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October 17, 2018

VIA FEDERAL EXPRESS and
ELECTRONIC MAIL
aida.camacho@bpu.nj.gov
board.secretary@bpu.nj.gov

Honorable Dianne Solomon, Commissioner
In care of Aida Camacho-Welch, Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey 08625-0350

RE: In the Matter of the Petition of Atlantic City Electric Company for Approval of an Infrastructure Investment Program, and Related Cost Recovery Mechanism, Pursuant to N.J.A.C. 14:3-2A.1 *et seq.*
BPU Docket No. EO18020196

Dear Commissioner Solomon:

As directed in the amended Prehearing Order With Procedural Schedule and Motions to Participate (issued June 6, 2018), enclosed herewith for filing are an original and ten (10) copies of Rebuttal Testimony of the following representatives of Atlantic City Electric Company ("ACE" or the "Company") in connection with the above referenced matter:

- Kevin M. McGowan, Vice President, Regulatory Policy and Strategy for Pepco Holdings LLC ("PHI");
- Bryan L. Clark Director, Utility of the Future, PHI;
- Joseph F. Janocha, Manager of Retail Pricing, PHI (with Schedule); and
- Robert B. Hevert, Partner, ScottMadden, Inc. (with Schedules).

An attachment to the testimony of Company Witness Clark contains information that is claimed to be confidential. As such, ACE will be filing a "confidential" version of the attachment and a "public" version. Consistent with past practice, a single copy of the confidential version is being forwarded to the Secretary of the Board with the hard copies of this filing. The public version of the document is being provided to the parties and Participants hereunder. Confidential electronic copies of the attachment will be provided to the parties that signed the Agreement of Non-Disclosure of Information, dated as of May 2, 2018 under separate cover.

Case Mgmt
list copied

An additional copy of this submission is also enclosed. Please date stamp and return the copy as "filed" in the pre-addressed, postage-prepaid envelope provided.

Thank you for your assistance and cooperation. Feel free to contact the undersigned with any questions.

Respectfully submitted,

/jpr
Philip J. Passanante
An Attorney at Law of the
State of New Jersey

Enclosures

cc: Discovery Service List
Honorable Dianne Solomon, Commissioner (Federal Express)
Robert M. Hevert (electronic mail)

ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY
BOARD OF PUBLIC UTILITIES
REBUTTAL TESTIMONY OF KEVIN M. MCGOWAN
BPU DOCKET NO. EO18020196

Q1. Please state your name and position.

A1. My name is Kevin M. McGowan, Vice President, Regulatory Policy & Strategy for Pepco Holdings LLC (PHI), a subsidiary of Exelon Corporation (Exelon). I am testifying on behalf of Atlantic City Electric Company (ACE or the Company).

Q2. Are you the same Kevin M. McGowan who filed direct testimony in this docket on February 28, 2018?

A2. Yes.

Q3. What is the purpose of your rebuttal testimony?

A3. The purpose of my rebuttal testimony is to address certain issues raised in the direct testimonies of Messrs. Peterson, Griffing, and the joint testimony of Salamone and Chang on behalf of the New Jersey Division of Rate Counsel (Rate Counsel).

Q4. Please summarize your rebuttal testimony.

A4. I will address the following issues:

1. Issues Mr. Peterson raised concerning the Infrastructure Investment Program (IIP) regulations, benefits to customers and shareholders, and the reasonableness of the amount requested by ACE.
2. Issues raised by Mr. Griffing concerning the capital structure.
3. Issues raised by Messrs. Salamone and Chang regarding the Company's proposed baseline calculation.

<u>General Comments on Rate Counsel Testimony</u>

Q5. Please comment on the overall theme of Rate Counsel's witnesses' testimony that the Company's IIP filing does not comply with the IIP regulations.

