriate to use system load factor to determine the weighting within the SWPA method.**

A. The use of the system load factor is not arbitrary. To the contrary, the load factor is the ratio of average demand (kWh usage) to the peak demand and is calculated based on actual usage of the system. Average demand can be described as the capacity needed to serve "on average" the demand required by customers during every hour of the year and is determined by dividing total annual kWh usage by number of hours in the year. For 2018 the System average demand was 10,264,685 kW (Form E-1, Item 45f page 3). The average of the System S/W peak is 17,423,014 kW (Form E-1, Item 45f page 3), resulting in a system load factor of 58.9145% (10,265,685/17,423,014).

The use of the system load factor is a reasonable approach for weighting capacity responsibility between energy and demand since it represents the portion of peak capacity that is needed to, on average, serve customer energy requirements throughout the year. The Company's system load factor is evidence of the verified usage of the Company's generation capacity throughout the course of the year relative to our installed capacity.

The Company's generating units that are available are operated such that the units with the lowest variable cost, mostly fuel, are dispatched to serve customer loads not just in the summer and winter peak hours, but throughout the year. This serves to minimize fuel expenses recovered through the fuel clause. The capability to provide lower cost energy, and lower fuel expenses, throughout the course of the year by system dispatch is accomplished by having available resources to efficiently serve utility loads during all hours and not only during the summer and winter peak hours. If all classes of customers are effectively paying "average fuel cost," then all customers are getting the benefit of the integrated system operation of the full range of generation resources from high capital cost/low operating cost generation to low capital cost/high operating cost generation. Allocating the costs of the generation plants fairly requires looking beyond just the peak load hour in the summer and winter. Because the SWPA method also has an average component that reflects energy usage for each hour of the year, this method is consistent with the operation of the Company's generation system and accurately reflects how it is used to serve customers.

Q. Is the SWPA method consistent with DENC's planning function as well as its operations?

A. I am not involved in any way in the system planning process. To determine whether using the SWPA method as proposed by the Company and supported by Public Staff reflects the Company's planning process, I refer to Commission's recently issued order in Docket No. E-100, Sub 157 related to 2018 integrated resource plan filings. First, as set forth in the Commission's order;

> North Carolina General Statute § 62-2(a)(3a) declares it a policy of the State to:
>
> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....[3]

In its Conclusion, the Commission stated:

> Integrated Resource Planning is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable, and safe electric service. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and reasonable for planning purposes in the present docket.[4]

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[3] Docket No. E-100, Sub 157, Commission Order on August 27, 2019, Pages 2-3.
[4] Docket No. E-100, Sub 157, Commission Order on August 27, 2019, Page 86.

In the same order, the Commission ordered, "[T]hat the IRP filed herein by Dominion Energy North Carolina is adequate for planning purposes, subject to DENC's 2019 IRP Update, and the Commission hereby accepts DENC's IRP."[5]

As a layperson, my reading of the statutory requirement and the Commission's conclusion requires that future growth be met through the provision of adequate, reliable and safe electric service in a manner that results in the least cost that is achievable. There may be many factors such as regulatory and marketplace considerations that determine what will be achievable but once those factors are known, the process to determine a plan appears to be directed toward obtaining that which is the least cost. Least cost planning conducted in this manner appears oriented to providing reliable service by having the proper mix of resources available to fully serve customers while considering the level of rates customers pay and, ultimately, the charges incurred on their utility bills. As with the operation of the system, the planning for the system seems to be aligned with a cost allocation methodology for generation facilities that considers when customers place the highest demand on the system (as measured by the demand during the summer and winter peak hours) and how they use the system over the course of the rest of the year.

[5] Docket No. E-100, Sub 157, Commission Order on August 27, 2019, Page 91.

Q. Since the Commission most recently approved DENC's SWPA COS method in the Company's 2016 general rate case in Docket No. E-22, Sub 532 ("2016 Rate Case"), has the Company continued to construct new generating facilities to meet both system peak demands as well as to serve customers' energy requirements throughout the year?

A. Yes. As noted in my testimony in the 2016 Rate Case, the Company added the 1,342 MW Warren County Generating Station and the 1,358 MW Brunswick County Generating Station. As shown in my Rebuttal Schedule 1, page 1, these natural gas combined cycle facilities operated at a net capacity factor % of 69.19 and 70.02, respectively during 2018 and at significantly higher capacity factors in high load and usage winter and summer months during 2018 and early 2019. As evidenced by these capacity factors, these units have served customers' load requirements for many hours during the year.

Since the Company's 2016 Rate Case, the Company has placed in operation the 1,588 MW Greensville County Generating Station in December 2018. In the Company's fuel factor filing made on August 13, 2019, Company Witness Katherine E. Farmer calculated that system fuel savings "are forecasted to be approximately $40 million in 2019" related to the Greensville County Generating Station.[6] As can be seen in my Rebuttal Schedule 1, page 1, the unit operated at a high capacity factor during the high load and usage winter months in early 2019.

These generating facilities are meeting a capacity need to serve peak loads and

[6] Docket No. E-22, Sub 579, Testimony of Katherine E. Farmer, Page 6, lines 12 – 15.

are being operated during many hours of the year to meet the energy requirements of customers.

Q. Does the Company continue to operate nuclear generation facilities to serve customers?

A. Yes. The Company operates two units at its North Anna Power Station and two units at its Surry Power Station. As I discuss further below, the Company's investment in nuclear plant at the end of 2018 represents approximately 26% of total production plant investment. According to the testimony of Katherine E. Farmer in the Company's fuel case, Docket No. E-22, Sub 579 filed on August 13, 2019, the Company's nuclear units operated at an aggregate capacity factor of 95.7% for the twelve months ended June 30, 2019 which was better than the industry five-year average for comparable units.[7]

According to Witness Farmer, these nuclear units accounted for 30.9% of the system's energy supply during the twelve months ended June 30, 2019 and incurred fuel expenses at a rate of $6.24 per MWh.

[7] Docket No. E-22, Sub 579, Testimony of Katherine E. Farmer, Pages 2-3.

Q. Considering the operation of both these newer combined cycle generation facilities and the nuclear generation facilities and the lower cost of fuel being incurred to serve customers by these facilities, does the allocation of the plant costs of these facilities using the SWPA method as proposed by the Company and supported by the Public Staff seem reasonable?

A. Yes. Public Staff Witness Floyd recognized "that a portion of plant costs, particularly those incurred for base load generation, is incurred to meet annual energy requirements throughout the year and not solely to meet peak demand at a particular time."[8] These higher capital cost generating facilities that I have discussed meet peak demand and are also operating to meet actual energy requirements throughout the year. Using the SWPA methodology, which includes an average component weighted by the system load factor based on the customers' use of capacity throughout the year and a peak demand component weighted by (1 minus the system load factor), is appropriate to determine cost responsibility for these facilities by the Company's jurisdictions and customer classes.

Q. Before turning to address criticism of the use of SWPA by intervenors, does Public Staff Witness Floyd accept two adjustments the Company used in the calculation of the SWPA allocation factors?

A. Yes. The Company proposed two adjustments to the calculation of the SWPA allocation factors. The first adjustment relates to adjusting the summer and winter peak demands. The load on the system is measured on the transmission

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[8] Docket No. E-22, Sub 562, Testimony of Jack L. Floyd, Page 4, lines 19 – 22.

system. Non-utility generation ("NUG") that is interconnected at the distribution level serves to reduce the load that is measured on the Company's transmission system. As Public Staff Witness Floyd observed, the aggregate consumption measured at customers' meters "is not consistent with the demand observed at the substation, because the NUG generation interconnected at the distribution level serves part of that consumption."[9] To address this inconsistency, the Company proposed adding back the NUG output to the demands measured on the Company's transmission system during the summer and winter peak hours. Public Staff Witness Floyd agrees with this adjustment.

The second adjustment relates to removing the demand and energy requirements of three customers, one wholesale customer, NCEMC, and two large industrial customers in the Company's Virginia jurisdiction. The Company's obligation to provide generation service to these customers has ended or will end during 2019. Public Staff Witness Floyd agrees with this adjustment.

Q. Does CIGFUR Witness Phillips agree with the use of the SWPA method as proposed by the Company and agreed to by Public Staff?

A. No. On page 16 of his testimony he states that "the SWPA method is inconsistent with both DENC's method of planning for future capacity requirements, and the increase in the portion of its generating mix represented by natural gas" and that it "over-allocates cost to large, high load factor,

[9] Docket No. E-22, Sub 562, Testimony of Jack L. Floyd, Page 5, lines 16 – 20.

customers without a symmetrical fuel cost allocation."[10]

I do not agree. The planning process has in recent years resulted in the construction of new, higher capacity cost, low operating cost generating facilities as evidenced by the construction of the Warren County, Brunswick and Greensville power stations. As discussed earlier, these units appear to be operating at high capacity factors to serve customers by meeting their usage requirements during many hours of the year. Likewise, the Company's nuclear units have performed extremely well meeting customer usage requirements throughout the year. And, according to the Company's 2018 IRP filing, there is an assumption "that all of the Company's existing nuclear generation will receive 20-year license extensions that lengthen their useful lives beyond the Study Period. The license extensions for Surry Units 1 and 2 are included in 2032 and 2033, respectively, extending the licensed life to 2052 and 2053, respectively, and the license extensions for North Anna Units 1 and 2 in 2038 and 2040, extending the licensed life to 2058 and 2060, respectively."[11]

With regard to the SWPA method over-allocating cost to large, high load factor customers without a symmetrical fuel cost allocation, I will first address what the SWPA method does. Assume two classes with the same peak demand, Class A and Class B. If Class A has energy usage that is greater than Class B, then Class A has a higher average demand and higher load factor. This will result in Class A being allocated more production cost under the

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[10] Docket No. E-22, Sub 562, Testimony of Nicholas Phillips, Jr., Page 16, lines 3-7.
[11] Docket No. E-100, Sub 157, 2018 Resource Plan of Virginia Electric and Power Company, Chapter 1 Executive Summary, Page 9.

SWPA method as opposed to another method such as 1CP. That seems reasonable based on what I addressed earlier about how the system is planned and how it is operated.

With base load generation having higher plant costs, the higher energy usage class (Class A described above) gets allocated more cost of that plant than the lower energy usage class (Class B). This is reasonable as discussed earlier in this testimony. There are a couple of considerations to address Mr. Phillips' point. First, the Company has rate schedules, such as Schedule 6VP, that provide strong price signals for large industrial customers to voluntarily reduce usage during peak load hours. Such customers can reduce their bills and thereby impact their allocation of costs by lowering their demand during the summer and winter peak hours that are used in the calculation of the SWPA allocation factor. Also, as addressed in my Direct Testimony and later in this testimony, consideration should be given to a number of factors in addition to the large industrial classes' rate of return when determining how such customers are apportioned responsibility for the proposed revenue increase, including the usage of industrial customers, factory utilization and the economic vitality of the service territory.

With regard to Mr. Phillips' point about symmetrical fuel cost allocation, this matter has been raised previously and most recently addressed in the 2016 Rate Case. The Commission found in Finding of Fact #41 of the 2016 Rate Case order that it was not reasonable nor necessary at that time to re-evaluate the fuel symmetry issue that was studied in Docket No. E-22, Sub 333 with significant discussion in the Evidence and Conclusions section for such finding.

Q. Does Nucor Witness Wielgus agree with the use of the SWPA method as proposed by the Company and agreed to by Public Staff?

A. Nucor Witness Wielgus has two sections in his testimony in which he addresses shortfalls of the SWPA allocation method. The first relates to recognizing the system's need for generation. The second relates to recognizing the system benefits associated with the NS Class (Nucor). He does not agree with the use of the SWPA method as proposed by the Company and supported by the Public Staff.

Q. Please describe the first shortfall of SWPA as explained by Mr. Wielgus related to recognizing the system's need for generation and provide your response.

A. With regard to the shortfall in recognizing the system's need for generation, Mr. Wielgus states that "In other words, it is the need for generation capacity to serve peak load that's driving the Company's generation costs."[12] He goes on to state that "the SWPA method is not consistent with the Company's primary need for generation capacity – the Company's need to serve its annual peak demand."[13]

In making this statement, I believe that Mr. Wielgus has drawn an improper conclusion from a Company data request response shown in his Exhibit PJW-

[12] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 8, lines 10 and 11.
[13] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 8, lines 14 and 15.

2, page 4. I have included this data request response in my Rebuttal Schedule 1, page 2. The question asks:

> Does DENC invest in generation primarily in order to serve its annual or seasonal peak load(s)? Explain you answer in detail.

This response states the following:

> The Company invests in generation to provide reliable electric service during all seasons. These investments help the Company meet its electric service obligations and manage the capacity performance risk in the PJM capacity market.

Mr. Wielgus tries to use the answer to equate solely to his question that investment in generation is related to annual peak load or seasonal peak load. He states that "[i]ts service obligation is to meet its peak load while at the same time managing its capacity risk in PJM."[14] I believe the answer says far more about the Company's service obligation than what the question asks. Mr. Wielgus has limited the Company's service obligation to meeting peak load. As I discussed and elaborated on earlier, the Company's system of generating plants (and its transmission system) are operated throughout the year, every hour of each day, and must perform reliably to meet the obligation to serve all customers throughout the Company's service territory in North Carolina and Virginia. The Company's service obligation is for the summer peak hour, the winter peak hour, and for the 8,758 other hours during the year. In support of this point, I earlier discussed the Company's investments in nuclear generation and combined cycle generation and discussed how these units have operated. The Company has not used the investment in these generation units solely to operate these facilities during the hours of peak demand. These

[14] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 8, lines 8 and 9.

higher capital cost, lower operating cost units were planned and are being operated to provide customers' usage requirements throughout the year and not just in periods of peak demand. Such units are an important part of Company's system units. The Company also has lower capital cost, higher operating cost units that operate during periods of high demand.

I disagree with Mr. Wielgus' conclusion that the SWPA method as proposed by the Company does not recognize the system's need for generation. Mr. Wielgus has limited the Company's service obligation and need for generation to meeting the one hour annual peak load or during the two seasonal, summer and winter, hours when load is the highest. The Company's service obligation is for 8,760 hours and its generation system (and transmission system) must serve customers reliably in all hours. The SWPA method as proposed by the Company and supported by the Public Staff recognizes this service obligation and allocates costs consistently with both the planning for generation and the operation of generation.

In addition, and as I will discuss later with regard to the 1CP allocation and the S/W CP methods, the Commission should be aware of the outcome of using such methodologies to determine cost responsibility. Using an allocation methodology that only considers customer usage during the one or two hours of the year (summer and winter) when system load is the highest will shift cost responsibility from large industrial customer classes to the residential class. I will demonstrate this effect later but it is important to keep this point in mind as I address criticism of the SWPA method.

Q. During his discussion of the SWPA method not aligning with the system's need for generation, does Nucor Witness Wielgus also criticize the weighting of the average (energy) component and the peak demand component as proposed by the Company and supported by Public Staff?

A. Yes. He says, "to make matters worse, the Company puts more weight on energy than on the demand or capacity part." He goes on to say that "[t]his is inequitable and even incredible considering the fact that the Company is located within the PJM footprint which uses a coincident peak demand." He finally adds that "[a]lthough SWPA should be replaced, given the history of these cases, I make a modest recommendation to adjust the weighting of the two SWPA components – demand and energy – such that more weight is on the demand part of the SWPA than on the energy part." [15] His recommendation is to place more weight on the peak demand component and less on average (energy) component in the calculation of the SWPA allocation factor. He adds that there is recognized support for "judgmentally weighting" the two parts of the SWPA factor and cites the NARUC Electric Utility Cost Allocation Manual. He states "at an absolute minimum, I recommend demand be weighted more than energy."[16] He notes that this would reduce the proposed increase to the NS class.

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[15] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 9, lines 5-14.
[16] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 10, lines 6-7.

Q. How do you respond to this concept of "judgmentally" adjusting the weighting within the SWPA method to weight peak demand more than the average (energy) component?

A. "Judgmentally" adjusting the weighting to weight the peak demand component more than the average (energy) component would move the weighting away from being based on the system load factor, and that would not reflect how customers actually use the Company's system of generation resources and the transmission system throughout the course of the year. In fulfilling this service obligation, the weighting that best reflects how customers use these systems is the system load factor. In approving the use of the SWPA method in the 2016 Rate Case, the Commission stated:

> The cost of service methodology employed in establishing an electric utility's general rates should be the one that best determines the cost causation responsibility of the jurisdiction and various customer classes within the jurisdiction based on the unique characteristics of each class's peak demands and overall energy consumption ... The Commission finds that, for purposes of this proceeding, the SWPA cost of service methodology properly recognizes the manner in which DNCP plans and operates its generating plants to provide utility service to customers in North Carolina.[17]

The Commission concluded that the cost of service methodology used in setting rates should be the one that "best determines the cost causation responsibility ... based on the unique characteristics of each's class's peak demand and overall energy consumption." The SWPA method calculated by weighting the average (energy) component using the system load factor and the peak demand component using (1- system load factor) reflects the usage

[17] Docket No, E-22, Sub 532, Final Order, December 22, 2016, Page 115.

characteristics of each jurisdiction and class, how these relate to the totals for the Company system, and how the generating units are operated. The Public Staff and the Company agree this weighting is appropriate. In addition, I will point out that the load during the two hours when demand is highest in the summer and winter are still weighted very heavily at approximately 41% while the average component based upon energy usage in all 8,760 hours is only weighted at approximately 59%. I do not believe any higher weighting of the peak demand component (two hours) is appropriate.

