PLACE: Dobbs Building
Raleigh, North Carolina
DATE: Monday, August 19, 2019
DOCKET NO.: G-9, Sub 743
TIME IN SESSION: 2:00 P.M. TO 5:12 P.M.
BEFORE: Commissioner ToNola D. Brown-Bland, Presiding
Chair Charlotte A. Mitchell
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Application of Piedmont Natural Gas Company, Inc., for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina, Continuation of its IMR Mechanism, Adoption of an EDIT Rider, and Other Relief

Volume 4

A P P E A R A N C E S:

FOR PIEDMONT NATURAL GAS:

James H. Jeffries, IV, Esq.
McGuireWoods, LLP
201 North Tryon Street, Suite 3000
Charlotte, North Carolina 28202-2146

Brian Heslin, Esq.
Deputy General Counsel
Duke Energy Corporation
550 South Tryon Street
Charlotte, North Carolina 28202

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES IV:

Warren K. Hicks, Esq.
Bailey & Dixon, LLP
Post Office Box 1351
Raleigh, North Carolina 27602

A P P E A R A N C E S Cont'd.:

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:
Robert F. Page, Esq.
Crisp & Page, PLLC
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

FOR FAYETTEVILLE PUBLIC WORKS COMMISSION:
James P. West, Esq.
Chief Legal Officer
Post Office Box 1089
Fayetteville, North Carolina 28302-1089

FOR NUCOR STEEL-HERTFORD:
Joseph W. Eason, Esq.
Nelson, Mullins, Riley & Scarborough, LLP
GlenLake One, Suite 200
4140 Parklake Avenue
Raleigh, North Carolina 27612

A P P E A R A N C E S (Cont'd.):

FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER AFFECTING THE PUBLIC INTEREST:

Margaret A. Force, Esq.
Assistant Attorney General
Jennifer T. Harrod, Esq.
Special Deputy Attorney General
Office of the North Carolina Attorney General
114 West Edenton Street
Raleigh, North Carolina 27603

FOR THE USING AND CONSUMING PUBLIC:

Elizabeth Culpepper, Esq.
Megan Jost, Esq.
William E.H. Creech, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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P R O C E E D I N G S

COMMISSIONER BROWN-BLAND: Good afternoon. Let's come to order and go on the record. I am Commissioner ToNola D. Brown-Bland with the North Carolina Utilities Commission, the presiding Commissioner for this hearing. With me this afternoon are Chair Charlotte A. Mitchell, Lyons Gray -- Commissioners Lyons Gray and Daniel G. Clodfelter.

I now call for hearing Docket Number G-9, Sub 743, In the Matter of an Application of Piedmont Natural Gas Company, Inc., hereafter Piedmont, for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina.

On April 1st, 2019, Piedmont filed an application for a general increase in its rates and charges and filed in support the direct testimony and exhibits of Witnesses Frank Yoho, Victor M. Gaglio, Jack L. Sullivan, III, Bruce P. Barkley, Pia K. Powers, Kally Couzens, Robert B. Hevert, Daniel P. Yardley, Dane A. Watson, and Paul M. Norman.

Overall, according to Piedmont, it seeks a 9 percent increa--- or sought a 9 percent increase in annual total revenues to recover cost necessary to the provision of adequate and reliable natural gas service in its North Carolina -- to its North Carolina customers. The Company stated that the increase was necessary primarily due to substantial capital investment in its system since its last rate case in 2013. According to the Company, this investment was made to accommodate system growth and to comply with federal safety requirements.

On April 22nd, 2019, the Commission issued an Order Establishing General Rate Case and Suspending Rates.

On May 16, 2019, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. The Order scheduled a hearing on Piedmont's Application for today, Monday, August 19, 2019.

The following parties filed petitions to intervene, which were granted by the Commission: Carolina Utility Customers Association, Inc., CUCA; Fayetteville Public Works Commission, FPWC or Fayetteville; Nucor Steel-Hertford, Nucor; The Carolina Industrial Group for Fair Utility Rates IV, CIGFUR IV. The Attorney General's Office filed Notice of Intervention which is recognized pursuant to North Carolina General Statute 62-20, and the intervention and participation of the Public Staff is recognized pursuant to North Carolina General Statute 62-15(d) and Commission Rule R1-19(e).

On July 19, 2019, the Public Staff filed the direct testimony and exhibits of Witnesses R. Tyler Allison, Mary A. Coleman, Lynn Feasel, Geoffrey M. Gilbert, John R. Hinton, Poornima Jayasheela, Jan A. Larsen, Zarka H. Naba, Neha Patel, and Julie G. Perry.

Also on July 19, 2019, CIGFUR IV filed the direct testimony of Nicholas Phillips, Jr. The Attorney General's Office filed the direct testimony of Randall J. Woolridge, and CUCA filed the direct testimony of Kevin W. O'Donnell.

On July 29, 2019, supplemental testimony and exhibits of Kally Couzens and Pia K. Powers were filed by Piedmont.

On August 9th, 2019, Piedmont filed the rebuttal testimony and exhibits of Robert B. Hevert and Bruce P. Barkley.

On August 12th, 2019, Piedmont refiled Witness Hevert's rebuttal testimony to include exhibits inadvertently omitted from the original filing, and the Public Staff filed the settlement testimony of John R. Hinton.

On August 13, 2019, Piedmont, the Public Staff, CUCA, and CIGFUR IV filed a Stipulation with the supporting testimony and exhibits of Witnesses Hevert and Powers.

On August 14, 2019, Piedmont filed a Motion to Excuse Witnesses Yardley, Norman, Watson, and Phillips from the hearing, and that motion has been allowed by Order of the Commission.

Also on August 14, 2019, the Attorney General served a -- served and filed a second data request to Piedmont regarding settlement to which Piedmont filed objection on August 15, 2019.

On July 30th, August 2nd, and August 15, 2019, Piedmont filed affidavits of the required publication of public notice.

On August 16, 2019, Commission -- the Commission issued an Order Providing Notice of Commission Questions. On the same day Piedmont filed verification of the mailing of Notice of Hearing to its customers.

In compliance with the requirements of Chapter 163A of the State Government Ethics Act, I remind all members of the Commission of our responsibility to avoid conflicts of interest, and I inquire whether any member of the Commission has any known conflict of interest with respect to this matter now before us?

(No response.)

COMMISSIONER BROWN-BLAND: The record will reflect that no conflicts have been identified.

And I will now call for appearances, beginning with the Applicant.

MR. JEFFRIES: Good afternoon, Madam Chair, Madam Chair, Commissioner Clodfelter, and Commissioner Gray. My name is Jim Jeffries. I'm with the law firm of McGuireWoods. I'm here on behalf of the Applicant, Piedmont Natural Gas Company.

MR. HESLIN: Good afternoon. I'm Brian Heslin. I'm with Duke Energy and representing Piedmont Natural Gas in this proceeding.

COMMISSIONER BROWN-BLAND: Good afternoon.

MR. PAGE: Madam Chair, members of the Commission, I am Robert Page representing Carolina Utility Customers Association.

COMMISSIONER BROWN-BLAND: Good afternoon, Mr. Page.

MS. HICKS: Good afternoon, Commissioners. My name is Warren Hicks with Bailey & Dixon, and I am here on behalf CIGFUR IV.

COMMISSIONER BROWN-BLAND: Good afternoon.

MR. EASON: May it please the Chair, my name is Joe Eason. I'm with the Raleigh office of Nelson Mullins, appearing for Nucor Steel-Hertford.

COMMISSIONER BROWN-BLAND: Good to see you again.

MR. WEST: Good afternoon. My name is James West. I'm appearing on behalf of the Fayetteville Public Works Commission.

COMMISSIONER BROWN-BLAND: All right. Thank you.

MS. HARROD: Good afternoon, Commissioners. Jennifer Harrod, and with me Peggy Force, here for the Attorney General's Office. We represent the Using and Consuming Public, the State and Its Citizens in this Matter of Public Interest.

COMMISSIONER BROWN-BLAND: All right. Thank you.

MS. CULPEPPER: Hello. Elizabeth Culpepper with the Public Staff, appearing on behalf of the Using and Consuming Public. Appearing with me are Megan Yost and William Creech.

COMMISSIONER BROWN-BLAND: All right. Thank you. All right. Are there any preliminary matters that we need to deal with before we begin?

MR. JEFFRIES: I'm not aware of any, Madam Chair.

COMMISSIONER BROWN-BLAND: No weirdness, and we -- we can proceed?

MR. JEFFRIES: All right.

COMMISSIONER BROWN-BLAND: All right. Then the case is with you as the Applicant, Mr. Jeffries.

MR. JEFFRIES: Thank you. Mr. Heslin will begin the presentation of evidence for Piedmont.

COMMISSIONER BROWN-BLAND: All right.

MR. HESLIN: And Piedmont calls Frank Yoho to the stand.

FRANK YOHO; Having been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MR. HESLIN:

Q Please state your full name for the record.

A My name is Franklin H. Yoho. Pour some water.

Q And Mr. Yoho, what's your position with the Company?

A I'm Executive Vice President and President, Natural Gas Business, at Duke Energy.

Q Did you submit prefiled testimony in this case on April 1st, 2019 consisting of 15 pages of written testimony?

A Yes, I did.

Q Was that testimony prepared by you or under your supervision?

A Yes, it was.

Q Do you have any corrections or revisions to make to that testimony?

A I do not.

Q Okay. If I were to ask you the same questions as those indicated in your prefiled testimony today, would your answers be the same?

A Yes, they would.

MR. HESLIN: At this time we would ask that Mr. Yoho's testimony consisting of 15 pages of written testimony be accepted into the record as if given orally.

COMMISSIONER BROWN-BLAND: All right. That motion will be allowed.

(Whereupon, the prefiled direct testimony of Frank Yoho was copied into the record as if given orally from the stand.)

Q. Please state your name and your business address.

A. My name is Frank Yoho. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

A. I am Executive Vice President and President, Natural Gas Business of Duke Energy Corporation ("Duke Energy"). In that role, I am responsible for all the operations and business activities of Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company").

Q. Please describe your educational and professional background.

A. I have a Bachelor of Arts degree in economics from Washington & Jefferson College and a Masters of Business Administration degree from Ohio State University. I moved to my current position following the closing of the merger between Duke Energy and Piedmont in late 2016. Previously, I worked for Piedmont as its Senior Vice President and Chief Commercial Officer. Prior to that, I was Vice President for Business Development at CT Communications, a telecommunications provider headquartered in Concord, North Carolina. And prior to that, I served as Senior Vice President for Marketing and Gas Supply for Public Service Company of North Carolina, Inc., a local natural gas distribution company headquartered in Gastonia, North Carolina.

Q. Have you previously testified before the North Carolina Utilities Commission ("Commission") or any other regulatory authority?

A. Yes, I have testified on numerous occasions before this Commission, the Public Service Commission of South Carolina, and the Tennessee Public Utility Commission (and its predecessor the Tennessee Regulatory Authority).

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

A. My testimony supports the Petition filed by Piedmont on April 1, 2019, seeking the establishment of a general rate proceeding in this docket. In this testimony, I will provide a brief description of Piedmont and its business, summarize our request for rate relief and the reasons behind such request, and provide an overview of the other significant aspects of our business and filing.

Q. Please describe Piedmont and its business.

A. Piedmont is a wholly-owned subsidiary of Duke Energy Corporation with its headquarters located at 4720 Piedmont Row Drive, Charlotte, North Carolina. The Company is principally engaged in the natural gas distribution business and, as of February 28, 2019, we served approximately 1.1 million customers in three states, including 752,000 in North Carolina, 149,000 in South Carolina, and 188,000 in Tennessee. We are fortunate to serve a growing service territory in North Carolina and anticipate continued customer growth in this State of approximately 2.0% for the foreseeable future.

Q. Please describe your gas distribution business in North Carolina.

A. Piedmont serves customers in numerous cities, towns, and communities in 66 counties across North Carolina. The largest of these are Charlotte, Greensboro, Winston-Salem, High Point, Burlington, Wilmington, Hickory, Salisbury, Reidsville, Indian Trail, Fayetteville, Goldsboro, Tarboro, Elizabeth City, New Bern, Rockingham, and Spruce Pine. We also provide service to the municipal gas systems of the cities of Wilson, Greenville, and Rocky Mount, and military facilities in Fayetteville and Jacksonville, as well as multiple gas-fired electric generation facilities located throughout the State, many of which are operated by either Duke Energy Progress, LLC ("DEP") or Duke Energy Carolinas, LLC ("DEC") and others of which are owned by third-parties.

Q. What are Piedmont's most important business goals?

A. We continuously strive to provide safe and reliable natural gas service to our customers at reasonable rates coupled with excellent customer service. Customer, public, and employee safety are absolutely critical to everything we do. We also want our firm customers to feel certain that we will be ready to serve on the coldest winter day. Finally, we want our customers to experience great customer service with each and every interaction. Our acronym used to represent our approach to customer service is EASE: we strive to be Experts, who express Appreciation, focus on Safety, and make working with us Easy.

Q. What is Piedmont seeking in this proceeding?

A. In this proceeding, Piedmont seeks Commission authorization to: (1) update and increase our rates and charges to account for changes in rate base, operating expenses, and capital structure that have occurred since our last general rate case in 2013 (including the roll-in of Integrity Management Rider capital expenditures); (2) extend our Integrity Management Rider mechanism, which has been critical to our ongoing efforts to comply with federal pipeline safety and integrity requirements; (3) implement new depreciation rates to amortize the costs of assets, net of salvage value, over the estimated useful life of the assets; (4) update and revise Piedmont's existing service regulations and tariffs; (5) amortize and collect certain deferred environmental, pipeline integrity, and other expenses that have accrued since Piedmont's last general rate case; (6) implement a distribution integrity management O&M deferral mechanism; (7) upgrade and expand our efforts at promoting customer conservation; and (8) implement a rider to address the rate impacts of federal and state income tax reductions. These rate case components are discussed in more detail later in my testimony.

Q. What else is Piedmont seeking to do in this case?

A. In addition to our requests for specific relief, as described above, we also: (1) provide updates to the Commission on our prior and projected capital investment activities to comply with federal safety mandates; (2) provide updates to the Commission on our post-merger operations and integration activities including the impacts of integration on our operations and maintenance ("O&M") expenses; (3) discuss the functioning of our Margin Decoupling Tracker mechanism and how it continues to benefit all parties by aligning the interests of Piedmont and its customers around variations in customer usage; and (4) explain why incremental natural gas infrastructure development, particularly in the eastern part of our service territory, is critical to our ability to continue to provide safe and reliable natural gas service to the growing demand from our customers and provide economic development opportunities to economically challenged areas of our state.

Q. What is the scope of the rate changes you are requesting in this rate case?

A. The Petition filed by the Company proposes rate changes that would produce an overall increase in annual revenues of approximately $83 million. This 9.0% increase in annual revenues is necessary to cover the costs, including a reasonable return on investment, of providing safe, adequate and reliable natural gas service to the Company's customers in North Carolina.

Q. Why it is necessary to file this rate case?

A. This rate filing is prompted by an insufficient return earned during the test period ended December 31, 2018 that was driven by several factors. First, since our last general rate case in 2013, Piedmont has made substantial capital investments in our system in order to (1) maintain and expand our gas distribution system for the benefit of our customers in order to accommodate system growth and service reliability, and (2) comply with ongoing federal pipeline safety and integrity requirements. The total amount of invested capital in system growth since our last rate case is approximately $1.2 billion. The total amount of invested capital in federal pipeline safety since our last rate case is approximately $1.1 billion. This rate case will allow us to roll these amounts into our base rates in order to facilitate our ability to earn a reasonable return on these investments.

During the same period, we have also experienced increases in the Company's operating costs.

Q. Can you discuss what other factors prompted Piedmont's rate case filing?

A. Yes, there are several other factors that support Piedmont's decision to seek rate and other relief in this docket. First, under the terms established in the Commission's Order issued October 4, 2016 in Docket Nos. G-9, Sub 631 and G-9 Sub 642 approving the Stipulation and Settlement Agreement between Piedmont and the Public Staff related to Piedmont's IMR, the mechanism is up for review this year and we have set forth our proposal to renew and continue the Integrity Management Rider mechanism in this filing. The renewal of the IMR is critical to Piedmont's ability to continue to timely invest in and earn on capital expenditures required by federal pipeline safety and integrity management regulations. In the period since our last rate case filing, Piedmont has averaged approximately $230 million a year in integrity management additions to its

North Carolina utility plant in service. That level of capital expense, which constitutes roughly 50% percent of all capital invested by the Company in North Carolina since our last general rate case, would have caused us to file annual or near-annual rate cases in order to roll that investment (and all other capital investment of the Company) into base rates in the absence of the IMR mechanism. Instead, Piedmont has been able to avoid a general rate case filing in North Carolina for almost six years, notwithstanding the fact that it has invested more than $1.2 billion in non-integrity management related capital since 2013. Given that rate cases generally result in both higher rates for base rate customers and rate case specific expenses well in excess of $1 million per case, the lack of general rate case filings in the last six years is a clear benefit to our customers. The need for and benefits of a continuation of the IMR mechanism is addressed in greater detail in the testimony of Piedmont witnesses Victor Gaglio and Bruce Barkley.

Second, Piedmont is proposing to implement new depreciation rates based on a more current depreciation study filed in this docket. This new depreciation study will permit us to more properly align the Company's recovery of its invested capital with the useful life of its underlying physical plant. Piedmont's new proposed depreciation rates are set forth in the testimony of Piedmont witness Watson.

Third, Piedmont is also proposing revisions to Piedmont's Rate Schedules and Service Regulations designed to clarify processes and procedures under Piedmont's tariffs. These revisions are described in the testimony Piedmont witness Bruce Barkley.

Fourth, Piedmont is proposing to amortize and provide for the recovery of certain environmental and pipeline safety and integrity related expenses that have been deferred since our last rate case pursuant to prior Commission Orders. These costs and our proposed amortizations are described in the testimony of Piedmont witness Pia Powers.

Fifth, we are also proposing to adopt, on a going forward basis, a deferral accounting mechanism for certain Distribution Integrity Management Program ("DIMP") O&M expenses incurred in compliance with federal pipeline safety and integrity regulations. This would be similar to the Transmission Integrity Management Program ("TIMP") O&M expense deferral mechanism already in place for Piedmont and would be essentially identical to a DIMP O&M expense deferral mechanism approved by the Commission for Public Service Company of North Carolina, Inc. in Docket No. G-5, Sub 565. The request for deferral accounting treatment for DIMP O&M expenses is addressed in the testimony of Piedmont witnesses Victor Gaglio and Bruce Barkley.

Sixth, we are proposing to modify and expand our existing conservation and energy efficiency programs to help our customers save money on their energy expenditures and reduce the amount of carbon emissions associated with natural gas consumption within the state of North Carolina. These expanded conservation and energy efficiency measures are made possible by Piedmont's Margin Decoupling Tracker ("MDT") mechanism which renders Piedmont indifferent to lower per customer consumption of natural gas on an intra-rate case basis which effectively aligns the economic interests of Piedmont with the economic interests of our customers around conservation. The request for expanded energy efficiency and conservation programs is set forth in the testimony of Piedmont witness Barkley.

Finally, as explained by witness Barkley, we seek a rider to facilitate the return to customers of previously overcollected amounts and excess accumulated deferred income taxes associated with reductions in state and federal income taxes that have occurred subsequent to our last general rate case.

Q. Please identify the other witnesses that will offer testimony on behalf of Piedmont in this proceeding?

A. Jack Sullivan will testify on our pro forma capital structure, cost of capital, and benefits to customers resulting from Piedmont's ongoing financial stability and strong credit ratings. Victor Gaglio will testify as to the requirements of federal pipeline safety and integrity regulations and the incurred and projected costs of compliance with those regulations along with major system enhancements needed to provide reliable service to Piedmont's growing customer base. Bruce Barkley will testify regarding our revenue request, the fairness of our proposed rate of return on common equity in light of changing economic circumstances, the propriety of extending the operation of our IMR mechanism, our proposal to initiate a DIMP O&M expense deferral mechanism, the proposed expansion of our energy efficiency and conservation programs, the ongoing prudence of Piedmont's decoupled rate structure, proposed tariff changes, and the proposed income tax rider. Pia Powers will testify in support of our cost of service and rate base, revenue requirement deficiency, G-1 compliance, integration costs and activities, amortizations of deferred assets, and the impact of new depreciation rates. Kally Couzens will testify regarding our pro forma revenue calculations, fixed gas costs, and rate design. In addition to these Company witnesses, we have also filed testimony of Dr. Robert Hevert on cost of capital and return, Dan Yardley on class cost of service and rate design, Paul Normand on cash working capital requirements, and Dane Watson on depreciation.

Q. Can you please provide a little more context to Piedmont's rate case filing in this docket?

A. I would be happy to do that. Probably the most significant factor about our rate filing is that it occurs in the context of two of the most significant changes in the natural gas industry in the last several decades. These changes are the maturing development of market access to plentiful new sources of shale gas (and the developing capacity to deliver those supplies to end-use markets) and the dramatically increased federal regulations around pipeline safety and integrity that are requiring unprecedented capital investment in existing natural gas infrastructure. The first factor is allowing us to maintain natural gas rates for our customers at historically low levels even in the face of the substantial and ongoing capital investment required by the second factor.

Coming out of our 2008 rate case, our projections showed that the average annual delivered cost of natural gas service for our residential customers was approximately $955. In our 2013 case, based upon the approved settlement adopted by the Commission, our projected annual delivered cost of natural gas to our residential customers was $724. In this case, and notwithstanding the fact that we have invested more than $2.3 billion in additional capital in our system and propose a 9.0% increase in our revenues, those same customers will pay only $778 per year for service if our proposed rate increase request is granted. It is difficult to think of another economic sector where end use customers will be paying rates, if our proposed rate increase request is granted, which are lower than they were ten years ago even with substantial investment in the safety, reliability, and integrity of our system.

In short, the continuing benefits of shale natural gas production have allowed us to comply with federal integrity management requirements and otherwise grow our system while preserving the essential affordability of natural gas service for our customers.

Q. Are there any other factors you want to draw the Commission's attention to that are particularly impactful to Piedmont's operations?

A, Yes. There are two pending natural gas infrastructure projects that are particularly important to Piedmont and our continuing ability to provide safe and reliable service to our customers. The first is the Atlantic Coast Pipeline project ("ACP") which has been the subject of significant oppositions, protests, rehearing requests, and appeals from environmental activist groups who oppose the construction of any additional natural gas infrastructure projects in the United States. This activity, which has gained some traction in the Fourth Circuit Court of Appeals, has slowed down construction of the ACP project and has also increased the costs associated with that project, primarily as a result of delay, despite the full support of federal and state governmental agencies with jurisdiction over or direct interests in the project. This support has spanned two administrations in each jurisdiction. We continue to believe that the project will ultimately be completed and placed into service but at increased costs and with in-service date delays. Despite rising costs, I continue to believe that this project provides customer benefits at competitive costs as compared to other infrastructure projects and that it is necessary to provide reliable service to Piedmont's growing North Carolina customer base.

The second infrastructure project Piedmont is involved in is the Robeson LNG facility under construction in Robeson County, North Carolina. This facility was originally considered more than 10 years ago in order to provide peaking on-system storage capacity for Piedmont in the

Carolinas but was shelved when the impacts of other infrastructure options materialized and demand growth slowed due to the Great Recession. System demand projections now support going forward with the project which will also have the beneficial effect of "firming up" some supplies that were historically delivered on a secondary firm backhaul basis off of Transco but which are no longer reliably deliverable in that manner. This project is also critical to design day deliverability on our system and is much more cost effective than alternative infrastructure projects.

Q. Will these projects have additional benefits other than simply increasing the availability of incremental supplies for Piedmont's customers?

A. Yes. Both of these projects have significant and critical operational benefits for Piedmont that will be extremely difficult to duplicate if either of the projects do not go into service. Specifically, the system strengthening in Piedmont's eastern North Carolina system that will result from the delivery of high-pressure natural gas off of ACP, which is integral to Piedmont's plans to serve end-use customer growth in the near future, cannot be readily or quickly duplicated. Obtaining these operational benefits in the absence of ACP will involve the expenditure of hundreds of millions of dollars by Piedmont. ACP will also provide new infrastructure and enhance existing infrastructure, thereby providing eastern North Carolina with enhanced economic development opportunities that are not currently available.

Q. Can you please provide an update on the status of Piedmont's merger with Duke Energy?

A. The merger was completed in the fall of 2016. Piedmont's culture and its focus on safety, reliability, and great customer service match very well with that of its parent, Duke Energy. I believe Piedmont's customers have benefitted from the scope and scale of Duke Energy and from the sharing of best practices. The benefits include:

- Lower rate of increase in operations and maintenance expense. Since Piedmont's final year of independent operation in 2015, operating and maintenance expenses have grown by 1% annually, significantly lower than the approximate 2% annual inflation over that period. During the merger proceeding, the parties identified approximately $9.5 million per year in projected O&M expense savings which have now been achieved.
- Adoption of Operational Excellence principles that have generated industry leading safety and efficiency results for Duke Energy's electric operations. Piedmont has experienced no significant events impacting reliability or system safety subsequent to the merger.
- Improvements in employee safety as a result of the constant focus placed in this area by Duke.
- Receipts of corporate services from Duke Energy Business Services in place of standalone departments including Human

Resources, Information Technology, Treasury, Legal, and Building and Land Services.

In summary, Piedmont has become more efficient, yet retained areas critical to safety, reliability and customer services and has continued to excel in these areas.

Q. Have Piedmont's customer service scores remained high?

A. Yes. Piedmont has continued to receive customer satisfaction and trusted brand scores from J.D. Power and Cogent Reports that exceed or closely approximate top quartile and top decile respectively. We have now begun to measure net promoter scores which have confirmed Piedmont's commitment to outstanding customer service. Also, our most recent report to the Commission concerning call center service quality indicated that we exceeded the goal of answering 80% of incoming calls within twenty seconds for the year ended February 28, 2019.

Q. Do you have anything else to add?

A. Yes. I would like to state that Piedmont is very excited about the opportunities to provide expanding safe, clean, reliable and economic natural gas service to our customers in North Carolina and in the other states where we operate.

Q. Does this conclude your testimony?

A. Yes.

BY MR. HESLIN:

Q Okay. And Mr. Yoho, did you prepare a summary of your testimony today?

A Yes, I did.

Q Can you please read it for the Commission?

A Yes. Good afternoon. My name is Frank Yoho.

MR. HESLIN: Hold on. I've got to --

THE WITNESS: Sorry.

MR. HESLIN: Everyone wants a copy.

A Good afternoon. My name is Frank Yoho. I'm the Executive Vice President --

COMMISSIONER GRAY: Sir, would you pull up the microphone? Some of us are hearing challenged.

THE WITNESS: Yes, sir. There we go. Third time.

A Good afternoon. My name is Frank Yoho. I am the Executive Vice President and President Natural Gas Business of Duke Energy Corporation. I prefiled direct testimony in this docket on April 1st, 2019 in support of Piedmont's petition seeking the establishment of a general rate proceeding in this docket.

My testimony provides a brief description of Piedmont and its business, summarizes the Company's request for rate relief and the reasons behind such requests, and provides an overview of the other significant aspects of Piedmont's business and filing. I explain the factors that support Piedmont's decision to seek rate and other relief in this docket.

My prefiled direct testimony also identifies the other witnesses that are offering testimony on behalf of Piedmont in this proceeding and provides contextual information surrounding Piedmont's rate case filing. For example, I discuss how the continuing benefits of shale natural gas production have allowed Piedmont to comply with federal integrity management requirements and otherwise grow our system, while preserving the essential affordability of natural gas service for our customers. It is also important to maintain our decoupling mechanisms in order to align our interests with our customers and allowing us to focus on safety, reliability, and great customer service.

In addition, I explain how the Atlantic Coast Pipeline and the Robeson LNG facility, two pending natural gas infrastructure projects, are particularly important to Piedmont and its continuing ability to provide safe and reliable service to our customers.

Finally, I provide a status update concerning Piedmont's merger with Duke Energy, which is largely compete -- complete and which has been a real success story due to the efforts and dedication of both legacy Piedmont and Duke employees, and has provided tangible benefits to the Company and to our customers.

This concludes my summary.

MR. HESLIN: Mr. Yoho is available for cross examination, if any.

COMMISSIONER BROWN-BLAND: All right. Does anyone from this other side of the room have any questions?

(No response.)

COMMISSIONER BROWN-BLAND: All right. So the Commission has a few questions for you, Mr. Yoho. Might be our parting gift to you.

THE WITNESS: Thank you.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q All right. In the Company's application filed this -- earlier this year, it states that the Company serves approximately 252,000 customers, and in the 2013 case I believe Piedmont was serving about 683,000. To us, that seems like a -- that it's growing its total customer count of -- at a rate a little less than 1.4 percent. Do you accept that?

A Yes. It varies from month to month, year to year, but it typically is in the 1.4 to 1.7 percent annual basis, yes.

Q And everything is relative, but that's a somewhat low level of growth, and yet growth is one of the reasons cited in the application for the need for the increase; is that -- is that accurate?

A That is accurate, but I would say from a national perspective, we're considered a relatively high growth gas company from a national perspective.

Q All right. And back when the Commission approved the Piedmont/Duke merger, Witness Skains testified generally that the merger would allow the Company to maintain and expand its high performance customer service focused culture in providing natural gas service to both existing and new customers. What we're seeing, and you correct me if I'm wrong, but we see that the Company reports its monthly customer counts by FERC curtailment priority in Docket G-100, Sub 24A, and there we compare the reported number of residential customers in the month of December 2018. With a number from December 2017 we see a 1.6 increase, and the other LDC in our state has a growth rate of about 2.8 percent.

Why is it -- if you have knowledge or information pertinent, why is Piedmont adding customers at what seems to be a significantly lower rate than Public Service of North Carolina?

A Once again, I'd say both companies are considered high growth gas utilities in the US. One of the big differences is in the -- PSNC's territory is Raleigh/Durham/Chapel Hill, which has one of the most rapid residential growth rates. Our Charlotte markets, our coastal markets, we have a lot of growth, but this is probably one of the best growth markets, and it just happens to be sitting in their territory.

The other aspect of this, we have all of eastern North Carolina, and other than the coast it is a fairly economically depressed area, and so we have that weighted in with our average growth rate, and so it does tend to weight it down a little bit. And that's one of the big reasons for bringing in infrastructure, so these communities which have been economically depressed, bringing in infrastructure like the Atlantic Coast Pipeline so they can enjoy the growth that other parts of our state has seen.

Q Do -- is that part of the Company's plans, that you foresee growth out towards the coastal areas, more growth?

A Yeah. We see New Bern and Wilmington, you see it more -- growth more like the large center city areas like Raleigh/Durham/Chapel Hill or like Charlotte, but in between when you go east of Raleigh until you get to the coast or east of Indian Trail and you get, it's -- there's some difficult economic areas, and we think there are some opportunities there if they can bring in some industry to -- to enjoy some better growth and better economic success.

Q Is -- to your knowledge, is the Company part of conversations with regard to growing industry in these areas?

A Yes. We take on -- whenever there's economic development, we get actively involved. And matter of fact, we've seen numerous requests, of which without this infrastructure it just can't -- industry can't be economically accomplished. Once Atlantic Coast Pipeline comes in and we get that eastern infrastructure, we can -- and eastern North Carolina can once again be in the game relative to attracting manufacturing and industry.

Q All right. In your testimony you discuss or state that coming out of the 2008 rate case, the Company's projections showed that the average annual delivered cost of natural gas service for residential customers was about $955, and in the 2013 case that number was $724. And in this case, if the Company were to get their original requested amount of 9 percent increase in revenues, that number was $778 per year. Why was -- 2008 seems like an outlier where the delivered cost of gas service so high?

A It was prior to, really, the development and the appreciation for the volumes of delivery of a low-cost shale natural gas specifically, really, all over the country, but from the -- also from Pennsylvania, Ohio, and West Virginia. And what we've seen is a shift -- excuse me -- where we believed -- I think in the industry the common thought was we're going to see 8 to $12 gas for a long time. The development and this technology breakthrough, now we believe we're going to see 2 to $4 gas for a long time.

The results are customers' bills are lower, which has been a great advantage for us. We can do a lot of work on our system, but also for -- homeowners can have lower annual bills. And it's also been very dramatic for power generation. Without these supplies, I don't -- Duke has been able to, A, bring down its carbon footprint almost 40 percent, and a lot of power generation has been brought down because of the natural gas supplies, along with supporting renewables. So it has really been a win/win from customers' bill to cleaner air.

Q And in your response you mention shale gas, so is it -- could you talk a little bit more about the role that horizontal drilling or the fracturing technology had in reducing that cost of gas?

A Yeah. To give you an example, early in my career I used to buy gas in West Virginia, and you go to a well pad and you get maybe 200 dekatherms. Today, one well pad in Pennsylvania will get you 200,000 dekatherms, given this technology. And it's just really -- it's one of the great technology breakthroughs that have really made a difference in, really, every homeowner's pocketbook and also the air we breathe. So the technology has advanced dramatically and been able to unlock this resource to really move the ball forward for lower cost for customers and also really help power generation shift rapidly from coal, but also from an operational perspective it helps support renewables, such as solar, which has been a success story in this state.

Q Would you attribute -- so that fracking was the reason for the lower cost?

A Horizontal drilling, and the fracking technology and the horizontal drilling has made a huge difference, yes. That's -- that is the reason.

Q And if there were a policy shift or we could no longer frack, what would you expect to -- or to do horizontal drilling, what would you expect to happen to the price of gas?

A You'd probably see dramatic price increases. If you could no longer use that technology, there would be, obviously, a supply reduction, and so -- and if demand didn't come down, prices would jump up dramatically. And you'd probably -- you'd see more coal usage and kind of reverse course relative to reducing carbon in the power generation sector.

Q Given what you know about the market today, and it might be hard to envision it without the benefit of the shale gas, but is there any basis of which to form an opinion about what those gas prices might look like --

A Well, I think --

Q -- if you didn't have it?

A -- just -- it's just my opinion and my experience. I think where we saw in 2008 where the belief would be 8 to $12 gas, and you would not see a shift in major markets like power generation taking place moving natural gas. So it's -- you know, right now we're around in the low $2.

There has been production increases where we were around -- prior to this around 50 bcf a day in North America. Today it's pushing 90 bcf a day, and that's in a pretty short order, and it has really been driven -- the big driver behind it is lower bills for customer and cleaner air for our country, and power generation has done this dramatic shift away from coal to natural gas which also benefits the operational and the ramping support for renewables.

Q All right. There's testimony that has been filed, I believe it's in Mr. Gaglio's prefiled testimony, where the Atlantic Coast Pipeline that we call ACP and the Robeson LNG facility are discussed, and it's stated that they provide greater diversification in supply sources and help mitigate the negative impacts of increasing constraints on traditional delivery flexibility on the Transco system. What's causing the increase in constraints?

A I think two things are causing it. First of all, Transco was south to north pipeline. Way more volume is moving from south to north. So when we took volumes from the north, you could displace it -- comfortably displace it because the volumes were so much greater moving from south to north.

When the volumes start coming from the north, and we were counting on -- it was called secondary firm, but it was reliable, it was more or less firm. When the volume started moving from Pennsylvania, Ohio, West Virginia south, it basically took the firmness and the dependability of those supplies away and we had to adjust. And so you'd either have to spend a lot of money for an incremental transportation agreement to move those gas -- that gas from Virginia down, or the other option was to build a LNG facility in Robeson County which could not -- which could serve our peaking customer. We're seeing a lot of residential growth, as you can see in our numbers, and that's very much a peaking type market. So it really reduced the cost and fit the need of our growing market.

Atlantic Coast Pipeline does a number of things. First of all, it offers infrastructure to eastern North Carolina, as I mentioned before. One of the reasons eastern North Carolina probably weighs down our average growth rate is so -- because it's so economically depressed. They -- if a large manufacturer needs natural gas, they're out of the game because of the cost to move gas from Transco across the state. Once ACP gets here they are very competitive. They will be able to compete. And we've had numerous industrial customers come to us, and we've been able to say from an economic perspective, it would be very challenging to get you service. ACP gets here, we can get you competitive service. So with that, with ACP, we get infrastructure to help the East grow.

Also, it hits our system where to move gas across our system from Charlotte over to Wilmington, going through Charlotte is getting very expensive. It's going to cost probably north of $700 million eventually. ACP eliminates that cost which we would have to get from our customers. So from an infrastructure perspective from Piedmont, we get -- it basically lowers our cost to provide service, given where we get service from ACP and the pressure that it -- it delivers to us.

Thirdly, with the growth of generation and not only, you know, heating our houses and our hot water, but now our lights to come on very much -- is very much dependent on natural gas power generation. This gives some redundancy and security from a power generation perspective that I think we need. And it also comes from a very low-cost supply basin, so from a cost security, helping eastern North Carolina actually reducing Piedmont's future need for investing in pipeline, thereby reducing our customers' cost, it allows us all those benefits.

And it continues as, you know, as we read today, as we shift to a lower carbon future, if you want to shift fast away from coal to natural gas and continue to bring our renewables and new technology, you need this gas from this pipeline to accomplish the objectives that have been set out there.

Q And if you can say -- if this next question causes you -- or you don't feel comfortable because it gets too close to some confidential information, then I don't want you to ask, but can -- answer, but can you say in a general way the types of industry that might be looking at our state that you are aware of?

A If it would be -- they are a broad array, whether it be automobile manufacturing, tire manufacturing, a lot -- you know, they'll go look at different sites and they'll check and see, okay, the things they need, power, gas, infrastructure. And as soon as they see the cost of gas, it basically takes the East if they do need natural gas supplies. If that's a critical factor to the industry, the East can't compete because of the cost. Once ACP gets here, it's very competitive.

Q All right. There's testimony in the docket filed by the Company regarding secondary market transactions, and that's the area where the Commission has allowed the LDCs to retain 25 percent of the margin that's generated in that -- in the secondary market transactions. How much margin did Piedmont retain on the secondary market transactions during this test period?

A During the test period it is just north of $7.9 million, which meant almost $24 million was returned to our customers in -- in lower bills, lower gas cost for our bills. So it is -- that incentive plan has worked very well for helping us reduce cost for our customers.

Q Okay. And this might be addressed to someone else, but if you know, can you speak to how that margin was accounted for?

A I'd have to defer that to one of our expert accounting witnesses on exactly how they account for that.

Q All right. What assurances or counterbalances exist that would allow the Commission to have and maintain confidence in the fact that the amounts of gas or commodity that is procured is not in some ways excessive because of the 25 percent retained for secondary market transactions? In other words, does that amount, that level of -- of amount that you're allowed to retain, does that serve as an incentive to somehow purchase or perhaps purchase more than is necessary?

A No, not at all. I think we take the -- the structure of gas supply is we have annual gas cost review, and that is the mechanism to review to make sure that that doesn't happen. And we work very hard to, first of all, make sure we have reliable supplies on the coldest day of the year for all our firm customers and, B, we try to have a little excess as possible. When you pick up supplies, it's -- you have to get them kind of in blocks. That's the way the market works. And so we work very hard to maintain our supply and capacity sources close to what we believe we will need on that design day, and we don't want to come below because we want to be there. Our customers are counting on us for reliability, but we don't want to be long, either. And I'd say the annual cost of gas review is a mechanism to assure that that doesn't take place.

Q All right.

COMMISSIONER BROWN-BLAND: Other questions from the Commission? Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Yoho, last week we had the annual gas cost review for your peer company, PSNC, and we were talking with them about the problems of backhaul these days --

A Uh-huh.

Q -- that you described. And one of the interesting things that we were told was that for that -- that company, that they're experiencing the problems of firm backhaul capacity really in the shoulder periods, not during peak periods. Is that true for Piedmont?

A We have concerns over the peak periods for the backhaul. Where we get gas, a lot of it is from Boswell Taverns, which is a location in Virginia. In talking to our supplier in the way that volumes flow, we are not confident they'd be available on a peak day.

Q Your -- your concerns are on peak periods, not the shoulder periods that they were talking about?

A It's -- any winter period --

Q All right.

A -- has our concerns, but especially on peak when we have the critical nature for the firm load. That is our biggest concern. And as generation starts, what we're seeing is, you know, the big changes in our industry are not just gas supplies have really grown, bringing down cost; we've seen a large growth in power generation market. In the old gas market things would move with temperature. With power generation across the country it really moves in much larger volumes, and it's a little bit different animal we're dealing with today and the pipelines deal with today than what we've historically seen.

It's a good thing. It's a good problem to have because prices are coming down and power generation is shifting from coal to lower carbon natural gas and also supporting renewables, but it's a little bit more of a challenge relative to operating and how flexible the operating systems are we're seeing on the interstate pipelines.

Q For the Robeson County LNG facility, to what extent do you anticipate needing to draw on that resource during peak summer periods for electricity generation? Is that facility going to be essential for that purpose or is it just primarily your winter peak?

A It's primarily winter peak.

Q It's not really a resource to support electricity generation on peak summer days?

A No, it is not, but I would say this, now, if we have a fleet -- we will have -- this will be our third on system and with power generation. We don't plan -- it's not expected to use for power generation. But if there was an event, a major event, it would be good to have on-system supply whenever it happened, from an emergency perspective. So while it's not designed and not planned for, in my opinion, to have it there, given the nature of dependency on a lot of different things more so than before, it's not a bad backup to have just in case, but that's not what it's there for. It's for peak residential and commercial heating loads.

Q Okay. Thank you. In your prefiled testimony you told us that that project had been on the books, on the drawing board for some time, and I haven't been around that long, so you said it was shelved when the impacts of other infrastructure options materialized. What were those? I'm just --

A When -- at that time Progress Energy needed to have, one, to go out and get gas for Sutton, their Sutton power generation plant.

Q Right.

A They wanted to make a natural gas-fired generation plant. When we built that, we got the real synergy, we piggybacked on top to satisfy that need to move gas across. Now, that's been about -- a number of years now, and so we've grown through that. And so basically it didn't eliminate the need. It delayed the need.

Q Okay. Thanks. At one of the public hearings, I think it was in Wilmington, but I'm not sure exactly which, one of the public witnesses was talking to us about the Robeson LNG facility and made some reference to an incident at the Huntersville facility. What was that about? Do you know what that was referring to?

A And Witness Gaglio could get in more detail, but a long time ago, about eight years -- in 2008 there was an issue there about some stuff was deposited there that shouldn't have been. By 2010 it was 100 percent remediated, and we've never had that issue again.

Q Not something that you expect to be --

A No.

Q -- a recurring issue --

A No. It will --

Q -- at the Robeson facility, for example?

A Absolutely not. This was a one time. It was identified and it was remediated. It was 2008 identified. By 2010 it was fully remediated under the supervision of the DEQ, in conjunction with the DEQ, and I don't see that ever happening again.

Q Okay. Thank you.

COMMISSIONER CLODFELTER: That's all.

COMMISSIONER BROWN-BLAND: Are there questions on the Commission's questions?

MS. CULPEPPER: No questions.

MR. HESLIN: No further questions for this witness.

COMMISSIONER BROWN-BLAND: All right. Then I think that was pretty painless, Mr. Yoho.

THE WITNESS: Thank you very much.

COMMISSIONER BROWN-BLAND: We wish you well, and you may -- you're excused. You may step down.

THE WITNESS: Thank you very much.

(Witness excused.)

MR. HESLIN: At this time Piedmont calls Victor Gaglio to the stand.

VICTOR M. GAGLIO; Having been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MR. HESLIN:

Q Can you please state your full name for the record?

A Victor M. Gaglio.

Q And what is your position with the Company?

A I'm Senior Vice President and Chief Operating Officer for the natural gas business unit of Duke Energy.

Q Did you submit prefiled testimony in this case on April 1st, 2019 consisting of 19 pages of written testimony and three accompanying exhibits?

A Yes, I did.

Q And was that testimony and those exhibits prepared by you or under your supervision?

A Yes, they were.

Q Do you have any corrections or revisions to your testimony or the exhibits?

A No, I don't.

Q If I were to ask you the same questions as though indicated in your prefiled testimony today, would your answers be the same?

A They would.

MR. HESLIN: Commissioner Brown-Bland, at this time we would ask that Mr. Gaglio's testimony consisting of 17 (sic) pages of written testimony and his summary -- well, just the testimony at this point be accepted into the record as if given delivered orally.

COMMISSIONER BROWN-BLAND: Without objection that motion will be allowed. And I believe earlier you said it was 19 pages.