A5. Rate Counsel witnesses Peterson, Salamone, and Chang contend that the Company's IIP filing is not compliant with the IIP regulations. I disagree in all respects. ACE's filing fully complies with the IIP regulations implemented by the Board, the purpose of which is to "encourage and support" systematic and sustained infrastructure investment by permitting a utility to "obtain accelerated recovery of qualifying investments." *See* <u>N.J.A.C.</u> 14:3-2A.1(a) and (b). The IIP regulations are designed to provide a rate recovery mechanism that covers a utility's spending related to the construction, installation, and rehabilitation of certain projects that are necessary for "system safety, reliability and resiliency, and sustained economic growth in the State of New Jersey." <u>N.J.A.C.</u> 14:3-2A.1(b). This section of the IIP regulations includes accelerated construction as one of the IIP's purposes, however it does not limit the IIP recovery mechanism to only accelerated construction. The section also states that the purpose of the IIP is to encourage and support installation and rehabilitation of certain utility plant and equipment. ACE's IIP proposal does just that and meets all criteria set forth in the regulations including:

- <u>N.J.A.C.</u> 14:3-2A.5(b)1: Projected annual capital expenditure budgets for a five-year period, identified by major categories of expenditures. *See* page 15 of the Company's Petition.

- N.J.A.C. 14:3-2A.5(b)2: Actual capital expenditures for the previous five years (2013-2017), identified by major categories of expenditures. *See* page 16 of the Petition.
- N.J.A.C. 14:3-2A.5(b)3: An engineering evaluation and report identifying the specific projects to be included in the IIP, with descriptions of project objectives, detailed cost estimates, in service dates and any applicable cost-benefit analyses. *See* page 16 of the Company's Petition; the Appendix to the Direct Testimony of Company Witness Clark; supplemental discovery containing in-service dates, produced on September 21, 2018; and the Rebuttal Testimony of Company Witness Clark, including attachments.
- N.J.A.C. 14:3-2A.5(b)4: An IIP budget setting forth annual budget expenditures. *See* page 17 of the petition.
- N.J.A.C. 14:3-2A.5(b)5: A proposal addressing when ACE intends to file its next base rate case. *See* page 17 of the Company's Petition; and page 6, lines 1 - 6 of the Direct Testimony of Company Witness McGowan.
- N.J.A.C. 14:3-2A.5(b)6: The proposed baseline spending levels. *See* page 17 of the Petition; pages 4 - 5 and 8 - 16 of the Direct Testimony of Company Witness McGowan; and the Direct Testimony of Company Witness Clark.
- N.J.A.C. 14:3-2A.5(b)7: The maximum dollar amount in aggregate, that ACE seeks to recover through the IIP. *See* pages 7, 12 and 18 of the Petition; and the Direct Testimony of Company Witnesses McGowan and Clark.

- N.J.A.C. 14:3-2A5(b)8: The estimated rate impact of the IIP on ACE's customers. *See* pages 13 and 18 of the Company's Petition; and the Direct Testimony of Company Witness Janocha.

Q6. Witnesses Peterson, Salamone and Chang assert in their testimony that the size of ACE's IIP tracker – $338 million – as a percentage of the Company's annual capital expenditure budget is too large. Why do you believe that ACE's request is reasonable?

A6. As required by the IIP regulations, a utility must define and propose a baseline spend that represents ongoing capital investments the company plans to make each year that may be recovered through a traditional base rate case. Capital expenditures in excess of the baseline spend, as approved by the New Jersey Board of Public Utilities (BPU or the Board), may be recovered through the IIP. The baseline spending proposed by the Company is approximately $60 million per year, or $240 million over the four-year 2019 - 2022 periods. The Company is proposing to recover $338.2 million of capital expenditures over the four-year 2019 - 2022 period through the ACE IIP which are in excess of the Company's proposed baseline spend. The Company's total capital forecast is $578.2 million over the four-year 2019 – 2022 period, excluding $55.8 million related to the PowerAhead program, which is necessary to provide safe and reliable service to our customers. These facts indicate the Company is forecasted to spend a significant amount of capital, approximately $240 million, over the four-year 2019 – 2022 period outside of the ACE IIP request.