Q. Please describe Mr. Wielgus' discussion of a second shortfall of the SWPA method in that it does not recognize the system benefits associated with the NS Class.

A. Mr. Wielgus begins by citing three reasons why Nucor's load results in significant benefits to the Company's system:

i) The size of Nucor's facility is "approximately 20% of the Company's load in North Carolina" and is the "Company's single largest customer." "Cost savings associated with the economics of scale of this very large load at a single point provide benefits to the Company's system not provided by any other single customer."

ii) Nucor's "high load factor, which unlike lower load factor customers, is very beneficial to the Company's system operations and corresponding costs."

iii) The service arrangement between the Company and Nucor: the "service to Nucor is not firm, it is interruptible. Under this

> arrangement Nucor must curtail if called upon to do so. This very high value attribute unlocks costs savings in the form of avoided capacity costs while providing system and customer benefits."[18]

He goes on to state that the Company acknowledges that Nucor and its service arrangement benefit its system and customers. He notes that the Company recognizes the operational and cost benefits to its system through the assigned ROR index for Nucor. However, he disagrees and states that "the Company does not adequately recognize Nucor's operational and cost benefits to its system through the company's assigned ROR index."[19]

Mr. Wielgus calculates a value of the capacity that is avoided when Nucor is curtailed based on its peak load of 171 MWs and its load during the summer and winter peak hours of 42 MW. He says that if Nucor was a firm customer, the Company would have to secure an additional 129 MWs of capacity every day of the year and values that based on the average capacity cost in the PJM market over the last 5 years and calculates an annual cost of $5.7 million.[20]

Next, Mr. Wielgus says that the weighting used in the SWPA method "does not adequately reflect the unique Schedule NS interruptible service arrangement nor does it adequately reflect the acknowledgment by the Company of the value of the beneficial factors associated with this arrangement and Nucor's load. The weighting of the two-part methodology

[18] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 11.
[19] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 13.
[20] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 13, lines 13-20.

falls short in a material way."[21] He contends that if Nucor increases its usage, while remaining interruptible, Nucor would be allocated more cost under the SWPA method and concludes that the weighting should be adjusted.[22]

Q. How do you respond regarding Mr. Wielgus' three points about the Company's service to Nucor and the benefits to the system?

A. I generally agree with Mr. Wielgus' three points about the Company's service to Nucor but have a couple of clarifications. First, I want to clarify that the service arrangement with Nucor represents a partial curtailment by providing for curtailment of its furnace load but not its total load. And, such curtailment is limited to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** hours during the year plus an additional **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** hours that it can allow Nucor to buy through at a price higher than the average embedded Tier 3 energy price. Although the Company can call any of the 8,760 hours during the year as Tier 1 or Tier 2 hours, it can only call **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** hours of the 8,760 hours in a year. The Company is obligated to supply Nucor's total required load during Tier 3 which includes the remaining **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** hours of the year. During Tier 1 and Tier 2 hours, Nucor is required to only

[21] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 16, lines 2-6.

[22] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 16, line 19 – Page 17, line 6.

curtail its arc furnace. Other than in an emergency situation, the Company cannot curtail the non-furnace load.

Second, while Nucor's load factor may be considered higher than those for the residential and small general service classes, its load factor is not in the range of higher load factor customers in the LGS class.

Q. **How do you respond to his estimate of the value of Nucor's curtailed load in terms of avoiding capacity cost?**

A. Nucor Witness Wielgus has assumed a maximum facility load in valuing its curtailment. In addition, he has calculated the avoided capacity cost over the last 5 years.[23]

I have prepared a similar analysis in which I have examined Nucor's hourly loads in 2018 during its Tier 3 hours when the Company is obligated to supply Nucor's total required load without curtailment and without Nucor buying through at higher Tier 1 and Tier 2 pricing. Since Mr. Wielgus made a point about Nucor's high load factor being beneficial for the system, I have analyzed three scenarios when Nucor's load is highest and when its furnace is curtailed to value Nucor's curtailment.

1) First, I consider the hours when Nucor is operating under Tier 3 pricing when there is no curtailment required or incentivized through price signals. I calculate the average load during the Tier 3 hours.

[23] Based on a data request response, Mr. Wielgus appears to have used PJM capacity pricing beginning with the delivery year 2017/2018 through 2021/2022.

Next, I considered Nucor's load during Tier 1, Type A hours which is when Nucor's furnace must be curtailed and calculated an average load for these hours. I then calculated the cost associated with the difference between these two load levels, Tier 3 Hours Average Load and the Tier 1 Type A Average Load. Instead of determining the cost of this load over five years of PJM capacity pricing, I am limiting my analysis to the first year that new rates will be in effect as a result of this proceeding which is the rate year beginning January 1, 2020 through December 31, 2020 and calculating a weighted capacity price based upon two delivery years, 2019/2020 and 2020/2021. I present this analysis in my Rebuttal Schedule 2, page 1.

2) Next, I consider the 1,000 hours when Nucor's load was the highest and calculated an average load during these highest 1,000 hours. These are Tier 3 hours. I again considered Nucor's load during Tier 1, Type A hours and used the same average calculated in (1) above. I also used the same weighted capacity price calculated in (1) above. I present this analysis in my Rebuttal Schedule 2, page 1.

3) Finally, I consider the top 5% of hours when Nucor's load was the highest and calculated an average load during these hours. I again considered Nucor's load during Tier 1, Type A hours and used the same average calculated in (1) and (2) above. I also used the same weighted capacity price calculated in (1) and (2) above. I present this analysis in Rebuttal Schedule 2, page 1.

Based on these analyses, I would consider the value of Nucor's avoided capacity to be lower than what is estimated by Mr. Wielgus but there is still considerable value of curtailment to be considered in the setting of rates.

Q. **Have you considered this range of value for Nucor being partially curtailable as compared to the benefit (subsidy) it is receiving by having a ROR less than the jurisdictional ROR and an index below 1.00?**

A. Yes. In the same rebuttal schedule in which I calculated a range of value, Rebuttal Schedule 2, I have provided calculations of the increase in revenue to move from a particular target ROR index to achieve an index of 1.00 and be at parity with the jurisdictional ROR. I calculate this revenue amount across a range of ROR indexes from 0.85 to 0.70 for the Schedule NS class. I consider these calculated revenue increases to be the benefit or subsidy to Nucor of having a ROR index lower than 1.00.

I find that the range of value of Nucor being curtailable is comparable to the range of benefit (subsidy) to Nucor that may accrue to it across a range of ROR indexes. However, before I conclude that this subsidy to Nucor is justified, that value must be weighed against the benefit that is being provided to the North Carolina jurisdiction and Nucor of recognizing Nucor's load after curtailment and its operation in other hours.

Q. Have you quantified the benefit to the North Carolina jurisdiction and Nucor of recognizing Nucor's actually-curtailed peak load under the Company's SWPA method?

A. Yes. The Company has prepared an analysis that assumes Nucor's average peak demand during these two hours equals its average demand for the year during the Tier 3 hours of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (the "Average Assumed Peak Demand"). Table 1 presents a comparison of "non-curtailed" SWPA allocation factors, assuming this Average Assumed Peak Demand, to the actually-filed SWPA allocation factors based upon Nucor's measured demand of approximately 42 MW during the summer and winter peak hours. I provide the calculation of the "non-curtailed" SWPA allocation Factor 1 for the Company's jurisdiction and North Carolina classes on pages 1 and 2 of Rebuttal Schedule 3.

Table 1

	SWPA As Filed using 42 MW as Peak Demand	SWPA using Nucor's Avg. Assumed Peak Demand
NC Jurisdiction	4.9507%	5.0952%
Nucor Class	14.0774%	16.8815%

Using the new set of SWPA factors based on this Average Assumed Peak Demand, the Company prepared a jurisdictional and class cost of service study. My Rebuttal Schedule 3, pages 3 through 6, provides cost of service Schedule 1 for the Company's four jurisdictions and for the customer classes. On my page 7 of Rebuttal Schedule 3, I summarize the results of this analysis

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and compare it to the Company's actual per books cost of service studies filed in this case in Form E-1, Item 45a. The result of this analysis shows that the North Carolina jurisdiction's and Nucor's net operating income decline while their allocated responsibility for rate base increases due to increased allocation of production and transmission plant. This lowers the North Carolina jurisdiction and Nucor's rate of return. I then calculate the revenue that would be required to get the North Carolina Jurisdiction and Nucor back to the filed per books rate of return of 6.4072%. The increase required for the North Carolina jurisdiction will be $4.49 million and the increase required for Nucor would be $9.2 million.

On page 7 of Rebuttal Schedule 3, I show that the increase required for the North Carolina jurisdiction of $4.49 million can be considered as a benefit to the North Carolina jurisdiction of Nucor's curtailment during 2018 to approximately 42 MW, which was the average of Nucor's load during the summer and winter peak hours. The increase required for Nucor of $9.2 million can be considered a benefit to Nucor. Taking the difference between the benefit to Nucor of $9.2 million and the benefit to the North Carolina jurisdiction of $4.49 million shows an excess benefit for Nucor over the jurisdiction of $4.7 million. I will note, however, that most of this excess benefit is made up by other class' rates today based on Nucor's low rate of return of 4.32% versus the per books jurisdiction rate of return of 6.4072%. Before any ratemaking adjustments to the revenue requirement in this case is considered, I calculate the NS Class subsidy on a per books cost of service basis (from Item 45a) to be $3.71 million.

Q. Does the Company's use of the SWPA method and its resulting cost of service studies overstate costs for the jurisdiction and the Schedule NS class?

A. Once again, the costs allocated to the North Carolina jurisdiction and Nucor, in particular, are based on actual measured demand, reflecting Nucor's curtailment at the hours of the summer and winter peaks, and energy consumption required during the test year just as it is for all other customers in the jurisdiction and on the Company's system. As the foregoing analysis shows, in that scenario, Nucor's load would have been higher resulting in more production plant and related expenses being allocated to both Nucor and the North Carolina Jurisdiction, thereby reducing the net operating income and rate of return for both. The Company has calculated the SWPA allocation factors in reasonable manner – consistent with the principles approved in the 2016 Rate Case – that appropriately recognizes the value of Nucor's interruptibility to the system and does not overstate cost nor understate returns for the North Carolina jurisdiction and its customer classes. Cost responsibility has been properly and fairly determined based on requirements placed on the system on the summer and winter peak days and throughout the year.

Q. What is your recommendation related to the SWPA method?

A. I reiterate the recommendation I made in my Direct Testimony. The SWPA method calculated using the system load factor to weight the average (energy) component and (1 – system load factor) to weight the peak demand component is the appropriate method to use in the cost of service to allocate production and transmission plant costs and related expenses in this proceeding.

II. Rebuttal of Cost Allocation Proposals

Q. While not making a formal proposal to use a different allocation method in this proceeding, does CIGFUR Witness Phillips advocate for the use of the S/W CP method and encourage the use of a peak demand method in future proceedings?

A. Yes. I have already addressed his criticism of the SWPA method. During the course of his discussion of the SWPA method, he expresses that using the summer and winter peaks through the S/W CP method would be preferential. I have already discussed during my defense of SWPA and my recommendation to continue using that method that using only two hours (the summer peak demand and the winter peak demand) is not consistent with the Company's planning process, its investment in generation, and its operation to meet the obligation to serve customers throughout the year and not only in the peak hours.

Q. Has Nucor witness Wielgus proposed that if the use of 1CP is not decided in this docket, that the Commission should commit to examine via a formal docket whether requiring 1CP of 5CP instead of SWPA would be most appropriate?

A. Yes. He specifically states that he is not proposing that the Company adopt the 1CP method but he does state that this method "would be preferable to SWPA since it is a fit at the system or Company level and at the class level. This method is aligned with why the Company invests in generation capacity and ... recognizes the beneficial factors associated with the NS class."[24] He notes that the ROR index for Nucor before revenue apportionment would be 3.10 compared to 0.79 using SWPA.[25]

Q. Could you please comment on your concerns regarding the use of the 1CP and the S/W CP for DENC with regard to significant plant costs and O&M expenses?

A. The most glaring deficiency of the 1CP and S/W CP for DENC is the assumption that the Company's investment in production plant ($19.463 billion) and transmission plant ($9.364 billion) was only incurred to serve load during one (0.01% of time) and two hours of the year (0.02% of time), respectively. While the peak load for a utility determines the amount of generation resources needed, it does not dictate the type of resources needed. The type of resources needed is dependent upon the level of sales that a utility has an obligation to provide over all hours of the year. Unlike the 1CP and

[24] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 6 lines 17 – 21.
[25] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 7 lines 3 – 5.

SW C/P methods, the SWPA method recognizes this principle as it considers annual energy consumption in developing the "average" component of the factor. (Again, the average component is the total annual kWh consumption divided by the number of hours in the year.)

Take, for example, the Company's approximately $5.0 billion total investment in nuclear plant at the end of 2018.[26] This represents approximately 26% of DENC's total production plant investment. The Company's investment in nuclear plant was made to contribute to the capacity needs of our customers during peak hours but also to serve energy requirements with low variable cost electricity during all other hours of the year. Therefore, the responsibility for the plant investment cost of these units should recognize the reasons for such investment – to contribute to the total capacity to meet peak demands and to serve energy (kWh) requirements throughout the year. The SWPA cost allocation method has the features that align closely with and accurately reflect the reasons for such investment. In contrast, reliance on peak-only cost allocation methods would require the Commission to assume that this nuclear investment was made solely to serve the load during a limited number of hours. This simply is not the case.

Regarding production O&M expenses (excluding fuel and purchased power), the 1CP and the S/W CP method assume that these expenses are only incurred to serve load during one or two hours of the year. For the 2018 test year nuclear O&M expenses, excluding fuel and reactor maintenance, totaled

[26] Form E-1, Item 45a, Page 38, line 42 plus line 49.

approximately $343 million. Nuclear units routinely operate more than 85% of the time and the O&M expenses are a function of how they operate. Similarly, DENC's new larger combined cycles (Warren County CC, Brunswick County CC, and Greenville CC) operate at higher capacity factors. Put another way, these new units will produce low cost energy in many hours of the year. Under the 1CP and S/W CP methods, the expenses associated with operating these units would be recovered based upon demands on the Company's system in only one or two hours of the year, while actual expenses are incurred as a result of the plant operating over the vast majority of hours during a year. As with production plant itself, the SWPA method, through the average demand component, recognizes that production maintenance expenses are incurred such that service can be provided from the Company's generation fleet to customers for all hours of the year.

Q. Do you also have concerns regarding the 1CP and S/W CP methods allocating the Company's production plant and transmission plant to the customer classes?

A. Yes. In evaluating these impacts, I have considered that using the 1CP or the S/W CP methods in the Company's cost of service studies applies to both production demand and transmission demand plant costs and related expenses. This goes beyond what Nucor Witness Thomas evaluated using the 1CP method and summarized in Nucor Exhibit JMT-3, which only involved changing SWPA Factor 1 to 1CP. He did not change SWPA Factor 2 in his cost of service analysis. I have prepared a calculation of the 1CP and S/W CP allocation factors and present them in my Rebuttal Schedule 4. Table 2 below provides a comparison of the customer class' production allocation factor (Factor 1) for the 1CP, S/W CP and SWPA methods.

Table 2
Comparison of the 1CP, S/W CP and the SWPA Methods

	Res	SGS&PA	LGS	6VP	Sch NS	St. Lts	Traffic Lts
Class 1CP Factor 1	71.6256%	14.6004%	6.7757%	2.9413%	4.0501%	0.0000%	0.0069%
Class S/W CP Factor 1	64.4116%	18.0448%	9.2231%	3.2389%	5.0740%	0.0000%	0.0076%
Class SWPA Factor 1	49.3792%	18.6501%	12.6175%	4.9392%	14.0774%	0.3264%	0.0102%

With both methods, a customer class, which under normal operating characteristics has no usage during the summer or winter peak, is allocated no production plant costs even though the class may require production service during many other hours of the year. Also, with both methods, a customer class that has the ability to reduce demand during the summer and winter peak can avoid a disproportionate amount of production plant and fixed O&M expenses.

Consider the Streetlight class. For 2018, the summer peak occurred at the hour ending 5:00 p.m. and the winter peak at 8:00 a.m., hours during which streetlights are not operating. Unlike the SWPA, this customer class would be allocated no production plant and associated production O&M under the 1 CP or the S/W CP even though they operate approximately 4,000 hours per year. Under the 1CP and S/W CP methods, the Streetlight class would receive no allocation associated with production plant.

Use of 1CP or S/W CP methods is also potentially more significant for DENC than other utilities due to the Company's obligation to serve a "one customer industrial class" – Schedule NS – which used approximately 20.3% 932,119,000) of the 4,579,058,000 jurisdictional production level kWh during the test year but that can also significantly reduce its demand on the peak. On average, Nucor has the capability of reducing its load by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. It is this reduced level of demand that would solely be used in the calculation of a production allocation factor under the 1CP or S/W CP allocation. In comparison, the average demand during the Tier 3 hours for the year for the Schedule NS class is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** this class would only be responsible for approximately 38 MW of production plant and related non-fuel expenses under the 1CP method and 42 MW (Avg of 38 MW and 43 MW). Under the 1CP and S/W CP methods, this class' production allocation factor would be reduced significantly from their corresponding SWPA factor.