MR. HESLIN: That's right. Thanks for the correction. That would be 19 pages of written testimony submitted by Mr. Gaglio. Thank you for that correction.

COMMISSIONER BROWN-BLAND: All right.

(Whereupon, the prefiled direct testimony of Victor M. Gaglio was copied into the record as if given orally from the stand.)

Q. Mr. Gaglio, please state your name and business address.

A. My name is Victor M. Gaglio. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

A. I am a Senior Vice President and Chief Operations Officer, Natural Gas Business for Duke Energy Corporation ("Duke Energy").

Q. Please describe your educational and professional background.

A. I graduated from Virginia Polytechnic Institute and State University with a B.S. in Engineering Science and Mechanics. I have attended development programs at the University of Virginia's Darden School of Business, University of Pennsylvania's Wharton School of Business and the University of Michigan's Ross School of Business. I serve on the Board of Directors for the Interstate Natural Gas Association of America ("INGAA") and I have previously held various leadership positions on technical committees for the Southern Gas Association ("SGA") and the American Gas Association ("AGA"). From 1981 until 2012, I served in various positions with Columbia Gas and NiSource culminating in my final position with that company of Senior Vice President of Operations for NiSource Gas Transmission and Storage. I joined Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company") in 2012. I held the position of Senior Vice President and Chief Utility Operations Officer at Piedmont until the business combination transaction between Duke

Energy and Piedmont, at which point I was promoted to my current position.

Q. Have you previously testified before this Commission or any other regulatory authority?

A. Yes. I have testified before this Commission on several occasions and have also testified before the Public Service Commission of South Carolina and the Tennessee Public Utility Commission (and its predecessor agency, the Tennessee Regulatory Authority).

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

A. My testimony in this proceeding will address: (1) Piedmont's efforts and activities undertaken in compliance with the requirements of federal pipeline safety regulations promulgated by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") since Piedmont's last general rate case; (2) Piedmont's projected spending on PHMSA compliance over the coming years in light of ongoing and projected changes to PHMSA regulatory requirements; (3) the importance of Piedmont's Integrity Management Rider ("IMR") mechanism to both its past and projected future spending on PHMSA compliance; (4) Piedmont's proposal to implement a Distribution Integrity Management Program ("DIMP") operations and maintenance ("O&M") expense deferral mechanism similar to that authorized for Public Service Company of North Carolina, Inc.; (5) Piedmont's incurrence of increased utility locate expenses in many parts of our service territory; (6) our efforts to reduce methane leakage from our system; and (7) our need for new infrastructure projects to support growth and deliverability in the eastern part of our system.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I have 3 exhibits. Exhibit_(VMG-1) is a summary of Piedmont's cumulative PHMSA compliance activity and utility plant additions since our last general rate case proceeding. Exhibit_ (VMG-2) is a projection of Piedmont's PHMSA compliance utility plant additions for 2019 through 2021. Exhibit_(VMG-3) is a summary of projected incremental DIMP expense activity.

Q. Were these exhibits prepared by you or under your direction?

A. Yes.

PHMSA Compliance Activities Since Piedmont's Last General Rate Case

Q. Can you provide an overview of Piedmont's PHMSA compliance activities since Piedmont's last general rate case?

A. Yes. As the Commission is aware, Piedmont is subject to expansive regulatory requirements imposed by PHMSA under its Transmission Integrity Management Program ("TIMP") and DIMP regulations. These regulations are issued under the authority of Subparts O and P of Part 192 of the regulations of the United States Department of Transportation and are fully binding on Piedmont as a provider of natural gas transmission and distribution services. These regulations require that Piedmont engage in extensive assessment, testing, planning, verification, record-keeping, documentation, inspection, and quality assurance activities with respect to its 2,711 miles of transmission main (and appurtenant facilities) and its 16,292 miles of distribution main (and appurtenant facilities). In compliance with these regulations, Piedmont has engaged in a broad range of compliance activities with respect to its transmission and distribution facilities since its last general rate case.

Q. Can you provide a summary of these activities?

A. Yes. During the period 2014 through 2018, Piedmont expended more than $1.18 billion in compliance with PHMSA integrity regulations on a wide variety of capital and O&M projects and activities designed to ensure that Piedmont's system remains safe and is fully compliant with applicable regulatory requirements. A summary of these projects is attached hereto as Exhibit_(VMG-1). The projects involved with these integrity investments cover a broad range of activities and include, among others:

(1) the analysis and designation of High Consequence Areas ("HCAs") within Piedmont's service territory;[1]

(2) the gathering and review of Piedmont's archived engineering files on its transmission and distribution facilities;

(3) the development of a new, integrated electronic system ("OASIS") designed to provide a centralized platform on which integrity management data can be stored and queried and which is

[1] Piedmont has 269 miles of HCAs in North Carolina.

also capable of managing and documenting ongoing integrity management compliance;

(4) retrofitting significant portions of Piedmont's transmission system to facilitate inspection of those facilities using smart-pig technology;[2]

(5) the actual survey and inspection of Piedmont's transmission lines using smart-pig technology;

(6) the mitigation or repair of flaws and defects detected through smart-pig inspections;

(7) the removal, repair, replacement, and/or upgrade of certain pipeline segments, including small diameter pipelines, where necessary to comply with PHMSA regulations either because of administrative documentation deficiencies or because they are non-compliant with current prevailing standards for modern pipeline facilities; and

(8) pipeline casing remediation and corrosion control.

Q. **Are these the types of activities Piedmont anticipated having to conduct in discussing prospective PHMSA compliance requirements in Piedmont's last rate case?**

A. Yes. I would say that we largely understood the bulk of the requirements that were imposed on us when we came before this Commission in 2013

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2 Smart-pig is an industry term for inspection devices that are inserted into pipelines to record information about the condition of a pipeline. They are used to detect conditions such as corrosion or metal loss.

for our last general rate case (Docket No. G-9, Sub 631). Having said that, we could not then anticipate exactly what sorts of remedial actions would be necessary based upon the results of our investigations or exactly how much each of the anticipated PHMSA compliance requirements would cost. What we discovered through experience is that the scope of activities required by our compliance with PHMSA turned out to be larger than we initially projected.

Q. Can you elaborate?

A. Yes, in my testimony in our last rate case, I projected approximately $150 million a year in PHMSA compliance-related spending going forward. Our actual PHMSA compliance experience has averaged approximately $230 million a year of utility plant additions.

Q. Can you explain the difference?

A. There is no simple answer that explains the entire difference other than to say that the scope, scale, and cost of PHMSA compliance turned out to be larger than we anticipated. Much of the difference is attributable to the fact that when we started engaging in a very granular analysis of our transmission facilities through smart-pig inspections, we found more anomalies that needed to be addressed than we originally anticipated finding. These were not necessarily leaks (in almost all cases they were not), but every time we found a dent, evidence of corrosion, a weak spot in the pipe, or a failure in cathodic protection we were obliged to analyze the risk associated with the anomaly and devise mitigation measures even if the anomaly was not currently dangerous. We also do not have complete control over the costs of undertaking specific projects since much of the PHMSA compliance work to date has been conducted by outside contractors who bid for the opportunity to do such work. Because the entire industry has ramped up to comply with PHMSA requirements over the last five years or so, competition for qualified contractors has increased, which has had an inflationary impact on costs of construction.

Q. **Have customers benefitted from Piedmont's PHMSA compliance work?**

A. Yes, and so has the public at large. Our system is both much safer and more transparent to us now than it was in 2013.

Q. **What has contributed the most to system safety?**

A. Obviously, any time we identify and remedy a potential physical system vulnerability, system safety is improved when that vulnerability is addressed. But our new systems, as they continue to be implemented, also allow us to manage our compliance activities efficiently with most of the data we need to engage in such management at our fingertips. This is a vast improvement from 2013 when most of our records relating to system construction, maintenance and repair were in paper format.

Q. **How does Piedmont prioritize TIMP and DIMP remediation requirements for discovered anomalies?**

A. We have a sophisticated risk analysis system that analyzes the type of anomaly in terms of the consequences of failure versus the likelihood of failure and then prioritizes mitigation measures associated with that anomaly accordingly.

Q. Are you satisfied with the progress Piedmont has made over the last five years and is Piedmont currently compliant with its obligations under PHMSA regulations?

A. Yes. We have made huge progress in the last five years in terms of system safety and integrity and we are currently compliant with our obligations under PHMSA. In the last five years we have retrofitted more than 600 miles of our North Carolina transmission system to make it piggable. During that same period we have actually conducted in-line inspections of more than 800 miles of transmission main and have uncovered more than 800 anomalies, more than 350 of which we have repaired or otherwise mitigated.

Q. Does that mean the TIMP and DIMP work that Piedmont has been heavily engaged in is coming to an end?

A. No. By design, the TIMP and DIMP requirements of PHMSA are cyclical and iterative. As such, we will continue to engage in the inspection, assessment, remediation, and documentation cycle with respect to both transmission and distribution integrity on an ongoing basis. Resulting capital costs as well as O&M expenses will continue to be difficult to predict because remediation is dependent on the inspection findings.

Proposed Changes to PHMSA Compliance Requirements and Piedmont's Anticipated PHMSA Expenditures for Fiscal Years 2020 Through 2023

Q. Are PHMSA's regulations static or do you anticipate changes to those regulations in the future?

A. We do anticipate changes to PHMSA's regulations in the future and actually have anticipated such changes for several years. PHMSA has been contemplating for some time now issuing what is referred to in the industry as the "Mega-Rule" which, if ultimately issued, will expand the requirements of PHMSA compliance.

Q. What is the Mega-Rule?

A. It is now actually three proposed rules that are under consideration by PHMSA and are anticipated to be issued by PHMSA in the near future. These three rules, if issued, will substantially expand obligations currently in effect and applicable to transmission providers relative to materials verification, maximum allowable operating pressure ("MAOP") testing, non-HCA assessments, repair criteria, corrosion control, and assessment requirements, among others. It will implement new Integrity Verification Process requirements and also expand many of the existing PHMSA requirements applicable to HCAs to Moderate Consequence Areas ("MCAs"), effectively expanding the geographic scope of the existing PHMSA obligations.

Q. What will be the impact of the Mega-Rule if it is ultimately issued by PHMSA?

A. Until we see what parts of the proposed rules are actually approved by PHMSA, it is somewhat difficult to predict with any certainty what the exact impact will be. However, it is a foregone conclusion that federal pipeline safety and integrity requirements will be increased as a result of the Mega-Rule.

Q. Does Piedmont have a projection of the cost of PHMSA compliance activities anticipated in the next few years?

A. Yes. Our current capital cost projection for North Carolina PHMSA compliance activities for 2019 through 2021 is attached hereto as Exhibit_(VMG-2). This capital cost projection, averaging approximately $173 million per year for the next three years, is based upon existing PHMSA compliance commitments. These amounts do not include any costs for compliance with the Mega-Rule requirements. We would anticipate material increases to this forecast if the Mega-Rule becomes applicable to Piedmont during this period, but are currently unable to provide specific projections about how large those increases might be.

The Importance of Continuing Piedmont's Integrity Management Rider Mechanism to Mitigate the Impacts of Continuing and Expanding PHMSA Compliance Requirements

Q. Please describe the importance of the IMR mechanism to Piedmont's efforts to ensure compliance with PHMSA pipeline safety and integrity requirements.

A. Nearly 50% of Piedmont's plant additions during the period since our last rate case have been committed to integrity management projects. Because of the accelerated cost recovery opportunity associated with these projects under the IMR, Piedmont does not face the inherent challenges created by normal regulatory lag associated with these capital projects. The IMR mechanism also disassociates our engineering efforts at compliance from normal budgetary and ratemaking considerations, allowing us to focus on the continuing safety and reliability of the Piedmont system without the need to "compete" for capital internally within the company and without being concerned with how investment in integrity projects will impact the company's return or drive rate case activity.

Q. Do you believe that it is important to continue to have the IMR mechanism available on an ongoing basis?

A. Yes. As I indicated above, this mechanism facilitates our ability to pursue compliance with PHMSA regulations in a significant way. In the face of potentially expanded PHMSA regulatory requirements under the Mega-Rule, I believe that it is absolutely critical to maintain the IMR as a means of facilitating our investment in projects which improve the safety and reliability of our operations and just as importantly comply with federal law. Mr. Barkley provides additional information and sponsors the IMR mechanism in his testimony and exhibits.

Q. Will there be any negative consequences if Piedmont's IMR mechanism is not extended by the Commission in this proceeding?

A. Yes. A failure to continue the IMR mechanism will create added pressure to seek additional rate relief from the Commission in the future in order to roll Piedmont's system integrity investments, which generate no incremental revenue, into rate base.

Q. In your opinion, does Piedmont's IMR mechanism constitute a reasonable approach to dealing with the significant ongoing capital costs associated with federal TIMP and DIMP requirements?

A. Yes. These costs will continue to be incurred and they will continue to be significant. If they are not addressed through the IMR mechanism, they will cause additional and unnecessary rate cases to be filed on a serial basis. Our IMR mechanism is a much more efficient way for all parties to deal with these extraordinary expenses and for that reason it is in the public interest.

Q. Are IMR type mechanisms common in the natural gas industry?

A. Yes. As discussed by Mr. Barkley, over 40 states have similar mechanisms designed to facilitate accelerated recovery of capital expenditures outside the filing of general rate case proceedings.

<u>Piedmont's Proposed DIMP O&M Expense Deferral Mechanism</u>

Q. Is the Company proposing regulatory asset treatment in this case relative to its ongoing O&M activities associated with compliance with federal DIMP requirements?

A. Yes. Piedmont is proposing to establish a deferral mechanism in this case to provide for the recovery of costs associated with certain DIMP O&M expenses on an intra-rate case basis. Mr. Barkley addresses the actual proposed deferral mechanism in his testimony. My testimony below describes the nature and scope of these future O&M expenses and the underlying justification for our proposed DIMP O&M expense deferral mechanism and why it is in the public interest.

Q. Why is it necessary to establish a deferral mechanism for DIMP O&M expenses?

A. The purpose of our DIMP plan is to continuously improve the safety of our distribution piping system by reducing pipeline safety risk. This is accomplished by identifying and evaluating threats to the distribution system and implementing programs aimed at mitigating the risks those threats pose. The success of a new program is unknown until it is implemented and evaluated. Some programs may need refinement while others may be determined to be ineffective. Similarly, some may be completed in a finite period whereas others may be permanent and ongoing. This up-front uncertainty is why a deferral mechanism is appropriate for capturing these costs.

Q. What is the estimated impact of this deferral mechanism?

A. Piedmont's incremental O&M expense requirements related to compliance with federal laws governing distribution integrity and safety efforts are projected to be significant in the years immediately following this rate case. In the five years projected on Exhibit_(VMG-3), incremental annual DIMP-related O&M expenses are projected to average approximately $11 million, which is a material amount to the Company. All of the expenses reflected on Exhibit_(VMG-3) will involve external contractors; Piedmont labor expense is not included in the amounts shown on this exhibit nor in the Company's requested cost deferral. These expenditures will be the direct result of Piedmont's prudent efforts to comply with prevailing federal standards for distribution integrity and safety. Because of the nature of these costs and their projected magnitude, the Company is proposing to establish a deferral mechanism in this case to provide for the recovery of costs associated with these DIMP O&M expenditures in the interim period between rate cases. Mr. Barkley addresses the actual proposed deferral mechanism in his testimony.

Q. Please describe these incremental O&M expenses.

A. These expenses fall into the following five categories:

- Establishing a formal cross bore inspection program. This involves visual inspection of sewer lines for possible contact with our natural gas lines.
- Analyzing tickets called into the North Carolina 811 Underground Utility Damage Prevention Organization. Tickets identified as high risk will prompt direct contact with excavators as a means of reducing damages to our pipelines.

- Conducting investigations to ensure that all distribution pipeline assets can be located in order to reduce excavation-related damages.
- Completing a robust digital mapping of distribution mains, services and related equipment.
- Performing close interval surveys on high pressure distribution piping.

Q. Will these incremental expenses be readily identifiable on Piedmont's books?

A. Yes, they will be. Piedmont will track these expenses separately and in a manner that will facilitate auditing by the Public Staff or any other appropriate party.

Q. Why can't you simply build these costs into your pro forma revenue requirement in this case?

A. Because they are highly variable in nature and, at present, we do not have enough information to formulate a reasonably certain estimate of what those costs will be from year to year. Importantly, the amount of remediation generated by a more comprehensive analysis of cross bore risks and non-locatable pipe cannot be determined at this time. Based upon these facts, we believe that it is preferable and in the public interest to seek regulatory asset treatment with respect to these anticipated costs rather than to rely on a fairly speculative cost projection in our revenue requirement for such costs.

Q. Does Piedmont have a similar mechanism for TIMP-related O&M expenditures?

A. Yes. Cost deferral for incremental and extraordinary TIMP-related O&M expenses was granted by this Commission by order issued December 2, 2004 in Docket No. G-9, Sub 495. Based on the ongoing nature and amount of these expenses, especially considering the potentially significant and current unknown impact of the pending Mega-Rule, I believe this cost deferral should continue in its current state. Ms. Powers elaborates on past activity and proposed treatment of these expenses in her testimony.

<u>**Increased Locate Expenses**</u>

Q. Is Piedmont experiencing an increase in expenses associated with "locate" requests?

A. Yes. Due primarily to increased activity by cable, internet, and telecommunications providers who are engaged in a widespread upgrade of existing facilities, we are receiving and expect to continue to receive an increased number of locate requests. So far in 2019, these requests have increased by more than 17% as compared to the same period of time in 2018, and we expect a continuation of this trend going forward. This activity is expected to increase our going-level annual O&M expense amount by approximately $1.7 million. Ms. Powers includes an associated pro forma O&M expense adjustment in her testimony and supporting schedules.

Methane Containment

Q. Is Piedmont aware of the assertions by some fossil fuel critics that due to leaks in the production, transmission, and distribution of natural gas the relative environmental benefits of using natural gas as a fuel in place of coal or oil is suspect?

A. Yes. We are aware of these statements.

Q. Do you have an opinion about the merit of this position?

A, Yes. In general, I disagree with the notion that natural gas is not a significant improvement over coal and fuel oil in terms of resulting emissions and potential impacts on climate change. Having said that, however, I wanted to advise the Commission that Piedmont is taking affirmative steps to reduce methane emissions on its system.

Q. What affirmative steps is Piedmont taking to reduce methane emissions on its system?

A. Piedmont has responded to the issue of methane leaks with several mitigation initiatives. The most significant initiatives are as follows:

- As necessary during pipeline pigging operations, the Company flares natural gas in lieu of releasing the methane into the atmosphere;
- Compressor station maintenance practices have been modified in order to limit the number of occasions that require venting and the amount of gas vented during such occasions.

- We have reduced by over 30% the number of third-party excavation related gas leaks caused by failure of the third-party excavator to request a marking of our pipelines by stressing frequent and proactive communication with the excavation community. These efforts began in 2017 and are a part of Piedmont's voluntary participation in the US EPA's Methane Challenge Program.

ACP and Robeson LNG

Q. Can you briefly explain the importance of these two projects to Piedmont?

A. Yes. Each of these pending projects provides two critical functions for Piedmont. First, they both provide access to new peak day and, in the case of ACP, year-round supplies of natural gas to meet Piedmont's customers growing natural gas needs. In doing so, they provide greater diversification in supply sources and they also help mitigate the negative impacts of increasing constraints on traditional delivery flexibility on the Transco system. These are significant benefits to Piedmont's system and Piedmont's customers. Second, they also both provide critical pressure and operational support for our system in periods of high demand that cannot otherwise be readily provided. If Piedmont were to try to provide a similar level of operational support through the construction of new facilities connected to our traditional supply sources, the costs would be in the hundreds of millions of dollars with no real increase in interstate capacity rights or supply access.

Q. What is the status of these two projects?

A. The Robeson LNG project is under construction at this time and we anticipate that it will be operational in the summer of 2021. ACP is currently stalled as the interstate pipeline works through some administrative and permitting issues created by unfavorable rulings from the US Court of Appeals for the Fourth Circuit.

Q. Do you expect that ACP will be able to overcome these obstacles?

A. I do. The federal agencies with direct jurisdiction over the pipeline and its construction have all supported the project and continue to support it – there have just been some perceived flaws in the administrative actions approving the pipeline that require correction. The unfortunate part of the rulings by the Fourth Circuit is that the construction progress and in-service delays attendant to those rulings are increasing the costs of the project without any discernible benefit to the public.

Q. Do you have anything to add to your testimony?

A. No, not at this time.

BY MR. HESLIN:

Q Did you prepare a summary of your testimony for this hearing?

A Yes, I did. My name is Victor M. Gaglio, and I am the Senior Vice President and Chief Operations Officer of the natural gas business unit for Duke Energy Corporation. I prefiled direct testimony in this docket on April 1st, 2019 in support of Piedmont's Application for a General Rate Case Increase.

My prefiled direct testimony addresses the following seven topics: 1) the efforts and activities undertaken by Piedmont in compliance with the requirements of the federal pipeline safety regulations promulgated by the Pipeline and Hazardous Material Safety Administration, PHMSA, since Piedmont's last general rate case; 2) Piedmont's projected spending on PHMSA compliance over the coming years, in light of ongoing and projected changes to PHMSA regulatory requirements; 3) the importance of Piedmont Integrity Management Rider mechanism to both its past and projected future spending on PHMSA compliance; 4) Piedmont's proposal to implement a distribution integrity management program operations and maintenance expense deferral mechanism similar to that authorized for Public Service Company of North

Carolina; 5) Piedmont's incurrence of increased utility locate expenses in many parts of our service territory; 6) the Company's efforts to reduce methane leakage from its system; and 7) Piedmont's need for new infrastructure projects, specifically the Atlantic Coast Pipeline project and the Robeson LNG facility, to support growth and deliverability in the eastern part of our system.

My prefiled direct testimony is accompanied by three exhibits. The first exhibit is a summary of Piedmont's cumulative PHMSA compliance activity and utility plant additions since our last general rate case proceeding; the second exhibit is a projection of Piedmont's PHMSA compliance utility plant additions for 2019 through 2021; and the third exhibit is a summary of projected incremental DIMP expense activity.

In summary, my prefiled direct testimony demonstrates Piedmont's commitment to compliance with federal pipeline safety regulations and the scope of its compliance with those activities. Piedmont recognizes and appreciates the Commission's willingness to support such mechanisms with effective regulatory mechanisms.

Thank you. This concludes my summary comments.

MR. HESLIN: The witness is available for cross examination, if any, and questions by the Commission.

COMMISSIONER BROWN-BLAND: Thank you, Mr. Heslin. Is there any cross examination for this witness?

(No response.)

COMMISSIONER BROWN-BLAND: All right. The Commission has a few questions for you, too, Mr. Gaglio.

THE WITNESS: Okay.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q In your prefiled direct testimony you discuss or you indicate that the Company has invested about 1.2 billion in system growth and 1.1 billion to comply with federal pipeline safety regulations. In the Commission's Order in that last rate case, the Commission commented on the need to be aware of the impact of rate--- on ratepayers of capital investments, and the Commission noted that it expected Piedmont to take a proactive role in ensuring that new federal pipeline safety regulations were reasonable for Piedmont's ratepayers and the general public in North Carolina. Tell us what actions Piedmont has taken to meet the Commission's expectations in this regard.

A Yeah. We have filed comments as Piedmont Natural Gas, and we've also participated with our industry trade groups, the American Gas Association and the Interstate Natural Gas Administration. In just June of 2018 they submitted 190 pages of comments to PHMSA regarding the mega rule that -- that's been proposed for a number of years now. And we also participate in something referred to as the GPAC. It's a Gas Pipeline Advisory Committee, and it's a group of industry people, regulators, and members of the public, to come up with reasonableness around these upcoming regulations.

So with that, we've seen benefits. This was coming out as one major rule called the mega rule. Through these efforts it's now coming out as three separate rules that will be spread out over time and be more manageable and practical to implement.

Q Can you tell us about these proposals and rules?

A Yeah. They really originate out of the San Bruno incident in September of 2010. The bulk of it -- there's a lot of stuff in it, but primarily it is around verifying the maximum allowable operating pressures on the pipelines you operate, making sure you've got good material data associated with that. There's enhanced -- there's enhanced corrosion control efforts associated with it. It expands what was a high consequence area in the original transmission integrity rule to a new concept called moderate consequence areas, so it expands the integrity rule over a much broader area of the pipeline.

Those are some of the highlights of it. I could go into some more detail, if it's helpful.

Q With regard to these and any other proposals, did Piedmont specifically bring to the table for discussion the issue of cost effectiveness of these proposals and measures?

A Yes, we did, especially from a material testing perspective. Some of the original recommendations coming out of the National Safety Transportation Board was requiring you to take cutouts of sections of pipe for every 100 feet when you're doing repair work, and that would mean taking the pipeline out of service, making repairs on what could probably be a perfectly good pipeline, and since then we've come up with better approaches. It's much more cost effective and it meets the ultimate goal of safety, which is our mutual -- mutual goal by all the parties.

Q And so you would say there was traction around -- there was success around your efforts to --

A Yeah.

Q -- get everybody focused on cost effectiveness?

A Yes, definitely.

Q And everybody was receptive to those concepts?

A Yes.

Q Tell us about and describe liquefaction storage and vaporization capacity of the Robeson LNG facility.

A Okay. Yeah. The three pieces to a -- to a LNG plant, one is liquefaction. That's where you take a vapor and turn it into a liquid and put it into a tank. The liquefaction is designed at a rate of 10 million standard cubic feet a day. This facility will have a storage tank with a capacity of 1 billion cubic feet. And the vaporization, that's taking the liquid and turning it back into a gas, that will be at a rate of 200,000 dekatherms a day.

Q All right. And how does that compare with the liquefaction storage and vaporization capacity of other LNG facilities --

A Well --

Q -- that Piedmont owns?

A -- we've got two other LNG facilities in the state of North Carolina. One is in Bentonville, North Carolina; the other is in Huntersville, North Carolina.

For the Bentonville, liquefaction rate is the same as it would be for -- for Robeson, 10 million standard cubic feet a day. Same size storage tank, 1 billion cubic feet. The vaporization is a little lower there. It's 120,000 dekatherms a day as opposed to the 200,000 at Robeson.

Huntersville has a lower liquefaction rate. It's 3 to 5 million cubic feet a day. Same size storage tank, a billion cubic feet, and a vaporization rate that's slightly lower at 100 million standard cubic feet a day.

Q All right. And you've testified that both ACP and Robeson LNG provide critical pressure and operational support for your system in periods of high demand that can't otherwise be readily provided. Have Piedmont's LNG facilities historically been used to meet periods of high demand?

A Oh, they have, yes. We depend on them in the coldest days of the winter. You know, when we talk about liquefaction, I'll use the Robeson plant, for example, it'll -- it would -- at 10 million cubic feet a day it would take 100 days to fill that tank to a billion cubic feet. With a 200,000 dekatherm rate, it would take just, you know, just five days to empty that tank. So we store that, we use it at the most critical times of the year, and we try and spread that out when we need -- when the need is the highest from a temperature perspective.

Q Okay. And with the growth for demand for use of natural gas for electric generation, will LNG be used to meet high demand in the hot summer -- on hot summer days? Do you foresee that?

A It -- it's not in our plans, as I've mentioned, and it -- we use the summer to fill those tanks. Like I said, Robeson will take 100 days, Bentonville would take about that same time, and Huntersville is more like around 200 days to fill the tank. So if there was an emergency on the system, we -- like Frank had said, we could -- we could turn the system around, but that's not a one-day thing. It takes -- it takes some time to be able to flip from one mode to another. But we'd have to be mindful of having that tank full for the winter when we really needed it most. We'd probably look to other alternatives as a first option, as opposed to trying to withdraw LNG in the summertime.

Q All right. And in your testimony you discuss the incremental DIMP related O&M expenses, and there you mention a cross bore inspection program that involves visually inspecting sewer lines --

A Yes.

Q -- to see if they come into contact with your natural gas lines. Is it reasonable to assume that directional drillers might have bored through sewer lines while installing other utilities?

A It is, yeah, and that's why we run those -- that's why we want to run those cameras to see if -- first, if there's anything impeding the sewer line already, and then be able to run the camera afterwards to make sure any work we did didn't damage the sewer line where our gas line would have been drilled through -- through a sewer line.

Q Now, would Piedmont engage others to share in the cost of the -- of that program or to sell --

A That would --

Q -- the results?

A That's certainly our goal and expectation. Our experience in Ohio has shown that that's a definite possibility. We would collect a lot of good electronic data for sewer operators. It would be able to show them where they may need to be doing maintenance on their system, which we think would be of high value to them. They would be the ultimate decision maker as to whether they saw the value of it and budgeted accordingly to help fund that, but it is our intention to share in the cost.

Q And that sharing, if it should occur, would help mitigate the cost to your ratepayers?

A Yes.

Q All right. With regard to the Company's methane reduction efforts, does the Company have any statistics on the results or the impact of those efforts on the volume of methane released?

A Not -- not so much statistics. What I will tell you is we haven't documented or formally tallied our methane reduction efforts, but we have participated in a voluntary methane reduction program that's focused on damage prevention. And the idea there is to reduce the number of damages to our line that releases methane in the air. We started that voluntary program in 2016, and we've reduced the damage to our pipelines by 30 percent since then. We haven't equated what that amounts to in methane reduction, but we're going to start trying to do those calculations.

We do a few other things, again, that we haven't formally documented, but one of them, as you all know, we do a lot of internal inspection of our lines through the smart pigging process. During that we used to vent gas to atmosphere. We use a flaring operation now, and for this -- for this year we'll have reduced methane emissions by 105 million cubic feet for the year by doing the flaring operation.

Another thing we've done, maintenance practice at our compressor stations we've got to do an annual emergency shutdown test. Historically, we used to -- and the purpose of that is to make sure you can isolate that station in a period of five minutes or less in the event there's an emergency, and traditionally you would vent all that -- valves would close, vents would open, and you'd vent all that gas to atmosphere. We now put flanges on top of the vents, so the -- we can still clock how quickly it takes the valves to operate to get to closure, but we're not venting the gas to atmosphere anymore. And that -- at six locations, that's about 1.3 million cubic feet we've saved in a year.

And some other operations that we've changed over time has to do with repairs we make on our system. If we've got to do a cutout on a pipeline, we would typically close valves in that section, vent the gas that's within that section, and then go in and make that repair. Today we use techniques where we no longer have to do that. We'll put what -- a device called a STOPPLE, and we'll hot tap the line and just isolate that section that needs to be replaced and minimize the amount of -- of gas that's -- methane that has to be emitted to the atmosphere.

Q So you know that you've either stopped or reduced the amount of escaping emissions that were -- that were coming from your operations, but you don't have any kind of quantification of what -- how much that amounts to?

A We haven't been keeping score to this point, but we're going to do that going forward. We have ways to go about that now.

Q All right. And tell me, you know, just at a high level, something I'm capable of understanding, about how the flaring operation works.

A Right. What -- the tool has to run through the line at about three to four miles an hour. If it goes too slow, it gets stuck and stops. If it goes too fast, you don't get good data on the condition of the pipe. So we'll use a flare to control the flow of gas through our gas control. They'll be bringing supply in front of the -- in front of the tool, and we'll be flaring it at the other end where it's going to be coming out to control the speed of the tool running through it.

Q All right. Thank you. And this gets somewhat into the questions that Commissioner Clodfelter had begun to ask Mr. Yoho, but at the hearing in Wilmington we had a public witness, Mr. Jefferson Currie, who expressed concern that an elementary school and a church were just about a mile from the Robeson LNG facility, and he expressed some concern that those facilities, the school and the church, would be in jeopardy from accidents and explosions. Can you talk to us about those concerns and why --

A Yeah.

Q -- he might have them and how they might be mitigated if they --

A I mean, it --

Q -- are concerns?

A -- it's understandable that people unfamiliar with an operation like that would be concerned. This facility is going to be sitting on 640 acres of our property. As a liquid, LNG is not explosive. It becomes explosive if it's in a contained area. If the tank were to leak, we've got an earthen dike around there to hold its capacity, but it would be in an open area and it would vaporize quickly. So the -- there hasn't been an LNG explosion because the liquid -- the liquid in that state does not -- does not explode.

Q All right. And your Robeson facility is being built and operated pursuant to Federal Regulation 49 CFR 193; is that correct?

A That's correct.

Q You're familiar with that?
A Yes.
Q Do those -- do your existing LNG facilities have the capability to put the LNG in liquid form into trucks for sale?
A Yes. The Bentonville and the Huntersville both have the ability to bring tankers in for LNG sales or transport to another LNG facility, and the Robeson facility will have the same capabilities.
Q Has Piedmont been asked to provide trucked LNG to any potential customers?
A We have, yes.
Q What can you tell us about that?
A I don't know the details around that. Sarah Stabley in our group manages -- manages those from a supply perspective, but they do schedule the trucks with our LNG plants, and so we know when trucks are coming in, at what amount, and we plan to staff up when those trucks come in to be able to fill them when they arrive.
Q Is there a tariff for that rate, for that service?
A I'm not familiar with that aspect. We'll have to refer to somebody else on that.
Q Do you know if that service is done just

pursuant to negotiated contract?

A I do not. I'm sorry.

Q All right. Do you know what witness I might ask about?

A I'm not sure if we've got somebody here to answer that right now or not.

MR. HESLIN: I believe Ms. Powers will be able to answer those particular questions.

THE WITNESS: Okay.

COMMISSIONER BROWN-BLAND: All right. We'll wait to hear from her, then.

Q Going back to Mr. Currie, he made reference to the illegal dumping, and this was the question that Mr. Yoho referenced you, although he did provide an answer. But he made -- but Mr. Currie made reference to illegal dumping, such as the groundwater contamination at the Huntersville LNG site. Can you explain anything further about --

A Yeah.

Q -- what Mr. Currie may have been referencing?

A Mr. Yoho did a good job of explaining, but what we discovered in 2008 was that there was unauthorized and improper waste management practices at the site that occurred in the mid 1990s. One of the materials in the processing is called a molecular sieve. It's oftentimes beads of aluminum, that it's used to bring gas -- when the gas comes into the system, it's used to purify it to take water and dirt contaminants out, and after about a 10-year period that material needs to be replaced. So this was disposed of in an improper way and has not -- has not occurred since then.

As Mr. Yoho said, it was a solid waste. It wasn't properly characterized at the time. It was determined to have characteristic of a hazardous waste. We removed about 6,000 tons of material. And, again, it was fully remediated in 2010 in accordance with DEQ procedures.

Q All right. And were there any other types of spills or releases or --

A No. And that -- and that --

Q -- disposals that he might have been referencing?

A Yeah. And that wasn't a spill or a release. It was just poor waste management practices.

Q All right. The Commission is aware that there was recently a tragic accident involving natural gas near Charlotte that resulted in a fatality. To your knowledge, was a leak on the system a cause of the accident?

A It was not. We were contacted by the Charlotte Fire Department after they arrived. We assisted them in -- at the scene. Our first order of business was to check the area to make sure our system was safe. We did a leak inspection on the piping outside of the home and in the neighborhood. We also did a pressure test on the service line going to that home, and we put pressure gauges on the -- on other parts of the neighborhood and the pressure was stable. We also did odorization tests to make sure there was a proper level of odorant in the gas, and it was at adequate odorant levels. The fire department concluded that the incident was caused by a problem inside the home. It wasn't on jurisdictional pipe.

Q All right. And I believe PHMSA reports statistics on jurisdictional accidents. Do you know how many fatalities per year are typically seen on the natural gas transmission and distribution system nationwide?

A Yes. I will say that natural gas pipelines continue to be -- are proven to be the safest form of energy transportation, but having said that, any fatality is tragic and unacceptable, and this industry learns from those incidences and comes up with methods to prevent them from occurring in the future.

PHMSA statistics puts things in averages for transmission and distribution pipe. They did a 20-year average, and there were 13 fatalities in the 20-year average. In the 10-year average it was 10, in the five-year average it was 11, and the three-year average is eight. So it has decreased in the past 20 years from 13 fatalities a year to eight, and that's both transmission and distribution nationwide.

Q All right. Thank you. Let's see. In the Stipulation there's discussion about the Line 434 Revenue Rider, and do you have the information that you could tell us about Line 434?

A I can tell you about Line 434. It's a 35-mile, 30-inch pipeline that connects Piedmont's existing transmission infrastructure in Richmond County to our existing infrastructure in Robeson County at a place we call Junction A. It parallels our existing west to east pipeline. We placed that facility in service in 2018, and that proved to be a critical asset for us last winter for our firm customers.

Line 434 was contemplated along with three other projects for the purpose of redelivering Atlantic

Coast Pipeline supply to our customers. That was expected to be in service in November of 2018. In 2017 it became apparent that ACP was not going to be available, so we needed to look at what we could do to ensure meeting -- meeting the requirements of our firm customers in the winter of 2018, 2019, and for some unknown length in the future.

We looked at construction of Line 434. We would be able to complete the construction in time for that winter, and it proved to be the lowest cost mitigant. We also had to look at things like running redundant horsepower we have at our compressor stations and looking at utilizing LNG that might not have been during the coldest periods of time to be able to meet supply.

So if ACP is continually delayed, we're going to have to continue to look at modifications to our system to meet our firm customer demands. One thing we're doing this year is as we go into another winter, we're making modifications to the Monroe compressor station to be able to provide additional assistance there.

I'll say while ACP is inactive, the state of North Carolina is not. The demand for natural gas continues to go up, and we've got an obligation to do what we need to, to try and meet that need. I'd say with or without ACP, Line 434 is going to be used and useful. It was last year, and it will continue to be into the future.

Q All right.

COMMISSIONER BROWN-BLAND: Are there other questions from the Commission for this witness?

(No response.)

COMMISSIONER BROWN-BLAND: All right. Are there questions on the Commission's questions?

MS. CULPEPPER: No questions.

COMMISSIONER BROWN-BLAND: Mr. Heslin?

MR. HESLIN: No further questions, but at this time we would ask that Exhibits -- Piedmont Exhibits VMG-1, VMG-2, and VMG-3 be accepted into evidence.

COMMISSIONER BROWN-BLAND: All right. Without objection, those exhibits will be accepted and identified as they were premarked when prefiled, and they will be received into evidence.

MR. HESLIN: Thank you, Your Honor.

(Whereupon, Exhibits VMG-1 through VMG-3 were identified as premarked and admitted into evidence.)

COMMISSIONER BROWN-BLAND: All right.

THE WITNESS: Thank you.

COMMISSIONER BROWN-BLAND: Mr. Gaglio, before you step down, is this also your last time before us, you think, at least in the capacity that you --

THE WITNESS: Probably so. I'll be around until February 1st, but I don't know of any proceedings between now and then.

COMMISSIONER BROWN-BLAND: Well, all right. Well, we wish you well, and we thank you for your cooperation in this matter today.

THE WITNESS: Well, thank you.

COMMISSIONER BROWN-BLAND: You may be excused.

(Witness excused.)

MR. HESLIN: Piedmont calls John Sullivan to the stand.

JOHN L. SULLIVAN, III; Having been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MR. HESLIN:

Q Please state your full name for the record.

A John L. Sullivan, III.

Q And what is your position with the Company?

A I'm the Director of Corporate Finance and Assistant Treasurer for Duke Energy Business Services and the Assistant Treasurer for Piedmont Natural Gas Company.

Q Did you submit prefiled testimony in this case on April 1st, 2019, consisting of 17 pages of written testimony and three accompanying exhibits?

A Yes.

Q Was that testimony and those exhibits prepared by you or at your -- or under your supervision?

A Yes.

Q Do you have any corrections or revisions to your testimony or those exhibits?

A No.

Q If I were to ask you the same questions as those indicated in your testimony, your prefiled testimony today, would your answers be the same?

A They would.

MR. HESLIN: Okay. At this time we would ask that Mr. Sullivan's testimony consisting of 17 pages of written testimony be accepted into the record as if delivered orally.

COMMISSIONER BROWN-BLAND: Without objection, Mr. Sullivan's prefiled testimony -- direct testimony will be received into the record as if given orally.

(Whereupon, the prefiled direct testimony of John L. Sullivan, III was copied into the record as if given orally from the stand.)

Q. Please state your name and business address.

A. My name is John L. Sullivan, III. My business address is 550 South Tryon Street, Charlotte, North Carolina.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as Director, Corporate Finance and Assistant Treasurer. I am also the Assistant Treasurer for Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company").

Q. Please describe your educational and professional background.

A. I received a Bachelor of Arts degree from the University of North Carolina-Chapel Hill in 1995 and an MBA degree from Wake Forest University in 2000. From 2000 to 2009, I worked in Bank of America's Global Corporate & Investment Banking unit, providing corporate finance, capital markets and strategic advisory services to energy and power clients. In 2009, I joined Duke Energy as a General Manager in the Treasury group. In 2010, I moved to Duke Energy's Corporate Development group where I served as a Director responsible for managing various strategic transactions for the Company's regulated and commercial businesses. In January 2016, I returned to Duke Energy's Treasury department and assumed my current role.

Q. Have you previously testified before this Commission or any other regulatory authority?

A. I have not testified previously before the North Carolina Utilities

Commission but I have filed testimony on behalf of other Duke Energy utility affiliates in other jurisdictions, including proceedings before state regulatory commissions in South Carolina, Ohio, and Kentucky.

Q. Do you have any exhibits supporting your testimony?

A. Yes, I have three exhibits. Exhibit__(JLS-1) shows the calculation of Piedmont's pro forma capital structure in this proceeding, including Piedmont's proposed cost of short-term and long-term debt and the Return on Equity ("ROE") recommendation of the Company's expert witness, Robert Hevert. Exhibit__(JLS-2) shows the derivation of the pro forma embedded cost of long term debt. Exhibit__(JLS-3) shows the derivation of the pro forma embedded cost of short term debt.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

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

A. My testimony will address Piedmont's financial objectives, capital structure, and cost of capital. I will also discuss the Company's current credit ratings and forecasted capital needs. Throughout my testimony, I will emphasize the importance of Piedmont's ongoing ability to meet its financial objectives and the benefits to customers resulting from Piedmont maintaining financial stability and strong credit ratings.

Q. Please provide an overview of your testimony.

A. As is discussed in greater detail in my testimony, Piedmont faces substantial capital needs over the next several years in order to continue its compliance with federal pipeline safety and reliability regulations and to construct new pipeline facilities in order to serve its growing North Carolina markets. In order to meet these capital demands, the Company will compete for capital in the open market and must appeal to debt and equity investors to attract the capital it needs.

Investors have a variety of investment opportunities available to them, and require a return commensurate with the risk they incur. Investors are less likely to invest in a company if they feel the expected return doesn't fairly compensate for the perceived risk of the investment. A company with lower credit quality weakens its attractiveness as an investment opportunity relative to similarly situated companies with higher credit quality. For this reason, it is critically important that a company maintain strong investment-grade credit quality, in order to assure its financial strength and flexibility and ensure access to capital on reasonable terms.

Piedmont has and will continue to make significant capital investments in order to meet its obligations under pipeline safety and integrity regulations promulgated by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") and to continue to provide cost effective, safe, and reliable natural gas service to its growing customer base within the State of North Carolina. The Company's proposed rate increase will allow the Company to recover prudently incurred costs, to compete in the capital markets for needed capital, and preserve its financial standing with both equity and debt investors as well as the credit rating agencies, to the long-term benefit of customers.

Q. What role does capital structure and financial stability play in Piedmont's ability to provide safe, reliable, and economic natural gas service to its customers?

A. Financial stability and consistent access to capital are necessary for Piedmont to provide safe, reliable, and economical service to its customers. Piedmont strives at all times to maintain financial stability, including investment grade credit ratings, to ensure reliable access to capital on reasonable terms. Our ability to access needed capital on reasonable terms is supported by the following specific objectives of the Company: (a) maintaining a strong (52% or higher) equity component in our capital structure; (b) pursuing timely recovery of prudently incurred costs of providing utility service; (c) maintaining sufficient cash-flows to meet our obligations; and (d) maintaining an adequate rate of return on common equity.

Q. What is Piedmont's proposed capital structure in this proceeding?

A. As shown on my Exhibit_(JLS-1), I recommend a capital structure consisting of 52.00% equity, 0.82% short-term debt and 47.18% long-term debt.