As noted in my Direct Testimony, the ACE IIP proposal requests recovery of capital expenditures that are not currently provided for in customer rates and provides a reasonable balance between capital recovered through traditional rate case filings and capital recovered through the ACE IIP. The Company believes the IIP proposal is reasonable and is allowed under the regulations.

Additionally, in accordance with N.J.A.C. 14:3-2A.2(c), ACE will maintain outside of the IIP recovery mechanism, its capital expenditures on projects similar to those included in the proposed IIP. Those expenditures equate to approximately 28% of the IIP, and therefore satisfy the requirement that they equal at least 10% of the approved IIP.

As described in my direct testimony, throughout the Company's history ACE has consistently invested in infrastructure to support system reliability, resiliency, and safety. ACE's investments have significantly increased over the past several years to maintain and improve the service quality that our customers demanded and rely on, as well as to comply with the goals of the Reliability Improvement Plan (RIP) and to fulfill the merger commitments which require ACE to spend at least 90% of its aggregate reliability budget amount over the six-year 2016 - 2021 period. Infrastructure capital expenditures have out-paced the Company's ability to receive timely recovery through traditional base rate filings. ACE's IIP proposal supports the need for ongoing system improvements and mitigates the need for annual base rate case filings by establishing a capital tracker that provides a reasonable balance between capital recovered through traditional rate case filings and capital recovered through the ACE IIP. This is precisely what is envisioned in the IIP regulations.

Q7. Do the IIP regulations specify how the baseline spend should be calculated?

A7. No. The IIP regulations do not provide the methodology to calculate the baseline spend, but rather requires the utility to determine and propose a baseline spend based on the unique facts and circumstances of that utility. It is clear from N.J.A.C. 14:3-2A.3, that a utility shall propose the annual baseline spending levels to be maintained by the utility throughout the length of the proposed Infrastructure Investment Program and shall provide appropriate data to justify the proposed annual baseline spending levels. Based on the information provided by the utility, the Board shall establish and approve the baseline spending levels for the utility.

IIP Policy and Customer Benefits

Q8. Witness Peterson asserts on page 8 of his testimony that the IIP procedures are improper because they ignore factors that influence the cost of service and therefore cannot fairly measure a utility's revenue requirement. Do you agree?

A8. No, I do not agree. As a threshold matter, Mr. Peterson's critique of the IIP rules is untimely and outside the scope of this proceeding. The rules were approved by the BPU on December 19, 2017 following extensive public comment and became effective on January 16, 2018 following publication in the New Jersey Register pursuant to the NJ Administrative Procedures Act. The opportunity to challenge how the rules are constructed or what factors the Board should consider has long passed. Mr. Peterson's comments about the rules provide no basis to disallow ACE's requested request.

The IIP rules require the utility to submit detailed cost information – "historical capital expenditure budgets, projected capital expenditure budgets, depreciation expenses, and/or any other data relevant to the utility's proposed baseline spending level." N.J.A.C. 14:3-2A.3(b). The BPU deemed such information necessary to evaluate an IIP petition. Further, the rules contain a provision that allows the Board to request and consider "any other data" relevant to the utility's proposed spending levels. In addition, approval of ACE's Petition is subject to the compliance requirements set forth in the rule, including a prudence review, along with "any other conditions set by the Board in approving an individual utility's Infrastructure Investment Program." N.J.A.C. 14:3-2A.1(a). The precautions are designed to balance the needs of the utility, customers, and regulators.

Q9. Witness Peterson asserts on pages 10 - 11 of his testimony that the IIP procedures do not enable a fair measurement of the company's revenue requirement and that certain adjustments, not provided for in the IIP regulations, should be made. Do you agree with that statement?