In general, there is a significant shift in cost responsibility under both of these methods from the larger industrial customer classes to the residential class.

Q. Has the Company prepared a fully adjusted cost of service based on the 1CP and S/W CP methods? If so, what are the results?

A. Yes. I have provided production and transmission allocation factors calculated using the 1CP and S/W CP method to Company Witness Miller who has prepared a jurisdictional and class per books cost of service study and a fully adjusted class cost of service study using these factors. Company Witness Miller provides the results of his analyses in his Rebuttal Schedule 1 for the 1CP method and in his Rebuttal Schedule 2 for the S/W CP method. The third box of these rebuttal schedules presents the fully adjusted class cost of service using the modified SWPA method before any revenue increase. I summarize the results in the following table for the customer classes.

Table 3
Fully Adjusted Cost of Service Rate of Return and Index
Prior to Any Revenue Increase

	SWPA*		1CP**		S/W CP***	
Class	ROR	Index	ROR	Index	ROR	Index
Residential	5.57%	0.89	1.94%	0.34	3.58%	0.54
SGS & PA	7.78%	1.24	10.17%	1.77	8.66%	1.30
LGS	8.32%	1.33	17.50%	3.05	13.69%	2.05
Schedule NS	4.93%	0.79	28.52%	4.97	24.84%	3.72
6VP	7.61%	1.22	14.75%	2.57	14.62%	2.19
St & Outdoor Lts	3.38%	0.54	5.04%	0.88	5.03%	0.75
Traffic Lts	6.66%	1.06	9.21%	1.61	9.14%	1.37

* Company Witness Miller Supplemental Schedule 4
** Company Witness Miller Rebuttal Schedule 1
*** Company Witness Miller Rebuttal Schedule 2

The shift in cost responsibility described above from the large industrial classes to the residential class is demonstrated even further by the results of the cost of service studies. As can be seen in Table 3, the rates of return and index for the residential class have declined significantly under the 1CP and

S/W CP compared to the SWPA method proposed by the Company and agreed to by Public Staff. Meanwhile, the rates of return and index for the LGS, 6VP and Schedule NS classes have increased significantly under the 1CP and S/W CP compared to the SWPA method.

As provided in Company Witness Miller's Rebuttal Schedule 1 for the 1 CP method, the revenue increase required to bring the residential class to the same ROR index of 0.97 as filed in Mr. Miller's Supplemental Schedule 4 would be $63,192,746. For the S/W CP method, the revenue increase would be $38,877,396 as shown in Mr. Miller's Rebuttal Schedule 2. As shown in Mr. Miller's Supplemental Schedule 4, under the SWPA method, the revenue increase would be $17,456,367.

While the residential class would require significant revenue increases under the 1 CP and S/W CP methods, the LGS, 6VP, and Schedule NS classes would receive decreases to achieve the same ROR index as filed in Mr. Miller's Supplemental Schedule 4 for each of these classes.

Q. What is your conclusion about the recommendations related to 1CP and S/W CP made by Witnesses Phillips and Wielgus?

A. I disagree with the use of both methodologies in the cost of service. I recommend that the Commission not approve the use of the 1CP and S/W CP method in the cost of service in this proceeding.

I also disagree with the proposal to have the Commission examine the use of one of these methods or another peak-based method instead of SWPA in future cost of service studies. When making decisions about cost allocation in the cost of service, I believe the Commission considers the unique circumstances for individual utilities, their customers and usage to determine the method that is most appropriate. This is best done during the course of rate case proceedings such as this one. Therefore, I do not believe a separate proceeding is needed to examine this matter.

Nucor Proposal – SWPA with Modified Weighting
60% Peak Demand / 40% Energy

Q. How do you respond to Nucor Witness Wielgus' recommendation that the demand part of the SWPA method be weighted at 60% (energy at 40%) giving more weight to the demand part than the energy part?

A. Earlier, I provided testimony addressing Mr. Wielgus' criticism of the SWPA method and the weighting that the Company has proposed and Public Staff has supported. The SWPA method with weighting of the average (energy) component at the system load factor and the peak demand component at (1 – system load factor) is consistent with how the Company operates its system and plans for the future. Earlier, I also addressed his concept of judgmentally weighting the peak demand component higher than the average (energy) and explained how that is not consistent with how customers actually use the system. Therefore, I disagree with the proposal to modify the SWPA method to have peak demand weighted at 60% and energy weighted at 40% ("Modified SWPA").

Q. Do you also have concerns regarding the Modified SWPA being used to allocate the Company's production and transmission plant to the customer classes?

A. Yes. I have evaluated the impact of the Modified SWPA as Mr. Wielgus proposes. In evaluating this impact, I have considered that Mr. Wielgus' proposal to modify the SWPA factor applies to the entire application of the SWPA method within the Company's cost of service studies, which means the Modified SWPA factor would apply to both production demand and transmission demand plant costs and related expenses. This goes beyond what Nucor Witness Thomas evaluated in his analysis shown in Nucor Exhibits JMT-4 and JMT-5, which only involved changing SWPA Factor 1 and not SWPA Factor 2. I have calculated the Modified SWPA factors present those in my Rebuttal Schedule 5.[27]

Q. Has the Company prepared a fully adjusted cost of service based on the Modified SWPA method?

A. Yes. I have provided production and transmission allocation factors calculated using the Modified SWPA method to Company Witness Miller, who has prepared a jurisdictional and class per books cost of service study and a fully adjusted class cost of service study using these factors. Company Witness Miller provides the results of his analysis in his Rebuttal Schedule 3. The third box of this rebuttal schedule presents the fully adjusted class cost of service

[27] Nucor Witness Thomas also calculates a SWPA allocation factor based on an equal weighting of peak demand and energy. I provided Company Witness Miller with factors that the Company calculated based on this same weighting assuming both Factor 1 and Factor 2 are modeled. Mr. Miller conducted the COS analysis and presented the results in his Rebuttal Testimony.

using the modified SWPA method before any revenue increase. I summarize the results in the following table for the customer classes.

Table 4
Fully Adjusted Cost of Service Rate of Return and Index
Prior to Any Revenue Increase

	SWPA*		Modified SWPA**	
Class	ROR	Index	ROR	Index
Residential	5.57%	0.89	4.85%	0.76
SGS & PA	7.78%	1.24	8.05%	1.26
LGS	8.32%	1.33	9.78%	1.53
Schedule NS	4.93%	0.79	8.30%	1.30
6VP	7.61%	1.22	9.40%	1.47
St & Outdoor Lts	3.38%	0.54	3.88%	0.61
Traffic Lts	6.66%	1.06	7.37%	1.15

* Company Witness Miller Supplemental Schedule 4
** Company Witness Miller Rebuttal Schedule 3

The shift in cost responsibility described above from the large industrial classes to the residential class is demonstrated even further by the results of the cost of service studies. As can be seen in Table 4, the rates of return and index for the residential class have declined under the Modified SWPA method compared to the SWPA method proposed by the Company and agreed to by Public Staff. Meanwhile, the rates of return and index for the LGS, 6VP and Schedule NS classes have increased under the Modified SWPA method compared to the SWPA method.

As provided in Company Witness Miller's Rebuttal Schedule 3 for the Modified SWPA method, the revenue increase required to bring the residential class to the same ROR index of 0.97 as filed in Mr. Miller's Supplemental Schedule 4 would be $24,674,496. As shown in Mr. Miller's

Supplemental Schedule 4, under the SWPA method, the revenue increase would be $17,456,367.

While the residential class would require an additional $7.2 million ($24.7 million – $17.5 million) revenue increase under the Modified SWPA method, the LGS, 6VP, and Schedule NS classes would receive a decrease to achieve the same ROR index as filed in Mr. Miller's Supplemental Schedule 4 for each of these classes.

Q. What is your conclusion about the recommendations related to the Modified SWPA method made by Nucor Witness Wielgus?

A. I disagree with the use of the Modified SWPA method. I recommend that the Commission not approve the use of the Modified SWPA method in the cost of service in this proceeding.

III. Addressing the Targeted ROR Index for Nucor

Q. With regard to the ROR index of 0.80 that you established for Nucor in your Direct Testimony, does Nucor Witness Wielgus agree this is appropriate?

A. No. He says that setting the index 10 basis points below the Parity Index Range of 0.90 to 1.10 is inadequate and contends that it should be set closer to that of the Streetlight class which was at 0.59 in my Direct Testimony. He asserts that since Nucor's load can be interrupted, including during peak hours, it gives sound reasoning as to why its ROR index should be set closer to that for the Streetlight class as these lights are not usually operating during the hours of the winter and summer peaks.

Q. Does Nucor Witness Wielgus recommend a ROR index based upon the proposed ROR index for Street Lighting?

A. Yes. He recommends that the ROR index for Schedule NS "should not exceed the mid-point between the proposed ROR index for Schedule NS and the Company's index for ROR for the Street Lighting class, which is 0.80 and 0.59, respectively."[28]

Q. Do you agree that deriving Nucor's ROR index based on the index for the Street and Outdoor Lighting class is appropriate?

A. No. First, in this proceeding, the ROR index for the Street and Outdoor Lighting class is too low. As discussed in my Direct Testimony, the rates the Outdoor Lighting class is currently paying are not reasonably aligned with costs. I apportioned a higher percentage increase to this class to bring it closer to the Parity Index Range, but there is more that should be done to bring the Outdoor Lighting class rates in line with costs. However, the primary reason is that Nucor uses a substantial amount of energy during the course of the year, and, while its load can partially be interrupted or incentivized through pricing to be reduced for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** during the year, its pattern of use is not at all similar to Street and Outdoor Lighting, which is off every day during the daylight hours.

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[28] Docket No. E-22, Sub 562, Testimony of Paul J. Wielgus, Page 23, lines 8-10.

Q. Earlier, you addressed Nucor Witness Wielgus criticism of the SWPA method not recognizing the system benefits of the NS class and concluded that the SWPA does indeed recognize the benefit. Is this correct?

A. Yes.

Q. Does that analysis still lead you to a position that the appropriate ROR index for the Schedule NS class based on the fully adjusted class cost of service using the SWPA method should be 0.80?

A. No. I have modified my position. This is based on the analyses I presented in my Rebuttal Schedule 2, and my Rebuttal Schedule 3, page 1-7. Upon examining the value of curtailment based on the evaluations in my Rebuttal Schedule 2 and the benefit that the North Carolina jurisdiction and the Nucor class are receiving in the cost of service analysis shown in my Rebuttal Schedule 3, page 7, I believe that a lower ROR index is appropriate.

IV. Addressing Comments from CIGFUR and Nucor on Revenue Apportionment and Rate Design

Q. Before addressing revenue apportionment and rate design based on the Company's rebuttal revenue requirement, do the intervenors address the Company's proposals with regard to revenue apportionment and rate design?

A. Yes. CIGFUR Witness Phillips and Nucor Witness Wielgus discuss revenue apportionment and rate design.

Q. Please address Nucor Witness Wielgus' recommendation that the percentage increase in base rates to Schedule NS should not exceed the average of the percentage increases applied to rate schedules in the LGS and 6VP classes.

A. I disagree. While I have just discussed modifying my position and lowering the ROR index for the Schedule NS class from 0.80 that I supported in my Direct Testimony, the ROR index for the LGS and 6VP classes is well above the Parity Index Range. Given that position and given other non-cost factors that I discussed in my Direct Testimony and later in this testimony, these two large industrial classes should receive a very low percentage increase. While I have discussed non-cost factors related to the benefit of the Company's service arrangement with Nucor and can justify a ROR index lower than what I initially recommended, I cannot give the Schedule NS class the average increase that LGS and 6VP should receive as that would place the Schedule NS class below the appropriate Target ROR index and provide a subsidization that is not reasonable based on non-cost factors.

Q. Please address CIGFUR Witness Phillips' comments on the Company's proposed method of distributing the requested increase in rates and his recommendation?

A. Mr. Phillips noted that the Company's proposed distribution of the revenue increase moves the rate of return for the 6VP and the LGS classes closer to cost and the system average rate of return.[29]

[29] Docket No. E-22, Sub 562, Testimony of Nicholas Phillips, Jr., Page 18, lines 4-5.

With regard to apportioning the revenue increase, he recommends that "(B)because DENC's proposed method of distributing the requested increase to classes moves rates closer to cost in a meaningful manner, it should be implemented as proposed."[30] I do not disagree with Mr. Phillips' recommendation.

Q. **Are there further thoughts that are important to consider regarding CIGFUR Witness Phillips' recommendation?**

A. Yes. After making his recommendation, Mr. Phillips specifically mentioned that the "the Rate 6VP class has been providing excess returns to DENC both in this rate case and the most recent case Docket No. E-22, Sub 532, which used a 2015 test year ... [t]hese excessive returns are based on the SWPA cost study." [31] The same is true for the LGS class in this proceeding. These two classes are very important to the Company's North Carolina service territory. The LGS class is composed of large general service customers with some classified as commercial / public authority and others classified as industrial. These customers vary in terms of size, operations, and quantity and manner of use of electric service. This class includes department stores, grocery stores, large hardware stores, colleges, health care facilities, governmental facilities and industrial manufacturers - some small and some large. The 6VP class is composed of large industrial customers engaged in manufacturing.

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[30] Docket No. E-22, Sub 562, Testimony of Nicholas Phillips, Jr., Page 7, lines 11-13.
[31] Docket No. E-22, Sub 562, Testimony of Nicholas Phillips, Jr., Page 18, lines 5-11.

Q. Why is it important to address "excessive returns" when establishing rates?

A. Both classes have a ROR index that is well above the Parity Index Range at 1.33 for the LGS class and 1.22 for the 6VP class.[32] In addition to these "excessive returns" and high ROR indexes, it is important to consider 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 when establishing rates. In particular, since the 2016 Rate Case, I am aware that the Company's service territory has had a large, high load factor industrial customer whose load once exceeded 12 MW and whose employment at one time exceeded 250 employees move almost all of its manufacturing operations to a sister facility in another service area. It remains an active account but has minimal usage. This customer had approached the Company prior to leaving and expressed a concern about the cost of electricity to run its operations at the facility. The Company gained approval of Rate Schedule 6L in the 2016 Rate Case to help large high load factor customers who may utilize their plant efficiently in multiple daily shifts. And, since the 2016 Rate Case, the Company filed and gained approval of two real-time pricing rate schedules that were designed to be combined with Rate Schedule 6L to help large high load factor customers. In a competitive environment, when at times even facilities within the same corporation are competing against each other to become more efficient and

[32] From Docket No. E-22, Sub 562 Company Supplemental Exhibit REM-1, Schedule 4, Page 1: Class Rate of Returns After All Ratemaking Adjustments Before Revenue Increase.

lower their cost, electricity usage and its pricing is a critical component to production decisions. I am aware of the decline in industrial customers and usage since the 1990s in our North Carolina service territory. Improvements in the level of pricing and rate design for large high load factor customers in the LGS and 6VP classes have been made, and should continue in the establishment of rates in this proceeding.

Q. **Earlier in your testimony, you stated that you have modified your position and believe that the Schedule NS class should have a lower ROR index. What is your recommendation for a target ROR index for Schedule NS?**

A. In the 2016 Rate Case based upon the stipulation and the Commission's order and Finding of Fact No. 42, this class received a non-fuel base rate increase that moved its ROR index from 0.43 to 0.75.[33] [34] This moved the NS class two-thirds of the way toward the low end (90% of jurisdictional ROR) of the Parity Index Range. Prior to the 2016 Rate Case, a deficiency had existed for a number of years, as reported in the Company's past rate cases and annual jurisdictional cost of service studies filed with the Commission.

I have discussed the Company's service agreement with Nucor and have provided some reasonable calculations of the value of this agreement in my Rebuttal Schedule 2. In my Rebuttal Schedule 3, I have provided an analysis

[33] Docket No. E-22, Sub 532, Agreement and Stipulation of Settlement Between Dominion North Carolina Power, Public Staff – North Carolina Utilities Commission, and Carolina Industrial Group for Fair Utility Rates I, Settlement Exhibit III, Page 1 of 3.

[34] Docket No. E-22, Sub 532, Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Finding of Fact No. 42, Page 16.

showing how the North Carolina jurisdiction is benefitting from the Company and Nucor having this service arrangement. As I described earlier in my Direct Testimony filed back on March 29, 2019, I proposed moving the Schedule NS class to a ROR index of 0.80. In the Company's supplemental filing, Schedule NS had a ROR Index of 0.79.[35] Now, considering this operational benefit to the system and the benefit in cost allocation to the North Carolina jurisdiction because of the partially interruptible nature of service to Nucor, I believe it is appropriate to target an ROR index of 0.75 for the Schedule NS class. This is a very important large industrial customer, and I believe that this reduction in the recommended ROR index is reasonable.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[35] From Docket No. E-22, Sub 562 Company Supplemental Exhibit REM-1, Schedule 4, Page 1: Class Rate of Returns After All Ratemaking Adjustments Before Revenue Increase.

TESTIMONY
OF
PAUL B. HAYNES
IN SUPPORT OF AGREEMENT AND STIPULATION OF SETTLEMENT
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

Q. Please state your name, business address, and position with Virginia Electric and Power Company.

A. My name is Paul B. Haynes and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am Director – Regulation testifying on behalf of Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I pre-filed Direct, Supplemental Direct, Additional Supplemental Direct, and Rebuttal Testimony in support of DENC's Application in this matter. My testimony has addressed cost of service, revenue apportionment, and rate design issues.