Q. Why did you choose this pro forma capital structure?

A. This capital structure represents an appropriate amount of risk due to leverage (48% or lower) while minimizing the weighted average cost of capital. Approval of the proposed capital structure will help Piedmont maintain its credit quality, the importance of which I will describe in subsequent sections of my testimony, and is consistent with Duke Energy's target credit ratings for Piedmont. The short-term debt component of the recommended capital structure is a thirteen-month average value of Piedmont's natural gas inventory balance. Procurement of natural gas is the largest driver of Piedmont's short-term indebtedness under normal operating conditions. The Commission has approved this method of calculating the short-term debt component of Piedmont's capital structure in multiple previous general rate case dockets.

Q. Does the Company's actual financial capital structure vary over time?

A. Yes, it does. The specific debt/equity ratio will vary over time, depending on a variety of factors, including, but not limited to, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, changes to inventory balances, equity infusions received from parent, and dividend payments made to the parent company. Achieving an approved regulatory capital structure as recommended above is consistent with the Company's financial objectives and overall plan to finance operations at favorable rates for customers. Piedmont will manage its capital structure within a reasonable range of this base. As of December 31, 2018, Piedmont's capital structure, including a thirteen-month average of natural gas inventory as a proxy for short-term debt, was 53.43% equity, 45.56% long-term debt and 1.01% short-term debt.

Q. What changes in the Company's capital structure will occur after December 31, 2018 and over the next two years?

A. As reflected on Exhibit_(JLS-1), Piedmont plans to issue approximately $600 million of long-term debt in the second quarter of 2019. Also in 2019, Piedmont is expected to receive an estimated $150 million equity infusion from its parent. Equity will also increase due to earnings achieved over the proforma period.

Q. What cost rates did you attribute to each component of the Company's capital structure?

A. I utilized a cost rate of 4.55% for long-term debt, 2.82% for short-term debt, and 10.60% for common equity.

Q. How were these cost rates determined?

A. For the Company's cost of common equity, I utilized the cost calculated and recommended by Piedmont's ROE Witness Robert Hevert in his direct testimony. For long-term debt, I used Piedmont's actual embedded cost of long-term debt as of December 31, 2018 adjusted for the previously referenced long-term debt offering planned for Q2 2019. For short-term debt, the rate was based on the Company's projected 2019 average borrowing rate under the Utility Money Pool Agreement. The derivation of these debt rates is shown on Exhibit_(JLS-2) and Exhibit_(JLS-3).

Q. Please explain credit quality and credit ratings, and how they are determined.

A. Credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. An assessment of Piedmont's creditworthiness is performed by two major credit rating agencies, Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"). Many qualitative and quantitative factors go into this assessment. Qualitative aspects may include an assessment of the regulatory climate in which Piedmont operates, Piedmont's record for delivering on its commitments, the strength of its management team, its operating performance, and the strength of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which Piedmont maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest and principal payments in particular) on the basis of internally-generated cash. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Q. What is the role of regulation in the determination of the financial strength of a utility company?

A. Investors, investment analysts, and credit rating agencies regard constructive regulation as one of the most important factors in assessing a utility company's financial strength. These stakeholders want to be confident the Company operates in a stable regulatory environment that will allow the Company to recover prudently-incurred costs and earn a reasonable return on investments necessary to meet the demand, reliability, service, and environmental requirements of its customers and service area. Important considerations include the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, and the strength of its capital structure. Positive consideration is also given for utilities operating in states where the regulatory process is streamlined, the time lag in capital investment recovery is minimized through cost recovery mechanisms such as riders and trackers, and outcomes are equitably balanced between customers and investors.

Q. How are Piedmont's outstanding securities currently rated by the credit rating agencies?

A. As of the date of this testimony, Piedmont's senior unsecured credit ratings and outlooks are as follows:

Rating Agency	S&P	Mood
Senior Unsecured	A-	A3
Outlook	Stable	Stable

Obligations carrying a credit rating in the "A" category are considered strong, investment-grade securities subject to low credit risk for the investor. "A" rated debt is presumed to be somewhat susceptible to changes in circumstances and economic conditions; however, the debt issuer's capacity to meet its financial commitments is considered strong. By contrast, ratings in the "BBB" (one level weaker than the "A" category) category are considered adequate and have less assurance of access to the capital markets in challenging market conditions.

S&P may also modify its ratings with the use of a plus or minus sign to further indicate the relative standing within a major rating category. An "A+" credit rating is at the higher end of the "A" credit rating category and an "A-"is at the lower end of the category. Moody's credit rating assignments use the numbers "1", "2" and "3", with the numbers "1" and "3" analogous to a "+" and "-", respectively. For example, Moody's credit ratings of "A2" and "A3" would be analogous to "A" and "A-" credit ratings at S&P.

The ratings outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years). Piedmont's "Stable" outlook at S&P and Moody's is an indication the credit ratings are not likely to change at this time, however a change in outlook or rating could occur if the Company experiences a change in its business or financial risk.

Q. Do Piedmont's customers benefit from the Company's strong credit ratings?

A. Yes. To ensure reliable and cost-effective service, compliance with federal pipeline safety regulations and to fulfill its obligations to serve customers, the Company must continuously plan and execute significant capital projects. This is the nature of regulated, capital-intensive industries like natural gas utilities. The Company must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions. The financial markets can experience periods of volatility, and Piedmont must be able to finance its needs throughout such periods. Strong investment-grade credit ratings provide Piedmont with greater access to the capital markets on reasonable terms during such periods of volatility. Any factors that negatively impact Piedmont's credit ratings, including an inadequate allowed ROE or an inadequate equity percentage of the capital structure, have the potential to reduce the Company's access to the capital markets and to increase the cost of such access.

Approval of the Company's request in this case will support its financial objectives by allowing timely recovery of its investments in plant and equipment, providing sufficient cash flows to fund necessary capital expenditures and service debt.

Q. What strengths and weaknesses have the credit rating agencies identified with respect to Piedmont?

A. The rating agencies believe Piedmont operates in generally constructive regulatory environments that support long-term credit quality, and they also view the Company's customer growth profile and system integrity investments as credit supportive. However, the rating agencies have identified a number of challenges Piedmont faces in maintaining its credit ratings. In August 2018, Moody's identified several factors that could adversely impact Piedmont's financial metrics (specifically, cash flow coverage ratios), which, in turn, could affect its ratings.[1]

Capital Expenditures: Moody's notes elevated capital expenditures and the associated leverage to fund customer growth and system integrity investments may weaken key credit metrics.

Tax Reform: Moody's estimates that federal tax reform will have a negative impact on regulated utilities, including Piedmont, due to reduced cash flows, which, in turn, places downward pressure on credit metrics.

Q. How do the rating agencies view the impact of tax reform on utility credit quality?

A. In January 2018, Moody's published a report outlining its initial assessment of the impact of tax reform on the regulated utility sector.[2] In its report, Moody's noted "the legislation was broadly credit positive for corporate cash flows but for regulated investor-owned utilities, which include electric, gas, and water utilities, the effect was the opposite." In addition to outlining the negative impact of tax reform on utilities and the regulatory uncertainties related thereto, Moody's changed the rating outlook of 24 utilities (including Duke Energy Corporation and Piedmont)

1 *See* Moody's Investors Service, Credit Opinion, "Piedmont Natural Gas Company, Inc. – Update to Credit Analysis," August 8, 2018 ("August 2018 Piedmont Report")
2 *See* Moody's Investors Service, Sector Comment, "Tax Reform is Credit Negative for Sector, but Impact Varies by Company," January 24, 2018 ("January 2018 Moody's Report")

from "Stable" to "Negative."[3]

In June 2018, Moody's updated its 2019 outlook for the regulated utility sector to "Negative" from "Stable."[4] A key factor in this outlook change was a decline in cash flows. Moody's stated that "the combination of a lower tax rate and the loss of bonus depreciation as a result of the federal Tax Cuts & Job Act ("TCJA") in December 2017 means that utilities and their holding companies will lose some of the cash flow contribution from deferred taxes on an ongoing basis."[5] Moody's estimated that since 2010, the cash due to deferred taxes averaged 14 percent of Funds from Operations ("FFO"), which is a measure of cash flow generated by a company's operations, on a consolidated basis.

Q. Has Moody's resolved its "Negative" Outlook on Duke Energy Corp. resulting from tax reform?

A. Yes. Of the 24 utilities Moody's placed on "Negative" outlook in January 2018, Duke Energy was the first to have its outlook restored. In August 2018, Moody's issued a credit opinion restoring Duke Energy's outlook to "Stable."[6] Moody's attributed this to an expectation that Duke Energy will maintain supportive regulatory relationships and highlighted credit supportive rate case outcomes across several regulatory jurisdictions. Moody's also described how Duke Energy's 2018 common equity

3 January 2018 Moody's Report, p. 1
4 *See* Moody's Investors Service, Outlook, "2019 Outlook Shifts to Negative Due to Weaker Cash Flows, Continued High Leverage," June 18, 2018 ("June 2018 Moody's Report")
5 June 2018 Moody's Report, p. 2
6 *See* Moody's Investors Service, Credit Opinion, "Duke Energy Corporation – Update Following Change of Outlook to Stable," August 14, 2018 ("August 2018 DE Corporation Report")

issuance of approximately $2.0 billion and reduced capital program in response to tax reform helped reduce parent-level debt financing.

Q. Has Moody's resolved its "Negative" Outlook on Piedmont?

A. Yes. After seven months on "Negative" outlook, Piedmont was downgraded on August 1, 2018 to "A3" from "A2" and placed on "Stable" outlook by Moody's. In its updated credit opinion following the downgrade, Moody's notes that weaker credit metrics over the near term are expected as the Company's significant capital investments coupled with the reduced corporate tax rate and loss of bonus depreciation from federal tax reform place downward pressure on Piedmont's cash flows.[7] The downgrade by Moody's to "A3" brought Piedmont's senior unsecured rating in-line with the Company's "A-" rating from S&P.

Q. What role do equity investors play in the financing of Piedmont, and how will the outcome of this case impact these investors?

A. Equity investors provide the foundation of a company's capitalization by providing significant amounts of capital, for which an appropriate economic return is required. Piedmont compensates equity investors for the risk of their investment by targeting fair and adequate returns, stable cash flows, and earnings growth - all necessary to preserve access to equity capital. Returns to equity investors are realized only after all operating expenses and fixed payment obligations (including principal and interest) of the business have been paid. Because equity investors are the

7 August 2018 Piedmont Report, p. 3

last to receive surplus earnings and cash flows, their investment involves significantly more risk. For this reason, equity investors require a higher return for their investment. Equity investors expect utilities like Piedmont to recover their prudently incurred costs and earn a fair and reasonable return for their investors. The Company's proposal in this proceeding supports this investor expectation.

Q. What effect does capital structure and return on equity have on credit quality?

A. Capital structure and return on equity are important components of credit quality. As mentioned in the previous answer, the greater the equity component of capitalization, the safer the returns are to debt investors, which translates into higher credit quality and lower borrowing costs. In addition, the allowed return on equity is a key component in the generation of earnings and cash flows. An adequate return on equity helps ensure equity investors receive fair compensation for their investment while also helping to protect the interests of debt investors. A strong capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. High credit quality creates financial flexibility by improving access to the capital markets on reasonable terms, and ultimately lower debt financing costs.

Q. Do you believe Piedmont's capital structure has an adequate equity component to enable the Company to achieve the company's financial

strength and credit quality objectives?

A. Yes. Piedmont' requested equity component of 52% enables it to maintain current credit ratings and financial strength and flexibility. Like many utilities, Piedmont is in a period of significant capital investment necessary to provide cost-effective, safe, and reliable service to its customers in a period of rising costs, growing customer load and evolving state and federal pipeline safety and integrity requirements. The magnitude of its capital requirements dictates the need for a strong equity component of the Company's capital structure in order to assure access to capital funding at reasonable terms.

Q. What are Piedmont's capital requirements over the next three years?

A. Piedmont faces substantial capital needs over the next several years in order to comply with pipeline safety and integrity regulations, refurbish, replace and upgrade aging infrastructure, construct additional on-system storage assets, and satisfy its debt maturities. The Company's capital requirements for the next three years (2019-2021) are projected to be in the range of $2.8 billion. This amount consists of approximately $2.3 billion in projected capital expenditures and approximately $500 million in debt retirements.

Q. How will Piedmont's capital requirements be funded?

A. Piedmont's capital requirements are expected to be funded from internal cash generation, the issuance of debt, and equity contributions from its parent. It is important to remember that Duke Energy also has dividend expectations from its shareholders. Duke Energy's corporate dividend policy targets a 70 percent payout ratio, based on adjusted diluted earnings per share. Piedmont, and other Duke Energy utility subsidiaries are expected to support this dividend policy over time.

Q. Do you anticipate Piedmont will be able to access sufficient debt and equity to support its ongoing operations without any problems?

A. I do, but the reasonableness of the terms upon which Piedmont can access those markets depends largely on Piedmont continuing to maintain favorable credit ratings. That, in turn, depends on the regulatory treatment Piedmont receives from the state public service commissions that regulate the Company. This is particularly true for this rate case and this Commission as North Carolina accounts for over 70% the Company's rate base and earnings potential.

Q. Can you explain?

A. Yes. Piedmont's investors and creditors carefully evaluate how we are regulated by this Commission, including what levels of allowed return are approved in our general rate proceedings. They are aware that allowed rates of return may vary over time with changes in general economic factors but they also believe we operate in a generally constructive regulatory environment – a conclusion with which we agree and which we believe is a significant benefit to our customers. This favorable regulatory environment assessment creates the potential that any ruling by the Commission perceived as unfair would lead investors and rating agencies to reconsider their views on the regulatory environment in NC. This, in turn, could raise capital costs for Piedmont and its customers. This vulnerability is especially acute in light of Piedmont's significant and ongoing investments in capital projects required to meet federal safety and integrity management requirements.

Piedmont management recognizes the Commission must balance the interests of customers with those of the Company when setting rates of return and capital structure in any general rate proceeding. At the same time, it is important to consider the long-term consequences these decisions can have on the terms under which Piedmont can access capital markets.

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

A. Yes.

BY MR. HESLIN:

Q And Mr. Sullivan, did you prepare a summary of your testimony for this hearing?

A Yes.

Q Okay. After we hand it out, we'll ask you to read it.

COMMISSIONER GRAY: And Mr. Sullivan, I'll ask that you speak into the microphone, please.

THE WITNESS: Yes, sir.

COMMISSIONER GRAY: Thank you.

A Good afternoon, Commissioners. My name is John L. Sullivan, III, and I am the Director of Corporate Finance and Assistant Treasurer for Duke Energy Business Services, LLC. I'm also Assistant Treasurer for Piedmont Natural Gas Company. I prefiled direct testimony in this docket on April 1st, 2019 in support of Piedmont's Application for a General Rate Increase.

My prefiled direct testimony addresses Piedmont's financial objectives, capital structure, and cost of capital. I also discuss the Company's current credit ratings and forecasted capital needs.

My testimony emphasizes the importance of Piedmont's ability to meet its financial objectives and how customers benefit from Piedmont maintaining financial stability and strong credit ratings. I provide an overview of Piedmont's substantial capital needs to maintain compliance with federal pipeline safety and reliability regulations and to construct new pipelines to serve its growing North Carolina markets.

My testimony explains how the Company competes for capital in the open market and must appeal to debt and equity investors to attract the capital it needs. I discuss how investors have a variety of investment opportunities available to them, and that it's critically important a company such as Piedmont maintain strong investment grade credit quality to ensure access to capital on reasonable terms.

My testimony also demonstrates that the Company's proposed rate increase will allow it to recover prudently incurred costs, raise capital at competitive terms, and preserve the Company's financial standing with both debt and equity investors, as well as the credit rating agencies, to the long-term benefit of customers.

My prefiled direct testimony is supported by three exhibits. My first exhibit shows the calculation of Piedmont's actual and projected capital structure in this proceeding, including Piedmont's proposed cost of short-term and long-term debt and the return on equity recommendation of Company expert Witness Robert Hevert. My second exhibit shows the derivation of the pro forma embedded cost of long-term debt, and my third exhibit shows the derivation of the pro forma embedded cost of short-term debt.

MR. HESLIN: The witness is available for cross examination, if any, and questions from the Commission.

COMMISSIONER BROWN-BLAND: All right. Thank you, Mr. Heslin. Is there any cross examination for Mr. Sullivan?

(No response.)

COMMISSIONER BROWN-BLAND: Well, there being none, the Commission has at least one question for you, Mr. Sullivan.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q And that is in your testimony, you discuss the capital structure for the Company as of December 31st, 2018. You recall?

A Yes.

Q What is Piedmont's actual capital structure as of June 30th?

A Yes. As included in Exhibit 1, as of December 31st it was an equity layer of 53.4 percent, but moving forward to June 30th, 2019, that measure went to 49.7

percent. And I can provide a bit of context as to how an equity ratio could swing that much in a six-month period of time going from above 53 percent to just below 50 percent.

Q Please do that for us.

A So on May 24th of this year, five weeks before that June 30th calculation, Piedmont completed a $600 million long-term debt issuance, and that represents the largest -- the single largest debt issuance in Piedmont's corporate history. And so by presenting the facts as of December 18th, it showed one capital structure, but we wanted to refresh that to show the most recent capital structure.

Also, in Exhibit 1 we anticipated that, and so we showed three other snapshots of what the capital structure would look like on a pro forma basis, making some assumptions about what would transpire in the next 18 months, including that $600 million debt issuance and the infusion of equity capital from the parent company. And the equity -- you know, the equity component of the capital structure sort of stayed within a roughly 50 percent to 53 -- 53.4 percent band and helped us, arriving at our proposed 52 percent equity component.

Q All right. And then what's the structure in terms of the debt and the long -- long and short-term debt?

A Sure. So with 52 percent equity, the remaining portion would be 48 percent debt split, still consistent with what was presented in Exhibit 1, which, I believe, is .85 -- sorry -- .82 percent short-term debt and 47.18 percent long-term debt.

Q Okay. And that's in the Exhibit 1 that was filed with your direct testimony, correct?

A That was in my direct testimony, but --

MR. HESLIN: Correct. And when he refers to Exhibit 1 in his testimony today, he's referring to JLS-1 from his prefiled testimony.

COMMISSIONER BROWN-BLAND: All right. Thank you for that. Any questions for this witness?

(No response.)

COMMISSIONER BROWN-BLAND: Any cross examination?

MS. CULPEPPER: No questions.

COMMISSIONER BROWN-BLAND: Or not cross, but questions on Commission's questions.

MR. HESLIN: Just a few questions.

EXAMINATION BY MR. HESLIN:

Q You mentioned the reasons for the fluctuations in the capital structure from December 31st, 2018 to June 30th, 2019, and you mentioned the -- the one time or the largest single debt issuance by Piedmont. What are other factors that impact the capital structure of a company like Piedmont?

A Sure. Seasonality and the timing of large capital expenditures. Another major influence is equity capital raising. In June of 2018 Duke Energy Corp., the parent company, infused 300 million of equity capital into Piedmont, and then again in June of 2019 Duke Energy did another $150 million equity infusion. Inventories can also have a play in it, but those are the -- those are the largest components.

Q Okay. Thank you.

MR. HESLIN: We have no further questions, but at this time I'd ask permission to approach the witness to lay the foundation for an exhibit for later cross examination.

COMMISSIONER BROWN-BLAND: You're allowed to.

(Whereupon, Exhibit JLS-4 was marked for identification.)

Q Mr. Sullivan, you've been handed what has been marked as JLS-4, for the record. Do you see that?

A Yes.

Q And what is it?

A It is a summary of approved ROEs by the North Carolina Utility Commission over a decade, spanning from 2008 to 2018.

Q And do you see the specific docket numbers listed on the -- in the third column --

A Yes.

Q -- which indicate North Carolina Utilities Commission docket numbers?

A Yes.

Q And to your knowledge, does this document accurately reflect the dates, overall cost rate, equity percentage, and NCUC allowed return on equity from those dockets?

A Yes.

MR. HESLIN: At this time we'd ask that Piedmont Exhibit JLS-4 be accepted into evidence.

COMMISSIONER BROWN-BLAND: Is there any objection?

(No response.)

COMMISSIONER BROWN-BLAND: There being no objection, that motion will be allowed. It will be received into evidence.

(Whereupon, Exhibit JLS-4 was

admitted into evidence.)

MR. HESLIN: Nothing further from this witness.

COMMISSIONER BROWN-BLAND: I think we have three other exhibits, JLS?

MR. HESLIN: Oh, thank -- thank you. Yes. At this time Piedmont would request that JLS-1, JLS-2, and JLS-3 be accepted into evidence.

COMMISSIONER BROWN-BLAND: All right. Without objection, that will be allowed, and JLS-1 through 3 exhibits will be received into evidence.

(Whereupon, Exhibits JLS-1 through JLS-3 were admitted into evidence.)

MR. HESLIN: Thank you, Your Honor. No further.

COMMISSIONER BROWN-BLAND: Mr. Sullivan, you may step down. Thank you.

THE WITNESS: Thank you.

(Witness excused.)

MR. JEFFRIES: Madam Chairman, Piedmont would call as its next witness Ms. Kally Couzens. I'm sorry -- Couzens.

KALLY COUZENS; Having been duly sworn, Testified as follows:

MR. JEFFRIES: Thank you, Ms. Couzens. Let me first apologize for bungling your name. I know better than that.

COMMISSIONER BROWN-BLAND: And the Commission will apologize, too.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q Could you state your full name and business address for the record, please?

A Kally Couzens, 4720 Piedmont Row Drive, Charlotte, North Carolina.

Q And you work for Piedmont Natural Gas; is that correct?

A That's correct.

Q And what's your title?

A I am their Rates and Regulatory Strategy Manager.

Q All right. And what are your responsibilities as the Rates and Regulatory Strategy Manager?

A I'm responsible for implementing rates, among other -- other matters, such as our IMR mechanism, and making sure that we take care of the appropriate filings for those.

Q Okay. Are you the same Kally Couzens that prefiled direct testimony on April 1 of this year consisting of 12 pages?

A Yes, I am.

MR. JEFFRIES: And Madam Chair, if -- I'd ask for clarification. We intend and had agreed with the other parties to present our witnesses -- all of our witnesses' testimony at the same time while they're on the stand, rather than having them do direct and then come back up and then come back and do rebuttal. I wanted to make sure that approach was agreeable to the Commission?

COMMISSIONER BROWN-BLAND: It is.

MR. JEFFRIES: Okay. Thank you.

Q And so you also prefiled supplemental on July 29th of this year, and that -- and that consisted of four pages and Exhibits KAC-1 through 4 Updated; is that correct?

A That's correct.

Q Okay. Thank you. Was that testimony and were those exhibits prepared by you or under your direction?

A Yes.

Q And do you have any corrections to them?

A No corrections.

Q All right. And if I ask you the same questions while you're on the stand today that are set forth in your prefiled testimonies, would your answers be the same?

A Yes.

MR. JEFFRIES: Madam Chairman, we would ask that Ms. Couzens' prefiled testimonies be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: That motion will be allowed. Her prefiled testimonies, both direct and supplemental, will be received and treated as if given orally from the stand.

(Whereupon, the prefiled direct and supplemental testimonies of Kally A. Couzens were copied into the record as if given orally from the stand.)

Q. Ms. Couzens, please state your name and business address.

A. My name is Kally Couzens. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

A. I am employed by Piedmont Natural Gas Company, Inc., ("Piedmont" or "the Company") as the Rates & Regulatory Strategy Manager.

Q. Please describe your educational and professional background.

A. I graduated from the University of South Florida in May of 2001 with a Bachelor's Degree in Business Administration. I was employed by TECO Energy Inc. for six years from 2001 to 2007 as an Analyst in the Strategic and Financial Analysis department. I was hired by Piedmont as a Business Development Analyst in December 2007. In 2009 I joined Regulatory Affairs as a Senior Regulatory Affairs Analyst and I was promoted to my current position as Rates & Regulatory Strategy Manager in 2016.

Q. Have you previously testified before this Commission or any other regulatory authority?

A. Yes. I submitted testimony in Piedmont's last general rate case proceeding before this Commission in Docket No. G-9, Sub 631.

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

A. My testimony supports the Company's computation of pro forma revenues (i) for the sale and transportation of gas based on normalized test period throughput, and (ii) revenues other than operating revenues. I also provide updated computational factors for the operation of our Margin Decoupling Tracker ("MDT") mechanism and support the reasonableness of our proposed rate design.

Q. Do you have any exhibits as part of your testimony?

A. Yes. The following exhibits are part of my testimony and are attached hereto:

Exhibit__(KAC-1)	Pro Forma Revenues for the Sale and Transportation of Gas
Exhibit__(KAC-2)	Components of Pro Forma Revenues
Exhibit__(KAC-3)	Present and Proposed Rates
Exhibit__(KAC-4)	Proposed Factors for the Margin Decoupling Tracker Mechanism

Q. Were these exhibits prepared by you or under your direction?

A. Yes.

Test Period

Q. What test period did Piedmont utilize in preparing this case?

A. We used the 12 months ended December 31, 2018.

Pro Forma Revenues

Q. Please explain your initial pro forma revenue calculations for the sale and transportation of gas.

A. My starting point for these calculations is actual test period customer usage. In Column (1) of Exhibit__(KAC-1), I show the actual test period bills and sales and transportation volumes by rate schedule. In Column

(2), I show the adjustment made to normalize the test period volumes to reflect the expected throughput levels under normal weather conditions. Column (3) shows the results of the adjustments in Column (2) on the actual volumes shown in Column (1). Column (4) shows the growth factor adjustment applied to bills and normalized consumption through June 30, 2019 in order to match customer counts with the updated rate base and plant. Column (5) shows the resulting sales and transportation levels after adjustments due to normalization and growth. Column (6) reflects the total bills that would be expected for each customer class as a result of the adjustments. Column (7) shows the current approved rates. These "clean" rates[1] were applied to pro-forma bills and volumes to compute the pro forma revenues shown in Column (8). The Integrity Management Rider ("IMR") revenues shown in Column (8) reflect the IMR revenue requirements from Piedmont's most recent 2018 Annual IMR report, which was authorized by the Commission in Docket No. G-9, Sub 734. Column (9) shows the adjustments made to revenues to reflect the Margin Decoupling Tracking mechanism, projected revenue requirement changes from the IMR mechanism and revenue changes to certain customer contracts. These adjustments were used to properly compute the pro forma revenues shown in Column (10).

Q. Please explain the normalization adjustment shown in Column (2).

1 "Clean" rates, as applied to billing determinates for the computation of pro forma revenues in Exhibit_(KAC-1) is comprised of Piedmont's current base margin rates, Piedmont's current COG commodity rates, and Piedmont's current COG demand rates.

A. This adjustment is necessary to adjust actual volumes to the quantities that would have been delivered had weather conditions been normal during the test period. Actual winter weather during the test period was 5.8% colder than the 30-year average used for normal, while the summer period was 3.7% colder than normal. To calculate this adjustment, I used our standard method of normalizing volumes, which has been accepted by the Commission in prior rate proceedings.

Q. Please explain the growth adjustment shown in Column (4).

A. The growth adjustment projects changes to the number of customers billed and future consumption levels anticipated through June 30, 2019. The methodology used for this adjustment is identical to the methodology used by the Company in prior rate case proceedings. This adjustment is made to match pro forma revenues with the expense and rate base adjustments to reflect ongoing business activity through June 30, 2019.

Q. Please explain the calculations in columns 5, 6, 7 & 8.

A. The growth adjustment in Column (4) is applied to the test period annual bills from Column (1) and the normalized volumes in Column (3) to derive the pro forma dekatherms shown in Column (5) and the pro forma bills shown in Column (6). These quantities are then priced out at our existing approved rates, which are shown in Column (7). The results are shown in Column (8), labeled Calculated Revenues. The IMR revenues also shown in Column (8) reflect the IMR revenue requirements authorized from Piedmont's 2018 Annual IMR report.

Q. Please explain what adjustments to revenues were captured in Column (9)

A. Column (9) incorporates revenue adjustments for the Margin Decoupling Tracker mechanism, the IMR and certain special contracts.

Q. Please explain the Margin Decoupling Tracker adjustments shown in Column (9).

A. The Margin Decoupling Tracker adjustments apply to the Residential, Small General and Medium General Service rate schedules. The adjustment to volumetric revenues shown in Column (9) increases total Residential pro forma revenues and decreases total Small and Medium General pro forma revenues to properly reflect the impact of the Margin Decoupling Tracker mechanism as defined in Appendix C of the Company's Service Regulations. The calculation is necessary to adjust margin in a manner that reflects the going-level of annual margin for the pro forma bills as identified in Column (6).

Q. Please explain the IMR adjustments shown in Column (9).

A. The IMR revenue adjustments apply to all rate classes. The IMR revenue adjustment shown in Column (9) reflects Piedmont's projected change in IMR revenue requirements based on projected integrity plant in-service at March 31, 2019 and rates effective June 1, 2019.

Q. Please explain the customer contract adjustments shown in Column (9).

A. Piedmont has certain non-residential customers that take gas service pursuant to a contract with Piedmont. In order to appropriately reflect the going-level revenues for those customers, I made adjustments based on the terms of those contracts.

Q. What are the results of these various calculations?

A. After all of the adjustments described above, I calculate total pro forma revenues for the sale and transportation of gas to be $916,267,107. This amount is shown in Line 356, Column (10) of Exhibit__(KAC-1). This total pro forma revenue amount is comprised of three categories of revenues. Margin revenues, cost of gas ("COG") commodity revenues and COG demand revenues. Exhibit__(KAC-2) provides the breakdown of total pro forma revenues by these three categories by rate schedule. Line 356 of Exhibit__(KAC-2), shows total pro forma revenues by category as follows:

Table 1

Revenue Category	Pro forma Amount	Reference
Margin Revenues	$583,246,668	Exhibit_(KAC-2) Line 356, Column 6
COG Commodity Revenues	$215,405,141	Exhibit_(KAC-2) Line 356, Column 10
COG Demand Revenues	$117,615,298	Exhibit_(KAC-2) Line 356, Column 8
Total Pro forma Revenues	$916,267,107	Exhibit_(KAC-1) Line 356, Column 10

Q. Do the figures and calculations shown in Exhibit__(KAC-1) and Exhibit__(KAC-2) accurately represent Piedmont's normalized and adjusted pro forma volumes and revenues for gas sales and transportation for ratemaking purposes in this docket?

A. Yes.

Q. Please explain your pro forma revenue calculations for other operating revenues.

A. My starting point for these calculations is actual test period per books other operating revenues, which amounted to $7,005,460. This amount largely consists of late payment charge revenue, rental revenue from gas properties, and other miscellaneous revenue. I made accounting and pro forma adjustments to bring this amount to the appropriate going-level amount of $4,343,374 for rate making purposes in the proceeding.[2]

Q. Please summarize the total pro forma revenues for rate making in this proceeding.

A. In summary, the appropriate amount of total pro forma revenues for rate making in this proceeding is $920,610,481. This amount is the sum of my computation of total pro forma revenues for the sale and transportation of gas, cited previously in my testimony as $916,267,107, and my computation of other pro forma operating revenues of $4,343,374. These pro forma revenue amounts are used in the revenue deficiency computation explained in the testimony of Piedmont witness Pia Powers.

2 The workpaper for this adjustment is provided in G-1 Item 4(a) on page 46.

Proposed Rates and Rate Design

Q. **What are the rates proposed by the Company in this proceeding?**

A. Piedmont's proposed rates are set forth in Schedule 2 of Exhibit__(KAC-3) and on Appendix I to the petition in this proceeding. The Margin Decoupling Tracker Factors aligned with these rates are shown in Exhibit__(KAC-4). These proposed rates yield a total annual revenue amount of $999,085,991 for the sale and transportation of gas. In this rate case, Piedmont is not proposing any changes to its other operating revenues. Therefore, the total proposed revenues in this rate case is $1,003,429,366. This is an increase of $82,818,884 from the Company's pro forma revenues in this proceeding. The testimony of Piedmont witness Powers supports the derivation of the proposed change in revenues.

Q. **What specific components of revenues is the Company proposing to change?**

A. Piedmont is proposing an increase to the margin component of revenues and the COG demand component of revenues. The total proposed revenue for gas sales and transportation by revenue category is as follows:

Table 2

Revenue Category	Proposed Amount	Increase / (Decrease)
Margin Revenues	$664,420,211	$81,173,543
COG Commodity	$215,405,141	$0

Revenue Category	Proposed Amount	Increase / (Decrease)
Revenues		
COG Demand Revenues	$119,260,639	$1,645,341
Total Proposed Revenues	$999,085,991	$82,818,884

The proposed margin revenue amount shown in Table 2 incorporates the revenue effect of the proposed EDIT Rider. The testimony of Piedmont witness Bruce Barkley supports and describes the proposed EDIT Rider in detail.

Q. What rate design is Piedmont proposing in this proceeding?

A. We propose to use the same basic rate design, including fixed monthly charges, seasonal cost allocations, and step rates. This is the same rate design methodology that was approved by the Commission in our last general rate case proceeding in 2013.

Q. Does this mean that the rates will remain the same?

A. No. We are proposing to change the volumetric billing rates (the rates per them) to reflect our revised cost of service and updated throughput. We are not proposing to change the monthly fixed charge amount for any rate schedule.

Q. How did Piedmont determine its approach to rate design in this case?

A. Our main objective is to design rates that fairly price services to all customer classes while also providing a fair return to our investors. It is also critical to design rates that are reflective of conditions in the market place and which send the correct market signals. Our fundamental goal was to remain consistent with our existing rate structure. In looking at this approach, however, we also had to be mindful of not disproportionately or unfairly burdening one class of customers versus another class in allocating our proposed rate increase, particularly when considering the various factors historically used to analyze rates.

Q. **Did the Company perform a Cost of Service Study in this proceeding?**

A. Yes. We utilized Mr. Dan Yardley, an outside rate consultant with Yardley Associates, to prepare a class cost of service study. The results of Mr. Yardley's study are reflected in his testimony in this proceeding. His study generally shows that class rates of return under existing rates vary. Mr. Yardley proposes that the revenue increase requested by the Company in this proceeding be spread equally across all customer classes, which will generally lead to more equalized rates of return across customer classes than under existing rates.

Q. How do the Company's proposed rates conform to Mr. Yardley's recommendations?

A. We adopted Mr. Yardley's recommended rate design for proposed revenues, which is to spread our proposed increase evenly across our various customer classes. My conclusion is that our proposed rate design is reasonable and consistent with previous rate design proposals approved in prior proceedings before this Commission, and does not unduly burden any of the customer classes.

Q. Can you please summarize the net effects of the rates you propose in this proceeding?

A. Yes. Table 3 below illustrates the pro forma revenues attributable to each class of our customers, the proposed revenue increase for each such class, the resulting proposed revenues by class, and the percentage increase in revenues to be collected from each class under our proposed rates.

Table 3

Proposed Changes to Operating Revenue

	Pro Forma Revenue	Proposed Increase	Proposed Revenue	% Change
Residential	$478,790,701	$47,021,618	$525,812,319	9.8%
Small General	$227,581,080	$25,240,573	$252,821,654	11.1%
Medium General	$34,765,350	$3,597,985	$38,363,336	10.3%
Large Firm General	$42,106,572	$2,768,690	$ 44,875,262	6.6%
Large Interruptible	$27,363,893	$3,866,594	$ 31,230,487	14.1%
Military Transport	$2,289,879	$205,719	$2,495,598	9.0%
Overall[3]	$916,267,107	$82,820,089	$999,087,196	9.0%

3 Due to rate rounding, the sum of the proposed revenues by class yields an immaterial variation from the revenue requirement adjustment in total.

Q. In your opinion, are the revenue increases proposed by the Company in this case equitable and fair to all classes of customers?

A. Yes, the revenue increases proposed are equitable and fair to all rate classes and are consistent with the revenue recovery approach underlying our existing rates approved by this Commission in our 2013 rate case.

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Kally Couzens. My business address is 4720 Piedmont Row Drive, Charlotte, North Carolina.

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

A. I am the Rates & Regulatory Strategy Manager for Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company").

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

A. N.C. Gen. Stat. § 62-133(c) and Commission Rule R1-17(c) permit Piedmont to update its rate case filing through the date of the hearing of this matter. In our Application in this proceeding filed on April 1, 2019, we specifically and expressly reserved our right to make these updates. As discussed in the Supplemental Testimony of Pia Powers, the Company has now made such updates based on available actual information to reflect our actual cost of service calculation as of June 30, 2019. My Supplemental Testimony supports the updated computation of gas sales and transportation pro forma revenues used in Ms. Powers' updated cost of service calculation as of June 30, 2019. My Supplemental Testimony also supports the derivation of proposed rates as aligned with Ms. Powers' updated cost of service calculation as of June 30, 2019.

Q. Do you have any exhibits supporting your Supplemental Testimony?

A. Yes. The following updated exhibits are part of my Supplemental Testimony and are attached hereto:

- Exhibit_(KAC-1 UPDATED) Pro Forma Revenues for the Sale and Transportation of Gas
- Exhibit_(KAC-2 UPDATED) Components of Pro Forma Revenues
- Exhibit_(KAC-3 UPDATED) Present and Proposed Rates
- Exhibit_(KAC-4 UPDATED) Proposed Factors for the Margin Decoupling Tracker Mechanism

The present and proposed rates shown in Updated Appendix I in the Company's update filing is consistent with the present and proposed rates shown in Exhibit_(KAC-3 UPDATED).

Q. **Were these four exhibits prepared by you and/or prepared under your direct supervision?**

A. Yes.

Q. **Please explain the rationale for updating the pro forma sales and transportation revenues.**

A. In my direct filed testimony, I explained my computation of pro forma sales and transportation revenues for the purpose of establishing the Company's going-level revenues absent a rate adjustment in this proceeding. In the period of time since then, the Commission has reset certain components of the Company's customer billing rates. Specifically, per the Commission order in Docket Nos. G-9, Sub 731 and G-9, Sub 737, Piedmont's base margin billing rates were reduced effective May 1, 2019 consistent with recent federal and state corporate income tax rate reductions. Also, per Commission order in Docket No. G-9, Sub 748, Piedmont's IMR margin revenue requirement and billing rates were changed effective June 1, 2019. Incorporating the combined effect of these rate changes yields a level of pro forma sales and transportation revenues that differs from the amounts shown in the Company's original filed application. Therefore, I have updated my computation of pro forma sales and transportation revenues for the purpose of re-establishing the going-level revenues under the now current Commission approved rates. My update is reflected in Exhibit_(KAC-1 UPDATED) and Exhibit_(KAC-2 UPDATED).

Q. Were there any other changes incorporated into your update of pro forma sales and transportation revenues?

A. In addition to updating that computation using the now current Commission approved rates, I also corrected a formula error in my original computation. The correction of this error resulted in an adjustment to annualized residential volumes of 4,392 dekatherms. It is this singular correction that yielded the update to the pro forma cost of gas expense referenced in Ms. Powers' Supplement Testimony.

Q. What is the overall impact of the updates to the level of pro forma sales and transportation revenues?

A. At the time of the Company's original filed application, I computed pro forma sales and transportation revenues to be $916,267,107. Updated for present rates, I compute pro forma sales and transportation revenues to be $895,894,522. This amount is shown in Exhibit_(KAC-1 UPDATED).

Q. Please explain the updates to the proposed rates reflected in Exhibit_(KAC-3 UPDATED).

A. The proposed rates shown in Exhibit_(KAC-3 UPDATED) are designed to produce annual gas sales and transportation revenues of $1,004,331,372, as aligned with the updated cost of service shown in Ms. Powers' Exhibit_(PKP-7 UPDATED). Exhibit_(KAC-4 UPDATED) shows the MDT factors associated with the updated cost of service and proposed rates.

Q. Do the updated proposed rates shown in Exhibit_(KAC-3 UPDATED) incorporate any change to the rate design methodology used in the Company's original filed application?

A. No.

Q. Does this conclude your Supplemental Testimony?

A. Yes.

BY MR. JEFFRIES:

Q Have you prepared a summary of your testimony?

A I do have a summary.

Q Okay. And could -- once we distribute it, would you provide that summary --

A Yes.

Q -- to the Commission? Thank you. You may proceed.

A My name is Kally Couzens, and I am the Rates and Regulatory Strategy Manager for Piedmont Natural Gas Company. I prefiled direct testimony in this docket on April 1st, 2019 in support of Piedmont's Application for a General Rate Increase. I also filed supplemental testimony on July 29th, 2019 in support of the Company's updated cost of service calculation as of June 30th, 2019.

My prefiled direct testimony supports the Company's computation of pro forma revenues for the sale and transportation of gas based on normalized test period throughput and revenues other than operating revenues. I also provide updated computational factors for the operation of our margin decoupling tracker mechanism and support the reasonableness of Piedmont's proposed rate design.

My direct testimony summarizes the net effects of the rates Piedmont is proposing in this proceeding and provides supporting data that demonstrates that the revenue increased -- increases proposed by the Company in this case are equitable and fair to all rate classes. I explain how Piedmont is proposing to use the same basic rate design, including fixed monthly charges, seasonal cost allocations, and step rates that were approved by the Commission in Piedmont's last general rate case proceeding in 2013.

My testimony demonstrates that Piedmont's proposed rate design is reasonable and consistent with previous rate design proposals approved in prior proceedings before this Commission and does not unduly burden any of the customer classes.

My prefiled direct testimony is supported by the following four exhibits: 1, Pro Forma Revenues for the Sale and Transportation of Gas; 2, Components of Pro Forma Revenues; 3, Present and Proposed Rates; and 4, Proposed Factors for the Margin Decoupling Mechanism.

I also filed supplemental testimony in this docket on July 29th, 2019 in support of the Company's updated cost of service calculation as of June 30th, 2019, which was performed and filed pursuant to North

Carolina General Statute 62-133(c) and Commission Rule R1-17(c).

My supplemental testimony supports the updated computation of gas and sales and transportation pro forma revenues used in Ms. Powers' updated cost of service calculation as of June 30th, 2019. My supplemental testimony also supports the derivation of proposed rates, as aligned with Ms. Powers' updated cost of service calculation as of June 30th, 2019.

My supplemental testimony is supported by the following four updated exhibits: 1, Pro Forma Revenues for the Sale and Transportation of Gas; 2, Components of Pro Forma Revenues; 3, Present and Proposed Rates; and 4, Proposed Factors for the Margin Decoupling Tracker Mechanism.

That concludes my testimony.

Q Thank you.

MR. JEFFRIES: The witness is available for cross examination and questions by the Commission.

COMMISSIONER BROWN-BLAND: Thank you, Mr. Jeffries. Is there any cross examination for this witness?

(No response.)

COMMISSIONER BROWN-BLAND: Are there questions by the Commission?

(No response.)

COMMISSIONER BROWN-BLAND: Well, you drew the lucky straw, Ms. Couzens. There are no questions for you. And so --

MR. JEFFRIES: We would -- we would move that Ms. Couzens' Exhibits KAC-1 through 4 and KAC-1 through 4 Updated be admitted into evidence.

COMMISSIONER BROWN-BLAND: All right. Those exhibits that were filed with her prefiled testimony --

MR. JEFFRIES: Correct.

COMMISSIONER BROWN-BLAND: -- will be marked as they were when prefiled and they will be received into the -- into the record as evidence.

MR. JEFFRIES: Thank you.

(Whereupon, Exhibits KAC-1 through KAC-4 and Updated Exhibits KAC-1 through KAC-4 were identified as premarked and admitted into evidence.)

COMMISSIONER BROWN-BLAND: Thank you for coming. You may step down.

(Witness excused.)

COMMISSIONER BROWN-BLAND: At this time we're going to take a break and try to come back on the record at 3:45.

MR. JEFFRIES: Thank you.

(Recess taken from 3:29 p.m. to 3:46 p.m.)

COMMISSIONER BROWN-BLAND: We'll come back to order now and go back on the record, Madam Court Reporter.

MR. JEFFRIES: Thank you, Madam Chairman. I would call Mr. Hevert to the stand, but he has already arrived, so...

COMMISSIONER BROWN-BLAND: He's the early bird.

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

DIRECT EXAMINATION BY MR. JEFFRIES:

Q Mr. Hevert, could you state your name and business address for the record, please?

A My name is Robert Hevert. Last name is spelled H-E-V, as in Victor, E-R-T. My business address is 1900 West Park Drive in Westborough, Massachusetts.

Q And where do you work, sir?

A I'm a partner with ScottMadden, Incorporated.