A9. No. First, the Company has followed all of the IIP requirements in making its request. As discussed previously, ACE's IIP proposal is consistent with the IIP regulations regarding the terms of measurement of a company's revenue requirement and treatment of its investments. By approving the IIP regulations, the Board determined that the rules were sufficient to properly evaluate whether to allow accelerated recovery for eligible investments.

Second, the IIP allows a company to recover only a portion of its capital expenses related to reliability investments in a more timely fashion than through a traditional rate case, which frequently takes over one year from filing and leads to a lag in cost recovery. A key requirement of the IIP regulations is that a company must exclude baseline projects, including 10% of similar projects. Therefore, the IIP does not and was not designed to reflect the company's total revenue requirement.

Third, the rules require an earnings test to prevent over-recovery. N.J.A.C. 14:3-2A.6(h). Specifically, N.J.A.C. 14:3-2A.6(i) states that "[f]or any Infrastructure Investment Program approved by the Board, if the calculated ROE [Return on Equity] exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, accelerated recovery shall not be allowed for the applicable filing period." Therefore, the Board has already considered the overall revenue requirement in developing the IIP regulations. If the Company is over-earning by 50 basis points or more, it will not be able to use the IIP.

Q10. Mr. Peterson suggests that, even though the IIP rates are provisional and subject to refund, the time between rate cases and difficulty in refunding makes it less likely that costs allowed under the IIP will be found imprudent in a base rate case. Accordingly, he encourages the BPU to be "especially conservative" when approving IIP programs. Is this a reasonable concern?

A10. No. In fact, it undermines the basic principles underlying the IIP regulations. Capital recovered through the IIP actually provides a greater opportunity to review capital investments than is available through a traditional rate case. The parties in a base rate case proceeding can, and most likely will, perform the same level of due diligence on all capital investments regardless of whether the capital investment is being recovered through the IIP mechanism. The base rate case proceeding is generally focused on capital investments that have already been made and are in service. For capital investments recovered through the IIP, in addition to the due diligence information provided in the rate case, the parties will also be able to review the capital investments in advance of the work being done and will have access to a significant amount of data to evaluate the capital investments as defined in the IIP regulations. The IIP program provides more transparency and information to the parties to evaluate the Company's capital expenditures and certainly does not make it more difficult as suggested by Mr. Peterson. Finally, if it were to become necessary, PHI could provide a refund to its customers, as it has done over the past three years, including interim base rates in Delaware and the Tax Cuts and Jobs Act benefits and merger-related credits to customers throughout the PHI jurisdictions. The

Company has addressed many variations to calculating and providing these refunds and credits to customers and in the event a refund is required under an IIP filing, the Company is certain the refund can be processed efficiently and timely without difficulty.

Finally, the IIP regulations state that "rates approved by the Board for recovery of expenditures under an Infrastructure Investment Program shall be provisional, subject to refund and interest." N.J.A.C. 14:3-2A.6(e). By approving this process and implementing these regulations, it is clear that the Board has found that this is a reasonable manner to balance any risk of overpayment by customers. Similarly, the Board has authorized provisional rates after 9 months in the context of base rate cases – demonstrating the reasonableness of this tool to protect customers.

Q11. Does the IIP tracker mechanism create special treatment or a "windfall" for shareholders, as suggested by Mr. Peterson?

A11. No. The IIP tracker mechanism does not create a windfall for shareholders as Mr. Peterson implies. Investors have provided debt and equity needed to fund the Company's capital expenditures under the premise the Company can and will earn its authorized rate of return. As explained in my Direct Testimony, the Company has been unable to earn close to its authorized ROE over the past several years, primarily due to the level of capital investments needed to provide the level of reliability service expected by our customers and the Board. The IIP proposal was developed and approved in regulations as a mechanism that can provide the Company more timely recovery of its investments and allow the Company to earn closer to its authorized ROE. The IIP is in no way a "windfall benefit" over and above what investors are reasonably entitled to receive.