Q. What is the purpose of your testimony?

A. The purpose of my testimony today is to provide testimony supporting the Agreement and Stipulation of Settlement ("Stipulation") as filed today by the Public Staff – North Carolina Utilities Commission ("Public Staff") and agreed to between DENC and the Public Staff (together, the "Stipulating Parties").

Specifically, my testimony in support of the Stipulation addresses cost allocation revenue apportionment, and rate design issues agreed upon in the Stipulation.

Q. **Are you sponsoring any exhibits with your testimony?**

A. Yes. I am sponsoring Company Settlement Exhibit PBH-1, which consists of Settlement Schedule 1 and Form E-1, Item Nos. 39.a and 39.c and 42.a-c, which was prepared under my supervision and direction, and is accurate and complete to the best of my knowledge and belief.

Q. **Are you familiar with the provisions of the Stipulation reached between the Company and the Public Staff as it relates to cost allocation, revenue apportionment, and rate design issues?**

A. Yes.

Q. **Do you believe the Stipulation represents a balanced compromise to establish appropriate rates and charges that are fair to all customers in this proceeding?**

A. Yes. While other Company witnesses support the reasonableness of the stipulated non-fuel base revenue increase, I believe the Stipulation in Section V Cost Allocation, Rate Design, and Terms and Conditions, Paragraph A presents a just and reasonable approach to establishing the Company's North Carolina jurisdictional cost of service and class cost of service for the allocation of production and transmission plant costs and related expenses based upon using the Summer/Winter Peak and Average ("SWPA") allocation methodology calculated using the system load factor to weight the average component and (1 - system load factor) to weight the peak demand component. The Company proposed this methodology in its direct testimony and defended and supported its use in its rebuttal testimony. Public Staff Witness Floyd supported this methodology in his direct testimony.

Section V, Paragraph A of the Stipulation also identifies two adjustments made in the course of calculating the SWPA factors. These are: i) the Company's proposed adjustment to its recorded summer and winter peaks to recognize the peak demand contributions of non-utility generators interconnected to the Company's distribution system is appropriate and reasonable, and ii) the Company's proposed adjustment to remove the demand and energy requirements of three customers, one wholesale customer, NCEMC, and two large industrial customers in the Company's Virginia jurisdiction for whom the obligation to provide generation service has ended or will end during 2019. The Company proposed these adjustments in its direct testimony, and Public Staff Witness Floyd agreed with such adjustments.

The Stipulation addresses the apportionment of the revenue requirement and the design of rates in Section V, Paragraph B. With regard to these matters, the Stipulation provides the following:

1. To the extent possible, the Company shall assign the approved revenue requirement consistent with the principles regarding revenue apportionment described in the testimony of Public Staff witness Floyd.

2. The Parties agree that the Company shall implement the rate design proposed by Company witness Haynes within his direct testimony, filed contemporaneously with the Company's Application in this docket as adjusted by this Stipulation.

3. The Parties agree that all classes should share in the base case revenue increase.

4. In meeting the provisions of (1), (2), and (3) in apportioning the approved revenue requirement to the customer classes, awareness and consideration is given to the rate of return indexes for the LGS and 6VP classes being above 1.20 and an appropriate rate of return index for the Schedule NS class.

I consider these provisions of Section V, Paragraph B to be reasonable for the purpose of establishing rates in this proceeding.

Q. **Has Company Witness Miller prepared an updated fully adjusted class cost of service study?**

A. Yes. Company Witness Miller sponsors the updated fully adjusted class cost of service study in Form E-1, Item No. 45c. and provides a summary of the results in his Stipulation Schedule 4. Using the results of the fully adjusted cost of service study, in accordance with the principles explained in my direct testimony and described further in my rebuttal testimony, and recognizing the Commission's orders in the Company's last two general rate cases pertaining to including both base non-fuel and base fuel revenue when considering how to apportion a change in revenue and calculate class rates of return, I have apportioned the revenue requirement to the customer classes and designed rates.[1] In the apportionment, I have reviewed the principles regarding revenue apportionment described in the testimony of Public Staff Witness Floyd and consider the results of the apportionment that the Company has prepared to conform with the principles described by Mr. Floyd.

Q. Do you have a schedule that summarizes the apportionment and final rate design that the Company has prepared?

A. Yes. Please refer to my Stipulation Schedule 1, Page 1, which provides a summary of final rate design showing present annualized revenue, proposed annualized revenue, change and percentage change, based on the Company's proposed revenue requirement, for the following:

a. Base Non-Fuel Miscellaneous Revenue

b. Base Non-Fuel Rate Schedule Revenue

c. Total Base Non-Fuel Revenue

d. Base Fuel Revenue

e. Total Base Revenue

f. Total Rider EDIT Revenue

g. Total Base Revenue and Rider EDIT Revenue

[1] Docket No. E-22, Sub 532, Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Finding of Fact No. 42, Page 16. Docket No. E-22, Sub 479, Order Granting General Rate Increase, Evidence and Conclusions for Finding of Fact No. 94, Page 120.

Pages 2 and 3 of my Stipulation Schedule 1 provide a detailed summary by rate schedule for the information presented on Page 1.

Q. **Has the Company prepared detailed rate design worksheets and calculations supporting the information provided in Settlement Schedule 1 referred to above?**

A. Yes. The Company provides this information in Form E-1, Item Nos. 39.a and 39.c and Item 42.a-c accompanying this testimony.

Q. **Does Item 39.c include workpapers and the rate design for the Company's proposed Rider EDIT?**

A. Yes. Item 39.c includes a workpaper showing the allocation of the Rider EDIT recovery amount to the customer classes and the design of Rider EDIT recovery rates.

Q. **Is the Company still proposing Rider A1 to become effective November 1, 2019?**

A. Yes. As discussed in my Additional Supplemental Direct Testimony and as provided for in Company Additional Supplemental Exhibit PBH-1 Schedule 2, the Company is proposing Rider A1 to mitigate the effect of the November 1, 2019 base non-fuel increase. Rider A1 is calculated to be the difference between the proposed February 1, 2020 Fuel EMF rate for each customer class as calculated on Page 1 in my Additional Supplemental Schedule 2, and the current EMF Rider B rates that became effective February 1, 2019.

Q. Does this conclude your testimony in support of the Stipulation?

A. Yes.

BY MS. KELLS:

Q Mr. Haynes, do you have a summary of your testimonies with you?

A Yes.

Q Will you please present that now.

A Chair Mitchell and members of the Commission, good afternoon. In my direct testimony I sponsor the allocation methods used to allocate the production and transmission fixed costs and related expenses and the cost of service studies. These studies are based on the Summer/Winter Peak and Average, or SWPA, cost allocation method which has been found to be just and reasonable by this Commission in the Commission's last six rate cases and produces fair and reasonable results.

The SWPA method recognizes two components of providing service to customers, peak demand and average demand. The peak demand component takes into -- the hour -- account the hour when the load is highest during both the summer and winter months. The average demand component recognizes that -- 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 divided -- provided to customers during the year divided by the total number of hours during the year. The SWPA method next 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 the average demand component. Subtracting this ratio from one obtains the ratio used to weight the peak demand component.

I also address the Company's proposed apportionment of the non-fuel base rate revenue increase among the customer classes, as well as the revisions to DENC's non-fuel base rates and charges in order to produce the additional revenues requested by the Company in this Application. I explain that 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, while taking into account other factors that impact customers and the service territory. In apportioning the revenue requirement and designing rates, I state that all classes should share in the non-fuel base revenue increase. For our large industrial customers I consider other factors related to their quantity of usage, the time of usage, factory utilization, economic vitality of the service territory as it relates to industrial customers. I explain that the Company has specifically considered these and a number of other factors in apportioning the revenue increase to the LGS, 6VP, and the NS classes. After discussing the apportionment of the non-fuel base rate increase to the customer classes and the target percentage increases, I explain how the components of the rate schedules are adjusted to achieve the non-fuel base rate increases.

Additionally, my direct testimony discusses the proposed base holder -- placeholder base fuel rate for each class to be updated through the 2019 annual fuel factor filing. This is consistent with the Company's approach in the 2016 rate case. I also provide a projection of the base fuel rate along with a projection of the experience modification factor, or EMF, anticipated in the Company's August 2019 fuel proceeding.

Finally, my direct testimony supports the Company's proposal to refund excess deferred income taxes, or EDIT, to North Carolina jurisdictional customers, as described by Company Witness Paul McLeod, and how that refund is to be allocated to the customer classes.

In my supplemental testimony I address a correction to Factor 2 used to allocate transmission plant costs and related expenses. I also update the weather, growth, and increased usage adjustment to annualize revenue based on actual information through June 30th, 2019, the update period, and explain changes in the calculation of the adjustment's impact on annualized revenue. Additionally, I calculate the energy efficiency program loss revenues adjustment based upon information provided by Company Witness Deanna R. Kesler. Finally, I state that the Company will provide an additional supplemental update once the Company's fuel case is filed to calculate revised base fuel rates and also explain Rider A1, a decrement rider, to be filed in the Company's fuel factor filing.

In my additional supplemental testimony I support the Company's updated base fuel rate, proposed Rider A1, and updated presentation of present and proposed fuel cost recovery by customer class after the Company's fuel factor filing was completed. I also revised the growth and usage adjustments and the calculation of annualized revenues filed in my supplemental testimony to conform with the methodology used in the Company's 2016 rate case.

My rebuttal testimony addresses the testimonies of Public Staff Witness Jack L. Floyd, CIGFUR Witness Nicholas Phillips, and Nucor Witnesses Paul J. Wielgus and Jacob M. Thomas regarding issues related to cost allocation and the cost of service. I also address the testimonies of Witness Wielgus and Phillips regarding apportionment of the revenue requirement to customer classes and rate design, and explain that the Company's use of the Summer/Winter Peak and Average methodology continues to properly recognize the Company's generation planning and operation and is the most appropriate cost allocation method for DENC's production and transmission plant cost and related expenses in the Company's cost of service. This method has been used since 1983, and Public Staff Witness Floyd agrees with its continued use in this proceeding. I explain why it be -- would be inappropriate to use both the Summer/Winter Coincident Peak methodology advocated by CIGFUR Witness Phillips and the 1 CP methodology advocated by Nucor Witness Wielgus. I also explain why Mr. Wielgus' recommendation to modify the calculation of the SWPA method to weight the peak demand at 60 percent and the average demand at 40 percent would be inappropriate.

In my testimony in support of the Agreement and Stipulation of Settlement I address cost allocation, revenue apportionment, and rate design issues based upon the Stipulation. Specifically, I believe that Section VI of the Stipulation presents a just and reasonable approach to establishing the Company's North Carolina jurisdictional cost of service and class cost of service for the allocation of production and transmission plant costs and related expenses based on the SWPA allocation methodology. This methodology, with the same weighting components, was presented in the Company's direct testimony and supported by Public Staff Witness Floyd.

The Company believes this Stipulation represents a reasonable compromise of the allocation and rate design issues in this case, it's fair to all parties, and should be approved by the Commission.

I also support the Stipulation entered into by the Company and CIGFUR filed today in this proceeding for the same reasons discussed in my testimony and support of the Stipulation with Public Staff. Thank you.

Q Thank you, Mr. Haynes. Now we'll move to Mr. Miller. Would you please state your name and business address for the record.

A (Miller) Certainly. My name is Robert E.

Miller, and my business address is 120 Tredegar Street, Richmond, Virginia, 23219.

Q And by whom are you employed and in what capacity?

A I am employed by Dominion Energy North Carolina, and my business title is Regulatory Analyst III.

Q Did you cause to be prefiled in this docket on March 29th, 2019, 15 pages of direct testimony in questions and answer form, an Appendix A, and one exhibit?

A I did.

Q Did you also cause to be prefiled in this docket on August 5th, 2019, 12 pages of supplemental testimony and one exhibit?

A I did.

Q Did you also cause to be prefiled in this docket on September 12th, 2019, nine pages of rebuttal testimony and one exhibit?

A I did.

Q And did you cause to be prefiled in this docket on September 17th, 2019, five pages of Stipulation testimony and one exhibit?

A I did.

Q Do you have any changes or corrections to any of your testimonies or exhibits?

A I would note, as Mr. Haynes also noted, that the business address listed on page 1 of my direct testimony and page 1 of my supplemental direct testimony has since changed to 120 Tredegar Street.

Q Thank you. With that correction, if I were to ask you the same questions that appear in your testimonies today, would your answers be the same?

A Yes.

MS. KELLS: Chair Mitchell, at this time I move the prefiled direct, supplemental, rebuttal, and stipulation testimonies of Mr. Miller be copied into the record as if given orally from the stand, and that his exhibits be marked for identification as prefiled.

CHAIR MITCHELL: That motion will be allowed.

(Whereupon, the prefiled direct, as corrected, supplemental, as corrected, rebuttal, and Stipulation testimony of Robert E. Miller were copied into the record as if given orally from the stand.)

(Whereupon, Company REM-1, Company Supplemental Exhibit REM-1, Company Rebuttal Exhibit REM-1, and Company Stipulation Exhibit REM-1 were identified as premarked.)

**DIRECT TESTIMONY
OF
ROBERT E. MILLER
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562**

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

A. My name is Robert E. Miller, and my business address is 701 East Cary Street, Richmond, Virginia 23219. I am a Regulatory Analyst III for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company"). A statement of my background and qualifications is attached as Appendix A.

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

A. I am responsible for the preparation of cost of service studies, distribution allocation factors, and minimum system analysis.

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 will describe those studies, as well as the minimum system analysis and distribution cost allocation factors that contribute to the development of the cost of service studies.

Q. In your testimony, will you be introducing any exhibits?

A. Yes. I am sponsoring Company Exhibit REM-1, which consists of Schedules 1 through 6. This exhibit was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. Schedules 1 through 6 provide and summarize information filed in Item 45 of Form E-1.

Q. Please explain the purpose of cost allocation and how costs are allocated in preparing the cost of service studies.

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").

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.

In general, 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.

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

A. In preparing the cost of service studies, an 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.

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's 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 and 44), etc., for the respective functions. The methodology to calculate production demand (Factor 1) and transmission demand (Factor 2) are explained in the testimony of Company Witness Paul B. Haynes. 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.

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, the calculation of which is described in the testimony of Company Witness Haynes.

Q. What method has been used to allocate production and transmission fixed costs in the Company's jurisdictional cost of service and customer class cost of service studies 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 six general rate cases, Docket Nos. E-22, Sub 273 (1983), Sub 314 (1990), Sub 333 (1992), Sub 459 (2010), Sub 479 (2012), and Sub 532 (2016), and in the Commission's 2004 general rate investigation, Docket No. E-22, Sub 412. Most recently, the Commission determined in the December 22, 2016 *Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Condition* (the "2016 Rate Order") that "[t]he SWPA cost of service methodology, as adjusted by DNCP to account for the peak demand contribution of distribution-connected NUGS, is appropriate for determining the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility." (2016 Rate Order, Page 16, Finding of Fact No. 37)

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. Was a specific allocation method, such as SWPA, used with respect to distribution costs?

A. No. As the Company has done in prior cases, distribution plant and related expenses were allocated on class peak demands, class non-coincident peak demands, and the number of customers at the different distribution voltages.

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-foot pole. The Company has a massed item file that provides both historic cost information for the combined number of 35-foot 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-foot 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.

Q. Please summarize the results of DENC's Cost of Service Studies.

A. Company Exhibit REM-1, Schedule 1 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, 2018 ("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 2018 was 6.4049%. Pages 3-4 provide the summary for all of the North Carolina customer classes.

Company Exhibit REM-1, Schedule 2 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 3 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 4 provides a summary of the information provided in Schedules 1 – 3.

Company Exhibit REM-1, Schedule 5 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 6 provides, for each component shown in Company Exhibit REM-1, Schedule 5, "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.

Q. How should the unit costs identified in your Schedule 6 be used in the development of actual rates?

A. The unit costs were provided to Company Witness Haynes 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. You stated earlier that you are sponsoring Item 45 (a – f) of the Form E-1, 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 based on the SWPA allocation method for the 12 months ended December 31, 2018 ("test year"). A summary of the results is provided in Company Exhibit REM-1, Schedule 1. All subsequent cost of service studies discussed in the following items will be based upon the SWPA allocation method for the purpose of allocating production and transmission demand-related costs.

ii) Item 45b provides "per books" jurisdiction and customer class Rate of Return Statements (Schedule 1 from the cost of service) with base rate non-fuel revenue annualized for the test year based upon rates in effect as of January 1, 2019. This information is also provided in Company Exhibit REM-1, Schedule 2.

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. A summary of the results, by jurisdiction and each class, is shown in Company Exhibit REM-1, Schedule 3.

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. A summary is provided in Company Exhibit REM-1, Schedule 5. 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 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 production allocation factor. Part B of Schedule 5 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 of Schedule 5 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. A summary is provided in Company Exhibit REM-1, Schedule 6.

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).

Q. Has the Company worked with Utilities International to develop a working Excel version of the cost of service model?

A. Yes. In Ordering Paragraph 15 of the 2016 Rate Order, the Commission directed the Company to work with Utilities International ("UI") to develop an application that would enable an intervenor or the Public Staff to perform certain UI model functionalities. The Company has completed this effort and has developed a working Excel version of the UI model into which intervenors or the Public Staff may enter their own allocation factors and see the results of such a change flow through to the end result cost of service study. This Excel model is available upon request.