Q All right. Now, Mr. Hevert, I think you win the prize for the most pieces of testimony that Piedmont filed in this case, so if you'll bear with me. You are the same Robert Hevert that filed on April 1 of this year 76 pages of direct testimony and Exhibits RBH-1 through 9; is that correct?

A Yes. That is correct.

Q And you're also the same Robert Hevert that on August 9th of this year filed rebuttal testimony consisting of 63 pages and Exhibits RBH-R-1 through RBH-R-15; is that correct?

A That is correct.

Q And finally, on August 12th you filed testimony supporting the Stipulation, the settlement in this docket, consisting of seven pages and exhibit identified as RBH-S-1; is that correct?

A That is correct.

Q All right. Thank you. And was that testimony and were those exhibits prepared by you or under your direction?

A Yes, they were.

Q All right. Mr. Hevert, if I asked you the same questions that are set forth in your prefiled testimony while you are on the stand today, would your answers be the same?

A Yes, they would.

Q Thank you.

MR. JEFFRIES: Madam Chair, Piedmont would move that Mr. Hevert's prefiled testimonies be entered into the record as if given orally from the stand.

COMMISSIONER BROWN-BLAND: All right. Without objection, Mr. Hevert's prefiled testimonies, all of them, will be received into the record as if given orally from the witness stand. We need to identify for the record his exhibits.

MR. JEFFRIES: Yes. The three sets of exhibits that Mr. Hevert filed in this docket with his direct testimony, the exhibits were marked as Exhibits RBH-1 through RBH-9, and we'd ask that they be identified as such.

COMMISSIONER BROWN-BLAND: They will be so identified.

(Whereupon, Exhibits RBH-1 through RBH-9 were identified as premarked.)

MR. JEFFRIES: And then with his August 9th rebuttal testimony, his exhibits were identified as RBH-R-1 through RBH-R-15, and we'd ask that they be so identified.

COMMISSIONER BROWN-BLAND: All right. And they will be so identified.

(Whereupon, Exhibits RBH-R-1 through

RBH-R-15 were identified as
premarked.)

MR. JEFFRIES: And finally, with his settlement testimony on August 12th, Mr. Hevert had a single exhibit denoted as RBH-S-1, and we would ask that it be identified.

COMMISSIONER BROWN-BLAND: And it will also be so identified.

MR. JEFFRIES: Thank you.

(Whereupon, Exhibit RBH-S-1 was
identified as premarked.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. G-9, SUB 743

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Piedmont Natural Gas	)	**ROBERT B. HEVERT FOR**
Company, Inc. for Adjustment of Rates	)	**PIEDMONT NATURAL GAS**
and Charges Applicable to Gas Service in	)	**COMPANY, INC.**
North 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. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this direct testimony ("Direct Testimony") before the North Carolina Utilities Commission (the "Commission") on behalf of Piedmont Natural Gas Company, Inc. ("Piedmont" 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 an MBA 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 more than 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, the Federal Energy Regulatory Commission, 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. SUMMARY OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. My conclusions are supported by the data and analyses presented in Exhibit RBH-1 through Exhibit RBH-9, which have been prepared by me or under my direction:

- Exhibit RBH-1 presents my Constant Growth Discounted Cash Flow ("DCF") model results;
- Exhibit RBH-2 presents the derivation of the proxy group retention growth rate applicable to the Constant Growth DCF model; .
- Exhibit RBH-3 presents the derivation of the Market Risk Premium for use in the Capital Asset Pricing Model ("CAPM");
- Exhibit RBH-4 presents the Value Line and Bloomberg Financial Beta coefficients for the proxy group for use in the CAPM;
- Exhibit RBH-5 presents my CAPM results;
- Exhibit RBH-6 presents my Bond Yield Plus Risk Premium analysis;

- Exhibit RBH-7 presents my Expected Earnings analysis;
- Exhibit RBH-8 presents regulatory mechanisms in place for the Company's proxy group; and
- Exhibit RBH-9 presents the derivation of flotation costs applicable to the Company's indicated Cost of Equity.

III. 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 a recommendation regarding the Company's Return on Equity ("ROE").[1] My analyses 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. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED TO YOUR ROE RECOMMENDATION.

A. Because all models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. I therefore applied four widely accepted approaches to develop my ROE recommendation: (1) the Constant Growth form of the DCF model; (2) the CAPM model; (3) the Bond Yield Plus Risk Premium approach; and (4) the Expected Earnings analysis. Those analyses indicate that the Company's Cost of Equity is in the range of 10.00 percent to 11.00 percent.

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

In addition to the methods noted above, I reviewed the Company's capital spending plan and regulatory recovery mechanisms; considered evolving capital market and business conditions, including changes in Federal monetary policy, increases in current and projected government bond yields on the utility industry; and calculated the cost of issuing additional shares of common stock. Although I did not make explicit adjustments to my ROE estimates for those factors, I did consider them in determining where the Company's Cost of Equity falls within the range of analytical results.

My analyses recognize that estimating the Cost of Equity is an empirical, but not an entirely mathematical exercise; it relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that inevitably must be applied. I therefore considered my analytical results in the context of such Company-specific and general capital market factors as those summarized above. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony, I find 10.60 percent to be a reasonable and appropriate estimate of the Company's Cost of Equity.

No single model is more reliable than all others under all market conditions, and all require the use of reasoned judgment in their application, and in interpreting their results. The results of each ROE model therefore should be assessed in the context of current and expected capital market conditions, and relative to other appropriate benchmarks. In developing my recommendation, I recognized that the low and high ends of the range of results (set by the low end of the range of Constant

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Growth DCF model results, and the high end of the range of CAPM results, respectively) are not likely to be reasonable estimates of the Company's Cost of Equity.

Q. PLEASE NOW SUMMARIZE THE RESULTS OF THE FOUR METHODS DISCUSSED ABOVE, AND HOW THEY CONTRIBUTED TO YOUR ROE RECOMMENDATION.

A. The range of results produced by the four approaches noted above are as follows:

- The Discounted Cash Flow method indicates an ROE in the range of approximately 9.60 percent to 12.00 percent (please refer to Table 2);[2]
- Giving less weight to the highest and lowest results, the CAPM model suggests an ROE in the range of approximately 10.50 percent to 12.50 percent (please refer to Table 3);[3]
- The Bond Yield Plus Risk Premium approach suggests an ROE in the range of approximately 9.90 percent to 10.10 percent (please refer to Table 4);[4] and
- The Expected Earnings analysis suggests an ROE in the range of approximately 9.60 percent to 12.10 percent (please refer to Table 5).[5]

Based on those estimates, I believe the Company's Cost of Equity falls in the range

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[2] As discussed above, my estimate of the indicated range is narrower than the overall range of model results. Moreover, for the reasons discussed below, I find the underlying assumptions of the DCF model inconsistent with the current capital market and believe the model's results should be viewed with caution.

[3] As discussed above, my estimate of the indicated range is narrower than the overall range of model results.

[4] Results rounded.

[5] Results rounded.

of 10.00 percent to 11.00 percent and, within that range, I recommend an ROE of 10.60 percent. As discussed in more detail throughout the balance of my Direct Testimony, my conclusions and recommendations reflect the following considerations:

- Widespread expectations for continuing increases in interest rates, as revealed in both market data and economists' consensus projections, which weigh in the evaluation of the DCF, CAPM, Bond Yield Plus Risk Premium, and Expected Earnings results;
- The Company's large capital expenditure plan and cost recovery mechanisms which affect its ability to earn its authorized Return on Equity;
- The effect of flotation costs, which represent a permanent reduction to the capital needed to support the assets required to provide safe and reliable utility service; and
- The need to maintain the financial profile required to access capital at reasonable rates, even during periods of capital market volatility.

Q. ARE THERE OTHER FACTORS THAT SHOULD BE CONSIDERED IN DETERMINING THE WEIGHT GIVEN TO THE METHODS AND RESULTS SUMMARIZED ABOVE?

A. Yes, there are. All models used to estimate the Cost of Equity are subject to certain assumptions, which may become more, or less, relevant as market conditions and market data change. An important consideration is the consistency of each model's underlying assumptions with current and expected market conditions, and the reasonableness of its results relative to observable benchmarks. For example, the Constant Growth DCF model assumes the estimated Cost of Equity will remain constant in perpetuity. We know, however, that the Federal Reserve is continuing to "normalize" monetary policy such that the conditions supporting current ROE estimates will not persist in the long-run. Because that model does not allow us to incorporate such important factors, or to reflect the expected risk associated with changing market conditions, its results should be viewed with caution.

Risk Premium-based methods (such as the Capital Asset Pricing Model), on the other hand, provide a measure of risk and have the benefit of directly considering investors' expectations regarding future market returns. Other Risk Premium approaches (*e.g.*, the Bond Yield Plus Risk Premium approach) reflect the well-documented finding that the Cost of Equity does not move in lock-step with interest rates. For example, at times interest rates fall because investors are so risk averse they would rather accept a very modest return on Treasury securities than take on the risk of equity ownership. In such circumstances, low interest rates suggest an increasing, not a decreasing, Cost of Equity. Therefore, the important analytical issue is understanding each model's fundamental structure and assumptions and interpreting its results in the context of current and expected market conditions.

The Expected Earnings analysis calculates the Cost of Equity based on the opportunity cost of the return of an alternative investment in an enterprise with similar risk and corroborates the findings from the DCF, CAPM and Bond Yield Plus Risk Premium approaches.

Because each model has its strengths and weaknesses, it is important to recognize those differences in estimating the Cost of Equity. On balance, I believe certain Constant Growth DCF model results should be viewed with caution,[6] and given less weight than the other approaches. Because Risk Premium-based methods provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the Cost of Equity, those methods likewise should be given more weight than the Constant Growth DCF method. The Expected Earnings approach may be used to assess the reasonableness of the DCF and Risk Premium-based methods. With those considerations in mind, I believe my recommendation reasonably reflects investors' return requirements in the current market environment.

[6] Other jurisdictions have noted similar conclusions. *See, for example, Martha Coakley v. Bangor Hydro-Electric Company,* Opinion No. 531, 147 FERC ¶ 61,234 (2014), *Order On Paper Hearing* Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), and *Order On Rehearing* Opinion No. 531-B, 150 FERC ¶ 61,165 (2015); Massachusetts Department of Public Utilities, D.P.U. 13-90, *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil,* May 30, 2014, at 219; *Formal Case No. 1093, In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service*, Before the Public Service Commission of the District of Columbia, Order No. 17132, May 15, 2013, at 17-18, 20. Also, an article recently published by Bloomberg notes the ultralow interest rate environment has "wrought havoc" on the DCF model. *See*, Kawa, Luke, "A Critical Idea in Valuing Stocks Is Being Made Obsolete by Low Rates," Bloomberg Business, October 13, 2016. http://www.bloomberg.com/news/articles/2016-10-13/a-critical-idea-in-valuing-stocks-is-being-madeobsolete-by-low-rates.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

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

- Section IV – Discusses the regulatory guidelines and financial considerations pertinent to the development of the cost of capital;
- Section V – Explains my selection of the proxy group used to develop my analytical results;
- Section VI – Explains my analyses and the analytical bases for my ROE recommendation;
- Section VII – Provides a discussion of specific business risks and other considerations that have a direct bearing on the Company's Cost of Equity;
- Section VIII – Discusses key economic indicators in the Company's service area;
- Section IX – Highlights the current capital market conditions and their effect on the Company's Cost of Equity; and
- Section X – Summarizes my conclusions and recommendations.

I also have included Appendices A and B, which explain in detail the selection criteria used for my utility proxy group, and the analysis and inputs for each Cost of Equity model.

IV. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS

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 investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return they *expect* is equal to, or greater than, the return 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 an 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 directly observed as the interest rate or yield on debt securities.[7] 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 based on market data and various financial models. As discussed throughout my Direct Testimony, each model is subject to specific assumptions, which may be more or less applicable under differing market conditions. Because 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 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

7 The observed interest rate may be adjusted to reflect issuance costs.

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 of West Virginia ("*Bluefield*");[8] and (2) Federal Power Comm'n v. Hope Natural Gas Co. ("*Hope*").[9] In those cases, the Court 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.

Q. HAS THE COMMISSION PROVIDED SIMILAR GUIDANCE?

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

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8 Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679, 692-93 (1923).

9 Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

> 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.[10]

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 EQUITY CAPITAL AT REASONABLE TERMS?

A. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe and reliable service while maintaining its financial integrity. 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 Piedmont the opportunity to earn a return on equity 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 Piedmont is provided a reasonable opportunity

[10] 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) ("DEC Remand Order").

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 the Company to provide safe, reliable natural gas 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 nature, those models produce a range of results from which the ROE is determined. That determination 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 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.

The use of multiple methods, and the consideration given to them, recently was addressed by the Federal Energy Regulatory Commission ("FERC"). In its November 15, 2018 *Order Directing Briefs,* FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE".[11] In its October 16, 2018 *Order Directing Briefs*, FERC found that although it "previously relied solely on the DCF

[11] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

model to produce the evidentiary zone of reasonableness...", it is "...concerned that relying on that methodology alone will not produce just and reasonable results."[12] As FERC explained, because the Cost of Equity depends on what the market expects, it is important to understand "how investors analyze and compare their investment opportunities."[13] FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods..."[14] Those methods include the CAPM and the Risk Premium method, which I have applied in this proceeding.

In summary, practitioners, academics, and regulatory commissions recognize that financial models are tools to be used in the ROE estimation process, and the 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 method employed, that is controlling in arriving at ROE determinations. A reasonable ROE estimate therefore considers multiple methods, and the reasonableness of their individual and collective results in the context of observable, relevant market information.

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[12] Docket No. EL11-66-001, *et al.*, *Order Directing Briefs*, 165 FERC ¶ 61,030 (October 16, 2018) at para. 30.

[13] *Id.*, at para. 33.

[14] *Id.*, at para. 35.

V. 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 PIEDMONT?

A. First, it is important to bear in mind that the Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. The value of individual business units reflects the risks and opportunities inherent in the sectors in which those units operate. In this proceeding, we are focused on estimating the Cost of Equity for the Company's North Carolina operations. Because the ROE is a market-based concept, and given the fact that the Company's jurisdictional operations within North Carolina are not a separate entity with its own stock price, it is necessary to establish a group of companies that are both publicly-traded and comparable to Piedmont to serve as its "proxy" for purposes of the ROE estimation process.

Even if the Company's North Carolina jurisdictional assets did constitute the entirety of the parent company's operations, it is possible that transitory events could bias its market value in one way or another over a given period of time. A significant benefit of using a proxy group is that it serves to moderate the effects of anomalous, temporary events associated with any one company.

Q. DOES THE SELECTION OF A PROXY GROUP SUGGEST THAT ANALYTICAL RESULTS WILL BE TIGHTLY CLUSTERED AROUND AVERAGE (I.E., MEAN) RESULTS?

A. No. For example, the DCF approach calculates the Cost of Equity using the expected dividend yield and projected growth. Despite the care taken to ensure risk comparability, market expectations regarding 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.[15] An ongoing issue is how to best estimate the market-required ROE within that range. That determination necessarily must consider a wide range of both empirical and qualitative information.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF PIEDMONT.

A. Piedmont provides natural gas distribution service to approximately one million customers in North Carolina, South Carolina and Tennessee.[16] Of this total customer base, the Company's North Carolina operations serves approximately 750,000 customers.[17] Piedmont currently has senior unsecured ratings of A3 (outlook: Stable) and A- (outlook: Negative) from Moody's Investor Service and Standard & Poor's Rating Services, respectively.[18]

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15 In Appendix B, I provide more substantive descriptions of the models used to estimate the ROE.

16 *See* https://news.duke-energy.com/releases/duke-energy-completes-acquisition-of-piedmont-natural-gas.

17 Company-provided.

18 *See* Moody's Investors Service, Piedmont Natural Gas Company, Inc. Update to Credit Analysis, 8/8/2018; and S&P Global Ratings, Piedmont Natural Gas Co. Inc. Rating Lowered To 'A-' On Completed Acquisition By Duke Energy Corp., Outlook Negative, 10/14/2016.

Q. WHAT COMPANIES ARE INCLUDED IN YOUR PROXY GROUP?

A. The criteria discussed in Appendix A resulted in a proxy group of the following eight companies:

Table 1: Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corporation[19]	CPK
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire Inc.	SR

VI. 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 capital investments. The overall rate of return ("ROR") weighs the costs of the individual sources of capital by their respective book values. While the cost of debt can be directly observed, the Cost of Equity is market-based and, therefore, must be estimated based on observable market information.

[19] Even though Chesapeake Utilities Corp. is not publicly rated by S&P, its Value Line Financial Strength Rating of B++ is comparable to the rest of the proxy group. CPK also has an National Association of Insurance Commissioners (NAIC) rating of "NAIC 1," which is equivalent to ratings in the "A" category for both Moody's and Standard & Poor's. *See* Chesapeake Utilities Corporation, Northeast Road Show, January 2018, at 16; National Association of Insurance Commissioners, CRP Credit Rating Equivalent to SVO Designations, November 2017.

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 several 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.[20] 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 discussed earlier, no individual model is more reliable than all others under all market conditions, and that the application of judgement is important in developing ROE estimates. The Commission and other state regulatory jurisdictions, such as Hawaii and Massachusetts, have made similar findings.[21] Therefore, it is both prudent and appropriate to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. As noted earlier, I therefore applied the Constant Growth DCF model, the Capital Asset

[20] *See, for example,* 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.

[21] *See, for example*: (1) State of North Carolina Utilities Commission, In the Matter of Application of Public Service Company of North Carolina, Inc. for a General Increase in its Rates and Charges, Docket No. G-5, Sub 565, Order Approving Rate Increase and Integrity Management Tracker, October 28, 2016, at 35-36; (2) Public Utilities Commission of the State of Hawaii, Docket No. 7700, Order No. 13704 in Docket No. 7700, In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of Rate Increases and Revised Rate Schedules and Rules, December 28, 1994 at 92; and (3) The Commonwealth of Massachusetts Department of Public Utilities, Investigation by the Department of Public Utilities, Docket D.P.U. 15-155, September 30, 2016, at 376-378.

Pricing Model, the Bond Yield Plus Risk Premium, and the Expected Earnings approach.

Q. WHY DID YOU SELECT THOSE FOUR MODELS?

A. I did so for two reasons. First, because the purpose of ROE analyses is to estimate the return that investors require, it is important to use the models on which those investors rely. As discussed in Appendix B, the models I apply are commonly used in practice. Second, the models focus on different aspects of return requirements, and provide different insights to investors' views of risk and return. Using multiple models provides a broader, and therefore a more reliable perspective on investors' return requirements.

Q. PLEASE BRIEFLY DESCRIBE THE CONSTANT GROWTH DCF MODEL.

A. The Constant Growth DCF approach defines the Cost of Equity as the sum of (1) the expected dividend yield, and (2) expected long-term growth. The expected dividend yield generally equals the expected annual dividend divided by the current stock price, and the growth rate is based on analysts' expectations of earnings growth. Under the model's strict assumptions, the growth rate equals the rate of capital appreciation (that is, the growth in the stock price).[22] In that regard, it does not matter whether the investor holds the stock in perpetuity, or for a finite period during which the investor collects (and reinvests) dividends, then sells at the prevailing market price. Under the model's assumptions, the result is the same

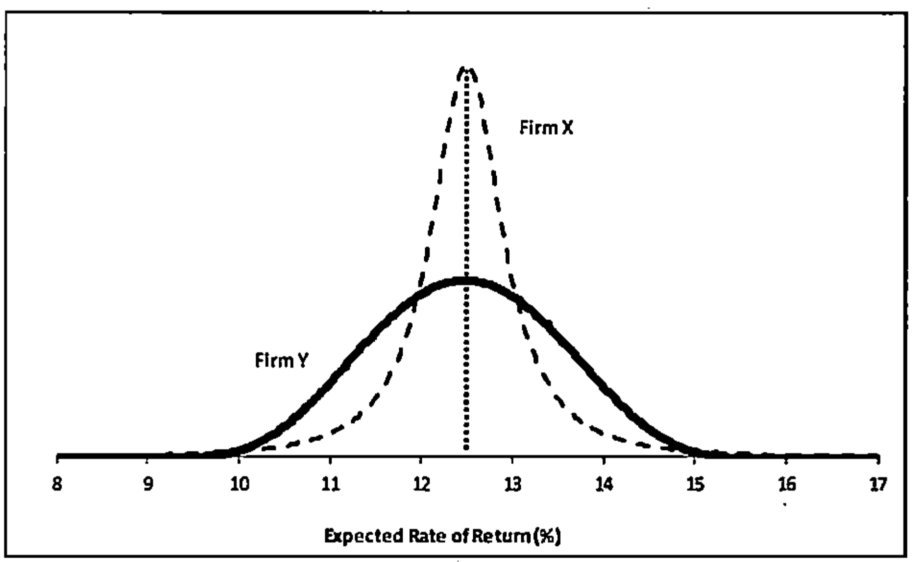
22 As discussed in Appendix B, the model assumes that earnings, dividends, book value, and the stock price all grow at the same constant rate in perpetuity.

either way.

Q. PLEASE BRIEFLY DESCRIBE THE CAPITAL ASSET PRICING MODEL.

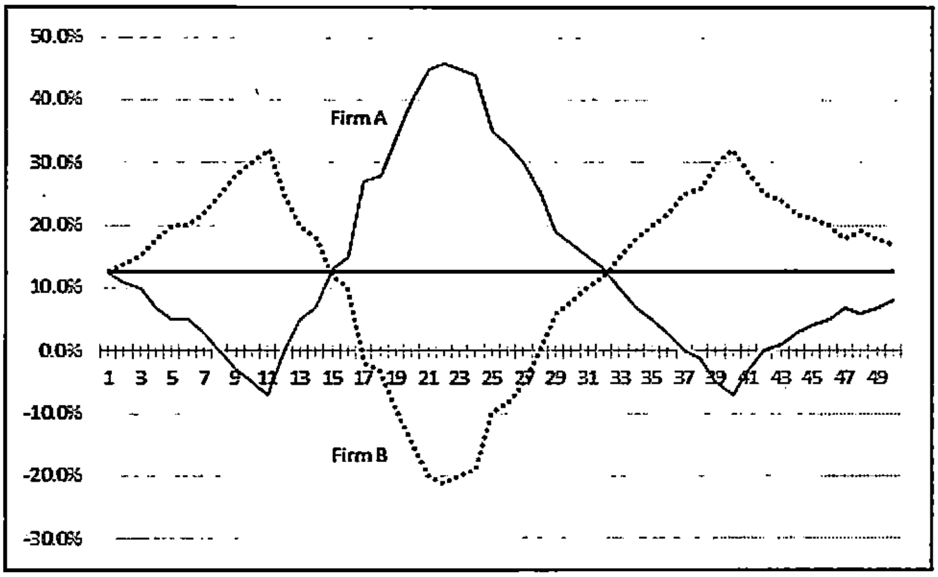
A. Whereas DCF models focus on expected cash flows, Risk Premium-based models such as the CAPM focus on the additional return that investors require for taking on additional risk. In finance, "risk" generally refers to the variation in expected returns, rather than the expected return, itself. Consider two firms, X and Y, with expected returns, and the expected variation in returns noted in Chart 1, below. Although the two have the same expected return (12.50 percent), Firm Y's are far more variable. From that perspective, Firm Y would be considered the riskier investment.

Chart 1: Expected Return and Risk



Now consider two other firms, Firm A and Firm B. Both have expected returns of 12.50 percent, and both are equally risky as measured by their volatility. But as Firm A's returns go up, Firm B's returns go down. That is, the returns are negatively correlated.

Chart 2: Relative Risk



If we were to combine Firms A and B into a portfolio, we would expect a 12.50 percent return with no uncertainty because of the opposing symmetry of their risk profiles. That is, we can diversify away the risk. As long as two stocks are not perfectly correlated, we can achieve diversification benefits by combining them into a portfolio. That is the essence of the Capital Asset Pricing Model - because we can combine firms into a portfolio, the only risk that matters is the risk that remains after diversification, *i.e.*, the "non-diversifiable" risk.

The CAPM defines the Cost of Equity as the sum of the "risk-free" rate, and a premium to reflect the additional risk associated with equity investments. The "risk-free" rate is the yield on a security viewed as having no default risk, such as long-term Treasury bonds, and essentially sets the baseline of the CAPM. That is, an investor would expect a higher return than the risk-free rate to purchase an asset that carries risk. The difference between that higher return (*i.e.*, the required return) and the risk-free rate is the risk premium.

$$\text{Risk} - \text{Free Rate} + \text{Risk Premium} = \text{Required Return} \quad [1]$$

The Risk Premium is defined as a security's Beta coefficient multiplied by the risk premium of the overall market (the "Market Risk Premium" or "MRP"). The Beta coefficient is a measure of the subject company's risk relative to the overall market, *i.e.*, the "non-diversifiable" risk. A Beta coefficient of 1.00 means that the security is equally as risky as the overall market; a value below 1.00 represents a security with less risk than the overall market, and a value over 1.00 represents a security with more risk than the overall market. Equation [2] provides the general format of the CAPM formula:

$$\text{Risk Free Rate} + (\text{Beta Coefficient x Market Risk Premium}) = \text{Required Return} \quad [2]$$

Q. PLEASE BRIEFLY DESCRIBE THE BOND YIELD PLUS RISK PREMIUM.

A. This approach is based on the basic financial principle that equity investors bear the risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are riskier than returns to bondholders, equity investors must be compensated for bearing that additional risk (that difference often is referred to as the "Equity Risk Premium"). Bond Yield Plus Risk Premium approaches estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

$$\text{Bond Yield} + \text{Equity Risk Premium} = \text{Required Return} \quad [3]$$

Q. PLEASE BRIEFLY DESCRIBE THE EXPECTED EARNINGS APPROACH.

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. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF?

A. The results of the model described in Appendix B, part A are provided in Table 2, below.[23]

23 *See* Appendix B for a more detailed description of the models, assumptions, and inputs described in this Section VI.

Table 2: Summary of DCF Results[24]

	Median	Median High
30-Day Average	9.60%	11.94%
90-Day Average	9.63%	11.97%
180-Day Average	9.65%	12.03%

Q. **PLEASE NOW SUMMARIZE YOUR REMAINING ANALYTICAL RESULTS.**

A. The Risk Premium-based results, including the CAPM, Bond Yield Plus Risk Premium and Expected Earnings methods, explained in detail in Appendix B, parts B, C and D, respectively, are provided below.

Table 3: Summary of CAPM Results

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.04%)	9.26%	11.08%
Near Term Projected 30-Year Treasury (3.25%)	9.47%	11.30%
Long Term Projected 30-Year Treasury (4.05%)	10.27%	12.10%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.04%)	10.36%	12.50%
Near Term Projected 30-Year Treasury (3.25%)	10.57%	12.72%
Long Term Projected 30-Year Treasury (4.05%)	11.37%	13.52%

24 For the purposes of my Direct Testimony, I have put more emphasis on the median results of my Constant Growth DCF analysis, because the mean results are affected by an anomalously high growth rate for Northwest Natural Gas Company of 25.50 percent from Value Line due to the company's significant losses in 2017.

Table 4: Bond Yield Plus Risk Premium Results

Treasury Yield	*Return on Equity*
Current 30-Year Treasury (3.04%)	9.89%
Near Term Projected 30-Year Treasury (3.25%)	9.92%
Long Term Projected 30-Year Treasury (4.05%)	10.11%

Table 5: Expected Earnings Results

	Return on Equity
Low	9.58%
Average	10.73%
High	12.13%

VII. OTHER CONSIDERATIONS

Q. WHAT ADDITIONAL INFORMATION DID YOU CONSIDER IN ASSESSING THE ANALYTICAL RESULTS NOTED ABOVE?

A. Because the analytical methods discussed above provide a range of estimates, there are several additional factors that should be taken into consideration when establishing a reasonable range for the Company's Cost of Equity. Those factors include the risks associated with the Company's capital spending plan and regulatory recovery mechanisms and flotation costs associated with equity issuances.

Capital Spending and Regulatory Mechanisms

Q. HAVE YOU REVIEWED THE COMPANY'S REGULATORY RECOVERY MECHANISMS?

A. Yes. An important element of my analysis is assessment of the Company's ability to earn its requested ROE. Accordingly, I have reviewed the Company's most recent financial statements, tariff and capital spending plans. The Company's regulatory environment should provide the opportunity to recover its costs and earn a reasonable return on its investments. The Company currently has in place an Integrity Management Rider ("IMR") to recover investments and associated costs associated with prevailing Federal standards for pipeline integrity and safety and not otherwise included in current base rates.

Q. ARE ALTERNATIVE REGULATION MECHANISMS COMMON AMONG THE PROXY GROUP COMPANIES?

A. Yes, they are. Exhibit RBH-8 provides a summary of alternative regulation mechanisms and cost trackers currently in effect at each gas utility subsidiary of the proxy group companies. As Exhibit RBH-8 demonstrates, substantially all the proxy companies have a capital recovery mechanism in place.[25]

As noted earlier, the *Hope* and *Bluefield* "Comparable Earnings" standard requires the allowed Return on Equity to be commensurate with the returns on investments of similar risk. To the extent the proxy companies have mechanisms in place to address revenue shortfalls or cost recovery, the Company's IMR mechanism makes it more comparable to its peers.

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[25] Only four of the 26 proxy group operating companies do not have a capital recovery mechanism.

Q. DOES THE IMR RECOVER ALL OF THE COMPANY'S CAPITAL SPENDING?

A. No, it does not. In 2018, the IMR only recovered 35.23 percent of the Company's total capital spending. Looking forward (2019-2023), the Company expects to recover 35.07 percent of its spending through the IMR.[26] As the Company moves forward with the execution of its capital spending plan, internally generated cash and retained earnings will be an important source of funding.

Q. PLEASE ELABORATE ON THE COMPANY'S NEED TO RELY ON INTERNALLY GENERATED CASH FLOWS AND RETAINED EARNINGS.

A. It is particularly important for utilities to fund capital investments with internally-generated cash flow, which is driven by the recovery "of", and the return "on" investments. Since 2014, when the Company completed its last rate case, its ratio of cash flow from operating activities to capital expenditures has remained considerably below its peers (see Chart 3, below).[27] Because its cash flows have been less able to support its capital investment, the Company must access external capital, increasing the potential for negative credit consequences.

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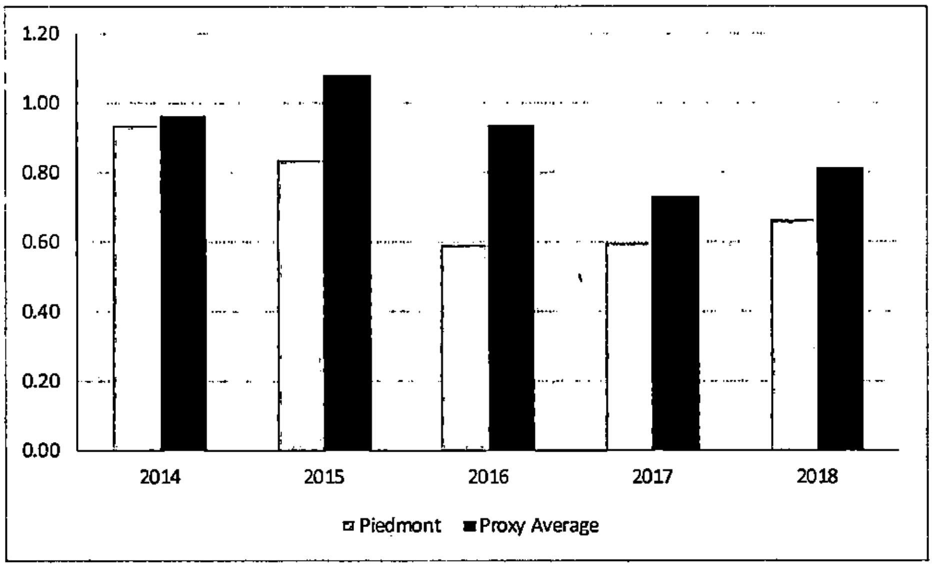
[26] Actual 2018 IMR spending was $254 million and total spending was $721 million. Projected 2019-2023 IMR spending expected to be $1,175 million and total spending expected to be $3,350 million. Source: https://www.duke-energy.com/_/media/pdfs/our-company/investors/march-2019-ir-presentation.pdf?la=en at 30.

[27] Piedmont's five-year average of CFFO-to-Capital Expenditures was 72.47 percent compared to the proxy group five-year average of 90.63 percent.

Chart 3: Historical Cash Flow From Operating Activities to Capital Expenditures[28]



Net income is a principal source of operating cash flow, which offsets the Company's need to rely on external capital. As shown above, however, the Company's capital expenditures have considerably exceeded its operating cash flow.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF THE COMPANY'S CAPITAL INVESTMENT PLAN AND ITS ASSOCIATED RECOVERY MECHANISM?

A. The Company's capital expenditure plan, which is significantly larger than its

[28] Source: SNL Financial. Reflects proxy group consolidated financial results publicly available through U.S. Securities and Exchange Commission filings. Operating company-level regulated financial results are not consistently available through various state agencies, but I believe that the consolidated financial results reflect a good comparison because of the high percentage of regulated operations prevalent for the proxy group. For the proxy group, regulated gas operating income reflects 81.70 percent (calculated excluding NWN and SJI because of large losses in 2017) of total operating income on average.

internally generated cash, places downward pressure on its free cash flow, and likely its credit profile. The Company's capital recovery mechanisms provide for more timely recovery of investments, supporting the ability to fund investments with internally generated cash and mitigating financing risk. That is, it likely is credit-supportive, rather than credit-enhancing. Consequently, the Commission's decision regarding the ROE in this proceeding will directly affect the Company's ability to fund capital investments with operating cash flows, and the financial community's view of its financial profile.

Flotation Costs

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are expenses associated with the sale of new issues of common stock. These include out-of-pocket costs for preparation, filing, underwriting, and other costs of issuance.

Q. ARE FLOTATION COSTS PART OF THE UTILITY'S INVESTED COSTS OR PART OF THE UTILITY'S EXPENSES?

A. Flotation costs are part of capital costs, which are properly reflected on the balance sheet under "paid in capital" rather than current expenses on the income statement. Flotation costs are incurred over time, just as investments in rate base or debt issuance costs. As a result, the great majority of flotation costs are incurred prior to the test year, but remain part of the cost structure during the test year and beyond.

Q. IS THE NEED TO CONSIDER FLOTATION COSTS ELIMINATED BECAUSE PIEDMONT IS A WHOLLY-OWNED SUBSIDIARY?

A. No, it is not. Wholly owned subsidiaries such as Piedmont 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 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 Piedmont, 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. HOW DID YOU CALCULATE THE FLOTATION COST RECOVERY ADJUSTMENT?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. My estimate of flotation costs recognizes the costs of issuing equity that were incurred by the proxy companies in their most recent two issuances. As shown in Schedule RBH-9, an adjustment of 0.05 percent (*i.e.*, 5 basis points) reasonably represents flotation costs for the Company.

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 recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. For example, Dr. Morin notes that "[t]he costs of issuing [common stock] are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs."[29] Dr. Morin further notes that "equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely."[30] 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.[31]

Similarly, Morningstar has commented on the need to reflect flotation costs in the

[29] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 321.
[30] *Id.*, at 327.
[31] Shannon P. Pratt & Roger J. Grabowski, *Cost of Capital: Applications and Examples* at 586 (4th ed. 2010).

cost of capital:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[32]

Q. HAVE COMMISSIONS IN OTHER REGULATORY JURISDICTIONS RECOGNIZED FLOTATION COSTS WHEN DETERMINING THE AUTHORIZED ROE?

A. FERC, along with regulatory commissions in jurisdictions such as Arkansas, Connecticut, and Mississippi have recognized flotation costs when determining the authorized ROE.[33] Although the method by which flotation costs are reflected in rates may vary (*e.g.*, implicit versus explicit basis point increases to authorized ROE), the recognition of those costs is not limited to, or constrained by recent equity issuances. For instance, the Arkansas Commission stated that "including some level of valid, sustainable, measurable, and material flotation costs in equity return is appropriate."[34]

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32 Morningstar, Inc. Ibbotson SBBI 2013 Valuation Yearbook, at 25.

33 *See, for example*, FERC Docket Nos. EL05-19-002 and ER05-168-001, *Golden Spread Electric Cooperative, Inc., v. Southwestern Public Service Company*, Opinion No. 501, 123 FERC ¶ 61,0047, (April 21, 2008); Arkansas Public Service Commission, Docket No. 04-176-U, *In the Matter of the Application of Arkansas Western Gas Company for Approval of a General Change in Rates and Tariffs*, Order No. 6, October 31, 2005, at 34; Connecticut Public Utilities Regulatory Authority, Docket No. 14-05-06, *Application of the Connecticut Light and Power Company to Amend Rate Schedules*, Decision, December 17, 2014, at 133-134, 145 (Table 64), and 223 (PP 280-281); Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, December 3, 2001, at 26.

34 *Id.*

Q. ARE YOU PROPOSING TO ADJUST YOUR RECOMMENDED ROE BY 5 BASIS POINTS TO REFLECT THE EFFECT OF FLOTATION COSTS ON THE COMPANY'S ROE?

A. No. Rather, I have considered the effect of flotation costs, in addition to the Company's regulatory recovery of its capital spending plan relative to the proxy group, in determining where the Company's ROE falls within the range of results.

VIII. 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 the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[35] 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.

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35 State of North Carolina Utilities Commission, Docket No. E-7, Sub 1026, Order Granting General Rate Increase, Sept. 24, 2013 at 24; *see also* Dominion Energy Carolina 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.").

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.[36]

The Supreme Court agreed, and upheld the Commission's Order on Remand.[37] The Supreme Court has also, however, made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[38] In *Cooper II*, which addressed an appeal of the Commission's order on Dominion Energy Carolina'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."[39] The Commission made such

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[36] State of North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, October 23, 2013, at 34 – 35; see also Dominion Energy Carolina 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").

[37] State of North Carolina ex rel. Utilities Commission v. Cooper, 766 S.E.2d 827 (2014).

[38] State of North Carolina ex rel. Utilities Commission v. Cooper, 758 S.E.2d 635, 642 (2014) ("Cooper II").

[39] Cooper II, 758 S.E.2d at 643,

additional findings of fact in its order on remand.[40] In light of the Cooper II decision and the Supreme Court precedent that preceded it,[41] 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.

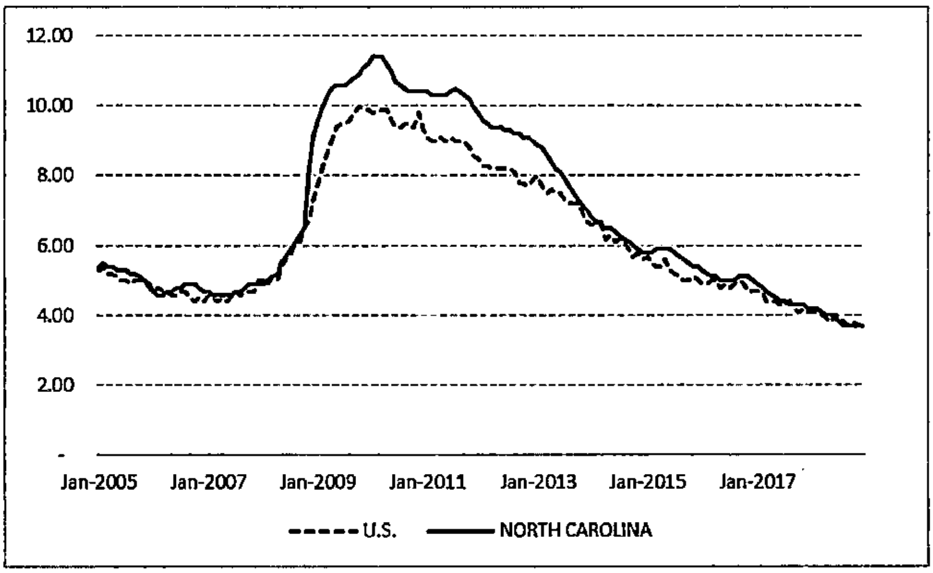
Q. PLEASE NOW SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.

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 11.40 percent and 10.00 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 the peak levels, to 3.90 percent and 3.70 percent nationally and in North Carolina, respectively. (*see* Chart 4, below).

40 State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, Order on Remand, July 23, 2015, at 4-10.

41 State of North Carolina ex rel. Utilities Commission v. Cooper, 366 N.C. 484, 739 S.E.2d 541 (2013) ("Cooper I").

Chart 4: Unemployment Rate[42]



Since the Company's last rate completed in January 2014, the unemployment rate in North Carolina has fallen from 6.80 percent to 3.70 percent, a reduction of 3.10 percentage points, which is comparable to the decline in the U.S. unemployment rate (2.70 percentage points). 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. From a broader perspective, 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).[43]

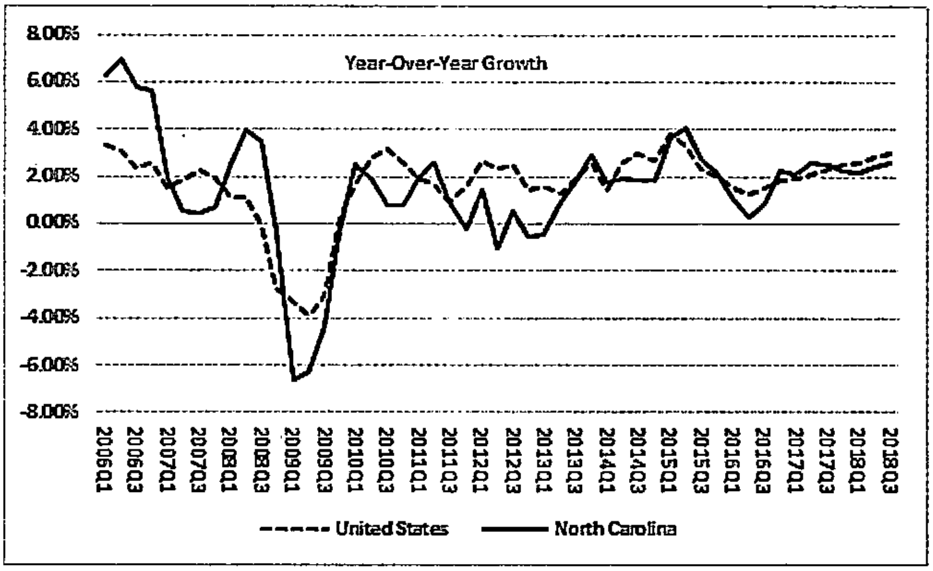
Looking to real Gross Domestic Product growth, again, there has been a relatively strong correlation between North Carolina and the national economy

42 Source: Bureau of Economic Analysis.

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

(approximately 75.00 percent). Since the financial crisis the national rate of growth at times (during portions of 2010 and 2012) outpaced North Carolina. In recent years (since 2015) North Carolina and the national Gross Domestic Product have grown at similar rates.