It is also important to note that the IIP recovery mechanism still requires the reliability projects to be closed to plant and be used and useful before they can be recovered though the IIP recovery mechanism. This means that customers will be receiving the benefits of these investments for 3 - 9 months before the Company begins to recover the costs. The Company and its investors will still incur a permanent financial loss over that 3 - 9 month period since they will be required to fund the financing costs associated with these investments until recovery begins.

The ACE IIP simply shortens the period between the time investments are placed in service and providing benefits to customers, and when customers begin to pay for those investments. Reducing this regulatory lag will reduce the amount of the investments that the Company has to finance and will decrease the amount of unrecoverable costs, thus providing a greater opportunity for ACE to come closer to earning its authorized ROE.

As discussed in my Direct Testimony, ACE has invested 100% of its earnings back into its business. While these investments have provided countless benefits to customers, it takes anywhere from 3 - 15 months to begin recovery of these investments through a traditional rate case, assuming annual rate case filings. The IIP allows the Company to recover these investments 3 - 9 months after they are placed in service, allowing more timely recovery of costs.

<u>Capital Structure</u>

Q12. Mr. Griffing opines that the long-term debt and capital structure requested by the Company in the most recently filed base rate case should be applied to IIP. Do you agree?

A12. I agree in principle. The cost of capital and capital structure from the most recently approved rate case should be used in the IIP filings. If a new cost of capital and capital structure is approved in a future rate case, the Company would use that cost of capital and capital structure in subsequent IIP filings. As of the date of the filing, ACE used the approved cost of capital and capital structure from the Company's most recently approved rate case (BPU Docket No. ER17030308). If a new cost of capital and capital structure is approved in ACE's pending base rate case, filed August 21, 2018, before the IIP case concludes, we will use the approved cost of capital and capital structure from the case.

<u>Capital Projects and Expenditures</u>

Q13. The joint testimony of Salamone and Chang proposes that the baseline should include the historical spend, including spend related to the RIP. What is your response?

A13. I disagree. The Company should not be penalized for accelerating its capital investments prior to the implementation of IIP rules. Over the years 2009 - 2011, prior to the RIP that was designed to increase reliability capital spending and reliability improvements, the average capital spending per year was approximately $113 million per year. However, as further shown in Table 1 of my direct testimony, the capital spending over the past six years (2012 - 2017) was approximately $156 million per year. The Company recognized the need for increased reliability investments back in 2011, and therefore increased its annual capital expenditures between 2012 and 2017 to meet the higher reliability expectations of the BPU and ACE's customers.

The reasons for the accelerated spending over those years – whether voluntary or due to the RIP – is not relevant. What is relevant, however, is that the reliability projects are incremental to the Company's depreciation expense and therefore not included in rates.

The Company's current capital plan includes accelerated spending for reliability including the RIP, which has been focused on improving reliability since 2011. This is further evidenced by the Company's last rate case settlement agreement, which requires the Company to propose a wind down of the RIP accelerated capital program. In the Company's pending base rate case, it has proposed a wind down of the RIP by 2023. Therefore, it is clear that, at a minimum, the RIP is incremental and should not be included within the Company's baseline.

Q14. Witnesses Salamone and Chang recommend a total IIP amount of $21 million over four years, which is less than 10% of ACE's Petition. What is your response?

A14. As explained in my Direct Testimony, ACE's IIP proposal allows the Company more timely recovery of its capital investments that are not included in rates and the opportunity to earn closer to its authorized ROE, without the need to file annual rate cases. If ACE's IIP is approved as proposed, the Company will be able to recover its ongoing capital investments without the need to file its planned annual distribution base rate case in 2019, and would anticipate filing instead in 2020. Messrs. Salamone's and Chang's recommendation of $21 million would not enable the Company to avoid filing a distribution base rate case in 2019.

Q15. Does this conclude your rebuttal testimony?

A15. Yes.