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 in 2015. Mr. Miller is also a Certified Public Accountant in Virginia.

Mr. Miller joined the Customer Rates Department in 2015, beginning as a part-time 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 2018, Mr. Miller was promoted to his current position as a Regulatory Analyst III. His job duties include calculation of distribution plant related allocation factors and preparation of cost of service studies for the Company's Virginia and North Carolina regulated customers and the Company's Non-Jurisdictional customers.

SUPPLEMENTAL DIRECT TESTIMONY
OF
ROBERT E. MILLER
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

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

A. My name is Robert E. Miller, and my business address is 701 East Cary Street, Richmond, Virginia 23219. I am a Regulatory Analyst III for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. Did you provide pre-filed direct testimony in this case?

A. Yes. I submitted direct testimony on behalf of the Company ("Direct Testimony") in support of DENC's application for authority to adjust and increase its retail electric rates and charges filed on March 29, 2019 ("Application"). My Direct Testimony presented the Company's cost of service studies as filed in Item 45 (a – f) of the Form E-1 and also supported the minimum system analysis and distribution cost allocation factors that were used in the development of the cost of service studies.

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

A. The purpose of my supplemental testimony is to address corrections made to the cost of service studies ("COSS") and to update Item 45 (a – f) of the Form E-1, Rate Case Information Report – Electric Companies ("Form E-1") for these corrections, as well as relevant corrections and updates described in the supplemental testimonies of Company Witnesses Paul B. Haynes and Paul M. McLeod.

Q. In your supplemental testimony, will you be introducing any exhibits?

A. Yes. I am sponsoring Company Supplemental Exhibit REM-1, which consists of Schedules 1 through 6. This exhibit was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief. As described further below, Company Supplemental Exhibit REM-1 is intended to update and replace affected Schedules included in Company Exhibit REM-1, as filed on March 29, 2019, in support of the Application.

Q. Please discuss your COSS Updates, as presented in the Company Supplemental Exhibit REM-1 and updated Form E-1 Items.

A. My Supplemental Schedules correct or supplement information presented in my Direct Testimony Schedules as follows:

- Supplemental Schedule 1 replaces all four pages included in my Direct Testimony Schedule 1. My Supplemental Schedule 1 presents Schedule 1 for the Four Jurisdiction and North Carolina Class cost of service studies, reflecting the cost of service corrections described further below.
- Supplemental Schedule 2 replaces all eight pages included in my Direct Testimony Schedule 2. Column 1 of each page reflects the corrected cost of service study, and these updates flow through to Column 3. While the revenue amounts in Column 2 have not

changed, lines 8 through 12 reflect updates to the Uncollectibles factor, the Regulatory Fee, and the Retention Factor.

- Supplemental Schedule 3 replaces all sixteen pages included in my Direct Testimony Schedule 3. Column 1 of each page reflects the corrected cost of service study. Column 2 reflects all updates and corrections to existing accounting adjustments, as well as accounting adjustments new on supplemental filing, as described by Company Witness McLeod. Column 3 is a sum of the first two columns and thus reflects the changes made to Columns 1 and 2. Column 4 has changed to show the updated revenue requirement, using an apportionment approximation as described below. Column 5 is a sum of Columns 3 and 4 and reflects updates and corrections made to those columns.
- Supplemental Schedule 4 replaces the single page included in my Direct Testimony Schedule 4. It summarizes the information contained in Supplemental Schedules 1, 2, and 3 and reflects the corrections and updates described above.
- Supplemental Schedule 5 replaces all seven pages included in my Direct Testimony Schedule 5. The information in Part A of each page has been updated to reflect the corrections to the North Carolina Class by Unit Cost cost of service study. The information in Parts B and C flows from Supplemental Schedules 2 and 3 and thus also has been updated.

- Supplemental Schedule 6 replaces all seven pages included in my Direct Testimony Schedule 6. The information contained in this schedule reflects the corrected North Carolina Class by Unit Cost cost of service study, as well as updates to Supplemental Schedules 2 and 3.

I am also sponsoring updated Item 45 (a – f) of the Form E-1, which updates the cost of service studies for the corrections described below and for updates and corrections described by Company Witnesses Haynes and McLeod. Form E-1, Item 45 (a – e), have been updated in their entirety and replace the versions provided in the Company's direct filing. Form E-1, Item 45 (f) has been partially updated. Page 27 of this updated Item 45 (f) was inadvertently excluded from the initial filing. Pages 1-37 have been updated, with the remaining pages of Item 45 (f) being unchanged from those contained in the initial filing and the errata filed in April 2019, but included with this update filing in the interest of presenting a complete updated Item 45 (f).

Q. Explain the methodology of the revenue apportionment that supports Column 4 of Item 45 (c)/Supplemental Schedule 4.

A. Company Rate Design Witness Paul Haynes did not perform an updated apportionment calculation for the supplemental filing; however, in order to complete the updated Item 45 (c – e), it is necessary to apportion the updated revenue requirement calculated by Company Witness Paul McLeod. As such, I have approximated a revenue requirement apportionment with the goal of having each class's index (as calculated in box 4 of my Supplemental

Schedule 4) equal to the indices shown in box 4 of my Direct Testimony Schedule 4. This method is used only to update Item 45 (c – e) and does not reflect an update by the Company in its apportionment methodology from the direct filing. The Company will prepare an updated revenue apportionment as part of its Rebuttal Filing.

Q. What were the corrections made to the cost of service studies?

A. There were five changes that impacted the North Carolina Jurisdictional amounts and the North Carolina Class amounts of the cost of service studies. The first is the correction made to Allocation Factor 2, as detailed in the Supplemental Testimony of Company Witness Haynes.

The second change corrected Allocation Factor 103D, which, in the cost of service study included in the Company's direct filing (Item 45 (a), page 63, line 112), allocated 99.1699% to the North Carolina Jurisdiction. The correct allocation percentage for the North Carolina Jurisdiction is 99.1013%.

The third change deals with the line named "456 Other Revenues – Wires", which is line 59 of Schedule 2 of the cost of service studies, located in Item 45 (a), pages 4 and 97 of the Company's direct filing (pages 4 and 96 of Item 45 (a) in the Company's supplemental filing). This FERC account includes revenues in the amount of $13,549,226 related to the Company's Private Military customer class (which is part of the Virginia Non Jurisdictional column of the cost of service study filed in Item 45 (a)), and these revenues were mistakenly allocated to all jurisdictions and customer classes using the Total Distribution Plant allocation factor. These revenues should have been directly assigned to the Private Military customer class. In the revised cost of service studies included in Item 45 of the Company's supplemental filing, these revenues are located on a separate line (line 60 of Schedule 2) and are directly assigned to the Private Military customer class.

The fourth change deals with the correction of the allocation factor used to allocate DSM/EE related tax items located on Schedules 6, 7, and 23 of the cost of service studies. Most of these DSM/EE related tax items were correctly allocated on Allocation Factor A5 Tax, but one item on each of these three schedules was incorrectly allocated on a different factor. On Schedule 6, line 73, "Reg Liab – DSM A5 – Current" (Item 45 (a), pages 23 and 117 in the Company's direct filing; pages 23 and 116 in the Company's supplemental filing), Allocation Factor 70 was initially used, which over-allocated the amount to Virginia Non-Juris customers and thus under-allocated amounts to the Virginia Juris and North Carolina Juris customers at the Four Jurisdiction level and additionally over-allocated amounts to Schedule NS, 6VP, Street & Outdoor Lighting, and Traffic Lighting customers at the North Carolina class level. On Schedule 7, line 137, "Reg Liab – A5 DSM – Current" (Item 45 (a), pages 32 and 126 in the Company's direct filing; pages 32 and 125 in the Company's supplemental filing), Allocation Factor 1 was initially used, which over-allocated amounts to Virginia Non-Juris and FERC customers and thus under-allocated amounts to the Virginia Juris and North Carolina Juris customers at the Four Jurisdiction level and additionally over-allocated amounts to Schedule NS, 6VP, Street & Outdoor Lighting, and Traffic Lighting customers at the North Carolina class level. On

Schedule 23, line 168, "Reg Liab – A5 Rec Costs VA – NonCurrent" (Item 45 (a), pages 87 and 179 in the Company's direct filing; pages 86 and 178 in the Company's supplemental filing), Allocation Factor 1RR was initially used, which did not allocate any amounts to North Carolina Juris customers. All three lines have been corrected to allocate using Allocation Factor A5 Tax.

The fifth change deals with the correction of the allocation factor used to allocate the Capitalized Interest tax items located on Schedule 6 (line 160; Item 45 (a), pages 26 and 120 in the Company's direct filing; pages 26 and 119 in the Company's supplemental filing), Schedule 7 (line 38; Item 45 (a), pages 30 and 124 in the Company's direct filing; pages 30 and 124 in the Company's supplemental filing), and 23 (line 63; Item 45 (a), pages 85 and 177 in the Company's direct filing; pages 84 and 176 in the Company's supplemental filing) of the cost of service studies. In the direct filing, the Total Plant allocation factor was used to allocate each of these lines; however, on review, the Company determined that this allocation factor did not accurately reflect the functional make-up of the Capital Interest item. A new allocation factor, Total CWIP Excluding AFC & Nuclear Fuel, was created and used to allocate the amounts on this line on Schedules 6 and 23, as well as a portion of the amount on Schedule 7.

On the remaining portion of the Capitalized Interest line on Schedule 7, the Company's tax department was able to provide a more detailed functional breakout of this amount and based on this functional detail, the Company was able to refine the allocation of this line by using appropriate allocation factors for each function. On all three schedules, the changes to Capitalized Interest decreased the amount allocated to North Carolina Juris at the Four Jurisdiction level. At the North Carolina class level, these changes resulted in lower amounts allocated to the Residential, SGS, Street & Outdoor Lighting, and Traffic Lighting customer classes and increased amounts allocated to the LGS, Schedule NS, and 6VP customer classes.

Q. What was the overall effect of the corrections made to the cost of service studies?

A. In total, the corrections described above resulted, at the North Carolina Jurisdiction level, in an increase in Adjusted Net Operating Income of $10,609 and a decrease in Rate Base of $261,559. Table 1 shows the effects of the corrections on Adjusted Net Operating Income and Rate Base for each customer class.

Table 1 - Effect of Cost of Service Corrections on Adjusted Net Operating Income and Rate Base for North Carolina Classes

	North Carolina Juris Total	Residential	SGS, Co. & Muni	LGS	Sched. NS	6VP	St. & Outdoor Lighting	Traffic Lighting
Adjusted NOI on Company Supplemental Filing	$ 76,357,144	$ 40,860,712	$ 17,616,144	$ 8,721,262	$ 5,683,186	$ 2,869,858	$ 594,375	$ 11,607
Adjusted NOI on Company Direct Filing	$ 76,346,536	$ 40,514,010	$ 17,647,197	$ 8,853,108	$ 5,923,247	$ 2,926,734	$ 470,978	$ 11,261
Change in Adjusted NOI (Supplemental - Direct)	$ 10,609	$ 346,702	$ (31,053)	$ (131,847)	$ (240,061)	$ (56,875)	$ 123,397	$ 347
Rate Base on Company Supplemental Filing	$ 1,191,741,713	$ 638,478,788	$ 217,680,826	$ 131,715,939	$ 131,556,266	$ 51,176,698	$ 20,965,715	$ 167,482
Filing	$ 1,192,003,271	$ 638,748,022	$ 217,687,705	$ 131,695,008	$ 131,516,154	$ 51,174,640	$ 21,014,087	$ 167,656
Change in Rate Base (Supplemental - Direct)	$ (261,559)	$ (269,234)	$ (6,878)	$ 20,930	$ 40,112	$ 2,057	$ (48,373)	$ (174)

Q. Please compare the fully adjusted cost of service study results from Item 45 (c) of the Company's direct filing to those of Item 45 (c) of the Company's supplemental filing.

A. Table 2 below indicates the adjusted net operating income, the rate base, the rate of return, and the rate of return index for each North Carolina customer class on both the direct filing and the supplemental filing. This information is taken from Item 45 (c), Column 3, and also appears in my Direct Testimony Schedule 3/Supplemental Schedule 3 and Direct Testimony Schedule 4/Supplemental Schedule 4.

Table 2 - Effect of Corrections and Updates to Item 45c, Column 3 of Supplemental Filing, Compared to Item 45c, Column 3 of Direct Filing

	North Carolina Juris Total	Residential	SGS, Co. & Muni	LGS	Sched. NS	6VP	St. & Outdoor Lighting	Traffic Lighting
Adjusted NOI - Supplemental Filing - Item 45c, Col. 3	$ 71,754,815	$ 34,670,588	$ 16,293,918	$ 10,362,759	$ 6,007,532	$ 3,666,815	$ 742,136	$11,068
Adjusted NOI - Direct Filing - Item 45c, Col. 3	$ 69,365,687	$ 32,405,759	$ 15,993,242	$ 10,488,613	$ 6,316,439	$ 3,720,841	$ 430,196	$ 10,597
Change in Adjusted NOI (Supplemental - Direct)	$ 2,389,128	$ 2,264,829	$ 300,676	$ (125,854)	$ (308,907)	$ (54,026)	$ 311,941	$ 471
Rate Base - Supplemental Filing - Item 45c, Col. 3	$ 1,147,952,571	$ 621,924,135	$ 209,429,317	$ 124,481,177	$ 121,817,822	$ 48,186,478	$ 21,947,335	$166,305
Rate Base - Direct Filing - Item 45c, Col. 3	$ 1,141,681,026	$ 614,757,351	$ 208,595,666	$ 125,297,474	$ 123,703,740	$ 48,643,229	$ 20,521,579	$ 161,988
Change in Rate Base (Supplemental - Direct)	$ 6,271,544	$ 7,166,784	$ 833,652	$ (816,297)	$ (1,885,918)	$ (456,750)	$ 1,425,756	$ 4,317
ROR - Supplemental Filing - Item 45c, Col. 3	6.2507%	5.5747%	7.7802%	8.3248%	4.9316%	7.6096%	3.3814%	6.6552%
ROR - Direct Filing - Item 45c, Col. 3	6.0758%	5.2713%	7.6671%	8.3710%	0.051061	0.076492	0.020963	0.065421
Change in ROR (Supplemental - Direct)	0.1749%	0.3034%	0.1131%	-0.0462%	-0.1745%	-0.0396%	1.2851%	0.1131%
ROR Index - Supplemental Filing - Item 45c, Col. 3		0.89	1.24	1.33	0.79	1.22	0.54	1.06
ROR Index - Direct Filing - Item 45c, Col. 3		0.87	1.26	1.38	0.84	1.26	0.35	1.08
Change in ROR Index (Supplemental - Direct)		0.02	(0.02)	(0.05)	(0.05)	(0.04)	0.19	(0.02)

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

REBUTTAL TESTIMONY
OF
ROBERT E. MILLER
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

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 Regulatory Analyst III for Virginia Electric and Power Company, which operates in North Carolina as Dominion Energy North Carolina ("DENC" or the "Company").

Q. **Did you provide pre-filed direct testimony in this case?**

A. Yes. My pre-filed Direct Testimony on behalf of the Company was submitted to the North Carolina Utilities Commission (the "Commission" or "NCUC") in this matter on March 29, 2019, and my pre-filed Supplemental Direct Testimony was submitted on August 5, 2019.

Q. **What is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to address the testimonies of Carolina Industrial Group for Fair Utility Rates I ("CIGFUR") Witness Nicholas Phillips, Jr., Nucor Steel-Hertford ("Nucor") Witness Paul J. Wielgus, and Nucor Witness Jacob M. Thomas, regarding issues related to the cost of service study.

Q. In your rebuttal testimony, will you be introducing any exhibits?

A. Yes. I am sponsoring Company Exhibit REM-1, which consists of Rebuttal Schedules 1 through 4. This exhibit was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Q. With regard to the cost of service study, please identify and summarize the issues raised by CIGFUR and NUCOR that you will address in your rebuttal testimony.

A. My Rebuttal Testimony responds to the arguments and recommendations of CIGFUR and NUCOR as follows:

- CIGFUR Witness Phillips recommends a Summer/Winter Coincident Peak ("SWCP") allocation methodology. Company Witness Haynes addresses the allocation methodology in his Rebuttal Testimony; I have prepared a cost of service study using SWCP allocation factors and additionally updated the ratemaking adjustments described by Company Witness Paul McLeod in his supplemental testimony to reflect how these adjustments would flow to the North Carolina classes under the SWCP methodology.
- NUCOR Witness Thomas prepared analysis based on a Single Coincident Peak ("1 CP") allocation methodology, a 60% Demand Weighting Summer/Winter Peak and Average ("SWPA") allocation methodology, and a 50% Demand Weighted SWPA allocation methodology. Company Witness Haynes addresses these allocation methodologies in his Rebuttal Testimony; I have prepared cost of

service studies using allocation factors developed through each of these three allocation methodologies and additionally updated the ratemaking adjustments described by Company Witness Paul McLeod in his supplemental testimony to reflect how these adjustments would flow to the North Carolina classes under each of these three allocation methodologies.

Q. Can you describe how you prepared cost of service studies to analyze the various alternative allocation methodologies proposed by CIGFUR and Nucor?