Chart 5: Real Gross Domestic Product Growth Rate[44]

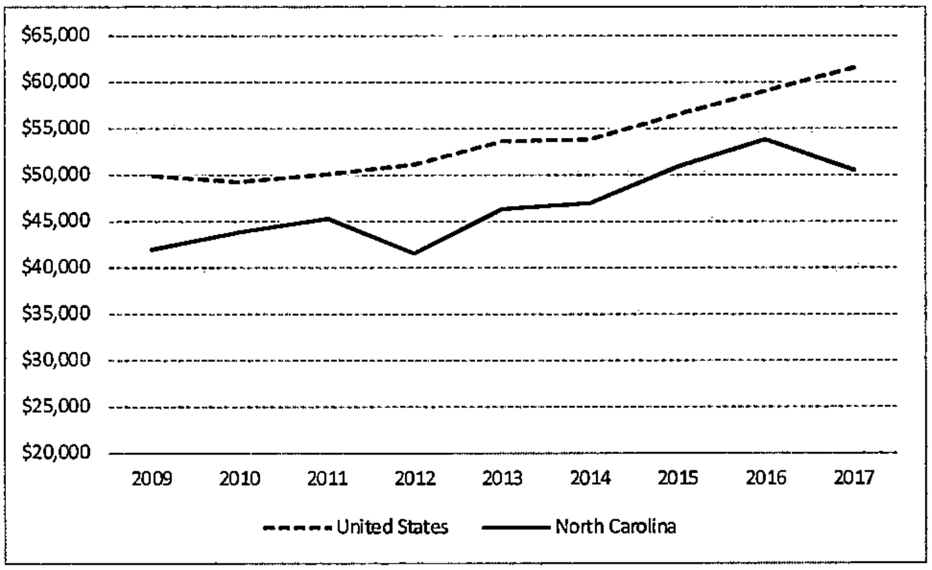


As to median household income, the correlation between North Carolina and the U.S. is relatively strong (nearly 67.00 percent from 2005 through 2017). Since 2009 (that is, the years subsequent to the financial crisis), median household income in North Carolina has grown at a somewhat slower annual rate than the national median income (2.32 percent vs. 2.65 percent; *see* Chart 6, 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

[44] Source: Bureau of Economic Analysis.

living index of the 50 states and the District of Columbia.[45]

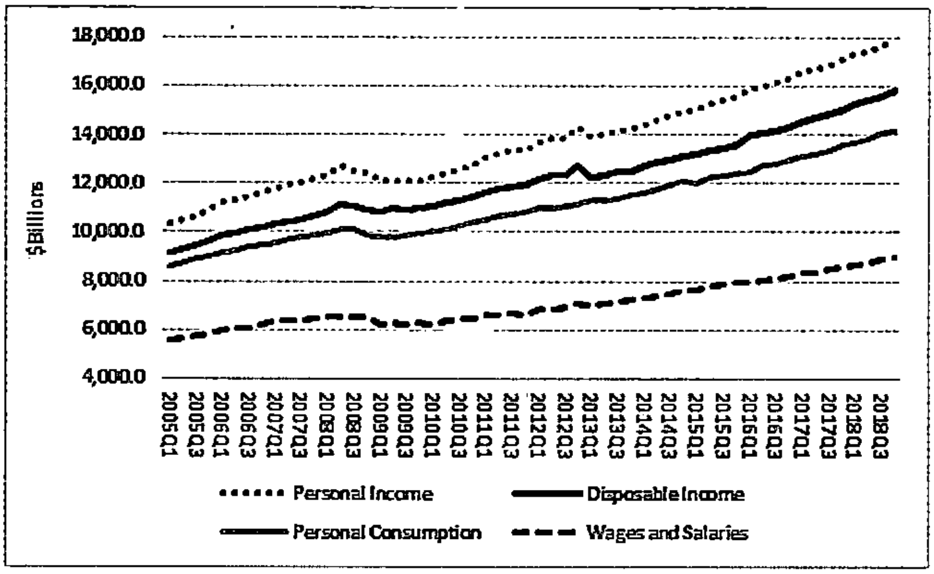
Chart 6: Median Household Income



Similarly, as shown in Chart 7, 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.

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

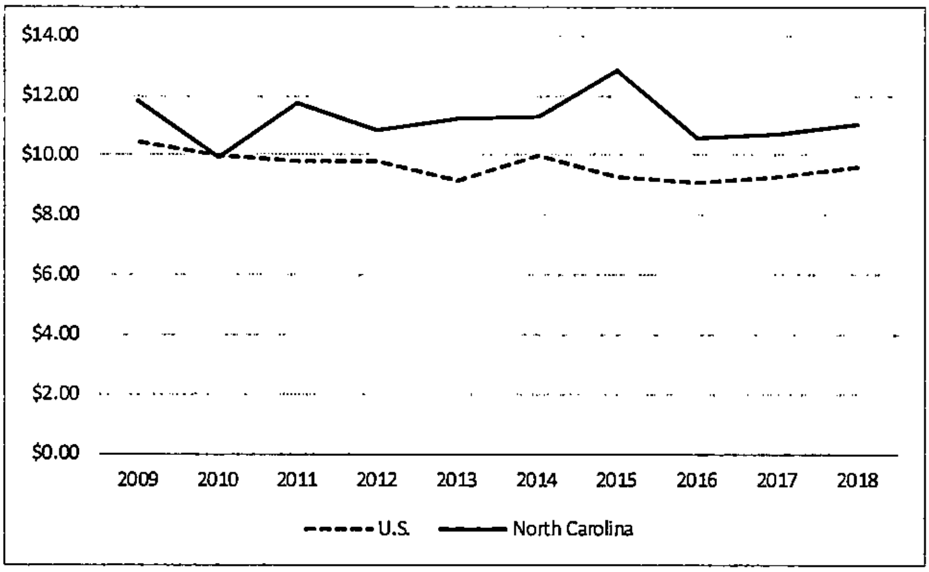
Chart 7: United States Income and Consumption[46]



In 2018 residential natural gas prices (measured in dollars per thousand cubic feet ("MCF")) in North Carolina were approximately 15.00 percent higher the national average which is consistent with the long-term average during the last ten years (2009 through 2018) of 16.42 percent (*see* Chart 8, below). Over this ten year period, rates decreased at a somewhat lower amount in North Carolina (-6.53 percent versus -7.58 percent nationally). The decline in prices both in North Carolina and nationally is consistent with the abundance of natural gas supplies as a result of shale exporation and production.

46 Source: Bureau of Economic Analysis. Data is seasonally adjusted.

Chart 8: Residential Natural Gas Rates ($/MCF)[47]

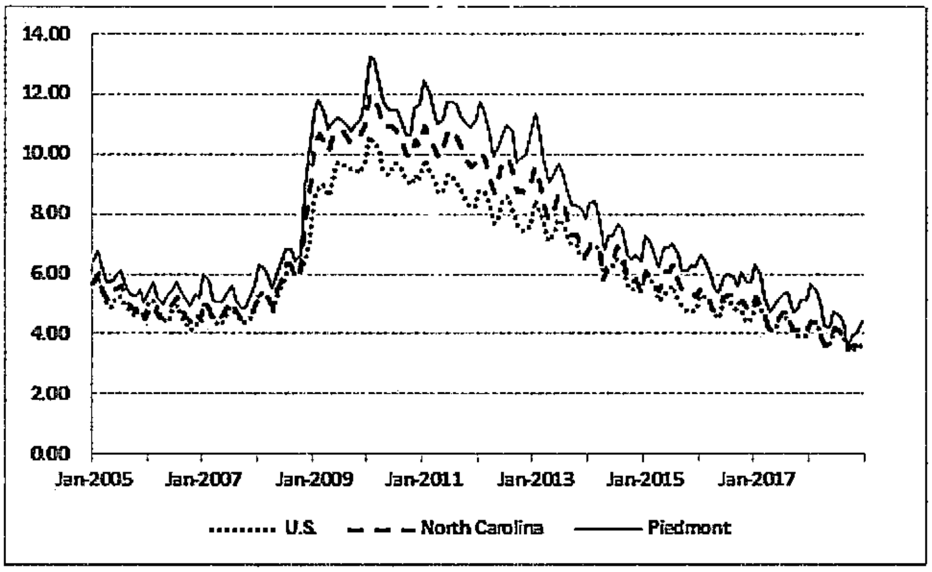


Lastly, I was able to review (seasonally unadjusted) unemployment rates in the counties served by Piedmont. At its peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 13.20 percent (1.20 percentage points higher than the State-wide average); by December 2018 it had fallen to approximately 4.40 percent (0.70 percentage points higher than the State-wide average). Since the Company's last rate filing effective January 2014, the counties' unemployment has fallen by approximately 4.00 percentage points. From 2005 through 2018, the correlation in unemployment rates between the counties served by Piedmont, and the U.S. and North Carolina, respectively, were approximately 99.00 percent. In summary, although it remains higher than the national and State-wide averages, it has fallen considerably since its peak in early

[47] Source: Energy Information Administration. As of December, each year.

2010.

Chart 9: Seasonally Unadjusted Unemployment Rates[48]



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, the same as the national average. North Carolina's unemployment rate fell by 7.70 percentage points from its peak, whereas the national average rate fell by 6.10 percentage points.
- Although the unemployment rate in the counties served by Piedmont remains above the national and State-wide averages, it too has fallen considerably since its peak in early 2010.[49]
- The State's Gross Domestic Product remains highly correlated with national

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

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

GDP, and has grown similarly to 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.
- The State's natural gas residential rates have been approximately 16.42 percent higher than national average gas rates, but rates have declined in both North Carolina and the nation over the past ten years as a result of natural gas supply fundamentals.

Q. HOW WOULD YOU SUMMARIZE THE ECONOMIC INDICATORS THAT YOU HAVE ANALYZED AND DISCUSSED IN YOUR TESTIMONY?

A. Based on the indicators discussed above, North Carolina and the counties contained within Piedmont'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.

Q. IN YOUR OPINION, IS THE PROPOSED ROE FAIR AND REASONABLE TO PIEDMONT, ITS SHAREHOLDERS AND ITS CUSTOMERS, AND NOT UNDULY BURDENSOME TO PIEDMONT CUSTOMERS CONSIDERING THE IMPACT OF THESE CHANGING ECONOMIC CONDITIONS?

A. Yes. Based on the factors I have discussed here, I believe that Piedmont's proposed ROE of 10.60 percent is fair and reasonable to Piedmont, its shareholders, and its customers in light of the effect of those changing economic conditions.

IX. <u>CAPITAL MARKET ENVIRONMENT</u>

Q. DO ECONOMIC CONDITIONS INFLUENCE THE REQUIRED COST OF CAPITAL AND REQUIRED RETURN ON COMMON EQUITY?

A. Yes. As discussed in Section VI and in Appendix B, 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 certain ROE estimates are incompatible with such data, or 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 FEDERAL RESERVE MONETARY POLICY, 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 monetary policy normalization.[50] A significant analytical 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 Discounted Cash Flow 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

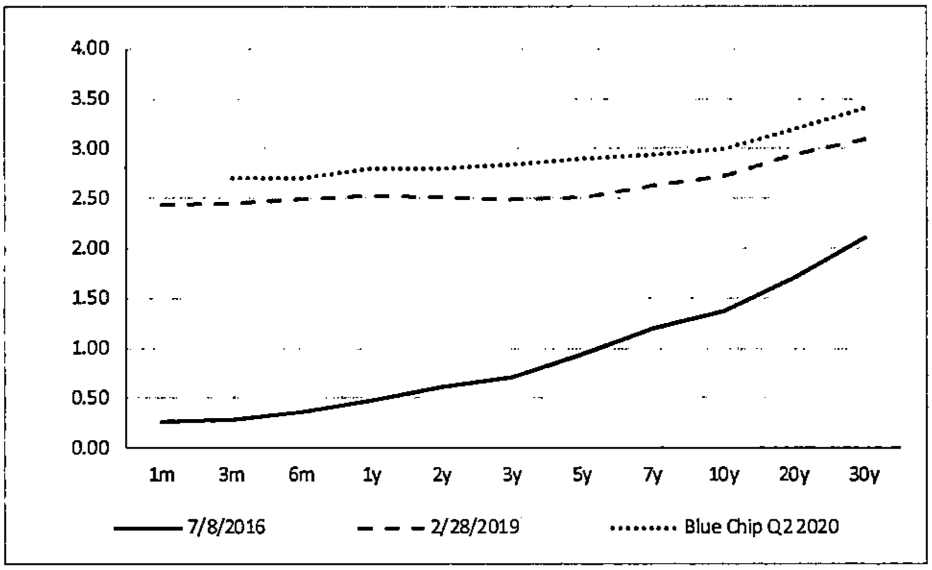
[50] *See* Federal Reserve Press Release, December 16, 2015.

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 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 kept interest rates historically low, since July 8, 2016 (when the 30-year Treasury yield 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 19, 2018 to 2.25 percent - 2.50 percent, short-term and long-term interest rates also increased (*see* Chart 10 below).[51]

[51] Federal Reserve Board Schedule H.15. One-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 10: Treasury Yield Curve: 7/8/2016, 2/28/2019 and Projected Q2 2020[52]



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.[53]

Aside from increases in the Federal Funds rate, in October 2017, the Federal Reserve initiated its balance sheet normalization program that includes gradual reductions to its security holdings by decreasing its reinvestment activities.[54] In the

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52 Federal Reserve Board Schedule H.15; Blue Chip Financial Forecasts, Vol. 38, No. 2, February 1, 2019, at 2. Three-year, seven-year and 20-year projected Treasury yields interpolated.

53 Transcript of Chairman Powell's Press Conference, December 19, 2018.

54 *See:* https://www.federalreserve.gov/monetarypolicy/policy-normalization.htm and Federal Open Market Committee ("FOMC") Press Release, June 14, 2017. In its January 30, 2019 press release the FOMC noted that although it continues to view changes in the federal funds target rate as the "primary means of adjusting monetary policy", it also would adjust the details of its balance sheet normalization based on economic and financial developments. *See, Federal Reserve Press Release* dated January 30, 2019. At its March 2019 meeting, the FOMC determined it would hold

January 2019 meeting, the Federal Reserve decided to continue with the balance sheet wind-down.[55] At the same time, the supply of marketable U.S. Treasury securities has increased by approximately $1.14 trillion.[56] The growing supply of Treasury securities from both the Federal Reserve and the U.S. Treasury puts upward pressure on Treasury rates.

Q. DOES MARKET-BASED DATA INDICATE THAT 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.[57] 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-

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the Federal Funds target rate constant, looking to current and expected economic conditions to determine future rate adjustments. *See, Federal Reserve Press Release* dated March 20, 2019.

55 Federal Reserve Press Release dated January 30, 2019.

56 Source: U.S. Treasury, Monthly Statement of the Public Debt. *See* 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.

57 Blue Chip Financial Forecast, Vol. 38, No. 2, February 1, 2019, at 2.

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."[58] 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.

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 11 (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. Throughout 2018 and into 2019, the VIX average increased to 16.76 with a standard deviation of 4.84. That is, since 2017, both the level and the volatility of market volatility increased.

[58] Source: http://www.cboe.com/vix

Chart 11: VIX Since January 2017[59]

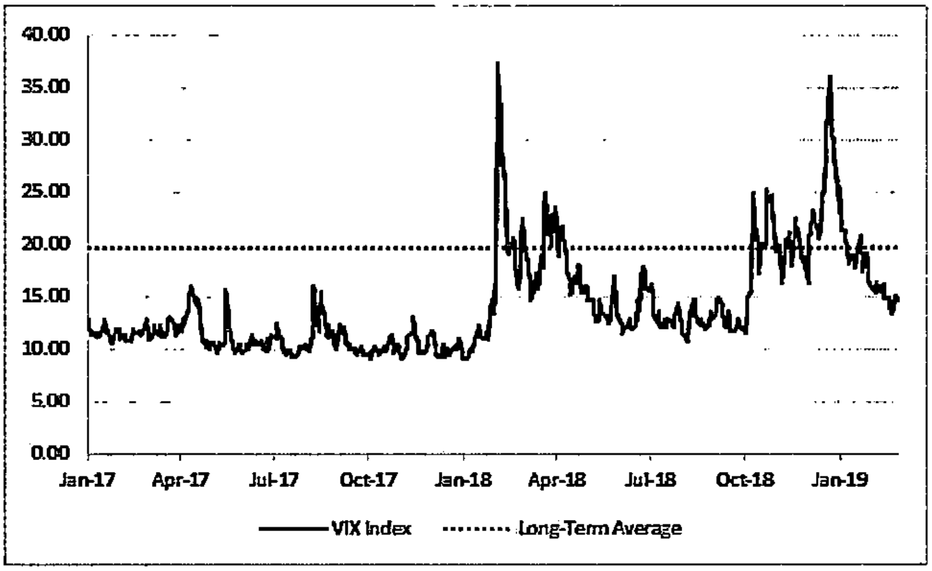

Table 6 (below) further demonstrates the increase in market uncertainty from 2017 to 2019. As that table notes, the standard deviation (that is, the volatility of volatility) in 2018-2019 is about 3.57 times higher than its 2017 level (1.36).

[59] Source: Bloomberg Professional. Data through Ferbuary 28, 2019.

Table 6: VIX Levels and Volatility[60]

Long-Term Average	19.69
2018-2019 Average	16.76
2018-2019 Maximum	37.32
2018-2019 Minimum	9.15
2018-2019 Standard Deviation	4.84
2017 Average	11.09
2017 Maximum	16.04
2017 Minimum	9.14
2017 Standard Deviation	1.36

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

Q. IS MARKET VOLATILITY EXPECTED TO INCREASE FROM ITS CURRENT 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.[61]

Cboe's term structure data is upward sloping, indicating market

60 Source: Bloomberg Professional. Data through February 28, 2019.
61 Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.

expectations of increasing volatility. The expected VIX value in June 2020 is 18.75, suggesting investors see a reversion toward the long-term average volatility over the coming months.[62] That increase in expected 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.

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 also 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

62 Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, accessed February 5, 2019.

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.[63] Although it did not increase the Federal Funds rate in its January 2019 meeting, the Federal Open Market Committee observed the labor market continued to strengthen, and economic activity continued to rise at a solid rate.[64] From that perspective, we would expect to see higher growth estimates for companies in the overall economy, including the utility sector.

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 estimate, 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

[63] Federal Reserve Press Release dated December 19, 2018.
[64] Federal Reserve Press Release dated January 30, 2019.

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.

X. CONCLUSIONS AND RECOMMENDATION

Q. WHAT IS YOUR CONCLUSION REGARDING THE COMPANY'S COST OF EQUITY?

A. As discussed earlier in my Direct Testimony, it is prudent and appropriate to consider multiple methodologies to arrive at an ROE recommendation for Piedmont. I have performed several analyses to estimate the Company's Cost of Equity and have considered several market-wide and Company-specific issues. Given those considerations, I believe that a rate of return on common equity in the range of 10.00 percent to 11.00 percent represents the range of equity investors' required rate of return for investment in natural gas utilities similar to Piedmont in today's capital markets. Within that range, it is my view that an ROE of 10.60 percent is reasonable and appropriate.

As discussed earlier in my testimony, my recommendation reflects analytical results based on a proxy group of natural gas utilities. My recommendation also considers (but does not make specific adjustments for) other factors, including regulatory recovery of capital spending, and the direct costs associated with equity issuances.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A: PROXY GROUP SELECTION

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. I began with the universe of companies that Value Line classifies as Natural Gas Utilities, which includes 10 domestic U.S. utilities, and applied the following screening criteria:

- Because certain of the models used in my analyses assume that earnings and dividends grow over time, I excluded companies that do not consistently pay quarterly cash dividends;
- To ensure that the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group are covered by at least two utility industry equity analysts;
- All the companies in my proxy group have investment grade senior unsecured bond and/or corporate credit ratings from S&P;
- To incorporate companies that are primarily regulated gas distribution utilities, I included companies with at least 60.00 percent of operating income derived from regulated natural gas utility operations; and
- I eliminated companies currently known to be party to a merger, or transformative transaction.

Q. WHAT COMPANIES MET THOSE SCREENING CRITERIA?

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

Table 7: Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corporation[65]	CPK
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire Inc.	SR

[65] Even though Chesapeake Utilities Corp. is not publicly rated by S&P, its Value Line Financial Strength Rating of B++ is comparable to the rest of the proxy group. CPK also has an National Association of Insurance Commissioners (NAIC) rating of "NAIC 1," which is equivalent to ratings in the "A" category for both Moody's and Standard & Poor's. *See* Chesapeake Utilities Corporation, Northeast Road Show, January 2018, at 16; National Association of Insurance Commissioners, CRP Credit Rating Equivalent to SVO Designations, November 2017.

APPENDIX B: COST OF COMMON EQUITY MODELS

A. Constant Growth DCF Model

Q. PLEASE MORE FULLY DESCRIBE THE 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 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:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_t}{(1+k)^t} \quad [4]$$

where P_0 represents the current stock price, D_1 … D_t represent expected future dividends, and k is the discount rate, or required ROE. Equation [4] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D(1+g)}{P_0} + g \quad [5]$$

Equation [5] often is 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) the Price to Earnings ("P/E") multiple remains constant in perpetuity; (4) the discount rate (that is, the estimated Cost of Equity) is greater than the expected growth rate; and (5) the calculated Cost of Equity remains constant, also in perpetuity. These simplifying assumptions, which may become more, or less relevant as market conditions change, are required to derive the familiar Constant Growth DCF model provided in Equation [5].

Q. WHAT MARKET DATA DID YOU USE TO CALCULATE THE DIVIDEND YIELD COMPONENT OF 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 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. Because utilities 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.[66] That adjustment ensures that the expected dividend yield is 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 [5] above) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, we must assume a fixed payout ratio, and that earnings per share ("EPS"), dividends per share ("DPS"), and book value per share all grow at the same constant rate in perpetuity. Because dividend growth can only be sustained by earnings growth, the model should incorporate a variety of long-term earnings growth estimates. That can be accomplished by averaging 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.

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66 *See*, Exhibit RBH-1.

Q. PLEASE SUMMARIZE THE FINDINGS OF ACADEMIC RESEARCH ON THE APPROPRIATE MEASURE OF GROWTH 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.[67] 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.[68]

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.[69] 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

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

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

[69] *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)

decisions."[70] Other research specifically notes the importance of analysts' growth estimates in 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."[71] 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."[72] 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."[73]

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.[74] 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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70 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. VanderWeide. The results of the updated study were consistent with the original study's conclusions.

71 Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

72 *Ibid.*

73 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).

74 *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 natural gas utility companies using the following inputs for the price and dividend terms:

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

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

1. The Zacks consensus long-term earnings growth estimates;
2. The First Call consensus long-term earnings growth estimates; and
3. The Value Line long-term earnings growth estimates.
4. The Retention Growth estimates.

Q. PLEASE DESCRIBE THE RETENTION GROWTH ESTIMATE AS APPLIED IN YOUR DCF MODEL.

A. The Retention Growth model, which is a generally recognized and widely taught method of estimating long-term growth, is an alternative approach to the use of analysts' earnings growth estimates. The model estimates growth as a function of (1) expected earnings, and (2) the extent to which earnings are retained. In its simplest form, the model represents long-term growth as the product of the retention ratio (*i.e.*, the percentage of earnings not paid out as dividends (referred to below as "b") and the expected return on book equity (referred to below as "r")).

Thus, the simple "b x r" form of the model projects growth as a function of internally generated funds. That form of the model is limiting, however, in that it does not provide for growth funded from external equity.

The "br + sv" form of the Retention Growth estimate used in my DCF analysis is meant to reflect growth from both internally generated funds (*i.e.*, the "br" term) and from issuances of equity (*i.e.*, the "sv" term). The first term, which is the product of the retention ratio (*i.e.*, "b", or the portion of net income not paid in dividends) and the expected Return on Equity (*i.e.*, "r") represents the portion of net income that is "plowed back" into the Company as a means of funding growth. The "sv" term is represented as:

$$\left(\frac{m}{b}-1\right) x\ Growth\ rate\ in\ Common\ Shares \quad [6]$$

where $\frac{m}{b}$ is the Market-to-Book ratio. In this form, the "sv" term reflects an element of growth as the product of (a) the growth in shares outstanding, and (b) that portion of the market-to-book ratio that exceeds unity. As shown in Exhibit RBH-2, all components of the Retention Growth model may be derived from data provided by Value Line.

Q. HOW DID YOU CALCULATE THE HIGH AND LOW DCF RESULTS?

A. I calculated the proxy group median low, median, and median high DCF results by using the maximum EPS growth rate as reported by Value Line, Zacks, First Call, and the Retention Growth method for each proxy group company in combination with the dividend yield for each of the proxy companies. The proxy group median high results then reflect the median of the maximum DCF results for the proxy group as a whole. I used a similar approach to calculate the proxy group median low results using instead the minimum of the Value Line, Zacks, First Call, and Retention Growth method growth rates for each company. For the purposes of my Direct Testimony, I have put more emphasis on the median results of my Constant Growth DCF analysis, because the mean results are affected by an anomalously high growth rate for Northwest Natural Gas Company of 25.50 percent from Value Line due to the company's significant losses in 2017.

Q. WHAT ARE THE RESULTS OF YOUR DCF ANALYSIS?

A. The results of my DCF analysis are summarized in Table 8 below (*see* also Exhibit RBH-1).

Table 8: Constant Growth DCF Results[75]

	Median	Median High
30-Day Average	9.60%	11.94%
90-Day Average	9.63%	11.97%
180-Day Average	9.65%	12.03%

B. CAPM Analysis

Q. PLEASE DESCRIBE THE GENERAL FORM OF THE CAPM ANALYSIS.

A. The CAPM analysis 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). The CAPM describes the relationship between a security's investment risk and the

[75] *See also*, Exhibit RBH-1

market rate of return. The CAPM assumes that all other risk, *i.e.*, all non-market or unsystematic risk, can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors require compensation only for systematic risk that is the result of macroeconomic and other events that affect the returns on all assets.

As shown in Equation [7], below, the CAPM is defined by four components, each of which theoretically must be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [7]$$

where:

k = the required market ROE for a security;

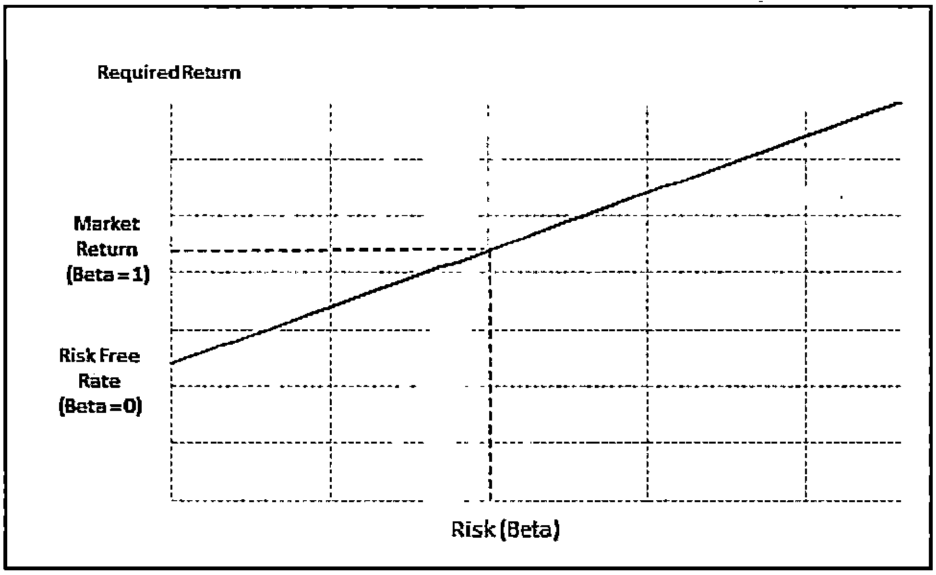
β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

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

Equation [7] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, which is graphically depicted in Chart 12 below. The intercept is the risk-free rate (r_f) which has a Beta coefficient of zero, the slope is the expected market risk premium ($r_m - r_f$). By definition, r_m, the return on the market has a Beta coefficient of 1.00. Under the CAPM, the expected Equity Risk Premium on a given security is proportional to its Beta coefficient.

Chart 12: Security Market Line



Intuitively, higher Beta coefficients indicate that the subject company's returns have been relatively volatile and 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.

In Equation [7], the term $(r_m - r_f)$ represents the Market Risk Premium.[76] According to the theory underlying the CAPM, because unsystematic risk can be diversified away by adding securities to their investment portfolios, the market will not compensate investors for bearing that risk. Therefore, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} x \, \rho_{j,m} \quad [8]$$

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

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.

Q. WHAT ASSUMPTIONS DID YOU INCLUDE IN YOUR CAPM ANALYSIS?

A. Because utility equity is a long duration investment, I used three different estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 3.04 percent)[77]; (2) the near-term projected 30-year Treasury yield (*i.e.*, 3.25 percent);[78] and (3) the long-term projected 30-year Treasury yield (*i.e.*, 4.05 percent).[79]

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. Because utility equity has a perpetual life, the 30-year Treasury yield is the appropriate measure of the risk-free rate.

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77 Bloomberg Professional Services.

78 *See*, Blue Chip Financial Forecasts, Vol. 38, No. 3, March 1, 2019, at 2. Consensus projections of the 30-year Treasury yield for the six quarters ending June 2020.

79 *See*, Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14. Consensus projections of the 30-year Treasury yield for the periods 2020-2024 and 2025-2029.

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 bond yield. To estimate the market required return, I calculated the market capitalization weighted average ROE based on the Constant Growth DCF model. To do so, I relied on data from Bloomberg and Value Line, respectively. 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 companies for which Bloomberg provided both dividend yields and consensus growth rates. I then subtracted the 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-3.

Q. HOW DID YOU APPLY YOUR EXPECTED MARKET RISK PREMIUM AND RISK-FREE RATE ESTIMATES?

A. I relied on each of the *ex-ante* Market Risk Premiums discussed above, together with the current, near-term projected, and long-term projected 30-year Treasury bond yields as inputs to my CAPM analysis.

Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM MODEL?

A. As shown in Exhibit RBH-4, I considered the Beta coefficients reported by Value Line and Bloomberg, both of which adjust their calculated (or raw) Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00. A notable difference between the two is that Value Line calculates the Beta coefficient over a five-year period, whereas Bloomberg's calculation is based on two years of data.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. The results of my CAPM analysis are summarized in Table 9 below (*see* also Exhibit RBH-5).

Table 9: Summary of CAPM Results

	Bloomberg Derived Market Risk Premium	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.04%)	9.26%	11.08%
Near Term Projected 30-Year Treasury (3.25%)	9.47%	11.30%
Long Term Projected 30-Year Treasury (4.05%)	10.27%	12.10%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.04%)	10.36%	12.50%
Near Term Projected 30-Year Treasury (3.25%)	10.57%	12.72%
Long Term Projected 30-Year Treasury (4.05%)	11.37%	13.52%

C. Bond Yield Plus Risk Premium Approach

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, because returns to equity holders are riskier 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. Because 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 gas distribution companies 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 authorized ROEs and the then-prevailing level of long-term (*i.e.*, 30-year) Treasury yields. I then gathered data from 1,116 natural gas rate proceedings between January 1, 1980 and February 28, 2019. I also calculated the average period between the filing of the case and the date of the final order (that is, the lag period). 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 187 days).

Because the data covers several economic cycles,[80] the analysis also may be used to assess the stability of the Equity Risk Premium. As noted above, the Equity Risk Premium is not constant over time; prior research has shown it is directly related to expected market volatility, and inversely related to the level of interest rates.[81] That finding is particularly relevant given the relatively low level of current Treasury yields.

Q. HOW DID YOU MODEL 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,

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80 *See,* National Bureau of Economic Research, U.S. Business Cycle Expansion and Contractions.

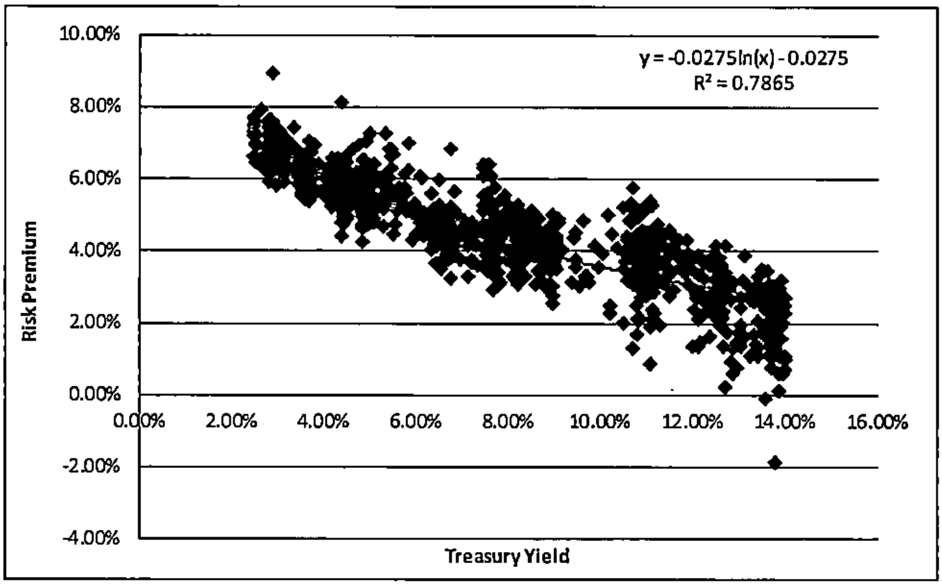
81 *See, e.g.*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial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

in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta(LN(T_{30}) \quad [9]$$

As shown on Chart 13 (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 13: Equity Risk Premium



As Chart 13 demonstrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. An important consequence of that relationship is that simply applying the long-term average Equity Risk Premium of 4.69 percent would significantly understate the Cost of Equity. Based on the regression coefficients in

Chart 13, however, the implied ROE is between 9.89 percent and 10.11 percent (*see* Exhibit RBH-6 and Table 10, below).

Table 10: Bond Yield Plus Risk Premium Results

Treasury Yield	*Return on Equity*
Current 30-Year Treasury (3.04%)	9.89%
Near Term Projected 30-Year Treasury (3.25%)	9.92%
Long Term Projected 30-Year Treasury (4.05%)	10.11%

D. 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, 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.[82] The results range from 9.58 percent to 12.13 percent, with an average value of 10.73 percent (*see* Exhibit RBH-7).

82 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, Financial Statement Analysis: Theory, Application, and Interpretation, Irwin, 4th Ed., 1988, at 630.

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MANAGEMENT CONSULTANTS

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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Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice 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)
Xcel Energy, Inc.	06/14	Public Service Company of Colorado	Docket No. 14AL-0660E	Return on Equity (electric)

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MANAGEMENT CONSULTANTS

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

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MANAGEMENT CONSULTANTS

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

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MANAGEMENT CONSULTANTS

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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)

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MANAGEMENT CONSULTANTS

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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)

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Testimony Listing of:
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Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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)

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Testimony Listing of:
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Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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)

scottmadden
MANAGEMENT CONSULTANTS

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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

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MANAGEMENT CONSULTANTS

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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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				

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. G-9, SUB 743

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Piedmont Natural Gas	)	**ROBERT B. HEVERT FOR**
Company, Inc. for Adjustment of Rates	)	**PIEDMONT NATURAL GAS**
and Charges Applicable to Gas Service in	)	**COMPANY, INC.**
North Carolina		

II. RESPONSE TO ATTORNEY GENERAL WITNESS DR. WOOLRIDGE

Q. PLEASE PROVIDE A SUMMARY OVERVIEW OF YOUR RESPONSE TO DR. WOOLRIDGE.

A. It is important to keep in mind that no financial model is more reliable than all others at all times, and under all market conditions. At times, certain models' assumptions become incompatible with market conditions, and their results do not make practical sense. Consequently, we cannot always take model results as given, and assume their results are reasonable measures of the Cost of Equity. Rather, we should apply reasoned judgment in vetting model assumptions, and in assessing the reasonableness of their results.

In this proceeding, Dr. Woolridge has given considerable weight to the Constant Growth Discounted Cash Flow method,[1] even though his results fall well below returns recently authorized for other natural gas utilities.[2] Table 1 (below) summarizes our respective ROE recommendations.

Table 1: Summary of ROE Recommendations

Witness	ROE Range		ROE Recommendation
	Low	High	
Dr. Woolridge (AG)	7.60%	8.70%	8.70%/9.00%[3]
Mr. Hevert (Piedmont)	10.00%	11.00%	10.60%

1 Dr. Woolridge's 8.70 percent recommendation equals his DCF estimate. *See*, Exhibit JRW-8.
2 Source: Regulatory Research Associates.
3 Dr. Woolridge offers an alternative ROE of 8.70 percent if the Commission accepts the Company's proposed capital structure.

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Q. IS THE PRINCIPAL USE OF A SINGLE METHOD COMMON IN FINANCIAL THEORY AND PRACTICE?

A. No, it is not. Considering multiple methods is a more robust approach, less susceptible to the limitations of any one particular model and its underlying assumptions. The Constant Growth Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"),[4] Risk Premium, and Expected Earnings methods provide alternative perspectives and capture different aspects of investor behavior. Each perspective is important, especially when we consider that models are meant to estimate an unobservable parameter (the Cost of Equity), that is set by the buying and selling behavior of investors whose decisions are motivated by any number of factors. We cannot assume one model reasonably captures all motivating factors, for all investors, under all market conditions, at all times. As Dr. Roger Morin notes:

> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory. The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use.
>
> No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible

[4] Including the Empirical CAPM, or "ECAPM".

> measurement difficulties and vagaries in individual companies' market data.[5]

Professor Eugene Brigham recommends the CAPM, DCF, and Bond Yield Plus Risk Premium approaches:

> Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) method, and (3) the bond-yield-plus-risk-premium approach. These methods are not mutually exclusive – no method dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand.[6]

Similarly, Dr. Morin (quoting, in part, Professor Stewart Myers), stated:

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.
>
> ***
>
> While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. Sole reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings in contrast to its virtual disappearance in academic textbooks does not make it superior to other methods. The same is true of the Risk Premium and CAPM methodologies.[7]

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5 Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 428.

6 *Ibid.*, at 430 – 431, citing Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341.

7 Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 430–431.

Put another way, the models used to estimate the Cost of Equity are general descriptions of investor behavior, not precise definitions of it. Investors appreciate that strict adherence to a single approach, or to the specific results of a single approach, may 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 method employed, that is controlling in arriving at just and reasonable rates. In my view, the Commission's practice of considering multiple methods, giving less weight to models that produce unduly low (or high) results is consistent with theory and practice, and should be maintained in this proceeding.

Q. HAVE OTHER REGULATORY COMMISSIONS RECOGNIZED THE IMPORTANCE OF CONSIDERING MULTIPLE METHODS IN SETTING AUTHORIZED ROES?

A. Yes. For example, in Baltimore Gas and Electric Company's 2016 rate case, the Maryland Public Service Commission discussed the importance of considering multiple analytical methods given the complexity of determining the investor-required ROE:

> The ROE witnesses used various analyses to estimate the appropriate return on equity [...] including the DCF model, the IRR/DCF, the traditional CAPM, the ECAPM, and risk premium methodologies. Although the witnesses argued strongly over the correctness of their competing analyses, we are not willing to rule that there can be only one correct method for calculating an ROE. Neither will we eliminate any particular methodology as unworthy of basing a decision. The subject is far too complex to reduce to a single mathematical formula. That conclusion is made apparent, in practice, by the fact that the expert witnesses used discretion to eliminate outlier returns that they testified were too high or too low

to be considered reasonable, even when using their own preferred methodologies.[8]

Q. HAS THE COMMISSION LIKEWISE EXPRESSED CONCERN WITH DCF MODEL RESULTS?

A. Yes, in its July 2017 *Order Accepting Stipulation* authorizing a 9.90 percent ROE for Duke Energy Carolinas, the Commission noted it "carefully evaluated the DCF analysis recommendations" of the ROE witnesses (which ranged from 8.45 percent to 8.80 percent) and determined that "all of these DCF analyses in the current market produce unrealistically low results."[9]

Q. IS IT YOUR VIEW THAT THE DCF MODEL SHOULD BE GIVEN NO WEIGHT IN DETERMINING THE COMPANY'S COST OF EQUITY?

A. No, it is not. It is my view, however, that we should carefully consider the range of results all models produce. As discussed later in my Rebuttal Testimony, doing so fully supports my ROE range and recommendation.

Q. PLEASE NOW BRIEFLY SUMMARIZE DR. WOOLDRIDGE'S ROE ANALYSES AND RECOMMENDATIONS.

A. Dr. Woolridge finds the Company's ROE likely falls in the range of 7.60 percent to 8.70 percent, but recommends an ROE of 9.00 percent to reflect "a small increase

8 In the matter of the application of Baltimore Gas and Electric Company for adjustments to its electric and gas base rates, Public Service Commission of Maryland, Case No. 9406, Order No. 87591, at 153. Citations omitted.

9 State of North Carolina Utilities Commission, Docket No. E-7, Sub 1146, In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, July 25, 2017.

in risk associated with [his] adjustment of the proposed capital structure".[10] If the Commission accepts the Company's proposed capital structure, Dr. Woolridge believes the ROE should fall to 8.70 percent.[11] In each case, Dr. Woolridge's recommendation is based on his Constant Growth DCF, and CAPM analyses.

Q. WHAT ARE THE SPECIFIC AREAS IN WHICH YOU DISAGREE WITH DR. WOOLRIDGE'S ANALYSES AND RECOMMENDATIONS?

A. There are several areas in which I disagree with Dr. Woolridge, including: (1) the overall reasonableness of Dr. Woolridge's ROE recommendation; (2) Dr. Woolridge's application of the Constant Growth DCF model; (3) Dr. Woolridge's application of the CAPM; (4) the reasonableness of the Bond Yield Plus Risk Premium analysis; (5) Dr. Woolridge's position that the Expected Earnings approach is not an accurate measure of investor expectations; (6) the relevance of Market-to-Book ("M/B") ratios in determining the ROE; (7) Dr. Woolridge's position that the Company is less risky than its peers; (8) the application of a flotation cost adjustment; and (9) the risks associated with the Company's projected capital expenditures. Lastly, although we review similar data and come to similar conclusions regarding economic conditions in North Carolina, I have some concerns with Dr. Woolridge's assessment of the effect of his ROE recommendation on the Company's revenue requirement.

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10 Direct Testimony of J. Randall Woolridge, PhD, at 2.

11 *Ibid.*

Recommended ROE

Q. IS DR. WOOLRIDGE'S 9.00 PERCENT ROE RECOMMENDATION CONSISTENT WITH RETURNS RECENTLY AUTHORIZED IN NORTH CAROLINA?

A. No, it is not. The lowest authorized return for a natural gas utility in a base rate case by the Commission was 9.70 percent.[12] That return is 70 basis points above Dr. Woolridge's recommendation, 100 basis points above his recommendation assuming the Company's proposed capital structure is adopted, and 210 basis points above the low end of his range. Dr. Woolridge has provided no evidence to support the conclusion that the Company is so less risky than its peers that investors would accept a return 70 to 210 basis points below those authorized by the Commission.

Constant Growth DCF Model

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE CONSTANT GROWTH DCF MODEL AND DR. WOOLRIDGE'S APPLICATION OF THE MODEL.

A. There are several practical concerns with Dr. Woolridge's application of the model, and his interpretation of its results. For example, Dr. Woolridge's approach includes a degree of subjectivity that prevents us from replicating the fundamental inputs that drive his results. Moreover, Dr. Woolridge's judgment is to give "primary weight"[13] to growth rate projections produced by equity analysts, despite

12 Since 2000. Source: Regulatory Research Associates.
13 Direct Testimony of J. Randall Woolridge, Ph.D., at 50.

his assertion that those analysts knowingly and persistently produce biased growth rate forecasts.

Q. WHAT GROWTH RATES DID DR. WOOLRIDGE REVIEW IN HIS CONSTANT GROWTH DCF ANALYSIS?

A. Dr. Woolridge reviewed a number of growth rates, including historical and projected Dividends Per Share ("DPS"), Book Value Per Share ("BVPS"), and Earnings Per Share ("EPS") growth rates as reported by Value Line; analysts' consensus EPS growth rate projections from Yahoo!, Reuters, and Zacks; and an estimate of "Sustainable Growth" provided by Value Line.[14] Dr. Woolridge states that in arriving at his growth rate projections for the proxy group he gave "primary weight" to projected EPS growth rates.

[14] Exhibit JRW-8.

Table 2: Summary of Dr. Woolridge's Growth Rate Estimates[15]

	Dr. Woolridge's Proxy Group
Value Line Historical Growth Rates (DPS, BVPS, EPS)	6.20%
Value Line Projected Growth Rates (DPS, BVPS, EPS)	6.30%
Sustainable Growth	5.00%
Analyst Projected EPS Growth Rates (excl. Value Line) – Mean/Median	5.60% / 6.20%
Dr. Woolridge's Assumed DCF Growth Rate	6.00%

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S REFERENCE TO A MARCH 2015 REPORT BY MOODY'S REGARDING THE EFFECT OF AUTHORIZED ROEs ON UTILITIES' NEAR-TERM CREDIT PROFILES.

A. Dr. Woolridge points to that report and concludes lower authorized ROEs are not impairing utilities' credit profiles, and are not "deterring them from raising record amounts of capital."[16] He argues the Moody's article "supports the prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital."[17]

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S ASSESSMENT OF THAT ARTICLE?