ATLANTIC CITY ELECTRIC COMPANY

**BEFORE THE NEW JERSEY
BOARD OF PUBLIC UTILITIES
REBUTTAL TESTIMONY OF BRYAN L. CLARK
BPU DOCKET NO. EO18020196**

I. INTRODUCTION AND PURPOSE

Q1. Please state your name and position.

A1. My name is Bryan L. Clark. I am the Director of Utility of the Future at Pepco Holdings LLC (PHI). I am testifying on behalf of Atlantic City Electric (ACE or the Company).

Q2. Did you previously submit testimony in this case?

A2. Yes, I previously submitted Direct Testimony in this proceeding.

Q3. What is the purpose of your Rebuttal Testimony?

A3. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony submitted jointly by Maximilian Chang and Charles Salamone on behalf of the New Jersey Division of Rate Counsel (Rate Counsel). Specifically, I will rebut their claims that 1) ACE has not provided adequate documentation for the Infrastructure Investment Program (IIP) filing; and 2) ACE should not be allowed to recover certain projects under the IIP.

II. IIP FILING DOCUMENTATION

Q4. Witnesses Chang and Salamone argue the Company's filing lacks sufficient documentation. Do you agree?

A4. No. Witnesses Chang and Salamone state that ACE is missing the following documents: 1) in-service dates of IIP projects; 2) the Engineering Report for the proposed projects; and 3) a cost-benefit analysis for the proposed projects. ACE provided some of this documentation in its initial filing and is now providing supplemental information with its rebuttal testimony.

ACE provided in-service dates to the Board of Public Utilities ("BPU" or "Board") and Rate Counsel following the parties' August 30, 2018 meeting to discuss the IIP.

With regard to the Engineering Report, ACE provided project descriptions and objectives in its 123 page Appendix to its original filing and has attached a supplemental Engineering Report to my rebuttal testimony as Schedule R-(BLC)-1[1]. In addition, ACE has provided detailed responses to all 111 engineering data requests submitted by Rate Counsel during the discovery period.

Q5. Have you performed a cost-benefit analysis for the proposed IIP Projects?

A5. Yes, as described in the Engineering Report, ACE quantified the benefits of each project category using the Interruption Cost Estimate tool provided by the U.S. Department of Energy. This tool provides a reasonable estimate of the benefits of reductions in outage frequency and duration and compares those benefits to the costs necessary to achieve them.

Q6. What were the results of the cost-benefit analysis?

A6. As shown in Table 2 of the Engineering Report, on an overall basis for all proposed IIP Projects the ratio of benefits to costs was 1.8—meaning the monetized benefits derived from the IIP Projects were nearly <u>twice</u> the cost of those projects. Clearly, this is a benefit to customers and demonstrates the value of the IIP Projects.

[1] The supplemental Engineering Report is considered confidential and should be treated by the parties in accordance with the Agreement of Non-Disclosure of Information, dated as of May 2, 2018.

Q7. Why is it appropriate to perform the cost-benefit analyses for categories of IIP Projects?

A7. ACEanalyzes these project categories in a holistic manner and considers how they impact the distribution system as a group. A cost-benefit analysis performed at the feeder level is more imprecise because it may not account for all variables on the distribution system affecting it, yielding a significantly different cost/benefit result. Given the often inter-related nature of the projects within a work category, it is reasonable to perform the cost-benefit analyses in the same fashion. The inputs systemwide are more predictable to fully assess the total impact of the work category and the benefits derived from that category of investment.

III. <u>IIP PROJECT RECOVERY</u>

Q8. Witnesses Chang and Salamone argue that the Company's baseline historical annual spending level is $146 million. Do you agree with that statement?

A8. No. The Company's baseline historical annual spending level is significantly less than $146 million. ACE has been committed to accelerated spending for reliability projects since 2011 as a result of the Reliability Improvement Plan (RIP). The projects associated with the RIP should not be included within baseline spending, but Witnesses Chang and Salamone have bundled these projects into their baseline spending calculation.