A. For each of the SWCP method, the 1CP method, the 60% Demand Weighted SWPA method, and the 50% Demand weighted SWPA method, Company Witness Haynes prepared a set of allocation factors. I then ran each set of factors through the Company's UI Cost of Service model to produce a Four Jurisdiction cost of service study and a North Carolina Classes cost of service study. These studies were then used to update the ratemaking adjustments described by Company Witness McLeod so that the adjustments would reflect the use of the alternative allocation methodology. No other changes to the adjustments were made. Using the alternative method cost of service studies and ratemaking adjustments, I produced a fully adjusted cost of service study comparable to my Supplemental Schedule 3 (Item 45c), with a summary schedule comparable to my Supplemental Schedule 4.

Q. Please compare the fully adjusted cost of service study results from Item 45c of the Company's supplemental filing to those of the alternative allocation methodologies proposed by CIGFUR and Nucor.

A. Table 1 below indicates, for column 3 of the fully adjusted cost of service studies presented in my Supplemental Schedule 3 and my Rebuttal Schedules 1 through 4, the adjusted net operating income, the rate base, the rate of return, and the rate of return index for each North Carolina customer class as shown in the Company's supplemental filing and as based on each of the four alternative allocation methodologies mentioned above. My Rebuttal Schedules 1, 2, 3, and 4 show, in summary and in detail, the fully adjusted cost of service study results for each of the 1 CP methodology, the SWCP methodology, the SWPA 60% Demand Weighted methodology, and the SWPA 50% Demand Weighted methodology respectively. As Table 1 demonstrates, the different allocation methodologies have a substantial impact on the class RORs. Under allocation methodologies that give demand more weight, the residential class has a lower ROR, ranging from 1.9407% under the 1 CP method (100% demand) to 5.5747% under the Company's SWPA method (41.0855% demand for the test period). All other classes have RORs increase as demand weighting increases, with the Schedule NS class having the most extreme ranges, going from 4.9316% under the Company's SWPA method to 28.5179% under the 1 CP method.

Table 1 - Fully Adjusted Cost of Service Results Under Different Allocation Methodologies - Prior to Revenue Increase

Adjusted NOI (Fully Adjusted, Before Revenue Increase)	North Carolina Juris Total	Residential	SGS, Co. & Muni	LGS	Sched. NS	6VP	St. & Outdoor Lighting	Traffic Lighting
Company Supplemental Filing	$ 71,754,815	$ 34,670,588	$ 16,293,918	$ 10,362,759	$ 6,007,532	$ 3,666,815	$ 742,136	$ 11,068
1 CP Methodology	$ 67,910,566	$ 15,922,132	$ 18,646,831	$ 14,303,015	$ 13,058,565	$ 4,989,730	$ 977,114	$ 13,178
SWCP Methodology	$ 74,626,547	$ 25,719,907	$ 17,247,101	$ 13,066,596	$ 12,622,078	$ 4,981,512	$ 976,197	$ 13,156
SWPA 60% Demand Methodology	$ 72,666,477	$ 31,701,302	$ 16,601,629	$ 11,250,000	$ 8,183,966	$ 4,098,647	$ 819,203	$ 11,730
SWPA 50% Demand Methodology	$ 72,203,753	$ 33,282,737	$ 16,442,441	$ 10,782,913	$ 7,034,783	$ 3,871,085	$ 778,395	$ 11,399

Rate Base (Fully Adjusted, Before Revenue Increase)	North Carolina Juris Total	Residential	SGS, Co. & Muni	LGS	Sched. NS	6VP	St. & Outdoor Lighting	Traffic Lighting
Company Supplemental Filing	$ 1,147,952,571	$ 621,924,135	$ 209,429,317	$ 124,481,177	$ 121,817,822	$ 48,186,478	$ 21,947,335	$ 166,305
1 CP Methodology	$ 1,184,659,294	$ 820,420,446	$ 183,357,788	$ 81,749,055	$ 45,790,817	$ 33,821,866	$ 19,376,244	$ 143,077
SWCP Methodology	$ 1,117,238,596	$ 718,075,389	$ 199,240,961	$ 95,473,886	$ 50,811,599	$ 34,077,239	$ 19,415,643	$ 143,878
SWPA 60% Demand Methodology	$ 1,138,220,549	$ 653,571,083	$ 206,159,774	$ 115,030,996	$ 98,615,709	$ 43,584,392	$ 21,099,420	$ 159,175
SWPA 50% Demand Methodology	$ 1,142,739,461	$ 636,364,686	$ 207,782,533	$ 119,991,320	$ 110,896,753	$ 46,006,684	$ 21,534,814	$ 162,671

ROR (Fully Adjusted, Before Revenue Increase)	North Carolina Juris Total	Residential	SGS, Co. & Muni	LGS	Sched. NS	6VP	St. & Outdoor Lighting	Traffic Lighting
Company Supplemental Filing	6.2507%	5.5747%	7.7802%	8.3248%	4.9316%	7.6096%	3.3814%	6.6552%
1 CP Methodology	5.7325%	1.9407%	10.1696%	17.4962%	28.5179%	14.7530%	5.0428%	9.2104%
SWCP Methodology	6.6796%	3.5818%	8.6564%	13.6860%	24.8409%	14.6183%	5.0279%	9.1441%
SWPA 60% Demand Methodology	6.3842%	4.8505%	8.0528%	9.7800%	8.2988%	9.4039%	3.8826%	7.3694%
SWPA 50% Demand Methodology	6.3185%	5.2301%	7.9133%	8.9864%	6.3435%	8.4142%	3.6146%	7.0073%

ROR Index (Fully Adjusted, Before Revenue Increase)	Residential	SGS, Co. & Muni	LGS	Sched. NS	6VP	St. & Outdoor Lighting	Traffic Lighting
Company Supplemental Filing	0.89	1.24	1.33	0.79	1.22	0.54	1.06
1 CP Methodology	0.34	1.77	3.05	4.97	2.57	0.88	1.61
SWCP Methodology	0.54	1.30	2.05	3.72	2.19	0.75	1.37
SWPA 60% Demand Methodology	0.76	1.26	1.53	1.30	1.47	0.61	1.15
SWPA 50% Demand Methodology	0.83	1.25	1.42	1.00	1.33	0.57	1.11

Q. What are the implications for the revenue increase for the North Carolina Classes?

A. As described above, the cost of service studies prepared using these alternative allocation methodologies were used to update the ratemaking adjustments that Company Witness McLeod describes in his supplemental testimony. By performing these adjustments, an approximate revenue requirement can be reached for each allocation methodology. I have used these revenue requirements as an approximation for the revenue increase that would be necessary based on the cost of service studies resulting from the different allocation methodologies, with all other assumptions being equal to the Company's supplemental filing. These revenue requirements do not necessarily represent the actual revenue requirements were the Company to support one of these alternate allocation methodologies, but they offer a reasonable grounds for comparison as to how the different allocation methodologies would impact each class. Table 2, below, shows the revenue increase necessary for each class to come to an ROR index equal to those arrived at in the Company's supplemental filing (or almost equal, as the LGS class under the SWCP, the SWPA 60% Demand Weighted, and the SWPA 50% Demand Weighted is slightly under at an ROR index of 1.12, and the SGS class under SWCP is slightly under at an ROR index of 1.14). Company Witness Haynes discusses in greater detail the various revenue shifting issues stemming from the different methodologies in his Rebuttal Testimony.

Q. Do you have any other comments about the methodology Nucor Witness Thomas used to develop the cost of service studies referenced in his testimony?

Table 2 - Revenue Increases Necessary to Bring ROR Index Equal to Those in Company Witness Miller's Supplemental Schedule 4

Base Rate Non-Fuel Revenue Increase	North Carolina Juris Total	Residential	SGS, Co. & Muni	LGS	Sched. NS	6VP	St. & Outdoor Lighting	Traffic Lighting
Company Supplemental Filing	$ 24,879,359	$ 17,456,367	$ 3,513,449	$ 893,759	$ 2,308,306	$ 324,837	$ 379,083	$ 3,558
1 CP Methodology	$ 34,118,297	$ 63,192,746	$ (2,784,965)	$ (9,481,686)	$ (13,689,282)	$ (3,014,183)	$ (102,461)	$ (1,871)
SWCP Methodology	$ 17,622,375	$ 38,877,396	$ 854,865	$ (6,267,922)	$ (12,725,429)	$ (3,009,040)	$ (105,646)	$ (1,849)
SWPA 60% Demand Methodology	$ 22,577,679	$ 24,674,496	$ 2,650,995	$ (1,481,508)	$ (2,701,688)	$ (782,774)	$ 216,341	$ 1,817
SWPA 50% Demand Methodology	$ 23,700,472	$ 20,812,514	$ 3,087,833	$ (237,981)	$ (64,151)	$ (201,816)	$ 301,395	$ 2,678

ROR (After Revenue Increase)	North Carolina Juris Total	Residential	SGS, Co. & Muni	LGS	Sched. NS	6VP	St. & Outdoor Lighting	Traffic Lighting
Company Supplemental Filing	7.8264%	7.6293%	8.9880%	8.8155%	6.2983%	8.0705%	4.6557%	8.2269%
1 CP Methodology	7.8264%	7.6126%	8.9975%	8.8425%	6.2972%	8.0944%	4.6476%	8.2289%
SWCP Methodology	7.8263%	7.5726%	8.9494%	8.7945%	6.2623%	8.0512%	4.6230%	8.1853%
SWPA 60% Demand Methodology	7.8264%	7.6240%	8.9736%	8.7885%	6.2351%	8.0386%	4.6380%	8.2039%
SWPA 50% Demand Methodology	7.8264%	7.6290%	8.9808%	8.8003%	6.2651%	8.0525%	4.6466%	8.2146%

ROR Index (After Revenue Increase)	Residential	SGS, Co. & Muni	LGS	Sched. NS	6VP	St. & Outdoor Lighting	Traffic Lighting
Company Supplemental Filing	0.97	1.15	1.13	0.80	1.03	0.59	1.05
1 CP Methodology	0.97	1.15	1.13	0.80	1.03	0.59	1.05
SWCP Methodology	0.97	1.14	1.12	0.80	1.03	0.59	1.05
SWPA 60% Demand Methodology	0.97	1.15	1.12	0.80	1.03	0.59	1.05
SWPA 50% Demand Methodology	0.97	1.15	1.12	0.80	1.03	0.59	1.05

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A. Yes. Based on the workpapers provided by Nucor, it appears that Mr. Thomas updated Factor 1 and other allocation factors derived from Factor 1 (Factor 1NUC, Factor 50, Factor 61, Factor 70, Factor 81, Factor 82, Factor 83, Factor 91, Factor 101, and Factor 161); however, Mr. Thomas does not appear to have updated Factor 2 or its derivatives, meaning that the cost of service studies he presents are based on an allocation methodology that uses one of the three allocation methodologies he analyzed (1 CP, 60% Demand Weighted SWPA, 50% Demand Weighted SWPA) to allocate production costs but that still uses the Company's SWPA methodology to allocate transmission costs. This blended methodology does not fully show the impacts of Mr. Thomas' proposed allocation changes, whereas the cost of service studies that the Company has prepared as part of its rebuttal filing do show the full impact of these changes.

Another issue is that Mr. Thomas developed his cost of service studies and his calculations of the ratemaking adjustments based on the Company's direct filing. Mr. Thomas also does not adjust the ratemaking adjustments at the North Carolina Jurisdictional level as would have been appropriate under each of the different allocation methodologies. My Rebuttal Schedules 1 through 4 reflect the Company's supplemental filing updates of August 5, 2019 and carry the effects of the allocation methodology through to the ratemaking adjustments in addition to the cost of service.

Finally, Mr. Thomas's calculations contain some rounding errors causing slight over or under calculations within the cost of service study (most notably, under his version of the SWPA 60% Demand Weighted methodology, his Four Jurisdiction Factor 1 totals 100.0001% and his North Carolina Class Factor 1 totals 99.9999%).

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

TESTIMONY
OF
ROBERT E. MILLER
IN SUPPORT OF AGREEMENT AND STIPULATION OF SETTLEMENT
ON BEHALF OF
DOMINION ENERGY NORTH CAROLINA
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-22, SUB 562

Q. **Please state your name, business address, and position with Virginia Electric and Power Company.**

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

Q. **Have you previously submitted testimony in this proceeding?**

A. Yes. I pre-filed Direct, Supplemental Direct, and Rebuttal Testimony in support of DENC's Application in this matter. My testimony has addressed the Company's cost of service studies, distribution allocation factors, and minimum-system analysis.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to support the Agreement and Stipulation of Settlement ("Stipulation") as filed today by the Public Staff – North Carolina Utilities Commission ("Public Staff") and agreed to between DENC and the Public Staff (together, the "Stipulating Parties"). Specifically, my testimony in support of the Stipulation addresses cost of service issues agreed upon in the Stipulation.

Q. **Are you sponsoring any exhibits with your testimony?**

A. Yes. I am sponsoring Company Stipulation Exhibit REM-1, which consists of Company Stipulation Schedules 1 through 6. 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 your Company Stipulation Schedules 1 through 4.**

A. My Company Stipulation Schedule 1, pages 1-4, provides a summary of the fully distributed "per books" jurisdictional and customer class cost of service studies based on the Summer/Winter Peak and Average ("SWPA") allocation method, the allocation methodology agreed to in the Stipulation. Note that there has been no change in this schedule when compared to my Supplemental Schedule 1 (pages 1-4), which was filed on August 5, 2019.

My Company Stipulation Schedule 2, pages 1-8, provides the effects of annualizing the base rate non-fuel revenues for each customer class. Again, there has been no change in this schedule when compared to my Supplemental Schedule 2 (pages 1-8).

My Company Stipulation Schedule 3 (pages 1-16), presents an updated fully adjusted cost of service study showing the effects of all adjustments and rate changes to the North Carolina classes. I explain below the specific changes made to this schedule when compared to my Supplemental Schedule 3.

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My Company Stipulation Schedule 4 (pages 1 and 2) summarizes my Company Stipulation Schedules 1 through 3.

My Company Stipulation Schedule 5 (pages 1-7) provides, for each customer class, the customer, demand, and energy related classifications and functions based on per books, annualized revenues, and proposed revenues (inclusive of the change in fuel revenue) in this proceeding. This schedule carries the updates to the fully adjusted cost of service shown in my Company Stipulation Schedule 3 through to Part C of each page. Parts A and B for each page are unchanged from my Supplemental Schedule 5.

My Company Stipulation Schedule 6 (pages 1-7) provides, for each component shown in Company Stipulation Exhibit REM-1, Schedule 5, "unit costs" for each class based on annualized base non-fuel rate revenue, fully adjusted base non-fuel rate revenues, and proposed base non-fuel rate revenues at an equalized rate of return. This schedule carries the updates to the fully adjusted cost of service and stipulated revenue requirement, as shown in my Company Stipulation Schedule 3, through to Part C and Part D, respectively, of each page. Parts A and B for each page are unchanged from my Supplemental Schedule 6.

I am also sponsoring updated Item 45 (c – e) of the Form E-1, Rate Case Information Report – Electric Companies ("Form E-1"), which reflect the ratemaking adjustments and revenue requirement at the levels agreed to in the Stipulation. Form E-1, Item 45 (c and e), have been updated in their entirety and replace the versions provided in the Company's supplemental filing. Form E-1, Item 45 (d) has been partially updated, with the updated Item 45 (d) replacing pages 1 through 7 of the Item 45d from the Company's supplemental filing.

Q. Have you made specific updates to your schedules reflective of the terms of the Stipulation?

A. Yes. My Company Stipulation Schedule 3 reflects the accounting adjustments, the base non-fuel revenue increase, and the base fuel revenue decrease at the levels agreed to in the Stipulation. In order to reflect the Stipulation, the amounts in columns 2 and 4 of this schedule have changed when compared to the amounts shown in my Supplemental Schedule 3. The amounts in columns 3 and 5, which are the results of addition of the two columns prior, have also changed. Additionally, as part of the Stipulation, the Company has accepted Public Staff Witness Jack Floyd's recommendation that the base fuel revenue decrease also be examined when considering the revenue apportionment to the classes. The proposed changes to base fuel revenues and expenses are now reflected in the fully adjusted cost of service study, where they are shown in column 6 of my Company Stipulation Schedule 3.

In addition, my Company Stipulation Schedule 4 now has two additional boxes: one showing the effects of the changes in base fuel revenues and expenses; and another showing the effect of all accounting adjustments and revenue changes, including base fuel revenue and expense changes. Part C of my Company Stipulation Schedule 5 also reflects the inclusion of the base fuel revenue change.

With regard to the base fuel changes, my Company Stipulation Schedule 3 shows a different presentation that Company Witness Paul McLeod's Company Stipulation Schedule 1. My Company Stipulation Schedule 3 shows separately, in Column 6, the effects of the decrease in proposed base fuel revenues and the corresponding decrease in base fuel expenses, whereas Company Witness McLeod's Company Stipulation Schedule 1 includes the expected decrease in base fuel expenses that results in the requirement to decrease base fuel revenues in its Column 4 and the subsequent decrease in base fuel revenues in its Column 6. By handling both the base fuel expense decrease and revenue decrease in the same separate column, the amounts shown in Column 3 of my Company Stipulation Schedule 3 are reflective of the base fuel revenues and the base fuel expenses offsetting, meaning that only the base non-fuel items impact the rate of return. As such, the class rates of return based on my Column 3 (summarized in Box 3 of my Company Stipulation Schedule 4) more accurately inform the apportionment of the base non-fuel revenue increase as agreed upon in the Stipulation. While my presentation does create some differences in the intermediate steps when compared to Witness McLeod's Company Stipulation Schedule 1, the end results, shown in Column 7 of each schedule, match.