A. No, I do not. The March 2015 Moody's article makes clear utilities' cash flow had benefited from increased deferred taxes, which themselves were due to bonus depreciation. In that report, Moody's noted the rise in deferred taxes eventually

15 *Ibid.*, at 49-50.; Exhibit JRW-8, at 1, 6.
16 Direct Testimony of J. Randall Woolridge, Ph.D., at 68.
17 *Ibid.*, at 69.

would reverse.[18] In January 2018, Moody's spoke to the effect of that reversal on utility credit profiles in the context of tax reform:

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150 - 250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.[19]

In June 2018, Moody's changed its outlook on the U.S. regulated sector to "negative" from "stable". Moody's explained that its change in outlook "...primarily reflects a degradation in key financial credit ratios, specifically the ratio of cash flow from operations to debt, funds from operations ("FFO") to debt and retained cash flow to debt, as well as certain book leverage ratios."[20] The sector's outlook could remain "negative" if cash flow-based metrics continue to decline, or if there emerge signs of a more "contentious" regulatory environment (which, Moody's notes, is not fully reflected in lower authorized returns). Dr. Woolridge's reference to a 2015 article does not consider Moody's more recent position.

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18 Moody's Investors Service, *Lower Authorized Returns Will Not Hurt Near-Term Credit Profiles*, March 10, 2015, at 4.

19 Moody's Investors' Service, *Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform*, January 19, 2018.

20 Moody's Investors Service, Announcement: *Moody's changes the US regulated utility sector outlook to negative from stable*, June 18, 2018.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT ANALYSTS' EARNINGS GROWTH PROJECTIONS ARE CONSISTENTLY BIASED?

A. No, I do not. Dr. Woolridge argues analysts' earnings growth estimates are "overly optimistic and upwardly biased", and suggests relying on analysts' estimates is a methodological error.[21] He further asserts "the DCF should also be adjusted downward from the projected EPS growth rate to remove the upward bias..."[22] Dr. Woolridge's position, however, is based on observations of the broad market; he has provided no evidence that any of the growth rates used in my (or his) DCF analyses are the result of a consistent and pervasive bias on the part of the analysts providing those projections. Notably, despite his view that they are biased, it was by "[g]iving primary weight to the projected EPS growth rate of Wall Street analysts" that Dr. Woolridge arrived at his assumed growth rates.[23]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THAT POINT?

A. There is no reason to believe the analyst growth rates used in my DCF analyses are biased. As a practical matter, the October 2003 Global Research Analyst Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling

21 Direct Testimony of J. Randall Woolridge, Ph.D., at 46.
22 *Ibid.*, at 47.
23 *Ibid.*, at 50.

financial institutions to fund independent third-party research.[24] I have reviewed the Letters of Acceptance, Waiver and Consent signed by financial institutions that were party to the Global Settlement, and found no reference to misconduct by analysts following the utility sector.

Moreover, pursuant to Regulation AC, which became effective in April 2003, analysts must certify that "...the views expressed in the report accurately reflect his or her personal views, and disclose whether or not the analyst received compensation or other payments in connection with his or her specific recommendations or views."[25] I further understand industry practice is to avoid conflicts of interest by ensuring that compensation is not directly or indirectly linked to the opinions contained in those reports. Dr. Woolridge has not explained why any of the analysts covering our respective proxy companies would bias their projections despite those certification requirements.

Q. IS THE USE OF ANALYSTS' EARNINGS GROWTH PROJECTIONS IN THE DCF MODEL SUPPORTED BY FINANCIAL LITERATURE?

A. Yes, it is. Several published articles support the use of analysts' earnings growth projections in the DCF model. Dr. Robert Harris, for example, found financial analysts' earnings forecasts (referred to in the article as "FAF") to be appropriate in

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24 The 2002 Global Financial Settlement resolved an investigation by the U.S. Securities and Exchange Commission and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts.

25 Securities and Exchange Commission, 17 CFR PART 242 [Release Nos. 33-8193; 34-47384; File No. S7-30-02], RIN 3235-AI60 Regulation Analyst Certification.

calculating the expected Market Risk Premium:[26]

> ... a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Such studies typically employ a consensus measure of FAF calculated as a simple average of forecasts by individual analysts.[27]

Dr. Harris further noted that:

> Given the demonstrated relationship of FAF to equity prices and the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements.[28]

Similarly, in *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts*, Harris and Marston presented "estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts."[29] As Harris and Marston reported:

> ... in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.[30]

Here again, the finding was clear: Analysts' earnings forecasts are highly related to stock price valuations and are appropriate inputs to stock valuation and ROE estimation models.[31]

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26 *See*, Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, 1986, at 66.

27 *Ibid.*, at 59.

28 *Ibid.*, at 60.

29 Robert S. Harris, Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992.

30 *Ibid.*, at 63.

31 In *the Risk Premium Approach to Measuring a Utility's Cost of Equity*, published in Financial Management, Spring 1985, 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."

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S POSITION THAT "THE DCF SHOULD ALSO BE ADJUSTED DOWNWARD FROM THE PROJECTED EPS GROWTH RATE TO REMOVE THE UPWARD BIAS"?[32]

A. No. If current stock prices (and therefore the dividend yield) already reflect analysts' bias, it is unclear why it is necessary to adjust the growth rate. Although Dr. Woolridge argues "…long-term earnings per share growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased"[33] in general, he has not demonstrated that to be true for the natural gas companies in the proxy group. To that point, I reviewed quarterly earnings presentations of companies in his proxy group and found analysts' growth rate projections to be within, or even toward the lower end if not below, the long-term growth rate ranges provided by the companies' management teams (*see,* Table 3, below). I therefore do not believe the earnings projections included in our respective analyses are likely to be systematically biased.

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32 Direct Testimony of J. Randall Woolridge, Ph.D., at 47.

33 *Ibid.*, at 72.

Table 3: Analysts' Earnings Growth Projections Relative to Management Presentations[34]

Company	Ticker	Zacks Earnings Growth	First Call Earnings Growth	Investor Presentation Earnings Growth Range
New Jersey Resources Corp.	NJR	7.00%	6.00%	6.00% - 8.00%
Northwest Natural Hold. Co.	NWN	4.50%	4.00%	3.00% - 5.00%
ONE Gas, Inc.	OGS	5.90%	5.00%	6.00% - 8.00%
South Jersey Industries, Inc.	SJI	7.20%	5.50%	6.00% - 8.00%

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S ARGUMENT THAT YOUR APPROACH LEADS TO "AN OVERSTATED EQUITY COST RATE."[35]

A. Dr. Woolridge states that combining Zack's, First Call, and Value Line growth rates leads to an overstated EPS growth rate. He principally argues Value Line's estimates are overstated due to the use of a three-year based period, especially if that base period includes years with "abnormally high or low earnings."[36]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THAT POINT?

A. Although Dr. Woolridge criticizes specific growth rates he considers too high, he fails to consider the implications of individual growth rates that would be unsustainably low. For example, on page 15, footnote 13 of his Direct Testimony, Dr. Woolridge states "inflation remains low and is also in the 2.0% to 2.5% range". Yet, Value Line projects earnings growth of 2.50 percent for New Jersey Resources Corporation, and First Call projects earnings growth rate of 2.42 percent for Spire

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34 Source: Zacks, Yahoo! Finance, and individual company fourth quarter 2018, first quarter 2019, and second quarter 2019 investor presentations.

35 *See*, Direct Testimony of J. Randall Woolridge, Ph.D., at 72.

36 *Ibid.*, at 73.

Inc.[37] Because the Constant Growth DCF model assumes growth in perpetuity, nominal growth rates in the range of 2.40 percent to 2.50 percent suggest modest, or even negative real perpetual growth.[38] It is unlikely investors would commit capital to an equity investment expected to contract (on a real basis) in perpetuity. Consequently, if we are concerned with growth rates that may be considered too high, we also should be concerned with those that are too low.

Q. DO YOU AGREE WITH DR. WOOLRIDGE THAT DIVIDEND AND BOOK VALUE GROWTH RATES ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?[39]

A. No, EPS growth is the fundamental driver of the ability to pay dividends. As noted in my Direct Testimony, to reduce growth to a single measure we assume a fixed payout ratio, and a constant growth rate for EPS, DPS, and BVPS.[40] Exhibit RBH-R-8 illustrates that, under the Constant Growth DCF model's strict assumptions, earnings, dividends, book value, and stock prices all grow at the same, constant rate in perpetuity.

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37 Exhibit_(RBH-1).

38 That is, those growth rates are only marginally above the 2.00 percent lower bound of the inflation rate Dr. Woolridge observes, and equal to or below the 2.50 percent upper bound.

39 Direct Testimony of J. Randall Woolridge, Ph.D., at 42.

40 Direct Testimony of Robert B. Hevert, at 61.

Q. DO YOU AGREE WITH DR. WOOLRIDGE THAT HISTORICAL GROWTH RATES ARE APPROPRIATE MEASURES OF EXPECTED GROWTH FOR THE CONSTANT GROWTH DCF MODEL?[41]

A. No, I do not. As Dr. Woolridge acknowledges, the growth component of the Constant Growth DCF model is a forward-looking measure reflecting investors' expectations of future growth.[42] To the extent historical growth influences expectations of future growth, it already will be reflected in analysts' consensus earnings growth estimates. Carlton and Vander Weide found "overwhelming evidence that consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price."[43] Consequently, I do not believe historical growth rates are appropriate for the Constant Growth DCF model.

Q. HAVE YOU UNDERTAKEN ANY ANALYSES TO DETERMINE WHICH MEASURES OF GROWTH ARE STATISTICALLY RELATED TO THE PROXY COMPANIES' STOCK VALUATION LEVELS?

A. Yes, I have. My analysis is based on the methodological approach used by Professors Carleton and Vander Weide, who compared the predictive capability of historical growth estimates and analysts' forecasts on the valuation levels of sixty-five utility companies.[44] I structured the analysis to understand whether projected

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41 Direct Testimony of J. Randall Woolridge, Ph.D., at 42-43.
42 *Ibid.*, at 41-42.
43 Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs History*, The Journal of Portfolio Management (Spring 1988).
44 *Ibid.*

earnings, dividend, book value, or retention growth rates best explain utility stock valuations. In particular, my analysis examined the statistical relationship between the Price/Earnings ("P/E") ratios of the natural gas and electric utilities as classified by Value Line, and the projected EPS, DPS, and BVPS growth rates as reported by Value Line, as well as the historical EPS, DPS, and BVPS as reported by Value Line. To determine which, if any, of those growth rates are statistically related to utility stock valuations, I performed a series of regression analyses in which the projected growth rates were explanatory variables and the P/E ratio was the dependent variable. The results of those analyses are presented in Exhibit RBH-R-9.

In that analysis, I performed nine separate regressions with the P/E as the dependent variable, and historical EPS, DPS, and BVPS; and projected EPS, DPS and BVPS, respectively, as the independent variable. I also performed a single regression analysis that included all nine variables as potential explanatory variables. I then reviewed the T- and F-Statistics to determine whether the variables and equations were statistically significant.[45]

Q. **WHAT DID THOSE ANALYSES REVEAL?**

A. As shown in Exhibit RBH-R-9, the only growth rate that was statistically significant and positively related to the P/E ratio was projected Earnings Per Share. Because EPS growth is the only growth rate that is both statistically and positively related

[45] In general, a T-Statistic of 2.00 or greater indicates that the variable is likely to be different than zero, or "statistically significant." The F-Statistic is used to determine whether the model as a whole has statistically significant predictive capability.

to utility valuation, earnings is the proper measure of growth in the Constant Growth DCF Model.

Q. DO YOU HAVE ANY CONCERNS WITH DR. WOOLRIDGE'S SPECIFICATION OF THE RETENTION GROWTH RATE?

A. Yes, I do. The full form of the model assumes growth is a function of its expected earnings, and the extent to which it retains earnings to invest in the enterprise. The form of the model on which Dr. Woolridge relies is its simplest form, which defines growth solely as a function of internally generated funds. As discussed in my Direct Testimony, the full form of the Retention Growth model (br + sv) reflects growth from internally generated funds and from issuances of equity.[46]

Capital Asset Pricing Model

Q. PLEASE BRIEFLY DESCRIBE DR. WOOLRIDGE'S CAPM ANALYSIS AND RESULTS.

A. Dr. Woolridge's CAPM analysis produces an estimated Cost of Equity of 7.60 percent.[47] I strongly disagree an estimate that low is a reasonable measure of the Company's Cost of Equity. As discussed below, Dr. Woolridge's unduly low CAPM estimate principally falls from his estimated Market Risk Premium.

Dr. Woolridge combines a risk-free rate of 4.00 percent and a Market Risk Premium ("MRP") of 5.50 percent to the average Beta coefficient of his and my proxy groups (0.65). In estimating the MRP, Dr. Woolridge reviews a series of

46 Direct Testimony of Robert B. Hevert, at 65; Exhibit_(RBH-2).
47 Direct Testimony of J. Randall Woolridge, Ph.D., at 64.

studies that calculate the MRP using different methods; he also considers the results of his "Building Blocks" approach. Based on that review, Dr. Woolridge argues the MRP ranges from 4.00 percent to 6.00 percent and, within that range, 5.50 percent is reasonable.[48]

Q. DOES DR. WOOLRIDGE EXPRESS ANY CONCERNS REGARDING YOUR CAPM ANALYSIS?

A. Dr. Woolridge's principal disagreements with my CAPM analysis include: (1) the Market Risk Premium component of the model; and (2) the use of current, near-term projected, and long-term projected Treasury yields that are abnormally high relative to current yields.

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S CONCERNS REGARDING YOUR USE OF EXPECTED MARKET RETURNS.

A. Regarding the use of expected market returns, Dr. Woolridge suggests the result is "excessive."[49] Dr. Woolridge also points to the long-term EPS growth rates for the S&P 500 based on the data from Bloomberg and Value Line, respectively, and notes that they "are inconsistent with both historic and projected economic and earnings growth in the U.S".[50] To support his position that the expected market return included in the CAPM analysis is overstated, Dr. Woolridge references MRPs provided in academic studies, assumed by investment banks and management

48 *Ibid.*, at 63.
49 *Ibid.*, at 79.
50 *Ibid.*, at 82.

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consulting firms, and found in surveys of financial professionals.[51]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THOSE POINTS?

A. Dr. Woolridge refers to two surveys of financial professionals in support of his MRP and in defense of his critique that my estimates are excessive; the Duke Chief Financial Officer ("Duke CFO") survey and the Philadelphia Federal Reserve Survey of Professional Forecasters.[52] Looking to the Federal Bank of Philadelphia's First Quarter 2019 survey, only 16 of 38 participants responded to the question regarding the expected return for the S&P 500 over the next ten years, and 21 of 38 responded to the question regarding expected return on ten-year Treasury bonds.[53]

Even if all 38 economists provided expected market returns and Treasury yields, Dr. Woolridge gives economists' interest rate projections little weight, going so far as to note that in a Bloomberg survey, "100% of the economists were wrong."[54] Yet, Dr. Woolridge gives economists' forecasts of market returns and GDP considerable weight in supporting his expected Market Risk Premium. It is unclear why Dr. Woolridge finds economists' estimates appropriate for his analyses, but improper for mine.

As for the Duke CFO survey, Dr. Woolridge's 9.00 percent ROE

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51 *Ibid.*, at 79.

52 *Ibid.*, at 56-57.

53 *See*, Federal Reserve Bank of Philadelphia, Survey of Professional Forecasters, First Quarter of 2019 at 19.

54 Direct Testimony of J. Randall Woolridge, Ph.D., at 11. [emphasis included]

recommendation, which applies to a company that is less risky than the overall market,[55] is 279 basis points above the expected market return suggested by the survey results. If the survey were a reasonable method of determining the expected market return, Dr. Woolridge's ROE recommendation would be no higher than 6.21 percent.[56] Lastly, over time the survey results have rather significantly underestimated actual market performance (*see,* Table 4, below).

Table 4: S&P 500 Market Return: Accuracy of Survey Estimates[57]

	Actual	Survey Estimate
2018	-4.38%	6.57%
2017	21.83%	5.00%
2016	11.96%	4.32%
2015	1.38%	6.07%
2014	13.69%	5.00%
2013	32.39%	3.40%
2012	16.00%	4.00%
2011	2.11%	5.30%
2010	15.06%	6.28%
Average	12.23%	5.10%

The Duke CFO Survey authors also have noted a distinction between the expected market return on one hand, and the "hurdle rate" on the other. In the Third Quarter 2017 survey, the authors reported an average hurdle rate, which is the return required for capital investments, of 13.50 percent. The authors further reported the

55 Dr. Woolridge agrees that Beta coefficients for our proxy companies are less than 1.0.

56 6.21 percent equals the expected annual average market return over the next 10 years suggested by the Duke CFO survey. *Duke/CFO Magazine Global Business Outlook survey – U.S., Fourth Quarter 2018*, at 45.

57 Source: Duff & Phelps, <u>2019 SBBI Yearbook</u> Appendix A-1; http://www.cfosurvey.org (One-year return estimates as of fourth quarter of the previous year).

average Weighted Average Cost of Capital, which includes the cost of debt, was 9.20 percent even though the expected market return was 6.50 percent.[58] In my view, Dr. Woolridge's reference to a 3.15 percent[59] expected Market Risk Premium estimate based on the Duke CFO Survey should be given little weight.

Q. DO YOU AGREE WITH DR. WOOLRIDGE'S REFERENCE TO STUDIES THAT REPORT MRP ESTIMATES BASED ON EXPECTED GEOMETRIC RETURNS?

A. No, I do not. The MRP should reflect the expected arithmetic average return. The important distinction between the arithmetic and geometric averages is that the arithmetic mean assumes that each periodic return is an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. The geometric mean, on the other hand, is a backward-looking calculation that equates a beginning value to an ending value. Although geometric averages provide a standardized basis of review of historical performance across investments or investment managers, they do not reflect forward-looking uncertainty. That is why investors and researchers commonly use the arithmetic mean when estimating the risk premium over historical periods to estimate the Cost of Equity. As Morningstar notes:

> The arithmetic average equity risk premium can be demonstrated to be the most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple

58 Duke/CFO Magazine Global Business Outlook Survey – U.S., Third Quarter 2017.
59 Direct Testimony of J. Randall Woolridge, Ph.D., at 60.

difference of the arithmetic means of the stock market returns and riskless rates is the relevant number.[60]

Lastly, investment risk, or volatility, typically is measured based on the standard deviation. The standard deviation, in turn, is a function of the arithmetic mean, not the geometric mean. In that regard, the Beta coefficients applied in CAPM analyses are a function of the standard deviation of returns.[61]

Q. TURNING TO DR. WOOLRIDGE'S POSITION THAT THE EPS GROWTH RATES USED TO DEVELOP YOUR ESTIMATED MARKET RETURN ARE TOO HIGH,[62] DID YOU CONSIDER WHERE YOUR ESTIMATE FALLS WITHIN THE RANGE OF HISTORICAL OBSERVATIONS?

A. Yes. I gathered the annual capital appreciation return on Large Company Stocks reported by Morningstar for the years 1926 through 2018, produced a histogram of those observations (*see* Chart 1, below), and calculated the probability that a given capital appreciation return estimate would be observed. The results of that analysis demonstrate that capital appreciation rates of 10.81 percent to 12.11 percent and higher actually occurred quite often,[63] representing approximately the 51st and 53rd percentiles, respectively.

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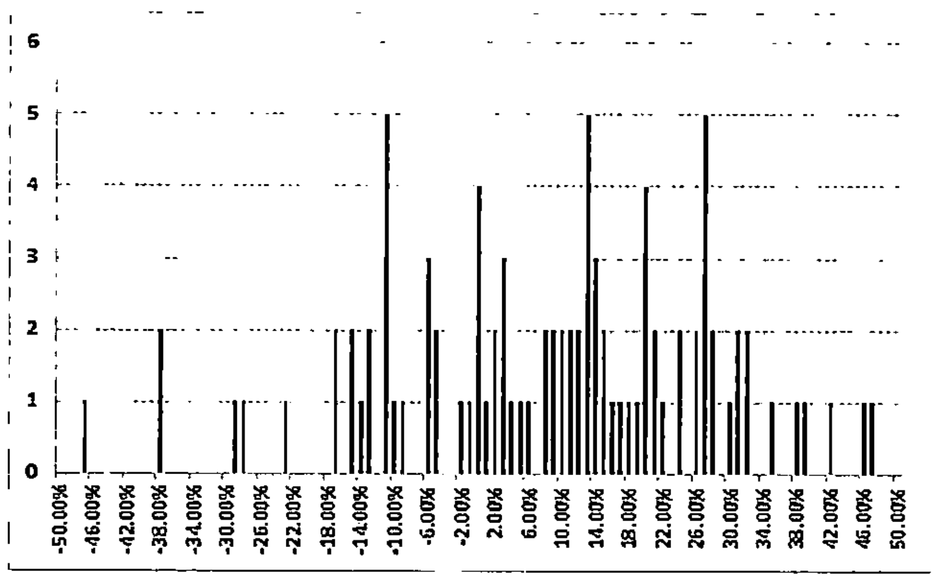
60 Morningstar, Inc., 2013 Ibbotson SBBI Valuation Yearbook, at 56.
61 *See*, Direct Testimony of Robert B. Hevert, at 68-69.
62 Direct Testimony of J. Randall Woolridge, Ph.D., at 79.
63 Under the Constant Growth DCF model's assumptions, the growth rate equals the rate of capital appreciation.

Chart 1: Frequency Distribution of Capital Appreciation Returns, 1926-2018[64]

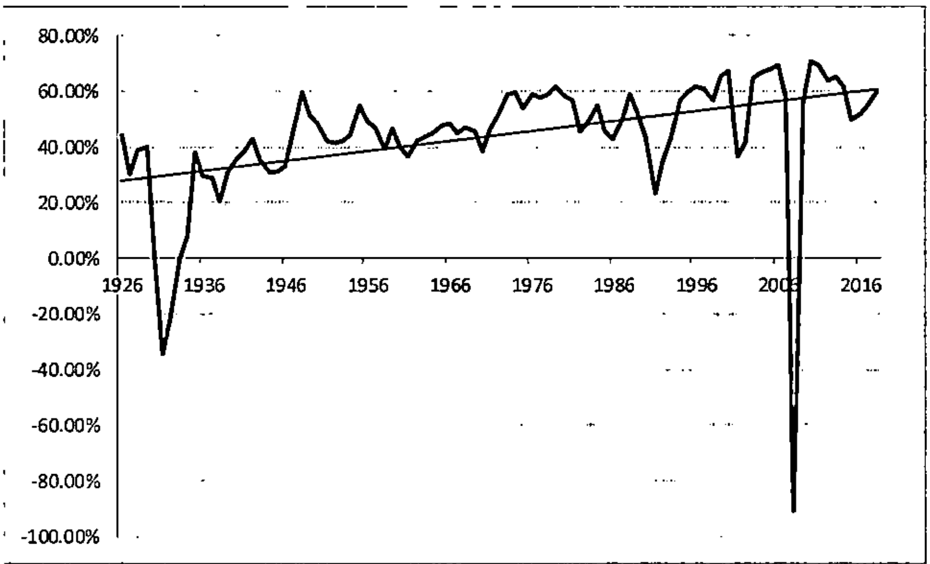


As to Dr. Woolridge's analysis of the S&P 500 EPS and Gross Domestic Product ("GDP") growth rates (in his Table 10), his conclusion that net income of the S&P 500 would grow to approximately equal that of GDP[65] is substantially driven by his unduly low GDP growth rate. Under the Sustainable Growth model, if the retention ratio is higher now than it historically has been, there would be reason to believe expected growth rates would be higher than historical growth rates. To determine whether that has been the case, I calculated the annual retention ratio from 1926 to 2018 using earnings and dividends data published by Dr. Robert J. Shiller. As shown in Chart 2 (below), that data indicates the S&P 500 earnings retention has trended upward over time and is currently well above its historical

64 Duff & Phelps, 2019 SBBI Yearbook, at A-3.
65 Direct Testimony of J. Randall Woolridge, Ph.D., at 88-92.

average. Consequently, the Sustainable Growth model included in my and Dr. Woolridge's DCF analyses suggests that the future growth of the S&P 500 could outpace its historical growth.

Chart 2: S&P 500 Annual Earnings Retention Ratio, 1926 – 2018[66]



Lastly, although Dr. Woolridge is concerned with the expected market return based on Value Line estimates, all six CAPM results derived from that measure fall outside my recommended range.

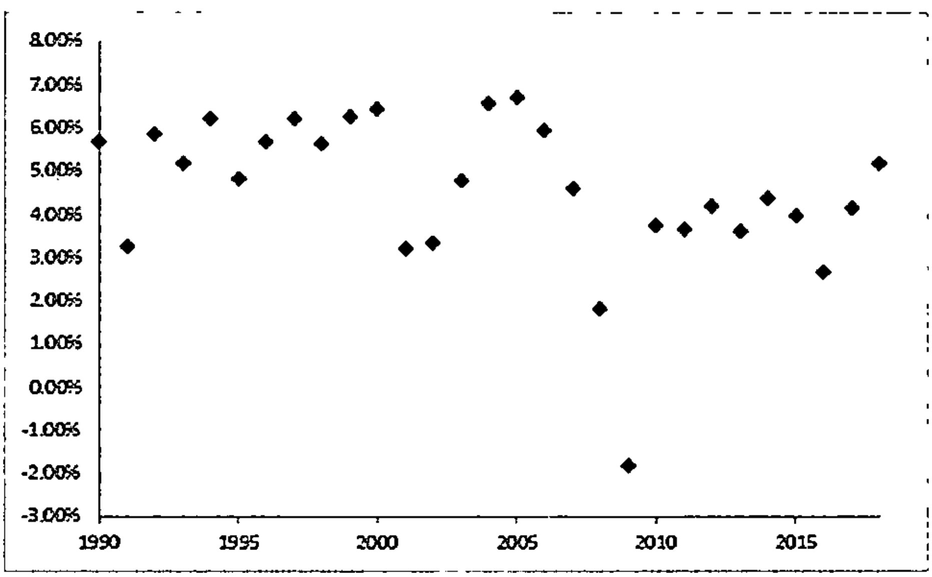
Q. WHAT IS THE BASIS OF DR. WOOLRIDGE'S CONCERN WITH YOUR MRP AS IT RELATES TO HISTORICAL NOMINAL GDP GROWTH RATES?

A. Dr. Woolridge argues "nominal GDP growth in recent decades has slowed and that a figure in the range of 3.0% to 5.0% is more appropriate today for the U.S.

[66] Source: http://www.econ.yale.edu/~shiller/data.htm.

economy."[67] To support his position, Dr. Woolridge reviews average nominal GDP growth over periods of ten to 50 years. As shown on Chart 3 (below), however, since 1990 (that is, in "recent decades") the annual nominal growth rate in GDP has remained relatively stable, but for the period 2008 to 2012, which includes the recent recession. Over that time, annual nominal GDP growth rates greater than 5.00 percent (the high end of Dr. Woolridge's suggested range) occurred in 13 of 29 years.

Chart 3: Annual Nominal GDP Growth Rates[68]



[67] Direct Testimony of J. Randall Woolridge, Ph.D., at 85.
[68] Source: Bureau of Economic Analysis, June 27, 2019 update.

Q. AT PAGES 86 AND 87 OF HIS TESTIMONY DR. WOOLRIDGE REFERS TO A 2015 STUDY BY MCKINSEY & CO., AND ARGUES THAT REAL GDP GROWTH MAY FALL BY 40.00 PERCENT. DO YOU AGREE WITH DR. WOOLRIDGE'S CONCLUSION?

A. No, I do not. Dr. Woolridge argues future real global economic growth will fall to 2.10 percent, principally due to slowing growth in the working age population. He argues that is the case "even if productivity remains at the rapid rate of the past fifty years of 1.80%".[69] McKinsey, however, also points to five "sector case studies", that find "more than enough productivity-acceleration scope to counter slower labor growth."[70] Based on those studies, McKinsey finds sufficient potential for productivity growth to reach 4.00 percent. Of note, about three-quarters of that global potential "would come from the broader adoption of existing best practices", which the firm would characterize as "catch-up" productivity improvements."[71] As to the remainder, McKinsey states:

> The remaining one-quarter, or about one percentage point a year, could come from technological, operational, or business innovations that go beyond today's best practices and that "push the frontier" of the world's GDP potential. In contrast to some observers, we do not find that a drying up of technological or business innovations will act as a constraint to growth. On the contrary, we see a strong innovation pipeline in both developed and developing economies in the sectors we studied. Our estimate of the potential here is based only on the innovations that we can foresee. It is quite possible that

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69 Direct Testimony of J. Randall Woolridge, Ph.D., at 87.

70 McKinsey Global Institute, *Global Growth: Can Productivity Save the Day In An Aging World?*, January 2015, at PDF 9.

71 *Ibid.*, at 53 (PDF 63).

> waves of innovation may, in reality, push the frontier far further than we can ascertain based on the current evidence.[72]

In short, the McKinsey study does not conclude the declining workforce necessarily means lower real global GDP growth. Rather, the potential for meaningful productivity increases may provide greater avenues for global real economic growth well greater than Dr. Woolridge assumes.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S REFERENCE TO GDP FORECASTS PROVIDED BY THE *SURVEY OF PROFESSIONAL FORECASTERS*, THE ENERGY INFORMATION ADMINISTRATION, AND THE CONGRESSIONAL BUDGET OFFICE ("CBO")?[73]

A. First, Dr. Woolridge has not demonstrated that investors rely on the surveys cited in his testimony. Second, as Dr. Woolridge points out, the *Survey of Professional Forecasters* relates to the years 2019 to 2029; given Dr. Woolridge's concern with my growth rates over the coming period of three-to-five years, his use of the *Survey of Professional Forecasters* does not address that issue. As to the CBO and EIA forecast, those projections cover only 15 to 25 years of a perpetual period, and are not consensus forecasts. In addition, because the EIA's GDP growth forecast is an input to its annual energy projections, the assumptions and methods underlying its GDP forecast are for that specific purpose.

The CBO provides updates regarding its forecasting record. In that context, the CBO noted that comparisons to other forecasts are not always apt, at least in

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72 *Ibid.*

73 Direct Testimony of J. Randall Woolridge, Ph.D., at 85-86.

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part because they may be based on different assumptions and used for different purposes.[74] The CBO also observes that it is required to assume that future fiscal policy generally will reflect current law, so that it may provide a benchmark against which proposed changes in law may be assessed.[75] The CBO goes on to explain that "because forecasters make different assumptions about future fiscal policy, it is difficult to compare the quality of forecasts without considering the role of expected changes in laws."[76] The CBO also notes that among its two-year forecasts (since the early 1980s), the forecast error for "real output growth" and inflation (measured by the Consumer Price Index) has been 1.30 percentage points and 0.90 percentage points, respectively.[77]

As to the accuracy of the EIA's GDP forecast, the agency reviews its projections in its *Annual Energy Outlook ("AEO") Retrospective Review*. In the *AEO Retrospective Review*, the EIA notes: "[t]he projections in the AEO are not statements of what will happen but of what may happen given assumptions in the underlying National Energy Modeling System (NEMS)."[78] As EIA makes clear,

74 *See*, *CBO's Economic Forecasting Record: 2017 Update*, October 2017, at 4–5.

75 *Ibid.*, at 8. "CBO is required by statute to assume that future fiscal policy will generally reflect the provisions in current law, an approach that derives from the agency's responsibility to provide a benchmark for lawmakers as they consider proposed changes in law. When the Administration prepares its forecasts, however, it assumes that the fiscal policy in the President's proposed budget will be adopted. Forecast errors may be driven by those different assumptions, especially when forecasts are made while policymakers are considering major changes to current fiscal policy."

76 *Ibid.*, at 4–5.

77 *Ibid.*, at 9. Root mean square error.

78 U.S. Energy Information Administration, *Annual Energy Outlook Retrospective Review: Evaluation of AEO2018 and Prior Reference Case Projections*, December 2018, at 1. Clarification added.

the Reference case assumes current laws and regulations are unchanged throughout the projection period.[79] The agency's projections therefore are based on the economic environment at the time of the forecast. As shown in Table 3 of the *AEO Retrospective Review*, the EIA compares its past real GDP growth projections to actual real GDP growth. In its 1994 forecast of GDP growth – a time during which the U.S. was coming out of a recession – the agency generally underestimated GDP growth. During the stronger economic times of the 2000s, the agency generally overestimated GDP growth into the future.[80] The agency's 2018 to 2050 reference case is based on the current economic environment of below average GDP growth, inflation, and interest rates.[81]

Q. HOW DOES THE HISTORICAL RELATIONSHIP BETWEEN INTEREST RATES AND RISK PREMIUMS COMPARE TO YOUR MRP ESTIMATES?

A. As discussed in my Direct Testimony, the Equity Risk Premium is inversely related to the level of interest rates.[82] I therefore considered whether there is a similar inverse relationship between interest rates and the Market Risk Premium. To do so, I gathered the monthly market return and long-term (income only) return on government bonds as reported by Duff & Phelps. For each month, the interest rate was subtracted from the market return to arrive at the annualized Market Risk

79 U.S. Energy Information Administration, *Annual Energy Outlook 2018 with Projections to 2050*, February 2018, at 9.

80 U.S. Energy Information Administration, *Annual Energy Outlook Retrospective Review: Evaluation of 2014 and Prior Reference Case Projections*, March 2015, Table 3, at 7-8.

81 U.S. Energy Information Administration, *Annual Energy Outlook 2018 with Projections to 2050*, February 2018, at Table 20.

82 Direct Testimony of Robert B. Hevert, at 73.

Premium.[83]

With that data, I performed two regression analyses. The first was a simple linear regression in which the dependent variable was the Market Risk Premium, and the independent variable was the income-only return on long-term government bonds. That analysis showed that the Market Risk Premium has been negatively related to interest rates, with a high level of statistical significance. To determine whether a portion of that relationship was simply a matter of time (that is, whether it simply was a trend) a second analysis that included time (as measured by the monthly date) as an additional explanatory variable was undertaken. In that case, interest rates again were negative and significant, but the trend variable was insignificant. The results of both analyses are provided in Exhibit RBH-R-10.[84]

Q. DR. WOOLRIDGE STATES THAT COMPANIES WITH LOWER BETAS HAVE LESS MARKET RISK,[85] IMPLYING A LOWER REQUIRED RETURN. IS HE CORRECT?

A. Although I agree utilities are less risky than the overall market, it is important to understand how Beta coefficients and their components reflect systematic risk. As shown below in Chart 4, since 2012 the correlation between the S&P 500 Index and Dr. Woolridge's proxy group companies (*i.e.* low-Beta coefficient companies) has

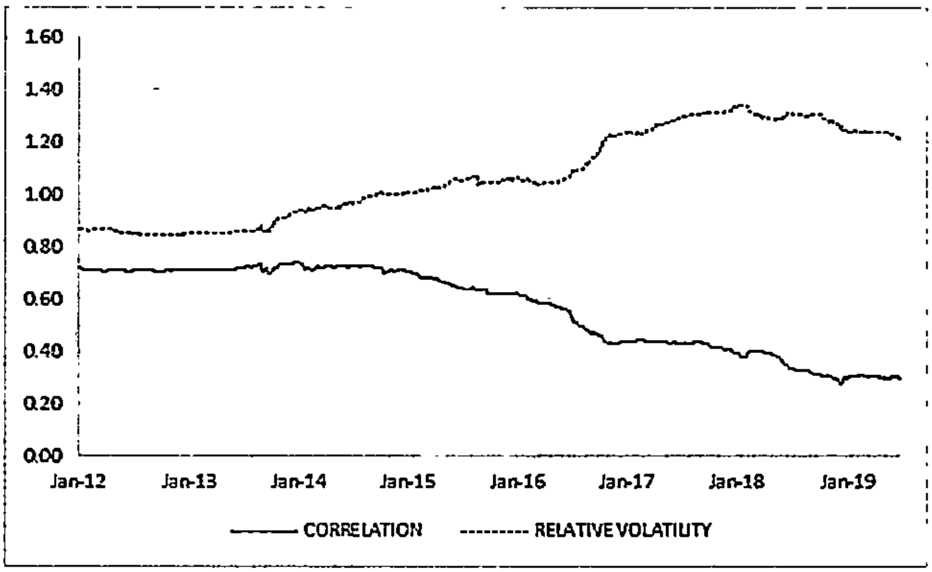
83 Source: Duff & Phelps, 2019 SBBI, Appendix A-1, Appendix A-7. I calculated returns on a monthly basis because annual returns likely mask the variation in data and may not provide as reliable results as the more granular monthly calculations.

84 I recognize that the R-squared for the regression analyses are low, even though the regression equation, and the regression coefficients are highly statistically significant.

85 Direct Testimony of J. Randall Woolridge, Ph.D., at 54.

declined, while the relative risk has increased. As such, the CAPM may not adequately reflect the expected systematic risk and returns required by investors in low-Beta coefficient companies, such as utilities.

Chart 4: Components of Beta Coefficients Over Time[86]



Q. WHAT CONCLUSIONS DO YOU DRAW FROM CHART 4?

A. Beginning in 2012 the Federal Reserve began its third round of Quantitative Easing, which was meant to put downward pressure on long-term interest rates. The effect of that policy may have been to encourage investors, at times, to "reach for yield" by investing in dividend-paying sectors, such as utilities. When macroeconomic conditions evolved such that interest rates began to increase, or other growth-based sectors appeared more appealing, investors would rotate out of the utility sectors. Because utilities faced downward credit pressure due to the TCJA, and because

[86] Source: S&P Global Market Intelligence. Calculated as an index.

utilities could not benefit from the TCJA in ways other sectors could, they became relatively less attractive. In summary, since 2012, federal policies have affected trading decisions in ways that have caused the utility sector's correlation with the overall market to fall.

At the same time, the volatility in utility returns increased relative to the overall market. The question is whether current Beta coefficients, even though adjusted, reasonably reflect expected returns. As discussed below, published research has found low-Beta coefficient companies have tended to earn returns greater than those predicted by the CAPM. Given the decline in correlations discussed above, that may be an even more acute concern in the current market.

Q. IN YOUR VIEW, DO THOSE FACTORS LIKELY EXPLAIN THE DIFFERENCE IN BETA COEFFICIENTS PROVIDED BY BLOOMBERG AND VALUE LINE?

A. Yes, they do. As explained in my Direct Testimony, Bloomberg's default method is to calculate Beta coefficients over two years (as opposed to Value Line's five-year convention).[87] Because correlations have fallen over the past two years, the relationship shown in Chart 4 will have a particularly meaningful effect on Bloomberg Beta coefficients. As discussed, earlier, however, the fall in correlations may largely be related to Federal policy initiatives that are not likely to persist over the long-term. That being the case, an important question is whether the change in

[87] Direct Testimony of Robert B. Hevert, at 71. *See*, also, Exhibit_(RBH-4).

Beta coefficients reasonably represents the long-term investor expectations.

Q. WITH THOSE POINTS IN MIND, IS THERE A METHOD THAT MAY BE APPLIED TO ADDRESS THE CHANGE IN BETA COEFFICIENTS?

A. Yes. One method of doing so is to apply the Empirical form of the CAPM, which adjusts for the CAPM's tendency to under-estimate returns for companies that (like utilities) have Beta coefficients less than the market mean of 1.00, and over-estimate returns for relatively high-Beta coefficient stocks.[88] Fama and French describe the empirical issue addressed by the ECAPM noting that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[89] Similarly, Dr. Roger Morin observes "[w]ith 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."[90] As Dr. Morin also explains, the ECAPM "makes use" of those findings, and estimates the Cost of Equity based on the following equation:[91]

$$k_e = R_f + \alpha + \beta(MRP - \alpha) \qquad [1]$$

where α, or "alpha", is an adjustment to the risk/return line, and "MRP" is the Market Risk Premium (defined above). Summarizing empirical evidence regarding the range of estimates for alpha, Dr. Morin explains that the model "reduces to the

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88 Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 175 - 176.

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

90 Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 175.

91 *Ibid.*, at 189.

following more pragmatic form:"[92]

$$k_e = R_f + 0.25(R_m - R_f) + 0.75\beta(R_m - R_f) \quad [2]$$

where:

k_e = the investor-required ROE;

R_f = the risk-free rate of return;

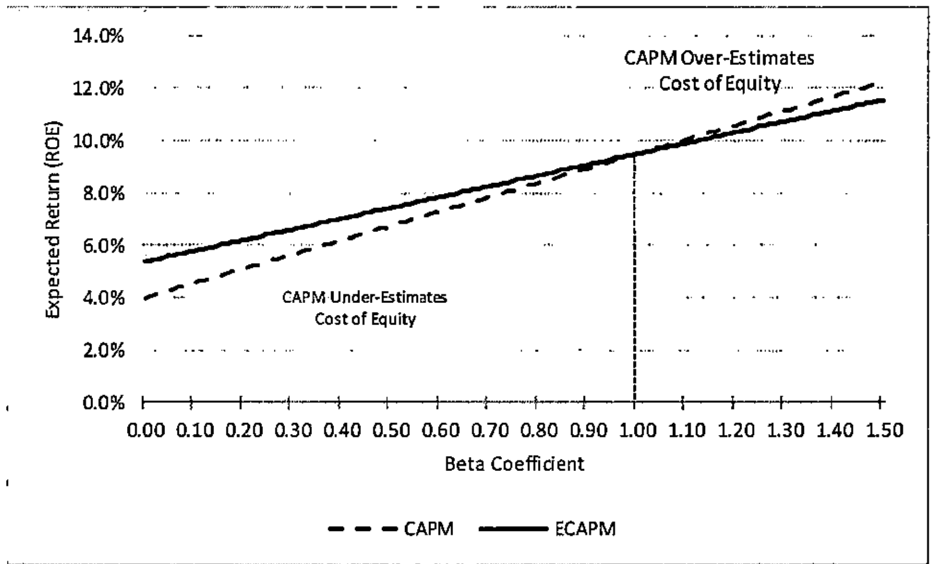
β = the adjusted Beta coefficient of an individual security; and

R_m = the required return on the market.

The relationship between expected returns under the CAPM and ECAPM approaches can be seen in Chart 5, below. Chart 5, which reflects Dr. Woolridge's risk-free rate and MRP, illustrates the extent to which the CAPM under-states the expected return relative to the ECAPM when Beta coefficients – whether adjusted or unadjusted – are less than 1.00.

[92] *Ibid.*, at 190. Equations [1] and [2] tend to produce similar results when "alpha" is in the range of 1.00 percent to 2.00 percent. *See*, Exhibit RBH-R-11. As Dr. Morin explains, alpha coefficients in that range are highly consistent with those identified in prior published research.

Chart 5: CAPM and ECAPM Expected Returns[93]



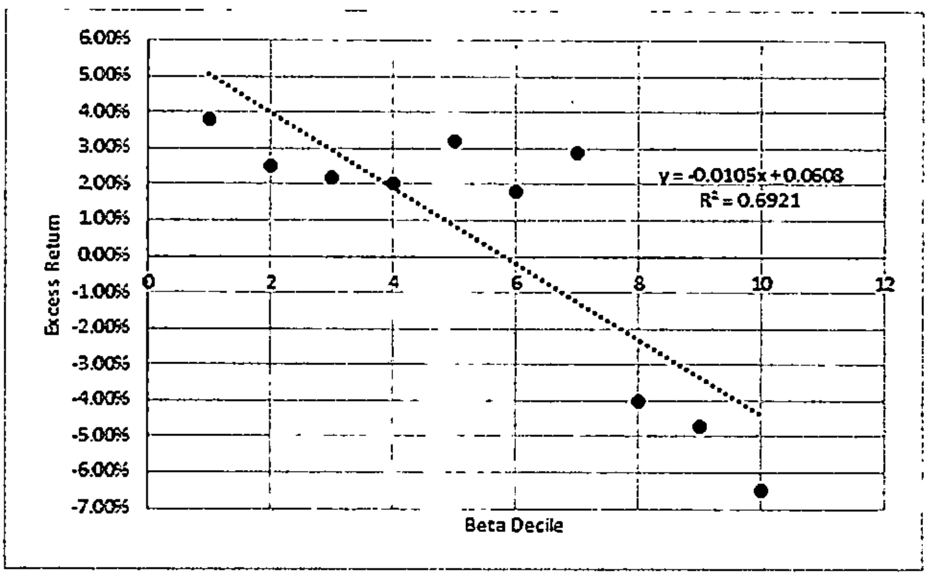
Q. **HAVE YOU UNDERTAKEN ANY INDEPENDENT ANALYSES TO DETERMINE WHETHER THERE IS A RELATIONSHIP BETWEEN BETA COEFFICIENTS AND EXCESS RETURNS PRODUCED BY THE CAPM AND ECAPM?**

A. Yes, I performed an analysis of excess returns produced by the CAPM, by Beta coefficient decile, over the ten years ended 2018. The analysis compared the observed returns of the companies in the S&P 500 Index to expected returns based on the CAPM. Observed returns were calculated as the total return for each company from the first day of a given year to the end of that year. The expected

[93] Exhibit RBH-R-11. Source: Direct Testimony of J. Randall Woolridge, Ph.D., at 64; Exhibit JRW-9, page 1. The finding that the ECAPM is not an adjustment to the Beta coefficient also is clear in Equation [1] ($k_e = R_f + \alpha + \beta(MRP - \alpha)$), in which the alpha coefficient increases the intercept (the expected return when the Beta coefficient equals zero), and reduces the Market Risk Premium. Please note that the use of Dr. Woolridge's CAPM estimates in Chart 5 is for illustrative purposes only.

return for each company was calculated using the CAPM as applied to the following annual data: (1) a risk-free rate equal to the average 30-year Treasury yield for that year; (2) an adjusted Beta coefficient as of the beginning of the year using Bloomberg's standard calculation method (two years of weekly return data, using the S&P 500 Index as the comparison benchmark); and (3) a market return equal to the S&P 500 Index total return for that year. The companies were grouped into deciles each year based on their Beta coefficients, and the median excess return (or return deficiency) was calculated for each decile group. Excess returns were calculated as the observed return less the return implied by the CAPM. Chart 6 (below) summarizes those results.