Q9. Should the projects associated with the RIP be considered part of the Company's baseline spending as Witnesses Chang and Salamone argue?

A9. No. Projects associated with the RIP should not be considered part of ACE's baseline spending for purposes of the IIP. The RIP is an accelerated program that was proposed by the Company to address concerns affecting service quality. The six areas for improvement and investment targeted by the RIP are enhanced vegetation management, priority feeders, load growth, distribution automation, feeder improvements, and substation improvements. The areas targeted by the RIP are designed to focus on overall ACE reliability improvement. Since the RIP began in 2011, ACE's average number of service interruptions decreased by 51% and the average time customers are without power declined 66% as measured by the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI) metrics, respectively. To date, the RIP has been an unqualified success.

Since 2011, the Company added incremental funding to its distribution budget in order to fulfill the RIP's requirements. For the first three years of the RIP, spending was significantly higher in order to undertake several projects, reaching more than $80 million in 2012 and 2013. Another spending increase occurred in 2016 following the approval of the proposed merger agreement between PHI and Exelon. Given the program's success, the parties agreed to continue the RIP and to set a target for ACE whereby it would achieve a reliability performance of 1.05 SAIFI and 100 CAIDI (based on a three-year average).

The Company also committed to a minimum spending threshold for the RIP through 2020 to help meet these requirements. Thus, the design and intent of the RIP has always been temporary in duration—funding will cease by year-end 2023 at the latest—so that reliability indices may be improved, which is precisely what has occurred. For all of the above reasons, the RIP should not be considered baseline spending.

Q10. By excluding the RIP from the historical annual baseline spending under the IIP, is the accurate level for baseline spending significantly less than $146 million?

A10. Yes. The appropriate level of historical annual baseline spending should be $60 million, as explained by Company Witness McGowan in his Direct Testimony on page 9.

Q11. Witnesses Chang and Salamone argue "Upgrades" and "Replace/Retire" projects should not be included in the IIP. Do you agree?

A11. No. For any project to be eligible under the regulations, it must be non-revenue producing and promote the reliability, resiliency, or safety of the distribution system. So long as a project submitted under the IIP meets these requirements, it may be included within the petition even if it could arguably be classified as an upgrade or a replacement. There is no denying that many projects that promote the reliability, resiliency, or safety of the distribution system include the installation of new equipment. The Rate Counsel witnesses' broad prohibitions of "replacement" and "upgrade" projects preclude a majority of the otherwise qualified projects and thereby render the regulations ineffective.

Moreover, it is difficult to understand what is even meant by the terms "Upgrades" and "Replace/Retire" since ACE has properly classified projects according to Targeted Reliability Improvements, Infrastructure Renewal, Distribution Automation, Facilities, and Emergency spending. The projects in the two categories discussed by Witnesses Chang and Salamone, "Upgrades" and "Replace/Retire", necessarily fit within several of ACE's project categories. "Upgrades" and

"Replace/Retire" both contain Infrastructure Renewal projects; "Upgrades" also contains Targeted Reliability projects; and "Retire/Replace" also contains a Distribution Automation project. Because these categories are misaligned with ACE's IIP filing, the spending amounts identified by ACE cannot simply be rejected, as Rate Counsel summarily attempts to do.

Further, the witnesses state "Upgrades" and "Retire/Replace" projects total $63 million and $86 million respectively, but they do not provide any detail or analysis to support why they have placed the projects in these categories. These project classifications not only misalign with the categories ACE has presented in its filing, there is no underlying document showing which projects are classified where and how they ended up with their spending totals. Unless witnesses Chang and Salamone show which projects fall under what category and how they are calculated, they have not offered evidence as to why any project in the IIP should be excluded.

Q12. What amount for Targeted Reliability Improvements and Infrastructure Renewal projects should be approved in the IIP?