Q. **Does this conclude your testimony in support of the Stipulation?**

A. Yes.

BY MS. KELLS:

Q Mr. Miller, do you have a summary of your testimonies?

A I do.

Q Will you please present it now?

A Certainly. Chair Mitchell and members of the Commission, good afternoon. In my direct testimony I sponsor the cost of service studies filed in Item 45 of the form E-1 Rate Case Information Report. I describe those studies, as well as the minimum system analysis and distribution cost allocation factors that contribute to the development of the cost of service studies. I also explain how the Company allocated the production and transmission plant and their related expenses using the Summer/Winter Peak and Average, or SWPA, method, which is the same methodology used in the Company's last six general rate cases. The calculation of the SWPA is described in the direct testimony of Company Witness Paul Haynes. My direct testimony exhibits provide the fully distributed "per books" jurisdictional and class cost of service studies based on SWPA allocation method for the test year, the effects of annualizing the base rate non-fuel revenues for each customer class, the fully adjusted cost of service for each class, a class unit cost cost of service study for each class, and a per book -- per unit cost information for each unit grouping of each class.

In my supplemental direct testimony I address corrections made to the cost of service studies and update Item 45 of the Form E-1 for these corrections, as well as other relevant corrections and updates described in the supplemental testimonies of Company Witnesses Paul Haynes -- or Paul McLeod and Paul Haynes.

In my rebuttal testimony I address the testimonies of CIGFUR Witness Nicholas Phillips and Nucor Witnesses Paul Wielgus and Jacob Thomas regarding issues related to the cost of service study. I prepared a cost of service study using Witness Phillips' recommended Summer/Winter Coincident Peak, or SWCP, methodology, and I prepared cost of service studies using Witness Thomas' suggested allocation methodology, specifically the single coincident peak or 1 CP allocation methodology. The SWPA allocation methodology modified to weight demand at 50 percent, and the SWPA allocation methodology modified to weight demand at 60 percent, this last method being the method recommended by Witness Wielgus. Each of these different allocation methodologies has a substantial impact on a class rate of returns. I also provide a comparison of the revenue increase necessary to each class to come to a rate of return index equal to those arrived at in the Company's supplemental filing. Finally, I note several errors with the calculations used by Witness Thomas.

In my testimony in support of the Agreement and Stipulation of Settlement I support how the Stipulation addresses cost of service issues. I also explain any changes in my schedules in Item 45 of Form E-1 from the Company's supplemental filing. The Company believes the Stipulation represents a reasonable compromise of the cost of service issues in this case, it's fair to all parties, and should be approved by the Commission.

I also support the Stipulation entered into by the Company and CIGFUR filed today in this proceeding, for the same reasons discussed in my testimony in support of the Stipulation with Public Staff. Thank you.

Q Thank you.

MS. KELLS: Witnesses are available for cross examination.

MR. XENOPOULOS: Thank you, Your Honor. Damon Xenopoulos on behalf of Nu--- Damon Xenopoulos on behalf of Nucor Steel-Hertford. Thank you.

CROSS EXAMINATION BY MR. XENOPOULOS:

Q Good afternoon, Mr. Haynes. Good afternoon, Mr. Miller.

A (Haynes) Good afternoon.

A (Miller) Good afternoon.

Q I'm going to try to keep this brief today, touch on the most salient high-level points and not run through the details of the various methodologies. You're welcome to elaborate, but that's my goal.

So as you've just related, Mr. Haynes, in your summary, in this case the Company used the Summer/Winter Peak and Average cost allocation method to allocate generation costs, and in conjunction with that method it used the system load factor to weight the Summer/Winter Peak on the one hand and average or energy components of the Summer/Winter Peak and Average method; is that correct?

A (Haynes) That -- that is correct. I will also note that we used the Summer/Winter Peak and Average to allocate transmission plant cost responsibility. And just to be clear, the weighting based upon the system load factor, which is approximately 59 percent, is applied to the average component based upon energy. The peak demand component is weighted by one minus the system load factor, so that's weighted by about 41 percent.

Q Thank you. So Mr. Haynes, in other words, given the 59 versus 41 percent weightings you just mentioned, the energy component that you've used is weighted more heavily or plays a more significant role in your allocation than the -- than the coincident peak component which, as you said, is weighted at 41 percent rather than the energy component which you just said is weighted at 59 percent?

A Yes. That is because the system load factor is not a judgmental application of a weighting. That weighting is based upon empirical evidence based upon how our customers use our generation and transmission systems throughout the year based upon their energy consumption over 8,760 hours of the year. Our generation fleet and that transmission system have to serve peak demand the two hours of the year when load is the highest, one in the summer, one in the winter, but it also has to perform efficiently in the other 8,758 hours of the year.

So it is appropriate to weight that average component based upon the energy usage divided by the hours in the year to determine the average demand and then dividing that by the peak demand because that's how customers actually use our system and that's how our generation units perform during the year to meet our service obligation to customers. They don't -- our generation units are not there just to meet peak demand. They have to perform in a least cost manner efficiently throughout the year. And the same is true of the transmission system.

Q Thank you, Mr. Haynes. Mr. Haynes, you're aware of the fact that this Commission approves the use of the so-called 1 CP cost allocation method for purposes of allocating generation cost in the Duke cases in this state, are you?

A Yes. I believe I found out during the course of the proceeding that both of the Duke companies use 1 CP, and I may have testified at some point or answered a discovery response that I was only aware that one did. My belief is that the Commission weighs the evidence in each utility's general rate case proceedings to determine the allocation method for transmission and plant cost -- production plant cost that are appropriate for that particular utility and its customers and how they use electricity.

I'm asking you in this proceeding to consider how our customers use electricity and determine what the appropriate method is for us. I'm not trying in any way to say that the Commission's determination and judgment in another proceeding for another utility is not correct. I'm just asking you to examine the use of our system by our customers and weigh that in making the appropriate determination of the allocation factor that should be used for Dominion Energy North Carolina.

Q Mr. -- thank you, Mr. Haynes. Mr. Haynes, you're aware that with the 1 CP cost allocation method energy is not taken into account. The allocation is based exclusively on coincident peak; is that correct?

A That's correct. The one hour of the year when load is the highest is used to allocate all of the production and transmission and plant costs.

Q Okay. So in the Duke cases the Commission does not take energy into account in the allocation of generation plant costs, and I assume that you would not say that it's because Duke Energy customers do not use energy; is that correct?

A Yes. That would be correct.

Q Okay.

A They use energy.

Q Yeah. Those customers use energy, too, and yet no energy is taken into account in allocating the generation plant costs in the Duke cases.

Would you agree that the 1 CP cost allocation method is a well-recognized method outside of North Carolina as well?

A I'm not familiar outside of North Carolina. In other states other than in Virginia we do not use the 1 CP method to allocate production and transmission cost to our Virginia jurisdictional customers. We use a method called Average and Excess that recognizes peak demand, but also energy usage throughout the year, and it is a method while not exactly the same as the Summer/Winter Peak and Average, it's similar in that it does recognize customers' usage of energy throughout the year in the calculation of the allocation of production and transmission cost.

Q Are you aware that the NARUC Cost Allocation Manual recognizes 1 CP as a valid cost allocation method?

A Yes.

Q Are you aware that Nucor Steel-Hertford supports the 1 CP cost allocation method for purposes of Dominion Energy North Carolina cases?

A Yes. You are -- advocate. Your witnesses did advocate that. They also made another proposal with regard to another method, a Modified Summer/Winter Peak and Average method.

Q The Company is -- the Company is behind PJM, the RTO PJM, is it not?

A Yes.

Q Are you aware of the fact that PJM allocates production plant cost based on a 5 Coincident Peak method?

A I'm not -- I'm not here as an expert witness on the Company's market operations within the PJM independent system operator footprint. I am aware that for purposes of determining capacity obligation for the -- what's called a load-serving entity, which Dominion is a load-serving entity, and PJM we're serving load to retail and wholesale customers, that we -- PJM does look at the five coincident peaks during the summer months, June through September -- they can't all be on the same day, so it's five distinct days -- and determining that as one significant input in determining capacity obligation within PJM for purposes of having reliable capacity on hand and available to serve your load.

Q And thank you. And the 5 CP does not take energy consumption into account; is that correct?

A It does not.

Q And are you aware that CIGFUR's witness in this case is proposing the -- essentially a 2 CP method, being the Summer/Winter Coincident Peak method, for allocating production plant cost?

A Mr. Phillips, on behalf of CIGFUR, did advocate and discuss the Summer/Winter Coincident Peak method.

Q Also a method that does not include energy?

A That's correct. It does not. It looks at two hours of the year instead of one to allocate plant costs.

Q And would you agree that the allocation of production plant costs that results from the application of Summer/Winter Peak and Average, particularly using the system load factor, is substantially different from the allocation of production plant costs that would result from the application of a 1 CP?

A Yes. And let me talk about that for a moment. The -- if you look at a 1 CP or a Summer/Winter CP compared to our Summer/Winter Peak and Average method, effectively what this method does or these -- these two alternative methods, 1 CP and Summer/Winter CP, do is they recognize the loads only in either one hour of the year or the highest hour in the summer or winter and allocates all $19 billion of our production plant cost on the basis of those two hours.

If you consider the Summer/Winter Peak and Average method, as I have explained, it looks at all 8,760 hours during the year. So I have a table. I want to show the Commission the results of some analysis that Company Witness Miller and I conducted, and it's in my Table 3 on page 38, that I think summarizes the effect of these three methods for the Commission in a concise manner. This is Table 3 in my rebuttal testimony on page 38.

Based upon some allocation factors that I provided Company Witness Miller, he prepared a cost of service -- a fully adjusted cost of service study for the 1 CP and the Summer/Winter CP methods. I take the results of that study and compare them to the results of the Summer/Winter Peak and Average method, and I want to show you what happens here.

I want to note first the Residential class which I list at the top of the table. Under the Summer/Winter Peak and Average method, this is before any revenue increase in this is applied, so this is just what's called a fully adjusted cost of service.

The -- I'm going to talk about rates of return and rates of return indexes, but I think if you look at the rate of return index, which is just each class' rate of return divided by the jurisdictional return, that's probably the most simple thing to consider here. That rate of return index for the Residential class under a

Summer/Winter Peak and Average is .89. When you move across the -- the table to the 1 CP method, that index declines to .34, and for the Summer/Winter CP method it declines to .54.

So what is happening here is revenues have not changed. There is a shift in the allocation of cost responsibility toward the Residential Class such that the rate of return index and really the rate of return decline rather dramatically under the 1 CP and Summer/Winter CP method. So if it's declining for the Residential class, who benefits under as you move across this table?

Look at the -- the Schedule NS class, the LGS class, and the 6VP classes toward the middle. Their rate of return indexes respectively in the first column are 1.33, .79, and 1.22. In the middle column for 1 CP method their indexes go to 3.05, 4.97, and 2.57. The revenues haven't changed. The reason their rate of return indexes go up is you shifted all the cost responsibility away from them and it's gone to the Residential class.

So while I think it's deficient to use a 1 CP and a Summer/Winter CP method just on the principle that it looks at only one or two hours to allocate cost responsibility, some may feel that that's okay. I'm asking you to consider the effects of that allocation method in moving cost from certain classes toward the Residential class. I don't think, and speaking on behalf of our residential customers in North Carolina, that is a fair and reasonable proposition for our North Carolina customers.

Q Thank you, Mr. Haynes. So looking at this Table 3 that you just pointed us to, first of all, you say that the revenues haven't changed, but the loads haven't changed, and the operations haven't changed either, correct?

A That is correct.

Q Okay. And you pointed to the Residential class and indicated that as one moves from left to right, the index declines and that the industrial customers' indices increase and that the industrial customers are benefiting by virtue of the residential customers' indices declining, but I would submit to you that the -- that the indices for the industrial customers increase from left to right, and that the shifting is going in the opposite direction. The shift -- the cost shift is from the industri--- sorry -- from the residentials to the industrials using the Summer/Winter Peak and Average versus the Summer/Winter Coincident Peak or the 1 CP.

A If you -- I think you said left to right, but if you move from right to left, the cost shifts back. If you move from 1 CP to Summer/Winter Peak and Average, yes, the cost shifts from the Residential class to the LGS, Schedule NS, and 6VP classes.

Q The point being -- one of the points being here is are we talking about a cost of service or a cost allocation method that is based on cost of service or that is results oriented?

A We're talking about a decision here to establish the cost of service based upon an allocation method that best reflects how we plan for our system and how we utilize and operate our system to meet not only the load during the one or two hours of the year when it's the highest, but to provide efficient generation that can be operated throughout the course of the year to meet customer loads and our obligation in all hours.

For example, we have nuclear units. That comprises about 26 percent of our $19 billion in production plant, okay? Nuclear units are high capital cost, very low operating cost units. They run during the peak load hours, and they run -- based upon some capacity factors I saw from our fuel case they have a capacity factor of 9--- of about 95 percent. They run almost all the time of the year to provide the system with low-cost energy, low fuel cost. That satisfies the Commission's -- one of the Commission's objectives in resource planning. You want a resource mix that not only meets the peak demand, but one that operates at a least cost to provide low rates and ultimately low bills to customers.

Having -- if you're just trying to meet the peak demand and that's the sole thing that you want to do as a Commission, you wouldn't be building high capacity cost units. You would be building low capital cost units, but the problem is when you start running those units frequently throughout the year, your fuel costs go up dramatically, so instead of having a low fuel factor of around 2 cents, if you start running these low capital cost, high operating cost units, your fuel rates are going to go up dramatically. So your planning process rightly looks at not just the peak demand, but having low cost generation available to run and provide low cost energy and low cost fuel to customers throughout the year.

So a decision on an allocation method is critically important and needs to weigh both planning and operation of the system in determining what method is appropriate. And I'm telling you on behalf of the Company that I do not believe a 1 CP method or a Summer/Winter CP method is appropriate in -- in being used in a cost of service study that ultimately is used to establish rates in a general rate case proceeding. Yes, Mr. Miller.

A (Miller) I'd also like to add since you mentioned the cost of service study, one of the principles of the cost of service study is that costs are allocated to customers in a manner that reflects how those customers cause those costs to be incurred. And as Mr. Haynes described with nuclear units or other plants like that, those costs are incurred eight hundred six--- 8,760 hours a year as opposed to just one or two hours a year.

Q Thank you. Mr. Haynes, going back to your last response, you referred to the Commission's objectives, and one of them being to produce low rates and low bills. The fact is that this Commission applies the 1 CP method to the Duke companies, and so are you suggesting that the Commission's objectives do not apply to the Duke companies?

MS. KELLS: Objection. I don't think Mr. Haynes can speak to the Commission's decisions in the

Duke cases other than they are what they are.

CHAIR MITCHELL: I'll allow the question. We recognize the limitations of the witness, but --

MR. XENOPOULOS: Thank you, Your Honor.

CHAIR MITCHELL: -- please answer the question if you can.

MS. KELLS: Could you repeat the question, please?

MR. XENOPOULOS: Yeah.

Q Mr. Haynes was referring to the Commission's objectives and that in support to his contention that the 1 CP and 2 CP or the Summer/Winter Coincident Peak methods are inappropriate as applied to Dominion Energy North Carolina, and he did so, again, referring to the Commission's objectives being to produce low rates and low bills. And my question to him was is he saying or suggesting that there's a difference between the Commission's objectives as to Dominion Energy North Carolina and those as to Duke Energy or the Duke companies?

A (Haynes) No. I do not believe that the objectives are probably any different. What I was referring to is that the Commission, in the way I read a recent resource planning order pertaining to -- and the part pertaining to Dominion Energy North Carolina, was that there was reference to determining the proper mix of resources that provides to the Company's customers the least cost that would accrue to them ultimately through their bills. And what I'm saying is that this cost allocation method that you'll be making a decision about in this proceeding should consider the planning process, the way you plan our system in terms of whether we need high capital cost, low operating cost generation such as a new base load unit, or maybe we need an intermediate unit, or maybe we need a low capital cost, high operating cost peaking unit.

The planning process determines that proper mix of resources such that the least cost is the objective. And what I'm saying is the least cost translates ultimately into bills through having the best mix of capital and operating cost, that that generation can be operated to meet the peak, and throughout the course of the year to provide the system energy. And I'm saying that the selection of an allocation method should be consistent with both the planning of the system and with the operational use of the system by customers. Summer/Winter Peak and Average does that, in my opinion. The 1 CP and the Summer/Winter CP methods do not.

Once again, I can't state the factors that are considered by the Commission in evaluating the Duke companies' resource plans, but I can -- I can state to you the factors and resources that are considered with regard to the Company's, DENC's planning and operation, and that this method, Summer/Winter Peak and Average, is more appropriate than 1 CP and Summer/Winter CP.

Q Okay. Thank you, Mr. Haynes. So in this particular context we are talking about primarily the allocation of generation plant cost. This is relevant in connection with Mr. Miller's statement that essentially the Company must serve during 8,760 hours per year. But you do agree that essentially what you're doing with generation is you are serving peak load?