Chart 6: Excess Returns Under CAPM[94]

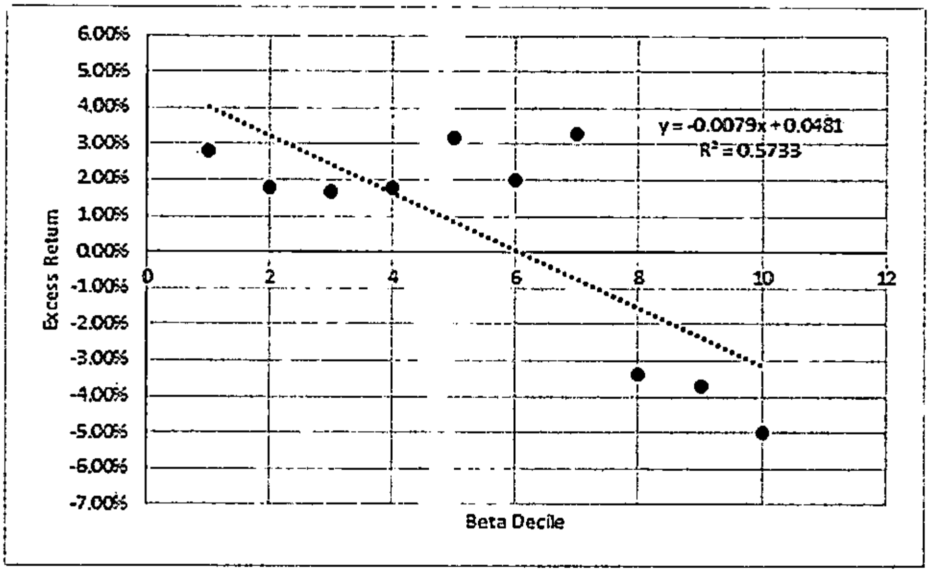


As Chart 6 demonstrates, the relationship between Excess Return and Beta

94 Source: Bloomberg Professional Services.

coefficient deciles is strong, with deciles explaining approximately 69.00 percent of the Excess Return. Using the same data and calculating the Excess Return by reference to the ECAPM (as defined by Equation [2], above), produces the same downward sloping relationship, but not to the same degree (*see* Chart 7, below).

Chart 7: Excess Returns Under ECAPM[95]



There are two principal observations to be drawn from the data presented in Charts 6 and 7. First, under the ECAPM the slope coefficient is somewhat less negative (relative to the CAPM), suggesting a flatter relationship between Beta coefficient deciles and the excess return. The flatter slope moves closer to the point at which the excess return is zero across all deciles. Second, the excess return values are somewhat moderated under the ECAPM; the high excess returns are lower than under the CAPM, and the low excess returns are higher. Again, that

95 Source: Bloomberg Professional Services.

finding suggests the ECAPM mitigates, but does not solve the issue of the CAPM underestimating returns for low-Beta coefficient firms.

In summary, Charts 6 and 7 support the position that the CAPM tends to underestimate returns for low-Beta coefficient firms, and the ECAPM moderates that effect to some extent, but it does not appear to eliminate it. Because the ECAPM mitigates the drift in Beta coefficients (which Dr. Woolridge addresses in his discussion of adjusted Beta coefficients), I believe it is a reasonable method, and have included results based on the ECAPM in my updated analyses.[96]

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S CONCERNS WITH THE RISK-FREE RATE ESTIMATES INCLUDED IN YOUR CAPM ANALYSES.

A. Dr. Woolridge finds the projected Treasury bond yields "excessive", and argues investors would not buy bonds at their current yield, if they believe yields will increase.[97]

Q. WHAT IS YOUR RESPONSE?

A. Dr. Woolridge's concern is misplaced. In his CAPM analysis, Dr. Woolridge relies on a 4.00 percent risk-free rate,[98] 137 basis points above the current 30-day average risk-free rate. Still, Dr. Woolridge argues investors give such projections no weight in their decision to purchase bonds at current yields. I disagree. The Cost of Equity is fundamentally forward-looking, and the use of projected Treasury (such as the

[96] Exhibit RBH-R-5.
[97] Direct Testimony of J. Randall Woolridge, Ph.D., at 77.
[98] *Ibid.*, at 53.

4.00 percent Dr. Woolridge applies) is consistent with that principle.

Bond Yield Plus Risk Premium Analysis

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S RESPONSE TO YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS.

A. Dr. Woolridge believes the Risk Premium derived from the analysis is "inflated" and "is a gauge of *commission* behavior and not *investor* behavior."[99] Dr. Woolridge further argues that the Risk Premium approach results reflect "other utility- and rate case-specific information in setting ROEs" and points to what he views as a potential discrepancy between settled and litigated cases.[100] He then suggests the analysis overstates the actual ROE, because the estimated risk premium is based on historical Treasury yields, whereas the model is applied to current and expected yields.[101]

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S POSITION REGARDING THE YIELDS USED IN YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS.

A. As discussed above, Dr. Woolridge disagrees with my use of Treasury yields that fall between 50 and 150 basis points above the current Treasury yield of 2.55 percent he presents. As explained above, the use of projected Treasury yields is entirely appropriate.

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99 *Ibid.*, at 96 [*emphasis included*].
100 *Ibid.*
101 *Ibid.*

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S POSITION THAT THE RISK PREMIUM ANALYSIS IS A STUDY OF UTILITY COMMISSION BEHAVIOR, RATHER THAN INVESTOR BEHAVIOR?

A. Those cases, and their associated decisions, reflect the same type of market-based analyses at issue in this proceeding. As noted earlier, because authorized returns are publicly available (the proxy companies disclose authorized returns, by jurisdiction, in their 2018 SEC Form 10-Ks),[102] it therefore is reasonable to conclude that data is reflected, at least to some degree, in investors' return expectations and requirements. From that perspective, ROE recommendations, such as Dr. Woolridge's, that are far removed from prevailing levels should be reconciled by reference to differences in risk. I do not believe Dr. Woolridge's recommendation reasonably does so.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S POSITION THAT YOUR ANALYSIS APPLIES AN HISTORICAL RISK PREMIUM TO PROJECTED RATES AND, AS SUCH, OVERSTATES THE COST OF EQUITY?[103]

A. I applied both historical and projected interest rates to the regression coefficients developed in the Risk Premium analysis, not to an average historical risk premium.

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102 *See, for example*, Atmos Energy Group, SEC Form 10-K for the period ending September 30, 2018, at 7; Northwest Natural Gas Company, SEC Form 10-K for the period ending December 31, 2018, at 35; ONE Gas Inc., SEC Form 10-K for the period ending December 31, 2018, at 27-29; Southwest Gas Holdings, SEC Form 10-Kfor the period ending December 31, 2018, Exhibit 13.01, at 10; Spire Inc., SEC Form 10-K for the period ending September 30, 2018, at 124-125.

103 Direct Testimony of J. Randall Woolridge, Ph.D., at 96.

As discussed in my Direct Testimony, the regression coefficients specifically recognize that as interest rates decrease, the Equity Risk Premium increases.[104] A consequence of that relationship is that interest rates and the Cost of Equity generally move in the same direction, but not on a one-to-one basis. As projected interest rates increase, the Cost of Equity also increases, but not to the same degree. Dr. Woolridge's concern that I applied projected interest rates to an historical risk premium is misplaced, in that (1) the analysis does not rely on an historical risk premium; and (2) because the estimated Equity Risk Premium does not increase in lock step with interest rates, the resulting ROE estimate does not overstate the Cost of Equity.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE'S POSITION THAT YOUR RISK PREMIUM ANALYSIS MUST TAKE INTO CONSIDERATION THE SPECIFIC ASPECTS OF THIS PROCEEDING RELATIVE TO ALL OTHERS?[105]

A. There is no disagreement that every case has its unique set of issues and circumstances. Reviewing over 1,100 cases over many economic cycles and using that data to develop the relationship between the Equity Risk Premium and interest rates mitigates that concern.

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104 Direct Testimony of Robert B. Hevert, at 74.
105 Direct Testimony of J. Randall Woolridge, Ph.D., at 96.

Q. IS IT A CONCERN, AS DR. WOOLRIDGE ARGUES, TO INCLUDE BOTH FULLY LITIGATED AND SETTLED RATE CASES IN YOUR RISK PREMIUM ANALYSIS?[106]

A. No, it is not. Of the 1,121 rate cases in Risk Premium analysis (*see* Exhibit RBH-R-6), 775 were fully litigated and 346 were settled. More recently (from January 2015 through June 28, 2019), 37 cases were fully litigated and 73 were settled. Over the same period, the difference in average authorized returns between the two, however, was approximately 4 basis points. Further, the same inverse relationship between interest rates and the Equity Risk Premium is present, whether the analysis includes fully litigated rate cases, settled rate cases, or both.[107] I therefore disagree with Dr. Woolridge's concern.

Expected Earnings Analysis

Q. PLEASE SUMMARIZE DR. WOOLRIDGE'S CONCERNS WITH YOUR EXPECTED EARNINGS ANALYSIS.

A. Dr. Woolridge argues the Expected Earnings approach is inappropriate because: (1) it is accounting-based and does not measure market based investor return requirements; (2) book equity does not change with investor return requirements as do market prices; (3) the approach is circular; and (4) the data partially reflect earnings of non-regulated operations.[108]

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106 *Ibid.*
107 Exhibit RBH-R-12.
108 Direct Testimony of J. Randall Woolridge, Ph.D., at 98-100.

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE?

A. Although I agree economic and financial factors, and the market-based models that depend on them are important, I do not agree those factors invalidate the Expected Earnings approach. As discussed in my Direct Testimony, no single method best captures investor expectations at all times and under all conditions. Market-based models necessarily require us to draw inferences from market data, based on the assumptions and construction of methods such as the DCF and CAPM approaches. The simplicity of the Expected Earnings approach is a benefit, not a detriment.

Further, utility rates are set based on the book value of equity. The Expected Earnings approach provides a direct measure of the book-based return comparable-risk utilities are expected to earn. In that sense, it is a direct measure of the expected opportunity cost on the book value of equity. Equally important, because it looks to the earnings expected of comparable-risk companies, the approach is consistent with the *Hope* and *Bluefield* "comparable return" standard. As Dr. Morin notes, the method "is easily understood, and is firmly anchored in regulatory tradition," concluding that "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with [Expected] Earnings, is highly meaningful."[109]

Lastly, among the growth rates Dr. Woolridge considers in his DCF analyses is the "sustainable growth" method. Under that method, expected growth depends

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109 Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006 at 392. 395. [clarification added].

on the expected return on the book value of common equity, and the extent to which that return is retained (that is, not paid in dividends). Although he does not adjust them to reflect average book value balances, Dr. Woolridge reports mean and median expected returns of 9.90 percent and 10.00 percent, respectively.[110]

Market-To-Book Ratios and the Cost of Equity

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S POSITION REGARDING THE RELATIONSHIP BETWEEN M/B RATIOS AND THE COST OF EQUITY.

A. Dr. Woolridge suggests M/B ratios greater than one[111] indicate the subject company's earned Return on Equity exceeds its Cost of Equity.[112] To support his position, Dr. Woolridge provides a regression analysis reflecting the relationship between the Return on Equity and M/B ratios for natural gas utilities and electric utilities. Because the R-Squared is 50.00 percent, Dr. Woolridge concludes there is a "strong positive relationship" between M/B ratios and the ROE for utilities.[113]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THOSE POINTS?

A. The M/B ratio equals the market value (or stock price) per share, divided by the total common equity (or the book value) per share. Book value per share is an accounting construct that reflects historical costs. In contrast, market value per

110 *See*, Exhibit JRW-8.
111 M/B ratios in excess of unity simply means that the firm is worth more as a going concern than the book value of its assets.
112 Direct Testimony of J. Randall Woolridge, Ph.D., at 30-32, 97.
113 *Ibid.*, at 31 and Exhibit JRW-4.

share (*i.e.*, the stock price) is forward-looking, and a function of many variables, including, but not limited to, expected earnings and cash flow growth, expected payout ratios, measures of "earnings quality," the regulatory climate, the equity ratio, expected capital expenditures, and the earned return on common equity.[114] As Dr. Morin states, it is rarely the case in cost of service-based regulation that M/B ratios equal 1.00, which further complicates the Constant Growth DCF method:

> The third and perhaps most important reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the market-to-book (M/B) ratio of a given stock exceeds unity. This was particularly relevant in the capital market environment of the 1990s and 2000s whose utility stocks are trading at M/B ratios well above unity and have been for nearly two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.[115]

As Dr. Morin notes, in the context of rate setting, the M/B ratio often is discussed relative to the Constant Growth DCF model. Under certain restrictive assumptions, that model can be rewritten to express the M/B ratio as follows:[116]

$$\frac{M}{B} = \frac{ROE - g}{k - g} \quad [3]$$

114 *See*, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 366. Please note, Dr. Morin cites several academic articles that address the various factors that affect the M/B ratio for utilities.

115 *Ibid.*, at 434.

116 B. Branch, A. Sharma, C. Chawla, and F. Tu, *An Updated Model of Price-to-Book*, Journal of Applied Finance, No. 1 (2014).

where ROE is the return on book equity, *k* is the risk-adjusted discount rate, and g is the long-term growth rate in dividends per share. Rearranging Equation [3] produces the familiar Gordon Growth model:

$$P = \frac{D}{k\text{-}g} \quad [4]$$

and the Constant Growth DCF model:

$$P = \frac{D}{P} + g \quad [5]$$

Dr. Woolridge's assumed relationship between the accounting Return on Equity and the Cost of Equity simply falls from the Constant Growth DCF model; one cannot be assumed without the other. Any inferences drawn from relationships among M/B, ROE, and *k* from Equation [3] therefore rely on the explicit acceptance of all assumptions underlying the Constant Growth DCF model, including a constant dividend growth rate in perpetuity, and the constancy of the DCF result. Equally important, Equation [5] only can be drawn from the Constant Growth DCF model if we assume: (1) a constant dividend payout ratio in perpetuity; (2) no stock issuances or repurchases; and (3) that the firm is in a steady state, in which the book equity growth rate equals the dividend growth rate, in perpetuity. Taken together, those assumptions are quite restrictive, and call into question the definitive linkage between M/B, ROE, and *k* that Dr. Woolridge assumes.

Q. WHAT WOULD BE THE RESULT IF REGULATORY COMMISSIONS DID FORCE M/B RATIOS TOWARD UNITY?

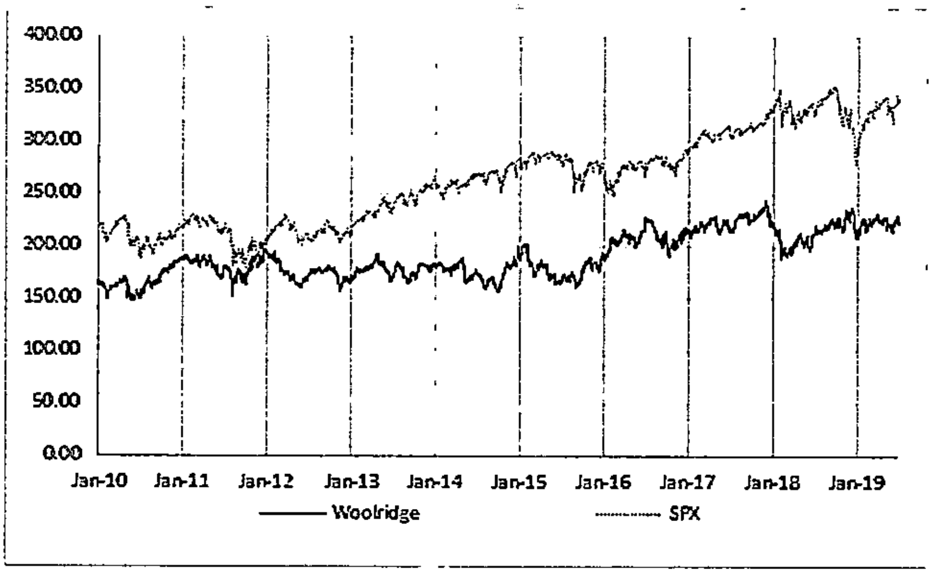
A. Looking to Dr. Woolridge's Gas Proxy Group, the average capital loss for equity investors would be about 55.13 percent.[117] That loss would not just affect investors, it also would substantially diminish the ability of utilities to attract external capital. To summarize, if regulatory commissions were to set rates with an eye toward moving the M/B ratio toward unity, that practice may well impede the ability to attract the capital required to support its operations, especially in markets during which the M/B ratio for the overall market is significantly greater than 100.00 percent.

Q. HAVE UTILITY M/B RATIOS GENERALLY EXCEEDED 1.00?

A. Yes, they have. Chart 8 (below) demonstrates that since 2010, Dr. Woolridge's, and my proxy groups' M/B ratio have exceeded 1.00, and generally have moved with the S&P 500 Index M/B ratio. If Dr. Woolridge is of the view that M/B ratios greater than 1.00 reflect earned returns greater than the Cost of Equity, it follows that utility commissions have long been incorrect in their ROE determinations.

[117] Based on Dr. Woolridge's proxy group average M/B ratio of 222.88. (222.88-100.00)/222.88 = 55.13 percent. Exhibit JRW-2, page 1.

Chart 8: Comparison Groups, S&P 500 Market/Book Ratios (2010 – 2019)[118]



Although the broad market represents a cross section of risk and return profiles, of which the utility sector is just one, the observed variation in market-level M/B ratios speaks to the time-varying influence of general macroeconomic factors, not to any failure of regulation. The relationship between both Dr. Woolridge's and my proxy group M/B ratios, and the S&P 500 M/B ratio, is positive and statistically significant. That is the case even when we control for serial correlation.[119] We therefore reasonably can conclude that broad macroeconomic and capital market factors affect both utilities and non-regulated entities.

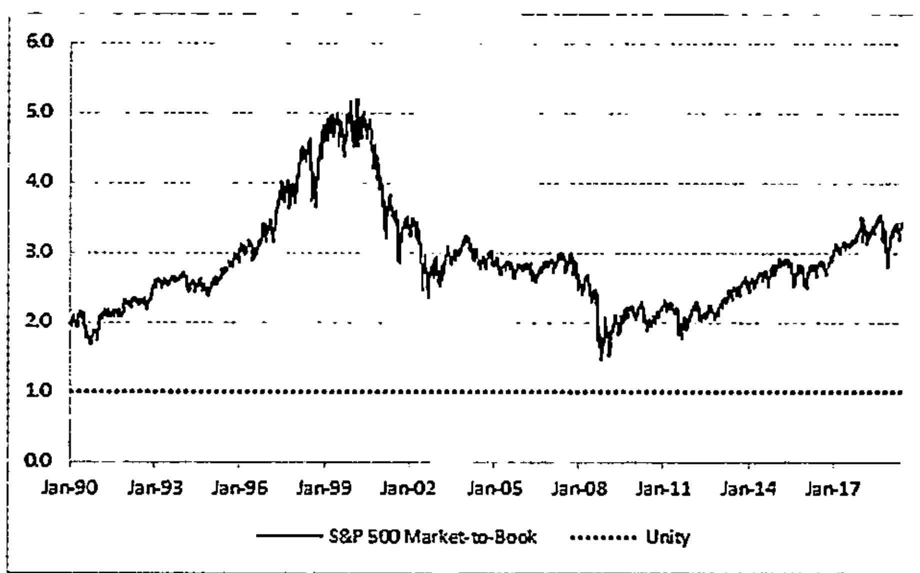
118 Source: S&P Global Market Intelligence, Bloomberg Professional. Note, Dr. Woolridge and I have the same proxy group.

119 Using the Prais-Winsten routine.

Q. HAVE UTILITY M/B RATIOS GENERALLY EXCEEDED 1.00?

A. Yes, they have. As Chart 9 (below) demonstrates, since 1990 the average M/B ratio for the S&P 500 Index has been 2.88; it has never reached unity.

Chart 9: S&P 500 M/B Ratio Over Time[120]



If investors felt the returns they expected had so significantly exceeded the returns they required, they would adjust their requirements. In Dr. Woolridge's construct, the difference between expected and required returns would dissipate, and take with it the difference between market and book values. As Chart 9 indicates, that has not occurred (the M/B ratio has remained greater than 1.00).

Q. ARE YOU AWARE OF LITERATURE THAT HAS FOCUSED ON THE M/B RATIOS OF REGULATED UTILITIES?

A. Yes. Literature focusing on utilities has long concluded that regulation may not

120 Source: Bloomberg Professional Services.

necessarily result in M/B ratios approaching unity. As noted by Phillips in 1993:

> Many question the assumption that market price should equal book value, believing that 'the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.'[121]

In 1988 Bonbright stated:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market. In short, market prices are beyond the control, though not beyond the influence, of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ... would result in harmful, uneconomic shifts in public utility rate levels.[122]

And in 1972 Stewart Myers came to the following conclusion:

> In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that the market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book.[123]

Lastly, corporate finance managers have considered metrics such as Stern Stewart & Company's Economic Value Added,[124] and related value-based-

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[121] Charles F. Phillips, The Regulation of Public Utilities – Theory and Practice (Public Utility Reports, Inc., 1993) at 395.

[122] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates (Public Utilities Reports, Inc., 1988), at 334.

[123] Stewart C. Myers, *The Application of Finance Theory to Public Utility Rate Cases*, The Bell Journal of Economics and Management Science, Vol. 3, No. 1 (Spring 1972), at 58-97.

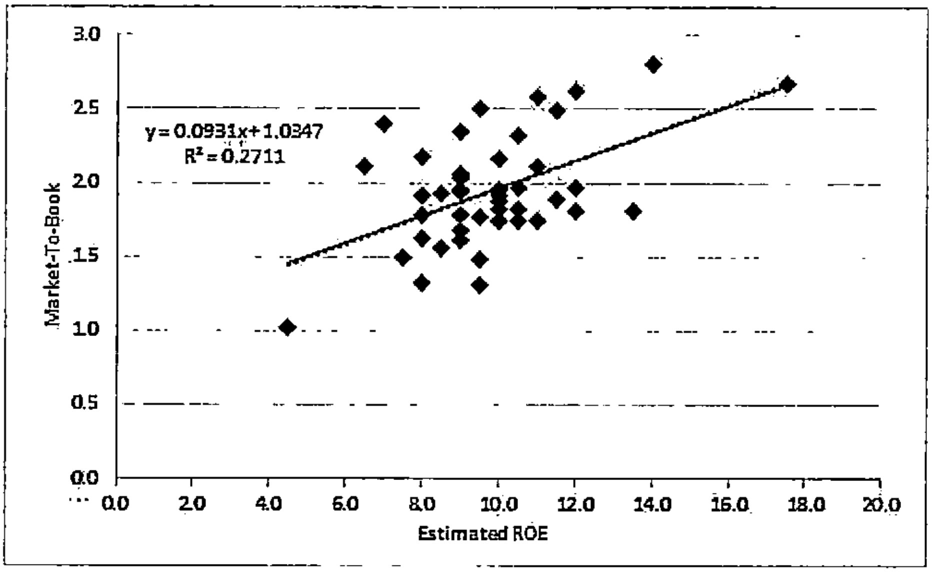
[124] *See*, G. Bennett Stewart, The Quest for Value, HarperCollins Publishers, Inc., 1990.

management systems[125] that focus on elements of Return on Net Assets, and Return on Invested Capital. That practice suggests accounting-based performance measures are relevant to investors.

Q. HAVE YOU REVIEWED THE ROE AND M/B RATIO DATA PROVIDED IN EXHIBIT JRW-4?

A. Yes. Although the earned Return on Equity may be one factor explaining M/B ratios, it is not the only factor. I have updated the chart contained in Exhibit JRW-4, including the regression coefficients, based on the methodology described by Dr. Woolridge,[126] using recent data from Value Line in Chart 10 (below).

Chart 10: Update of Exhibit JRW-4, With Regression Coefficients[127]



Based on an update of Dr. Woolridge's data, an M/B ratio of 1.00 is associated with

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125 *See*, Institute of Management Accountants, *Measuring and Managing Shareholder Value Creation*, 1997.

126 Direct Testimony of J. Randall Woolridge, Ph.D., at 30 - 31; Exhibit JRW-4.

127 Source: Value Line, downloaded July 29, 2019.

an ROE of negative 0.37 percent,[128] a condition that is highly improbable. Dr. Woolridge's data, therefore, do not support the theory that ROEs greater than 1.00 indicate the subject company's return exceeds investors' required returns.

Q. HAVE YOU ANALYZED WHETHER THE ACTUAL EARNED RETURN ON EQUITY EXPLAINS THE M/B RATIOS FOR THE COMPANIES IN DR. WOOLRIDGE'S EXHIBIT JRW-4?

A. Yes, I have. Using data provided by S&P Global Market Intelligence, I performed a regression analysis in which the M/B ratio was the dependent variable, and the Return on Average Common Equity ("ROACE") for 2018 was the explanatory variable. As shown in Exhibit RBH-R-13, the R-squared was 28.46 percent. An R-squared of 28.46 percent means that factors other than ROACE explain up to 71.54 percent of M/B ratios in the proxy group.[129] Those results support the position that although the earned Return on Equity is a factor that explains M/B ratios, it is not the only factor. In any case, the regression equation indicates that an M/B ratio of 1.00 (that is, 100.00 percent) is associated with a Return on Common Equity of approximately -28.83 percent; an M/B ratio of 1.10 relates to an ROACE of approximately -28.81 percent. Because those estimates are not meaningful, I do not agree that M/B ratios greater than 1.00 demonstrate earnings in excess of investors' requirements.

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128 $1.00 = 1.03 + (9.31 \times -0.0037)$.

129 $0.7154 = (1 - 0.2846)$.

Relative Risk

Q. AT PAGE 100 OF HIS TESTIMONY, DR. WOOLRIDGE ARGUES THE COMPANY'S CREDIT RATING IS "IN LINE WITH OTHER GAS COMPANIES." DO YOU BELIEVE CREDIT RATINGS ARE FULL MEASURES OF RISK TO EQUITY INVESTORS?

A. Although over the long-term, credit ratings (and therefore credit spreads) may be directionally related to equity risk, a change in one is not a direct measure of a change in the other. Debt and equity are entirely different securities with different risk/return characteristics, different lives, and different investors. Debt investors have a contractual, senior claim on cash flows not available to equity investors and as such, equity investors bear the residual risk of ownership. Moreover, debt investors' exposure to business and financial risk is finite (due to the finite life of debt) whereas equity investors are exposed to residual risk in perpetuity. Consequently, any inferences drawn from differences in credit ratings regarding the Company's Cost of Equity should be drawn with caution.

A visible measure of the distinction of the risks to which debt and equity investors are exposed is the difference in their respective Beta coefficients. Although I disagree with his conclusions, Dr. Woolridge recommends an average Beta coefficient of 0.65[130] for his proxy group.[131] Duff & Phelps notes that as of June 2019, debt Beta coefficients for A-rated debt was 0.09,[132] far below the equity

[130] The average Value Line Beta coefficient for my proxy group is 0.675. *See*, Exhibit RBH-R-4.
[131] Exhibit JRW-9, at 1.
[132] Source: Duff & Phelps Cost of Capital Navigator.

Beta coefficient assumed by Dr. Woolridge. In fact, a debt Beta coefficient of 0.71 currently is associated with Caa rated debt, which is considered below investment grade.[133] Those differences are a clear indication that the risks assumed by debt investors are far different than those assumed by equity investors.

Q. DOES THE DATA PROVIDED BY DR. WOOLRIDGE INDICATE A RELATIONSHIP BETWEEN COST OF EQUITY ESTIMATES AND CREDIT RATINGS?

A. No, they do not. Using the growth rates and dividend yields reported by Dr. Woolridge, I produced Constant Growth DCF results for each of the comparison companies.[134] Those results do not support Dr. Woolridge's conclusion. For example, New Jersey Resources Corporation is rated A, and Southwest Gas Corporation is rated BBB+, two credit "notches" apart. Yet, based on Dr. Woolridge's data, their DCF results are 8.81 percent and 8.71 percent, respectively, only 10 basis points apart. On the other hand, New Jersey Resources Corporation (A), and Spire Inc., (A-) are one credit notch apart, but their DCF results differ by 246 basis points. We cannot say, based on Dr. Woolridge's primary method, that there is a definitive relationship between credit rating notches and Cost of Equity estimates.

133 *Ibid.*

134 Exhibit RBH-R-14. The following comparisons are based on 30-day average dividend yields.

Flotation Costs

Q. DID DR. WOOLRIDGE ADDRESS THE ISSUE OF FLOTATION COSTS IN HIS DIRECT TESTIMONY?

A. Yes, Dr. Woolridge devotes several pages of his testimony discussing various reasons why he believes such an adjustment is not necessary.[135] Dr. Woolridge does not account for flotation costs, reasoning that flotation costs for stock issuances are not out-of-pocket costs and, even if they were, current market conditions suggest that a *reduction* to the Cost of Equity is required to account for flotation costs.[136]

Q. PLEASE RESPOND TO DR. WOOLRIDGE IN THAT REGARD.

A. I disagree with Dr. Woolridge's position that flotation costs for stock issuances are different than issuance costs associated with long-term debt. Companies pay the same types of fees (both direct and indirect) regardless of whether they are issuing equity or debt. As to Dr. Woolridge's observation that underwriter fees are not "out-of-pocket" expenses,[137] I view that to be a distinction without a meaningful difference. Whether paid directly or via an underwriting discount, the cost results in net proceeds that are less than the gross proceeds.

I also disagree with Dr. Woolridge's position that flotation costs could represent a reduction in Cost of Equity. Flotation costs are true and necessary costs to the issuer, and represent funds that otherwise would be invested in long-lived

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135 *Ibid.*, 100-103.
136 *Ibid.*, at 101.
137 *Ibid.*, at 102.

assets. As explained in my Direct Testimony, to the extent flotation costs are not recovered, the issuing company is denied a portion of the opportunity to earn its expected (or required) return.[138]

Capital Expenditures

Q. DID DR. WOOLRIDGE ADDRESS THE COMPANY'S CAPITAL EXPENDITURES?

A. Yes, Dr. Woolridge reasons that because S&P and Moody's account for capital expenditures in their credit ratings, and that the Company's credit ratings are in line with the proxy group, that any additional risk has been accounted for. As discussed above however, credit risk is not a direct measure of equity risk and as such, the Company's projected capital expenditures should be considered in determining the appropriate authorized ROE.

North Carolina Economic Conditions

Q. PLEASE BRIEFLY SUMMARIZE DR. WOOLRIDGE'S RESPONSE TO YOUR ASSESSMENT OF ECONOMIC CONDITIONS IN NORTH CAROLINA.

A. In my Direct Testimony I reviewed several measures of economic conditions, including the rate of unemployment, real Gross Domestic Product growth, median household income, residential natural gas rates, and broad measures of income and

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138 Direct Testimony of Robert B. Hevert at 32.

consumption.[139] Based on that review, I found economic conditions in North Carolina have improved since the Company's last rate case; Dr. Woolridge generally agrees with that conclusion.[140] Dr. Woolridge argues, however, that although economic conditions generally have improved, certain measures do not support the Company's proposed Rate of Return, including my recommended ROE.[141]

Dr. Woolridge then calculates what he believes to be the incremental effect of his proposed overall Rate of Return on the Company's overall revenue requirement. He suggests his recommendations (his proposed capital structure and 9.00 percent ROE) would reduce the Company's annual operating income by about $58 million, from approximately $253 million to $195 million, reducing the overall revenue requirement by the same amount.[142]

Q. WHAT IS YOUR RESPONSE TO DR. WOOLRIDGE ON THOSE POINTS?

A. Although we generally agree economic conditions in North Carolina have improved since the Company's last rate case, I do not agree with Dr. Woolridge's conclusions regarding the effect of his proposal on the Company's overall revenue requirement. First, Dr. Woolridge's Exhibit JRW-13, page 2 of 2 appears to contain a calculation error. There, he seems to have transposed the short-term debt, and long-term debt balances, such that the long-term debt balance is associated with the

139 *See,* Direct Testimony of Robert B. Hevert, at 37 – 44.
140 Direct Testimony of J. Randall Woolridge, PhD, at 104.
141 *Ibid.*, at 104 – 105.
142 *Ibid.*, at 106, Exhibit JRW-13.

short-term debt cost rate, and the short-term debt balance is associated with the long term-debt cost rate. Dr. Woolridge's $195 million Operating Income calculation therefore is understated; the corrected amount is about $223 million. As a result, the difference in Operating Income between Dr. Woolridge's proposed Rate of Return and the Company's proposal is about $30.4 million, not $58 million (*see* Exhibit RBH-R-15).[143]

It is important to put that corrected difference in perspective. Dr. Woolridge's Exhibit JRW-13 refers to Ms. Powers' Exhibit_(PKP-7). There, Ms. Powers provides the Company's proposed revenue requirement of about $1.00 billion. The $30.4 million difference in Operating Income therefore represents about 3.03 percent of the total revenue requirement. Because his recommendation falls entirely on equity investors, Dr. Woolridge's recommendation reflects a $33.40 million, or 18.36 percent reduction in net income (*see*, Exhibit RBH-R-15).

143 Assumes the current Federal and State Income Tax expenses remain constant.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. I appreciate there seems to be no fundamental disagreement that conditions have improved since the Company's last rate case. I also appreciate that the Commission has the difficult task of considering those conditions as it balances the interests of investors and consumers. In my view, Dr. Woolridge's recommendations would have a disproportionate effect, reducing the income available to equity investors to a far greater degree than the revenue requirement borne by consumers.

V. CONCLUSION AND RECOMMENDATION

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING THE COMPANY'S COST OF EQUITY?

A. Lastly, for the reasons discussed throughout my Rebuttal Testimony, I find Dr. Woolridge's ROE recommendations to be unduly low. In my view, market conditions and model results continue to support my 10.00 percent to 11.00 percent ROE recommendation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. G-9, SUB 743

In the Matter of:	)	
	)	**STIPULATION SUPPORT**
Application of Piedmont Natural Gas	)	**TESTIMONY OF**
Company, Inc. for Adjustment of Rates	)	**ROBERT B. HEVERT FOR**
and Charges Applicable to Gas Service in	)	**PIEDMONT NATURAL GAS**
North Carolina		**COMPANY, INC.**

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 TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted Direct, and Rebuttal[1] Testimony before the North Carolina Utilities Commission ("Commission") on behalf of Piedmont Natural Gas Company, Inc. ("Piedmont" or the "Company").

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

A. My Stipulation Support testimony supports the 9.70 percent Return on Equity ("ROE")[2] provided for in the Stipulation dated August 12, 2019 (the "Stipulation") among the Company, Public Staff, the Carolina Utility Customers Association, Inc. ("CUCA"), and the Carolina Industrial Group for Fair Utility Rates IV ("CIGFUR", 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, and certain Exhibits attached to my Rebuttal Testimony, which have been

[1] Rebuttal Testimony filed August 9, 2019 in response to Attorney General Witness Dr. Woolridge;

[2] I refer to the 9.70 percent ROE contained in the Stipulation as the "Stipulated ROE".

prepared by me, or 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 dated August 12, 2019 among the Stipulating Parties. In particular, I understand the Stipulating Parties have agreed to the Stipulated ROE of 9.70 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 9.70 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.

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

A. Although it falls somewhat below my recommended range, the Stipulated ROE

[3] See, Direct Testimony of Robert B. Hevert, at 4; Rebuttal Testimony of Robert B. Hevert dated August 9, 2019, at 3, Table 1.

generally is within the ranges of analytical results presented in my Direct Testimony, 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 NATURAL GAS UTILITIES?

A. Yes, I have. As shown in Exhibit RBH-S-1, from January 2017 through June 2019, the average authorized ROE for natural gas utilities was 9.64 percent, only six basis points from the Stipulated ROE. From a somewhat different perspective, Regulatory Research Associates ("RRA"), which 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.[4]

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.[5] Across the 69 natural gas rate cases summarized in Exhibit RBH-S-1, the mean and median authorized ROEs were 9.68 percent and 9.73 percent, respectively, in jurisdictions that, like North Carolina, are rated at least Average/1. Those results are highly consistent with 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:

- The 37th percentile of the mean and median Constant Growth Discounted Cash Flow ("DCF") results provided in Exhibit RBH-R-1;[6]
- The 9th percentile of the Capital Asset Pricing Model ("CAPM"), and Empirical CAPM results provided in Exhibit RBH-R-5; and
- The 18th percentile of Expected Earnings analysis results provided in Exhibit RBH-R-7.

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4 Source: Regulatory Research Associates, accessed August 7, 2019.

5 Source: Regulatory Research Associates, accessed August 7, 2019. Of the 53 jurisdictions, 19 are ranked "Average/1" or higher.

6 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 Rebuttal Testimony filed August 9, 2019, and the subsequent Errata filing on August 12, 2019.

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 natural gas utilities. Second, although it is toward the lower end, 9.70 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.

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.[7] From that perspective as well, I believe the Stipulated ROE is a reasonable

[7] Direct Testimony of Robert B. Hevert, at 35-44.

outcome.

Q. **DOES THIS CONCLUDE YOUR STIPULATION SUPPORT TESTIMONY?**

A. Yes, it does.

BY MR. JEFFRIES:

Q Mr. Hevert, have you prepared a summary of your testimonies?

A Yes, I have.

Q All right. If you could hold on just a second while we distribute those.

Mr. Hevert, could you provide the summary of your testimony for the Commission, please?

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. Although my testimony necessarily discusses the financial models used to estimate the cost of equity, I also address other issues that are important in developing ROE recommendations.

In particular, I discuss capital market conditions and the effect of those conditions on the return investors require to accept the risk of equity ownership. My testimony also addresses business risks facing utilities such as Piedmont Natural Gas Company and the importance of maintaining a financial profile that enables the Company to access capital in 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 10.6 percent.

In my direct and rebuttal testimony I discuss the fact that all models used to estimate the cost of equity are subject to assumptions and constraints. I note that as market conditions change, each model's ability to reasonably estimate the cost of equity likewise changes. Consequently, a model that may have produced reliable results under one set of market conditions may become less reli--- excuse me -- less reliable under a different set of conditions. It, therefore, is important to understand each model's underlying assumptions and to -- and to assess the extent to which they are applicable or not in the prevailing capital market environment.

My rebuttal testimony responds to Dr. Woolridge's recommendation and analyses regarding the Company's cost of equity. There are several areas in which I disagree with Dr. Woolridge's analytical methods and conclusions. I address those issues in detail throughout my rebuttal testimony. In summary, none of the arguments or analyses contained in his testimony caused me to revise my conclusions or recommendations.

My Stipulation support testimony discusses my support for the Stipulation as it relates to the return on equity. I note the Stipulation represents the give and take among parties regarding multiple otherwise contested issues. I understand the Company has determined that the Stipulation, including the stipulated ROE, would be viewed by the financial community as constructive and equitable. My settlement testimony notes that I appreciate and respect that determination.

My Stipulation support testimony explains that since 2017, and as summarized on my Exhibit RBH-S-1, the average authorized return on equity for natural gas local distribution companies has been 9.64 percent, only six basis points from the stipulated ROE. Among jurisdictions that, like North Carolina, are seen as having constructive regulatory environments, the average authorized ROE was 9.68 percent and the median was 9.73 percent, both highly consistent with the stipulated ROE. I also explain that the stipulated ROE generally falls within the range of my analytical results, although generally toward the low end.

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. I, therefore, provided several analyses reviewing economic conditions in the US generally and in North Carolina specifically and, where possible, the Company's service territory. Those analyses indicated 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. That concludes my summary.

Q Thank you, Mr. Hevert.

MR. JEFFRIES: Mr. Hevert is available for cross examination, questions by the Commission.

COMMISSIONER BROWN-BLAND: All right. Is there cross examination for this witness? Ms. Force is pulling that mic toward her.

MS. FORCE: Okay. I'll do that. Just a minute, Mr. Hevert.

THE WITNESS: Uh-huh.

CROSS EXAMINATION BY MS. FORCE:

Q Good afternoon, Mr. Hevert.

A Good afternoon.

Q We're going to be talking about your rate of return on equity numbers, and I have -- let's see -- five areas that I'm going to cover, so get started.

A Okay.

Q If you -- do you have the stack of papers in front of you that is coming around?

A I do. Thank you.

Q All right.

MS. FORCE: I'm going to wait a minute until they get around because that's what I'm going to start with. We set? I'm going to ask that the first page of this exhibit be identified -- marked -- marked for the record as Attorney General's Office Hevert Cross Examination Exhibit 1.

COMMISSIONER BROWN-BLAND: Ms. Force, that's the one that --

MS. FORCE: I'm sorry.

COMMISSIONER BROWN-BLAND: -- has the caption Summary of ROE?

MS. FORCE: It says Summary of Recommendations.

COMMISSIONER BROWN-BLAND: All right.

MS. FORCE: That's right.

COMMISSIONER BROWN-BLAND: It will be so identified.

MS. FORCE: It's one page.

(Whereupon, Attorney General's Office

Hevert Cross Examination Exhibit 1
was marked for identification.)

Q It's one page. Mr. Hevert, this was provided Sunday. I don't know that you've had a chance to look at it before, but I'll submit to you that this is a summary of the recommendations that you've provided in your rebuttal testimony and that Dr. Woolridge, Mr. O'Connell (sic), and Mr. Hinton provided in theirs. Take a minute and take -- and look at it. Did you see this before now?

A Quite briefly, yes, I did.

Q Okay. Now, I'll submit to you that Dr. Woolridge's testimony in this case identified 8.7 as the rate of return on equity associated with a 52 percent capital structure. Do you recall that?

A Yes, I do.

Q And it was a 9 percent rate of return on equity if the capital structure had 50 percent equity; isn't that right?

A That is correct.

Q So this -- this doesn't reflect both of those since we're talking on settlement about 52 percent equity and 9.7 percent rate of return on equity; is that right?

A Yes.

Q Okay. Have you had a chance to look at it? Do you have any -- can you identify any here that you would disagree with?

A Well, I -- I guess --

Q And just to clarify, I don't mean that you wouldn't disagree with some of the results they reached, but as to what the numbers are?

A Well, I guess there are a couple things.

Q Uh-huh.

A One is let's look at, for example, the discounted cash flow col--- excuse -- yes, the column where you have the row of 7.54 percent, 13.8 percent, and then a midpoint of 10.67 percent. I do not report midpoints. I do not base my recommendation on midpoints. It's based on, in this case, the median results. So I'm not entirely sure what the point of having the midpoint there is. And the same thing for the capital asset pricing model. But that said, I recognize they come from my rebuttal exhibits.

Q I'm glad you pointed that out. The mid caption has brackets around it. You don't disagree that that is the midpoint, but it's not your position that that would be -- you wouldn't have identified it in a table of your discounted cash flow or your CAPM; is that right?

A That's right. I -- what I have presented in the discounted cash flow model are the average and the median results, and I presented the median results because I agree with Dr. Woolridge, there was an outlying growth rate estimate. I mentioned that in my direct testimony and discussed the fact that that being the case, for the purpose of presentation and for the purpose of determining the proper cost of equity, the median, which takes into account the effect of outlying results, was the proper measure.

Q Okay. And are there other points in the table that you want to comment -- that you think are incorrect, and we'll move on?