A Let me make this clear. We -- our service obligation to our customers is to meet peak demand. Granted, we have to have the capacity available when load is highest in the winter on a cold morning, when load is highest in that hot summer afternoon. We've got to have that capacity available. But we also have to have capacity available to meet the obligation to serve customers every single hour of the year, and what that means is having the most efficient set of generation resources that can be run to meet the peaks, but then run over all course, all hours of the year to provide the lowest cost possible to the system that ultimately translates into rates that recover those costs from customers. So it's not just meeting peak demand. It's meeting peak demand and providing the system with low cost energy throughout the course of the year that determines what types of capital investments need to be made in our facilities.

And I would add it's not just generation. There are also demand-side management, energy efficiency, and other things that weigh into that resource planning mix, but we're talking here today about production and transmission plan resources, supply-side resources.

Q Mr. Haynes, let's talk a little about the impact of Summer/Winter Peak and Average vis-à-vis an interruptible, a large interruptible load, as compared with the impact of 1 CP or a method that's based on coincident peaks only. Is it, in fact, the case that with the 1 CP or 2 CP or 5 CP where only the peak load that -- that's on the system during -- the customer's peak load that's on the system during the system's peaks is taken into account in allocating production plant costs?

A Yes. That's correct.

Q Okay. With regard to Summer/Winter Peak and Average, is it true that you're allocating production plant costs not only based on the peak we just spoke about, the peak load of the customer at the time of the system peak, but you're also allocating production plant cost based on energy consumption that is the average component of Summer/Winter Peak and Average; is that correct?

A That is correct. The peak demand component is rated -- weighted at about 41 percent or one minus the system load factor. The average component is weighted at the system load factor or about 59 percent, but that's proper. We've got $19 billion in production plant, okay? That's a lot. That plant is -- I keep saying this, but it's high capital cost, low operating cost units, all the way to low capital cost, high operating cost units.

Efficient system dispatch governs the operation of our system throughout the year such that we have capacity available to be dispatched so that generally in most hours, almost all hours, the lowest cost resource is dispatched to the system to meet our obligation each hour. As I said -- I keep saying, this minimizes the energy cost to customers, which is mostly fuel. Customers benefit by that by having lower cost fuel than they would if we didn't have a whole range of generation resources available from base load down to peak load to meet our customers' needs.

That's what establishes -- having that proper mix of resources establishes the ability to provide the least cost possible to customers. So it's appropriate to include energy in the allocation of production plant cost.

Q Thank you, Mr. Haynes. So okay, let's assume it is appropriate. I'm not agreeing that it's appropriate to include energy. Then the question becomes how much energy do you include or what weight do you give to energy versus demand? And as you mentioned earlier during the session, Nucor -- Nucor's Witness Wielgus suggested that instead of using system load factor to weight the demand versus the energy consumption, which in Dominion's case means that the energy counts for more than the demand, Wielgus suggested that the inverse be the case, that basically you use the system load factor to weight the demand and you use the one minus system load factor to weight the energy; is that right?

A Effectively. He was very close to that. He recommended a 60 percent weighting for peak demand and a 40 percent weighting for energy, but that's effectively a flipping of the weighting methodology.

Q Right. And while that would take energy into account, it would, in fact, be slightly more like a Coincident Peak method than the Summer/Winter Peak and Average using a system load factor; is that correct?

A Yes. It has that -- yes. That's a good point. It has that same effect of a 1 CP, just not as great. If you look at my rebuttal, page 42, rebuttal testimony, page 42, I have a table, Table 4, where I compare the Summer/Winter Peak and Average to a Modified Summer/Winter Peak and Average. Modified Summer/Winter Peak and Average is what Nucor Witness Wielgus proposed based upon a 60 percent peak demand weight and a 40 percent energy weight.

So the SWPA column in this table is the same as the earlier Table 3 that we looked at a few minutes ago. Here I'm comparing it to the Modified Summer/Winter Peak and Average. So what happens here? Residential, we're at .89 under Summer/Winter Peak and Average. It declines to .76. What happens on the LGS and NS Classes, 6VP? The index is 1.33, .79, 1.22 all go up to 1.53, 1.30, 1.47. Once again, customers' consumption, demand, nothing has changed, revenue hasn't changed. All you've done is through the magic of reweighting, and I will say this is a judgmental weighting, this Modified Summer/Winter Peak and Average, just by flipping the percentages you've moved plant cost responsibility from the Industrial classes to the Residential class, causing the decline in the -- in the rate of return index.

And this would shift if you -- if you had the same rates of return. Company Witness Miller provided a calculation in his Supplemental Schedule 4 which showed that this would shift about $7.2 million in -- toward -- in revenue recovery to the Residential class when you compare it to the Company's Summer/Winter Peak and Average method. So there would be more revenue recovery, thus higher rates that would be needed to be paid by the residential customers because of this judgmental weighting. I would not recommend this judgmental weighting of 60 percent/40 percent.

A (Miller) Just clarify. I think it was my --

COMMISSIONER GRAY: Use the microphone, please.

THE WITNESS: Oh, sorry.

A Just to clarify, I think it was my rebuttal Schedule 3 that showed the flip in the weighting as compared to my Supplemental Schedule 4.

Q So Mr. Haynes, Mr. Miller, thank you. So again, you refer to -- we referred to the use of the system load factor that the Company engages in, and we refer now to the inverse where we would weight demand at the system load factor and energy will average at one minus system load factor.

Now, the use of system load factor itself is, to an extent, a judgmental energy weighting, and the judgmental energy weighting is, in fact -- I think you already acknowledged, but I'll ask you now just to ensure that you agree -- judgmental energy weighting is, again, provided for or recognized as being potentially valid by the NARUC Cost Allocation Manual?

A (Haynes) I guess in the end all things could be considered a judgment, but this is a judgment that's based upon empirical evidence, actual usage of the system by our customers, actual operation of the units to meet those needs. That is the system load factor. So you could say deciding to use that in the Summer/Winter Peak and Average is judgmental. Okay. I'll accept that, but it's a judgment based upon empirical evidence, actual use of the system. I believe a -- the recommendation of Mr. Wielgus to flip that and weight the average demand by 40 percent and the peak by 60 percent does not have any basis other than judgment to support it. It's not based upon actual use of the system by customers.

Q Thank you. I'll submit to you -- just to go back to a point you made a few minutes ago, I'll submit to you that the inverse, this 60/40 demand -- sorry -- 60/40 energy demand that Mr. Wielgus has recommended is, in fact, closer to a 40/60 Summer/Winter Peak and Average allocation than it is to a 1 CP allocation. I believe you indicated that it's close to a 1 CP, but I'd like to ask you to elaborate or correct that.

A I will elaborate because you can look back at the Table 3 and Table 4. It is closer to Summer/Winter Peak and Average than the 1 CP method. That is, this Modified Summer/Winter Peak and Average is closer. It's -- if you had to choose between just 1 CP or Modified Summer/Winter Peak and Average, choose Modified Summer/Winter Peak and Average. But your choice is not limited to that. You should use Summer/Winter Peak and Average, as the Company has proposed and as Public Staff witness Floyd has supported the use of that in his testimony.

Q And then I suppose one could go to, well, you know, if one believes that energy is relevant, one -- we all agree that demand is relevant -- one might go to a Summer/Winter Peak and Average with a 50/50 because, you know, it's a judgment. So they're both relevant components. Maybe the Commission should approve Summer/Winter Peak and Average, but weight each component equally.

A I would say, first of all, this is -- this would be a new proposal from Nucor because Nucor -- while Nucor Witness Thomas evaluated a Summer/Winter Peak and Average weighted 50/50, that was not the recommendation from Mr. Wielgus on behalf of Nucor. His recommendation for using the Summer/Winter Peak and Average was to use it weighted 60 percent peak demand, 40 percent average.

But if we set that aside, I believe Company Witness Miller has some information in his rebuttal schedule that evaluated the 50/50 weighting, and we could certainly discuss that result if the Commission --

Q Okay.

A -- and counsel desires.

Q Thank you. I'm going to try to move through the rest of my cross, so I think we'll move on to the next point. Excuse me for a minute. So if one goes back to the interruptible customer whose load basically is not on the system during the summer and winter peaks, we're now looking at Summer/Winter Peak and Average and how it functions. So if you look at the interruptible customer whose interruptible load is not on the system during the summer and winter peaks, and so is not causing the Company's capacity costs during those summer and winter peaks, with the Company's version of Summer/Winter Peak and Average would you agree that by virtue of weighting the energy component higher than weighting the demand component, the interruptible customer is not receiving appropriate credit for taking its interruptible load off the system during the summer and winter peaks?

A I'm going to -- a few things to say in response to that question. First of all, yes, Nucor does benefit our system. We have a service agreement with them. It's a confidential agreement. I could probably talk about it to some limited degree. But it does, as I showed in my rebuttal testimony -- maybe we'll talk about this, too -- but I did show that Nucor provides benefit to the Company's system. Okay.

It gets a benefit under the Summer/Winter Peak and Average by when it reduces its load down to a curtailed load level, and that reduces its cost allocation rather dramatically, even when weighted at 40 percent. Nucor may not agree that it reduces it enough, but it reduces it a fair amount, and I've got some information in my rebuttal schedules that we can -- we can certainly talk to -- talk about.

But the other thing I want to point out is, yes, Nucor reduces their load at the peak hour, but they also have a high usage of our system during all other hours of the year. Their loads get very high. And Nucor benefits by having a very -- by having a system of assets, generation assets available, to provide low cost energy and low fuel costs throughout the course of the year such that their fuel factor is lower than it otherwise would be. So it's fair to ask Nucor and other high load factor customers to have a portion of their allocation of plant cost responsibility based upon energy consumption.

If you look at my Schedule 1 in my Company supplemental testimony page 3, if you can find it, I can tell you that of the North Carolina jurisdictional energy, Nucor uses 20 percent of it. So the total energy consumed during the year by our North Carolina customers, Nucor uses 20 percent of it. That's -- I mean, that's large. That is a large amount to have from a single class or a single customer in a single class. And I'm telling you that customer and that provision of energy to them, that energy and its consumption is provided through efficient dispatch of our units such that these high capital cost units that can run a lot during the year provide them with low-cost energy. Therefore, since they're paying the average fuel factor, they should be getting the allocation, the production plant that provides that average fuel expense to them over the course of the year.

Q Okay. Thank you for that. So basically what you've -- you're not asserting that Nucor uses 20 percent of the energy, but gets it for free or doesn't pay for it, right?

A That's right. They do pay for it.

Q Okay. And the Company earns a margin on all that energy, correct?

A Well, not on fuel. We don't -- we are in a return on our production plant on our capital investments, on our rate base. We don't make any money on the fuel expense that runs through the fuel clause. That's -- we have a fuel -- separate fuel case pending now before the Commission.

Q Not on fuel, but on energy which consists of components other than just fuel, the Company earns a margin on the energy it sells to Nucor?

A Oh, on Nucor. Yes, yes. There is --

Q Okay.

A -- there is energy that there is a -- within the Nucor contract that specifically there is a margin on energy.

Q Right. And that contribution to fixed costs benefits all customers on the system, doesn't it?

A It does.

Q Okay. And -- okay. So you have paid lip service to the benefits that Nucor's load offers to and provides to the system, and in that regard you had suggested that Nucor's -- that the rate of return index applicable to Schedule NS should be set at 0.80; is that correct?

A In my direct testimony, that --

Q Right.

A -- was my proposal.

Q Right. And then subsequently in your rebuttal testimony, which you referred to a few minutes ago, you actually recommended, agreeing in part with Nucor Witness Wielgus, you -- who had recommended a ROR index of .70, approximately .70, you then said that you had reconsidered your direct testimony and you believe that it would be appropriate to -- for Nucor's load to have a ROR index of .75; is that correct?

A Well, let me -- partially.

Q Okay.

A I did an evaluation in my rebuttal testimony, a detailed evaluation, looking at the benefits that Nucor provides to the jurisdiction. That's in my rebuttal, Schedule 3. I added back their load as if they didn't curtail and calculated, you know, that there was some benefit in the range of about three to three and a half million dollars that the North Carolina jurisdiction gets because Nucor is curtailable. That's a good thing for the jurisdiction.

But what I also did was a -- I evaluated based upon PJM capacity prices and looked at the level of load that Nucor can curtail to, and then looked at the level of load in three different scenarios. One, I looked at their average load when they weren't curtailed. I looked at their thousand highest hours of load and then I looked at their highest 5 percent of hours of load, and that's about 438 hours, and I did an evaluation of the value of Nucor being curtailable. And I show that in my rebuttal Schedule 2, and I got a range from about 1.9 million to about three and a half million dollars.

I compared that in my rebuttal Schedule 2 to a range of rate of return indexes for Nucor, that it would get a discount from having an index of 1, and I found that an appropriate evaluation for Nucor, based upon this case, could be between .80 and .75, so I said it was appropriate to target -- target is the key word here -- a rate of return index of 0.75. Target doesn't always mean you achieve something. And we can certainly talk about what I did in the Stipulation at some point as well, but that may be a future question.

Q I think it's a good segue to my next question. So basically in the rebuttal testimony you -- and I'll read this -- it's on page 50, line -- start at line 5. You can be my guest and read it if you would like or I can read it for you. This is your testimony, Mr. Haynes. "Now considering this operational benefit to the system and the benefit in cost allocation to North Carolina jurisdiction because of the partially interruptible nature of service to Nucor, I believe it is appropriate to target an ROR index of .75 for the Schedule NS class. This is a very important large industrial customer, and I believe that this reduction in the recommended ROR index is reasonable." So you agree that -- that's your testimony?

A That is my testimony.

Q Okay.

A And I emphasize the word target.

Q Okay. Within -- you shared the Stipulation of

Settlement, and we examined that Stipulation of Settlement, and the narrative does not address the issue of the ROR index that applies to Schedule NS or Nucor; is that correct?

A That's correct.

Q Okay. And then we examined the exhibits, specifically an Exhibit of Mr. Miller's, REM-1, Stipulation Schedule 4, which consists of two pages, and we discovered that you did not apply the ROR index of .75 to Nucor's load. In fact, you reverted to what you had in your pre-Nucor direct testimony, your original direct testimony, which is an ROR index of .80 for Schedule NS; is that correct?

A The -- I did -- the .80 that you see in Company Witness Miller's Stipulation Schedule 4 in that fourth box on the page, that wasn't a reversion back to my direct testimony. This was the result of the Company coming to terms, an agreement with the Public Staff, and we agreed on certain principles in the Stipulation. And one of those principles is -- and I'm going to read it -- it's in Section VI. It says "The parties" -- this is page 10 of the Stipulation. It's Section VI. Well, it's the last sentence before Section VII, and it reads "The parties agree that all classes should share in the total base rate revenue increase."

So I know Mr. Floyd, on behalf of the Public Staff, may be up later, maybe tomorrow, and he can certainly speak to the principles that the Public Staff has, but the -- but in reaching this agreement, at least in this section of the Stipulation, the Company and Public Staff reached agreement based upon the -- all the issues in this case, not just this cost allocation rate design, but all the broader issues of this case, that the Company and Public Staff could agree that all classes could share in the base rate revenue increase.

So what's happening in this case? There is a base fuel reduction that all customer classes are going to be getting. We're reestablishing the base fuel reduction, and that's a negative amount. And for Nucor that base fuel decrease is about $424,000. So what I did was I moved from the rate of return index in Mr. Miller's Schedule 4 in the third box, which is the fully adjusted cost of service, the starting point was .83, so I took their revenue almost as low as I could to get them to meet the Stipulation provision of everybody, every customer class sharing in the base rate revenue increase. That means the sum of the base non-fuel increase and the base fuel decrease which is negative, that everybody, every class gets a positive increase. That's what -- the principles that the Company and Public Staff agreed to for this proceeding -- for this proceeding.

So I gave Schedule NS Class, Nucor, a very low reduction, and it's provided in my Stipulation Schedule 1 -- in my Stipulation Schedule 1, page 1. This is called a Summary of Final Rate Design. And I will take you -- I will ask you to note part C. Part C, line 19, under the NS column they are getting a total base non-fuel under this agreement based upon the Company's revenue requirement, would get an increase in non-fuel-based revenue of $483,083. They would get a base fuel reduction of $424,233, such that their total base revenue increase is $58,850 out of the total base revenue increase base non-fuel and net fuel for the jurisdiction of $6,534,587. So they're getting $58,000 of that.

To meet -- so I gave them a very low total increase. That brought them down coincidentally to a .80 index. I wasn't going back and grabbing the .80 index from the -- the direct testimony that I supported. I still believe, based upon my rebuttal analysis, targeting .75 for Nucor. I could not get there and meet the terms of the Stipulation. I could only get them to .80. And that gives them a minimal total base revenue increase of

$58,850, shown on line E27 under the NS column.

So I was targeting a lower rate of return index. I could not get there because of the provision of the Stipulation that everyone shares or has a positive base revenue increase.

Q I understand. Thanks.

CHAIR MITCHELL: Okay. We have come to the end of our day. We will return in the morning and go back on the record at 9:00.

MR. XENOPOULOS: Thank you.

CHAIR MITCHELL: Thank you. Let's go off the record.

(The hearing was recessed, to be continued on September 24, 2019, at 9:00 a.m.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-22, Sub 562 and E-22, Sub 566, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 26th day of September, 2019.

Linda S. Garrett

Linda S. Garrett, CCR
Notary Public No. 19971700150

FILED

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N.C. Utilities Commission