A Oh, I didn't say it was incorrect. I said it was not how I presented --

Q Okay.

A -- the results, nor is it how I based my recommendation.

Q Thank you for that clarification. You and the other witnesses have used some different methods in coming up with the results for the discounted cash flow and for the capital asset pricing method. Would you agree with that?

A I think we all used the same structural form of those models, but we have, to some extent, differences among how we apply the models.

Q And the summary shows several different approaches, the discounted cash flow method, the capital asset pricing model, your expected earnings, and the comparable earnings analyses by Mr. O'Donnell and Mr. Hinton, and then the bond yield risk premium for you, and below that is Mr. Hinton's -- the summary of Mr. Hinton's approved ROE regression analysis. You see that, looking at the table?

A I do, yes.

Q So would you agree with me that that last column that you use for your bond yield risk premium authorized returns in that analysis, rather than looking at the stock market data directly?

A I guess I'm not entirely sure what you mean by that, but I can explain what I do do. This method looks at the relationship between the equity risk premium and interest rates. The equity risk premium is the difference between the return on stocks and the risk-free rate. As a measure of the return on stock I use authorized return, so if that's your question, then that's -- that's what I have done.

Q When you say authorized returns, am I correct that those are returns that are identified by regulatory commissions as opposed to stock market data directly?

A Yes. They are returns that are authorized in proceedings like this, where we talk about the market-based models such as we are right now, considering capital market conditions as they prevail right now. So, yes, that's true.

Q Okay. And you say on page 4 of your rebuttal testimony that you consider multiple methods when you estimate the rate of return on equity to provide alternative perspectives and capture different aspects of investor behavior; is that right? Give you a minute.

A Yes.

Q Okay. One more question along that line is -- I'd already asked you about your bond yield plus risk premium. You -- on page 3 of your rebuttal you critiqued Dr. Woolridge's results because he has given considerable weight to the constant growth discounted cash flow method even though his results fall well below returns recently authorized for other natural gas utilities. So, again, in that point you emphasize the authorized returns fixed by regulators; is that right?

A Well, I think authorized returns are -- are important in two respects. One, as we just talked about, they're based on the same types of market-based models we're talking about and probably will talk about this afternoon. Secondly, they are of great importance to investors. Companies disclose the returns that they're authorized to earn in their SEC Forms 10-K. If they felt they were not material to investors, if the companies felt investors had no interest in authorized returns, there would not be a disclosable item. So to me, they both are a good proxy for the expected or required return and we know that they are relevant to investors, so, yes, I think it's an important data point.

Q So I'm going to turn to my second line of questions for you, Mr. Hevert.

A Okay.

Q The capital structure in the settlement is 52 percent equity, but there was testimony supporting 50 percent equity capital structure instead. Do you agree with me that when there is more equity in a capital structure, it reduces the risk for shareholders as compared to when there is more debt?

A I -- I think there's a few points there. One is, of course --

Q Could you -- excuse me. Could you answer the question and then explain, if you would? I -- would you disagree with me that as you increase the equity, you decrease the risk to the equity shareholders?

A I will agree, with some qualifications that --

Q Okay.

A -- I'd like to explain. First, you cannot look at any one individual item of risk in isolation. But if we were to look at debt equity ratio in isolation, the question becomes is a movement from 52 percent to 50 percent, is that so different that it would require a 30 basis point difference from an investor's point of view in the return that they require? I don't think that's the case. I think if you are looking at a 52 percent equity ratio which, just based on my experience in the natural gas industry, is not at all out of line with what we see as actual equity ratios in place among natural gas operating utilities, I do not think moving from 50 to 52 percent would require a 30 basis point reduction in the return.

Q Would that work in the opposite direction as well, then?

A If you moved from 52 down to 50 -- excuse me -- from 52 down to 50? That's what I meant. I had it right the first time, didn't I?

Q It's easy to get tangled up in --

A Yeah.

Q -- but --
A Yeah.
Q -- if you were to instead -- since we're just switching between debt and equity, if instead the debt were 52 percent, then would you say that the -- there should be any kind of an adjustment to the rate of return on equity?
A I'm going to say again it depends. Let -- let's say that you're going to move down to, say, in your example, a 48 percent equity ratio. Is that your example, or are you talking about a 48 percent debt ratio?
Q Let's say 48 percent. It's easier than the little bit of numbers that are in this case for short-term debt, 48 percent equity, 52 percent debt, long-term debt.
A So if you're moving to 48 percent equity ratio, the question then becomes how far is it removed from industry practice, how far removed is it from regulatory practice? If there is a history of a consistent equity ratio in the 50, 52 percent range, moving down to 48 percent, to your original point, would add leverage. But secondly, there becomes another element of risk which is a departure not only from industry practice, but a

departure from regulatory practice that would add an additional element of risk not having really to do with financial risk, but investors' perception of regulatory risk within the -- within the jurisdiction. So moving down to a 48 percent equity ratio, it could add risk.

One thing I will say, it's very difficult to quantify that increment or decrement of the return required by equity investors. We can make general directional comments. There are models that are developed for that purpose. But I think it's hard to add specific basis points.

Q Okay. Thank you. If you look to the next item in that stack, I think we're going to pass out a couple of exhibits that go along with it. It will be familiar to you. It's just a copy of your Exhibit RBH-5 and RBH-R-5 which is your CAPM.

A I think I have that.

Q Okay.

MS. FORCE: Maybe everybody has it, but just in case. It's kind of hard to find. (To Ms. Harrod) Would you mind passing out one and I'll pass out the other?

THE WITNESS: I've got a couple extra for sale.

(Off-the-record discussion.)

COMMISSIONER BROWN-BLAND: The mistake is in the packet it had RBH-R-5 and the one that some people are now missing is RBH-5.

(Off-the-record discussion.)

Q All right. Mr. --

COMMISSIONER BROWN-BLAND: All right. Let's get these properly marked and identified.

MS. FORCE: They're for --

COMMISSIONER BROWN-BLAND: So I have Exhibit RBH-5 which was pre--- that's how it was filed when it was pre--- that's how it was marked when it prefiled. That's captioned Capital Asset Pricing Model Results. Is that correct? And do you want to identify it as an AGO?

MS. FORCE: I'm sorry. This was put on -- we got carried away with our labels, but I passed this out for -- for reference --

COMMISSIONER BROWN-BLAND: All right.

MS. FORCE: -- so you wouldn't have to dig it out as we go through this case.

COMMISSIONER BROWN-BLAND: All right. And the same is true for RBH-R-5?

MS. FORCE: That's right.

COMMISSIONER BROWN-BLAND: All right.

Q And for clarification, Mr. Hevert, these are familiar to you. The RBH-5 was prefiled on April 1st, 2019 with your testimony; is that correct?

A Yes. That's correct.

Q And it shows the capital asset pricing model results; is that right?

A It does.

Q And then RBH-R-5 is the same capital asset pricing model results, but that was filed with your rebuttal on August 12th, 2019, a week ago?

A How time does fly, but yes. It -- it was updated and it included, in addition to the capital asset pricing model, the empirical capital asset pricing model in columns seven and eight.

Q And you said it was updated, but this is the updated version, right? There's nothing more?

A Correct. I'm sorry. Updated from the direct testimony.

Q That's quite all right. So looking back to the stack of exhibits that were passed out, there was a Virginia case that I wanted to talk to you about, and we'll have these handy as we talk about it.

A Okay.

Q Are you familiar with this Virginia Order that came out --

MS. FORCE: I need to ask that this be marked for identification. You'll see at the top Case Number PUR-2017-00038. It's a Virginia State Corporation Commission decision -- Final Order. I'd ask that that be marked AGO Hevert Cross Examination Exhibit 2.

COMMISSIONER BROWN-BLAND: It will be so marked.

MS. FORCE: Thank you. I put my pen somewhere.

(Whereupon, Attorney General's Office Hevert Cross Examination Exhibit 2 was marked for identification.)

Q You're familiar with the Order? We're getting back to my questions. This is a case that you testified in, isn't it, Mr. Hevert?

A Yes, it is.

Q And would you agree with me that the Commission result, this is -- I guess you'd agree with me -- I bet you're going to point out to me, is -- is this a general rate case that this was decided in?

A I am glad you asked. No. This was not a general rate case. This was, as noted on the first page of the Final Order, a case regarding rate adjustment clauses. Those are rates for specific assets that are eligible for, generally, a 100 or 200 basis point premium on top of the base return on equity.

Q Hmm. Okay. Now, this is a decision about what's the fair rate of return on equity, would you agree, for -- for Virginia Electric and Power Company?

A Well, with that qualification again, and in the context of those rate adjustment clauses. My recollection is that Virginia Electric and Power Company's base rate -- excuse me -- the ROE associated with its current base rates is 10 percent, but these rates are set -- excuse me -- under the rate adjustment clauses.

Q And in this case the -- the Virginia Commission was looking at factors that it would use to evaluate the cost of equity for Virginia Electric and Power Company; isn't that right?

A I think that's -- I think that's generally fair, again, noting the differences between the two types of cases. But, yes, I think that's right.

Q To clarify, at -- on pages 8 and 9 of that Order there's quite bit of discussion about the different factors that the statute calls on the Commission to take into account, and one of those is the cost of equity, and then there is another factor that it looks at to determine what would be an appropriate floor for that. Do you see that on page 8?

A I do, although this -- when we're looking at page 8, I think what you're talking about is a separate exercise. It's not the -- the application of models as we're talking about them. This is an exercise to determine what the statutory floor should be, and that is set by reference to the average actual earned return on common equity for a select group of proxy companies, determined by criteria generally set out by statute.

Q So the formula is a little different in Virginia, it sounds like, but one of the factors that they take into account is the cost of equity; wouldn't you agree with that?

A I'm not quite sure what you mean by that, but the purpose of this calculation is to set the -- the floor, the lowest return that the Commission can authorize. And, again, that floor is set by reference to the actual earned return on equity for a group of regional utilities that meet a series of criteria.

So for -- and let me draw the distinction a little bit more. The companies that may be used for the purpose of setting the floor can be operating subsidiaries of a company. So it may be for -- by way of analogy Duke Energy Carolinas, which is not a publicly traded entity, but you can look in their SEC Form 10-K and calculate what their earned return on equity is. So these companies generally are not the publicly traded parent company. They're the utility operating companies.

Q All right. Let's go back to page 2 where the Order says the sole purpose of this case is a determination of the fair ROE to be used by Dominion as the general return applicable to these particular sorts of aspects of ratemaking. That's what you're saying, that there's -- this applies to certain of the assets of the Company; is that right?

A Well, there are two aspects. One is, you're right, the return that is set under this Order would not be for a general rate case. It would be for the rates associated with rate adjustment clauses, and those rate adjustment clauses are associated with specific types of generating assets that the Legislature determined were in the public interest for the company to build, and because the Commission -- excuse me -- the Legislature felt there was a common good, there was a policy objective to be gained by having in-state generation being built, they would award -- "they" being the Legislature would award the company, Virginia Electric and Power, 100 to 200 basis points on top of the base ROE as an incentive to build that type of generation.

Q I see. Thank you. That's -- that's a good clarification. So we don't have a similar policy in North Carolina, but you're saying that there are certain additives that are added in Virginia for particular items?

A For these types of assets. But, again, this would not be for a general base rate case. And just to draw -- let you know the distinction is important, for example, when we speak about Regulatory Research Associates and how they report authorized returns, quite frequently Regulatory Research Associates will distinguish between these Virginia cases that have the incentive returns and those that do not.

Q Okay. And on page 3, when the Commission sets out what it's about to do, it says, "First, the Commission determines the market cost of equity," and "Next, the statutory peer group ROE floor is applied." Do you see that at the top of page 3?

A I do, yes.

Q Okay. Now, let's turn to page 4.

A Okay.

Q On page 4, the conclusion of the -- the Final Order in this was to set a cost of equity of 9.2 percent; is that right?

A The base cost of equity, correct.

Q And in the paragraph on page 4 where it says "We conclude that a market cost of equity of 9.2 percent is supported by reasonable proxy groups, growth rates, discounted cash flow methods, and risk premium analyses," it goes on to say, "Indeed we conclude that the evidence supports a market cost of equity at the midpoint of the range, i.e., 9.0 percent. We find that approving an ROE above the midpoint of the range found reasonable is supported by the concept of gradualism in ROE determinations." Do you see that?

A Yes, I do.

Q Is that a policy you're familiar with in some states?

A It -- it is. I will say that in my experience, the principle of gradualism typically is applied in rate design. It's typically -- I should not say typically. I've seen it more frequently applied in rate design than in the determination of the rate of return. The cost of equity is a cost. It's the cost -- it's the return investors require. Gradualism typically is applied to avoid rate shock to a given rate class. That's generally where I see it, but I do agree there have been some jurisdictions that apply the concept of gradualism to the return on equity.

Q Including Virginia, evidently, when they were determining the cost of equity here?

A Including Virginia. I'm not aware that this Commission has, but -- but, yes, Virginia has.

Q Okay. And then next paragraph, then, the Virginia Commission goes on to say that "While the market cost of equity approved herein is supported by reasonable proxy groups, growth rates, DCF methods, risk premium analyses, and gradualism, the Commission finds that Dominion's proposed market cost of equity of 10.5 percent is not supported by reasonable growth rates, DCF methods, or risk premium analyses." Those were analyses that you testified on behalf of Dominion on --

A Yes. That's correct.

Q -- is that right?

A That's right.

Q And then the Commission describes some examples of why it was -- saw that as being flawed. "...the Company continues to use only earnings per share as the measure of growth in its DCF model." You see that?

A I do.

Q And that's something that you also would find in the testimony in this case that is one of your pieces of testimony in the case, isn't it, that the earnings per share growth factor used in the discounted cash flow methodology is the appropriate one to use?

A That is my position, correct.

Q And it goes on to state that the Commission in Virginia has stated previously that only using the earnings per share as the measure of long-term growth results in unreasonably high growth rates that upwardly skew results.

MS. FORCE: Sorry. I was distracted by the lighting.

Q You see that?

A Yes, I do.

Q Okay. Now, I haven't passed out your discounted cash flow analysis. The -- that's something that we've talked about in past cases. And the record speaks for itself. There's lots of testimony on that.

MS. FORCE: Excuse me. It looks like we have a storm perhaps going on outside. Well, that's worrisome. Okay.

Q The next sentence talks about the Company's capital asset pricing model, and the model, what they're describing there, I've passed out the model that you use in this case so that we can kind of look and see whether the same thing occurs in your testimony in this case as the Virginia Commission found troubling. The analysis -- the CAPM analysis is flawed, it says, because, for example, the Company's highest ROE estimates result from the use of 2019 projected 30-year Treasury bond yields of 4.2 percent and 2021 projected 30-year Treasury bond yields of 4.4 percent. Now, when they're talking about the Treasury bond yields, am I correct if we look at the RBH-5, which was your initial testimony, what the -- what we -- where we would find that on your schedule is column one? There's a current and then a projected 30-year and then a long term. Is that a similar measure?

A Two of the three are. The first one is the -- the actual observed. The projected and the long-term projected are just that, they're forecasts.

Q They're forecasts. And is that what we're talking about in the Virginia case, too, the forecasts?

A It is.

Q Okay.

A We'll let the -- of course, as in Virginia, I provided the current Treasury yield here, no forecast. And even then you can see in RBH-5, the estimates range from 9.26 percent up to 12.5 percent and, of course, that well exceeds the upper end of my range. So I think here my recommendation is fully supported by the current Treasury yields.

Q The interest rates or the Treasury yields that are identified in this Order from Virginia refer to lower -- lower interest rates or higher -- higher interest rates than you have in your testimony in this case; is that right?

A The projected ones, yes, correct.

Q The projected ones are?

A That's right.

Q And if you look at the testimony that you filed, your rebuttal, the schedule is lower still; isn't that right? If you look at those long-term interest rates in your numbers, they're lower than what's shown in Virginia. They've dropped?

A Oh, they sure have dropped. We are in a very, very unusual market environment right now. That's right.

Q So the risk-free rate that was the current rate in that Virginia case was 3.04; now it's 2.63 in your schedule from your rebuttal, but what was it recently? Do -- can you give us an idea?

A Sure. This morning it was 2.08 percent. Last Thursday it was 2.025 percent. That shows you how incredibly unstable this market is. And we know what happened. We saw the events that occurred, geopolitical events that occurred that caused investors to rush to the safety of Treasury securities, and when they do that, they bid up the price and they bid down the yield. 2.025 percent is the lowest yield ever seen for a Treasury security, but we can't say that that's because investors don't have any level of risk out there. It's because they are very risk averse. That's why that yield is so low right now. They're very concerned about instability, so they would rather take a low yield like that, focus on preserving their capital than take the risk of owning an equity investment.

Q Hmmm. So the less risky investments are more appealing in this kind of a market. That's what you're saying there, I take it?

A They are. And I think I know where your next question might be. You can look at what happened to utilities late last week as well. And when the whole market fell 800 points, utilities fell as well. When markets become this unstable, the saying is that correlations go to one. There's -- every sector trades the same in an unstable market like this. So, yes, we saw utilities lose value at the same time.

Q Hmmm. Going back to the Virginia decision, then, the -- in this case the Commission looked at the use of the projected Treasury bond yields and found that it's explicitly rejected those in prior cases; isn't that right?

A It has. The -- and, again, the -- in this case, and I cannot recall in that case, to be honest, what -- my results were based on the current Treasury yield, but as I said earlier, even if we didn't -- even if I did not include projected Treasury yields here, these results, these capital asset pricing model results, would have fully supported my recommendation.

Q So the other point that comes up next in the Virginia's -- Virginia Commission Order is that in the capital asset pricing model it also rejects the use of -- excuse me -- that the Comp--- the -- that your testimony exclusively used earnings per share as the measure of long-term growth to develop the market risk premium component of its capital asset pricing mechanism. That's a little bit confusing because now we're talking about using a DCF method in order to come up with the risk premium. Is that how you've conducted it --

A Yes. That's right.

Q -- in Virginia? And you did that in this case, too; is that right?

A I've consistently done that. That's right.

Q So if we look at your -- your analysis and look at the columns, I think they're three and four, where you identify the market risk premium for Bloomberg and Value Line, when you've identified those, and then you identify two different studies, one using Bloomberg and one using Value Line, those market risk premium numbers, those are all identified by you through a computation that you've done. Those aren't from a publication that investors would use; isn't that right?

A I'm not sure I fully agree with that. I would agree it's my calculation. I would not agree it's foreign to investors. This -- these methods are based on growth rates provided by Bloomberg. You know, any time you turn on CNBC or a business channel, you see people sitting at a Bloomberg terminal. I think they're fairly commonly accepted as a method of information. And, of course, the other is Value Line that Dr. Woolridge and I both use.

The use of this method, this discounted cash flow method, to calculate the expected market return is something I do in each jurisdiction. It's accepted in some jurisdictions, so I don't think it's -- it's foreign and I don't think it's controversial everywhere.

Q Now, investors can go to many resources in order to find published data that gives them a market risk premium factor to use and, in fact, as I recall in other testimonies, in particular Dr. Woolridge's, he cites to quite a few of those, but instead of doing that, what you've done is come up with your own by calculating it with this discounted cash flow method, right?

A I do, that's right, because in my view, looking at the current market expectation is the best measure of the expected market return at this point in time. The market risk premium does not stay constant over time. It moves. It changes with interest rates. It changes with market conditions. So I think a more current measure is the proper measure.

Q But now you said that -- but it is true, isn't it, that in developing that discounted cash flow analysis you've relied on earnings per share that are projected earnings per share in order to develop it?

A Correct. And in large measure you'll see it's because I used two sources, Bloomberg and then Value Line. I don't know that Bloomberg provides projected book value growth or dividend growth rates. They provide earnings projections. Value Line, of course, does provide those two things, but Bloomberg, as best I know, does not.

Q Okay. And so that -- we've gone through pretty much what the Virginia decision said about the capital asset pricing method. They also referred to another method that you used in Virginia that was used in this case, the Company's bond yield plus risk premium analysis, and find that there are similar flaws. They don't go into detail on that, but as I understand it, perhaps the future -- the use of forecasted interest rates, is that what you do when you do -- you do your bond yield plus risk premium analysis --

A It's the --

Q -- using --

A Oh, I'm sorry.

Q I should have stopped sooner, but just --

A No, no.

Q -- you're using forecasted rates, are you not, for the Treasuries?

A The same thing as before. I use both current observed and forecast. So in this case, if we were to look at my Exhibit RBH-R-6 for the bond yield plus risk premium, you'll see, based on the current Treasury yield, the return on equity estimate is 9.87 percent, about 17 basis points above the stipulated ROE of 9.7 percent.

And then just in preparing for hearings, I wanted to see what the number would look like, what the estimated return on equity would look like at a 2 percent current Treasury yield, and the ROE actually goes up. It's 9.99 percent. So in each case, without even having to look at projected Treasury yields, they actually -- the current yields support the stipulated ROE.

Q And that's in your -- just to clarify, you're talking there about your bond yield method for -- where you use the authorized returns to measure the stock market?

A Correct. That's right.

Q Okay. I would ask you to turn to the next exhibit, then, in that stack, and I would ask that this document -- just to clarify, this is before the Public Utilities Commission of the State of South Dakota, EL18-021.

MS. FORCE: I'd ask that that be marked for identification as AGO Hevert Cross Exhibit 3.

COMMISSIONER BROWN-BLAND: It will be so marked.

MS. FORCE: Thank you.

(Whereupon, Attorney General's Office Hevert Cross Examination Exhibit 3 was marked for identification.)

Q Mr. Hevert, you testified in this case as well for the Company, is that right --

A I did, yes.

Q -- for Otter Tail Power Company. And the case was decided on May 30th, 2019 by the South Dakota Commission, not too long ago.

A Not too long ago.

Q They adopted an 8.75 percent rate of return on equity; is that right?

A They did.

Q Your DCF growth rate in that case was, once again, based on earnings per share, is that right --

A It was.

Q -- to calculate growth. And the Commission in South Dakota seems to have focused on the DCF. It says that that's the main reason why your recommendation was so much bigger than the analysis of the other witness, using forecasted growth per share rather than looking at -- also at other measures, such as dividends per share, book value per share, as well as earnings per share.

A That was one of the issues. It was a fairly complex case in terms of methodological issues, but I -- I agree, that's what the Commission said right there.

Q Okay. I think -- I don't have -- maybe I shouldn't ask you this, but it seemed to me -- was there also a risk premium that uses bond yield in this case?

A I'm sure there was. I tend to use that in each case.

Q And do you always use the authorized returns when you do that, or do you sometimes use something else when you're looking at rate of return?

A I always use authorized returns.

Q Okay. Okay. So I -- then I have some questions for you -- I think we're done with these exhibits and I have another set to pass out. That's going to be -- I have questions for you about market conditions in your testimony --

A Okay.

Q -- in past cases. I'm going to give you these for reference. They're the K-1 cases. I didn't copy them all.

A Oh, no.

Q And that's the excerpts we'll be referring to.

A Okay.

Q I have made copies of all of the Orders for you so you can refer to them and then use the excerpts.

A Okay. Thanks.

Q Mr. Hevert, I'll submit that I have eight decisions -- excuse me -- eight excerpts in the exhibit, and I've given you the eight full-length testimony so that you can refer back to it if you'd like. And we have them in reverse chronological order, but I'd like to take them in chronological order. This was a miscommunication. I apologize. But it will have us shuffling paper a little bit more as we go through it.

A That's okay.

Q Okay. And so I'd ask you to take a look first at the one that's E-7, Sub 989.

A Okay.

COMMISSIONER GRAY: Ms. Force, would you give me that reference number again, please?

MS. FORCE: Sure. The last one in your stack should be E-7, Sub 989. Okay.

I'd ask that this be marked for identification as this -- the one that's marked E-7 -- that's E-7, Sub 989 be marked for identification AGO Hevert Cross Exam Exhibit 4.

COMMISSIONER BROWN-BLAND: I'm trying to determine if I have it.

MS. FORCE: Oh.

COMMISSIONER BROWN-BLAND: I do. My assistant found it for me.

MS. FORCE: Good. Thank you.

COMMISSIONER BROWN-BLAND: It will be so identified.

(Whereupon, Attorney General's Office Hevert Cross Examination Exhibit 4 was marked for identification.)

Q Mr. Hevert, would you agree with me, looking at this, it was testimony that you filed, direct testimony, so it would have gone in with the Company's application July 1st, 2011 in a Duke Energy Carolinas rate case?

A Yes. I agree with that.

Q All right. I'm not going to go through all of the details, but if you look on page 2 of the Table of Contents, it appears to me that you use two methods in that case, the constant growth DCF model and, secondly, what you abbreviate as the CAPM model. We've talked about that. Or -- excuse me -- CAPM analysis, correct?

A Yes. That -- that's right.

Q And if you flip over to page 3 of that exhibit, it shows a summary of your analytical results, Table 8. You see that?

A Yes, I do.

Q So I notice that when you give the results, you gave the results for the constant growth DCF, and then the supporting methodology was your CAPM. So you used the DCF result, and then the CAPM was used as a check. You agree to that?

A I agree with that.

Q Okay. And it doesn't say on this page, but on the next page if you look in the really small print, you've given -- we've got a picture here of your model that you used for the capital asset pricing model, and in this case you used two interest rates, is that right, the current 30 year and the near term?

A Yes. That's correct.

Q Okay. And the interest rates were 4.34 current and near term -- oh, boy -- 4.88.

A 4.88, correct.

Q Okay. Let's go to your next -- the next one. And I'm going in reverse order, so we'd be looking at E-22, Sub 479. Do you see that?

A Yes, I do.

Q All right.

MS. FORCE: And I'd ask that that be marked as AGO Hevert Cross Examination Exhibit 5.

COMMISSIONER BROWN-BLAND: It will be so identified.

(Whereupon, Attorney General's Office Hevert Cross Examination Exhibit 5 was marked for identification.)

Q The date on this one is March 30th, 2012, right?

A It is, yes.

Q This is for Dominion North Carolina.

A It is.

Q In that case, if you turn to page 2, you used two methods again. You used the constant growth DCF model and the CAPM analysis, right?

A Correct.

Q And if you go to page 3, again, you've used two interest rates when you were calculating the risk-free rate for your capital asset pricing model. One is the current rate and the other is the near-term projected rate, right?

A Correct.

Q All right. So there's -- the interest rates that are identified there, then, are 3.09 for the current, 3.50 --

A Right.

Q -- for the projected. All right. Let's go to the next one, 2012, E-2, Sub 1023. That's the Progress

Energy Carolinas case. Again, you use --

A Oh, I'm sorry. 1023?

Q 1023.

A Okay. I'm with you.

MS. FORCE: And I'd ask that that be marked as AGO -- Hevert -- excuse me -- AGO Hevert Cross Examination Exhibit Number 6.

COMMISSIONER BROWN-BLAND: It will be so marked.

(Whereupon, Attorney General's Office Hevert Cross Examination Exhibit 6 was marked for identification.)

Q So in this case we see once again the -- that you've used two methods --

A Yes. Correct.

Q -- the constant growth DCF model and the CAPM?

A That's right.

Q And you have -- if you flip back a few pages, you have the current, near-term, and long-term interest rates in -- in calculating your capital asset pricing model.

A That's right.

Q So the use of that, if you look at the difference, then, actually has quite an increase --

boosts the ROEs associated with the use of that 5.30 in your CAPM analysis on the top end of the range; is that right?

A Well, you say "the top end of the range." It was the top end of the range of results. I do not believe it would have been the top end of my recommended range. I believe these numbers would have been higher than the upper end of my recommended range.

Q I see what you're saying. So if we were to look at those same rate cases that we were just talking about, the -- the Duke Carolinas case, E-7, Sub 989, would you agree with me that you recommended an ROE of between 11.5 or -- excuse me -- recommended an ROE itself of 11.5 percent?

A I'm sorry. So --

Q I'm taking you back.

A -- 989?

Q 989.

A Do you have a page reference for that? I'm sorry.

Q Oh, I don't think I do. I don't think that's -- go ahead.

A Okay. If you go to page 68, it's there, 11.5.

Q Okay. Thanks. And I'll try to have page numbers if I ask you in the future. I don't think that's as --

A That's okay.

Q -- that's not as much the focus. So we've looked at the Progress case in 1023. Let's go to the next one, and that's Duke Carolinas, 2013.

A Okay.

Q According to my notes, the proposed rate of return in that case was 11.25. Does that sound right to you? And I'm afraid I don't have a page number for that.

A I'll -- I will take that.

Q So --

COMMISSIONER BROWN-BLAND: Do you want to get this one marked?

MS. FORCE: Oh, yes. I'm sorry. That's --

COMMISSIONER BROWN-BLAND: Hevert -- AGO --

MS. FORCE: -- AGO Hevert Cross Examination Exhibit --

COMMISSIONER BROWN-BLAND: Seven (7).

MS. FORCE: -- 7. Thank you.

COMMISSIONER BROWN-BLAND: It will be so identified.

(Whereupon, Attorney General's Office Hevert Cross Examination Exhibit 7 was marked for identification.)

Q So we have two measures again, the DCF and the capital asset pricing mechanism, in this case?

A We do. That's right.

Q And the interest rates that you show on the schedule include three different interest rates again.

A They do.

Q The current, the near-term, and the long-term --

A Correct.

Q -- when you do the CAPM. Okay. Let's jump ahead a little bit and look at your -- skipping over one, go to 2016, E-22, Sub 532.

A Okay.

MS. FORCE: And that case, I'd like to ask that that be marked AGO Hevert Cross Examination Exhibit 8.

COMMISSIONER BROWN-BLAND: It will be so marked.

(Whereupon, Attorney General's Office Hevert Cross Examination Exhibit 8 was marked for identification.)

Q In this case, Mr. Hevert, you have three different approaches that you use, and for your DCF you use two different approaches.

A Correct.

Q Constant growth and multi-stage --

A Correct.

Q -- is that right? And you have a capital asset pricing mechanism and a bond yield plus risk premium.

A Correct.

Q In this case, once -- let's see -- but you go back and you use 30 -- the current and the near-term for your interest rates in this case?

A Correct.

Q If we look at -- the next case would be E-2, Sub 1142. That's the 2017 Duke Energy Progress case.

A Okay.

MS. FORCE: And I'd ask that this be marked as AGO Hevert Cross Examination Exhibit 9.

MR. JEFFRIES: I'm sorry. I'm not sure I have that one. Which -- which docket was it?

MS. FORCE: E-2, Sub 1142.

MR. JEFFRIES: Okay. Now I've got it. Thank you.

Q And you have multiple approaches that you've identified in this case, too; isn't that right? In addition to the DCF constant growth, you do a multi-stage. You also do a capital asset pricing method, a bond yield, risk premium, so I guess you'd call that three approaches.

A So on page 4, lines, roughly, 8 to 11, that's right. That's what it says.

Q Uh-huh. I don't think there was a -- there wasn't a Table of Contents this time. And the -- so you use two interest rates in this case, the current at 3.06 and the near-term at 3.52, is that right --

A Yes. That's right.

Q -- in your capital asset pricing mechanism? But I think if you look at the last page, there's also a chart there where you do the bond yield plus risk premium, and there's three that you use in that one, right?

A Right.

Q The third is the long-term projected --

A Right.

Q -- when you do your bond yield?

A Correct.

Q So there's also a couple of pages in here that describe -- let's flip to page 3 of this exhibit. You have a chart here that shows Treasury yield curves. Do you see that?

A I do.

Q And on the page after that -- and excuse me -- before we turn to page -- this is page 76. Before we turn to page 77, at the bottom you say there's an increase in the 10 and the 30-year yields from 26 to -- July 2016 to March 2017. You have a discussion here about increasing interest rates and the effect that that's having on capital cost. Is that --
A I'm -- I'm sorry.
Q -- correct?
A Where are you?
Q Looking on pages 76 and 77.
A Yes.
Q You can look at that for a minute.
A I'm there, yeah.
Q You see "Does market-based data indicate that investors see a probability of increasing interest rates?" And you say, "Yes. Forward Treasury yields implied by the slope of the yield curve and published projections," so in other words, published sources and other measures that you're using suggest that interest rates are going up --
A Correct.
Q -- isn't that right?
A Correct.

Q And I believe there's some discussion here about the easing. Turn over to page 79. The probability that the federal funds rate increases will occur; is that right?

A Right. So it's sort of the opposite of easing, just to be right.

Q I'm sorry. You're right.

A No, no. That's okay.

Q Removing easing. And what will that do? It will raise interest rates --

A Correct.

Q -- isn't that right, and drive up capital cost; is that --

A Well, it would drive up the -- the overnight federal funds rate, correct.

Q Okay. And is -- your testimony here speaks for itself, but is your point that the interest rates are going up, that that should be taken into account, the forecast for increasing interest rates should be taken into account when we're setting the capital cost?

A Yes. My view is always that the capital market environment, interest rates and what's driving interest rate changes should be considered.

Q Now, we've gone through this. There's one more case. The --

COMMISSIONER BROWN-BLAND: Ms. Force, before we move on from this one, for the record, I'll identify that one as Hevert Cross Examination 9, AGO Hevert 9.

MS. FORCE: Thank you very much. I had put it down on paper, but I forgot --

COMMISSIONER BROWN-BLAND: You said it. I never identified it.

MS. FORCE: Oh, I'm sorry. Okay.

(Whereupon, Attorney General's Office Hevert Cross Examination Exhibit 9 was marked for identification.)

Q All right. There's one more. Let's -- that's E-7, Sub 1146, where you testified in 2017. It all blurs together a little bit, but this is the Duke Energy Carolinas case. Do you see that? It's the top one in the stack that --

A I do --

Q -- now that we've --

A -- yes.

Q -- reversed order. And that was filed a little bit later, your testimony. It was filed August 2017. You used three methods in that one. I don't see expected earnings in it, but you do use the DCF, CAPM, and the bond yield; is that right?

A Yes. That's right.

Q And I think --

COMMISSIONER BROWN-BLAND: And is this Hevert Cross Examination Exhibit 10?

MS. FORCE: Yes. Thank you.

COMMISSIONER BROWN-BLAND: All right. It's so identified.

(Whereupon, Attorney General's Office Hevert Cross Examination Exhibit 10 was marked for identification.)

Q And some of this testimony looks similar. The numbers may be different, but you're, again, talking about forward interest rates going up --

A That -- that's correct.

Q -- is that right?

A That's right.

Q Now, if we look at those interest rates from the beginning to the end, we can do that on our own, but isn't it true that the prevailing interest -- current interest rates, as opposed to the forecast, we're actually going down as a trend?

A Absolutely. And so if you start your chronology in 2011 and work through 2017, of course, that was the period that the Federal Reserve added about $4 trillion of liquidity into the market. The intent of that was, in fact, to bring down interest rates. And when you do that, when you have such a large intervening force in the capital markets, things start to become disjointed. Markets -- excuse me. The models that we tend to use may not be as reliable as they once were.

You pointed out that early on I used two models, then three models, now four models. That's precisely the reason why. As the markets become more disjointed, as the Federal Reserve took a larger position in the markets, it has been my view that it's important to look at a broader array of models simply because any one model cannot fully accommodate the effect of capital market intervention of that magnitude.

Q So in the last period since -- when was it that the reversals began on easing in capital markets?

A So there are two aspects. The Federal Reserve stopped adding liquidity in -- excuse me -- stopped purchasing bonds in late 2015. It's largely kept the balance sheet intact. It's fallen off a little bit, but roughly $3.8 trillion of assets on the balance sheet now relative to 4 trillion in, say, 2016. The Federal Reserve lowered interest rates in July of this year, the overnight federal funds rate, lowered it by 25 basis points.

Q Those are short-term rates; is that right?

A Correct. It's --

Q Overnight, you said.

A -- the overnight rate, correct.

Q And they don't set the longer term rates; isn't that right?

A Well, that was the intent of that $4 trillion. The stated intent was to bring down long-term interest rates and to dampen market volatility. So the overnight rate is what the Federal Reserve has some control over, and they try to exert some control through quantitative easing.

Q And -- but the predictions, when the -- some of the reversal was going on of the quantitative easing happened was that interest rates were -- would go up, and they have not gone up as expected. Would you agree?

A I would agree with that. And not only have they not gone up, but they've gone down to unprecedented levels. And what -- again, what that tells us is what an unstable market environment we're in.

If you look back at what has happened in this market and just look at the very -- excuse me -- the level of Treasury yields, the closest analogy we had is 2016. That was when the Brexit vote happened. That was the market moving event then. Now we have geopolitical events that also are unsettling the markets. When in 2016 the Treasury yield hit 2.11 percent, now we're at, again, this morning, 2.08 percent. But, again, it was in 2016 that I think the Commission ordered 9.7 percent ROE for Public Service, 52 percent equity ratio, just at the stipulated levels here. So in my view, the closest analogy we have to the current market supports the stipulated ROE and equity ratio.

Q The closest example. Is that the Public Service case you're --

A The closest analogy. I'm sorry.

Q I want to follow what you just said.

A Sure.

Q Are you talking about the Public Service case being the closest analogy?

A No. I'm talking about the capital markets. Right now we have a roughly 2.08 percent Treasury yield. In July 2016 we had a 2.11 percent Treasury yield. In July 2016 we had a large geopolitical event, the Brexit vote that unsettled the markets. In 2019 we have tariff and trade disputes unsettling the markets. They're not exactly the same. No two markets are. But as close as we can come to an analogy, as close as we can see returns of levels of interest rates were 2016. And as I look at what the Commission authorized in 2016, it is the stipulated ROE, it is the stipulated equity ratio.

Q So your comparison is to -- between the interest rate level for current risk-free interest and comparing that to the authorized return that this Commission set?

A I'm saying we're -- we are in a -- an unprecedented market right now. The only -- the closest thing we can come to is what happened three years ago, if we -- if we wish to look backwards.

Q And when you're looking at this over the years, isn't it true that you've been predicting that interest rates were going to go up considerably since you've been testifying here and perhaps longer?

A Well --

Q You can answer the question first, and then explain.

A I -- I am answering the question. They're not my predictions. They're the predictions of the 50 economists that contribute to blue chip. It's the prediction of the investors that establish the slope of the yield curve. And if the investors that establish the slope of the yield curve were wrong, that tells you, again, how unsettled this market is.

Q And when you're describing that, you're saying the predictions that were made of future interest rates, when you talk about blue chip --

A Correct.

Q -- just for clarification?

A Correct.

Q Okay.

A The slope of the yield curve can tell us something about what the market expects future interest rates to look like. So when the yield curve was steeper a year, two years ago, it suggested that investors felt long-term interest rates were increasing in the -- would increase in the future. Obviously, we've fallen by, wow, 130 basis points on the 30-year Treasury yield. The only way that could have happened, again, is the -- some event that so unsettled markets that investors became very risk averse.

Q But, again, the prediction was that they would go up, and they didn't; is that correct?

A Absolutely agree.

Q Okay. Thank you.

MS. FORCE: I don't have any other questions.

THE WITNESS: Okay.

MS. FORCE: Appreciate it.

COMMISSIONER BROWN-BLAND: All right. Good stopping place. We're going to stop and resume in the morning at 9:30.

MR. JEFFRIES: Madam Chair, if I may, I actually had a couple of redirect questions for Mr. Hevert. And I believe he's trying to get out of here this evening; is that right?

THE WITNESS: Well, if it's possible, but I -- I'm not sure what the Commission has --

MR. JEFFRIES: Maybe 10 minutes, very quick, unless the Commission has follow-up questions. I'd ask for us to try to finish him up in the next few minutes, if that's all right.

(Off-the-record discussion.)

COMMISSIONER BROWN-BLAND: And you're short here?

MR. JEFFRIES: I'm sorry?

COMMISSIONER BROWN-BLAND: You won't take too long?

MR. JEFFRIES: I won't take too long. I promise.

COMMISSIONER BROWN-BLAND: All right. Was that the end of the cross examination?

MS. FORCE: Yes. I --

COMMISSIONER BROWN-BLAND: No cross -- no further cross examination?

MS. FORCE: I'd like to get the exhibits admitted.

COMMISSIONER BROWN-BLAND: Okay. Just a moment. You can go ahead with the redirect.

MR. JEFFRIES: Thank you, Madam Chair.

REDIRECT EXAMINATION BY MR. JEFFRIES:

Q Mr. Hevert, the AG Cross Exhibits 3 and 4, which are the Dominion Virginia decisions and Otter Tail, in your opinion, are they meaningful for purposes of this Commission determining what an appropriate ROE is in this case?

A Well, again, the Virginia Commission decisions were for the rate adjustment clauses, not base rate proceedings, so they are not the same thing. The Otter Tail decision was a base rate proceeding, but that was the lowest return that I've seen authorized. In the Order itself, it notes that the South Dakota jurisdictional assets are 7 percent of Otter Tail's overall assets. Its revenue in South Dakota is about 10 percent of its overall revenue.

And I know this is just a short period, but if we look at what happened to Otter Tail stock price during May, it lost about 6 percent of value, whereas the utility industry stayed about even during that time. If you can draw conclusions from that short period, it appears as though -- I was disappointed with that Order, and it appears that the market may have reacted as well.

Q And Otter Tail is an electric company, correct?

A Otter Tail is an electric company.

Q In South Dakota?

A In South Dakota.

Q Do you know how many customers they serve?

A About 11,000.

Q Okay. Thank you. For Ms. Force, referencing her cross or AG Cross Examination Exhibits 4 through 10, and sort of took you through your previous testimonies in a number of cases before this Commission, I -- it seemed to me -- I shouldn't come right out and say it, but it seemed like there was an implicit criticism of the fact that maybe you didn't use exactly the same approach in every one of these cases. Would you -- would you agree that you didn't use the same exact approach in every one of these cases?

A I do agree. I did not use the same set of models.

Q Okay. Why not?

A Because as market conditions change, you have to look at each model, see how it aligns with the market. And, again, when markets become very unsettled and, in fact, when they become susceptible to such large intervention by the Federal Reserve, then, in my view, you really have to look at a variety of models, say, in our rebuttal testimony. Remember, models are general descriptions of investor behavior. They're not precise definitions of investor behavior. So we have to use a variety of models, each of which captures a different perspective on investor behavior.

So when the markets become susceptible to intervention by the Federal Reserve, when they become unsettled, then it's very important to use a variety of methods.

Q So if you use multiple interest rates in your CAPM analysis you're -- am I correct in thinking you're simply adding data points to your overall analysis?

A I'm adding data points, and in the final analysis, many times those results were higher than the upper end of my recommended range.

Q Okay. Did any -- did your review of your testimony in these dockets cause you to second guess either your recommendations in those dockets or the validity of your analysis --

A No.

Q -- in those dockets?

A I'm sorry. No. I think in the context of those markets they were proper.

Q Okay.

MR. JEFFRIES: That's all I have, Madam Chair.

COMMISSIONER BROWN-BLAND: All right. There are no questions from the Commission, so now I'll hear your motions.

MS. FORCE: I'd ask that the Attorney General's Cross Examination Exhibits AGO Hevert 1 through 9 be admitted.

COMMISSIONER BROWN-BLAND: I believe there are 10.

MS. FORCE: Oh, 1 through 10, please. Yes.

MR. JEFFRIES: No objection.

COMMISSIONER BROWN-BLAND: No objection -- no objections, those exhibits will be received into evidence.

(Whereupon, Attorney General's Office

Hevert Cross Examination Exhibits 1
through 10 were admitted into
evidence.)

MR. JEFFRIES: `And we would move the -- that Mr. Hevert's prefiled and previously identified exhibits be admitted into evidence, Your Honor.

COMMISSIONER BROWN-BLAND: That's his nine exhibits with his direct, his 15 exhibits with the rebuttal, and his one exhibit with the Stipulation; is that correct?

MR. JEFFRIES: That's correct.

COMMISSIONER BROWN-BLAND: Those will be received into evidence.

(Whereupon, Exhibits RBH-1 through
RBH-9, Rebuttal Exhibits RBH-R-1
through RBH-R-15, and Exhibit
RBH-S-1 were admitted into evidence.)

COMMISSIONER BROWN-BLAND: All right. Now we'll be back and resume in the morning at 9:30. Mr. Hevert, you are excused.

THE WITNESS: Thank you.

(Witness excused.)

COMMISSIONER BROWN-BLAND: And now we'll be adjourned.

(The hearing was recessed, to be continued on August 20, 2019 at 9:30 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. G-9, Sub 743, 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 22nd day of August, 2019.

Linda S. Garrett

Linda S. Garrett, CCR
Notary Public No. 19971700150