A12. The total of $169.5 million for Targeted Reliability Improvements and Infrastructure Renewal projects should be approved in the IIP, $111.2 million of which is accelerated spending projects under the RIP. As explained above and in ACE's Direct Testimony, these projects are incremental to the Company's regular distribution spending and should be recovered under the IIP, as the regulations permit.

Q13. Witnesses Chang and Salamone argue "Distribution Automation" projects should not be included in the IIP. Do you agree?

A13. No. In their testimony, they state that for any distribution automation project to be recoverable, they "must also be integral to the distribution automation system itself and not a…routine customer reliability expenditure," and by example they state it must operate "under the control of a distribution automation system."[2] By their prerequisites, every distribution automation project ACE is proposing under the IIP, totaling $93.1 million, would qualify for recovery because they all relate to the control of the distribution automation system in some form. This category of projects, by virtue of the work involved, is incremental to the Company's spending because it allows for the automation and communication of distribution infrastructure.

Witnesses Change and Salamone draw an arbitrary distinction as to what distribution automation projects are a "routine customer reliability expenditure" and which ones are advanced. Further, as with the "Retire/Replace" and "Upgrades" categories, they provide no analysis or detailed listing of Distribution Automation projects to be included or excluded in the IIP, offering only a $21 million total for recovery without any calculations. This lack of analysis undermines the very purpose of the IIP regulations.

Q14. What amount for Distribution Automation projects should be approved in the IIP?

A14. The total of $93.1 million for Distribution Automation projects should be approved in the IIP, $51.1 million of which is related to accelerated spending projects

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[2] BPU Docket No. EO18020196, Joint Testimony of Charles Salamone and Maximilian Chang on behalf of Division Rate Counsel, p. 28.

under the RIP. These projects are incremental to the Company's regular distribution spending and should be recovered under the IIP, as set forth under the IIP regulations.

Q15. Does this conclude your testimony?

A15. Yes, it does.

A PHI Company

Atlantic City Electric Company

Infrastructure Investment Program

Engineering Evaluation and Report

October 2018

Contents

1. EXECUTIVE SUMMARY

Atlantic City Electric Company (ACE or Company) is committed to providing safe and reliable service at a reasonable cost. This requires the Company and utility regulators to balance the cost of various system designs and equipment upgrade and replacement strategies with the increased reliability that these designs will provide to demonstrate reasonableness. It also requires balancing the effectiveness of these investments relative to the additional cost to our customers. In support of this objective, ACE's goal is to have a "robust" system with adequate systems and practices in place to assure continued reliable performance for a median range of operating conditions and the ability to respond to events that are in excess of the design of the system.

This report provides an overview of ACE's distribution system and selected efforts under way or planned as part of ACE's Infrastructure Investment Program (IIP) to increase reliability of the distribution system, all of which support ACE's goal to provide safe and reliable service to its customers.

2. INTRODUCTION

ACE delivers electricity to more than 555,000 customers throughout the Company's service territory. ACE's customer base is comprised of approximately 87% Residential and the remaining 13% is Commercial, Industrial and other services.

Reflective of its commitment to continuous improvement, ACE has been proactive in performing various assessments and studies internally and participates in assessments by independent external sources to assess its system performance and response to outages.

Combined, the system design and performance review constitute a model for evaluating ACE's distribution system robustness with the purpose of understanding its impact on the Company's ability to provide safe and reliable service. In particular, the Company evaluates those aspects and characteristics of the distribution system design, which have a direct impact upon an electric distribution system's reliability. This Infrastructure Investment Program for ACE (IIP) has therefore been developed to focus on those attributes of the Company's system.

2.1 SYSTEM OVERVIEW

ACE's service territory includes 2,767 square miles. Within this service territory, there are:

- 12 transmission substations
- 80 distribution substations
- 7,451 circuit miles of overhead distribution
- 1,104 circuit miles of overhead transmission
- 2,844 circuit miles of underground distribution
- 11 circuit miles of underground transmission

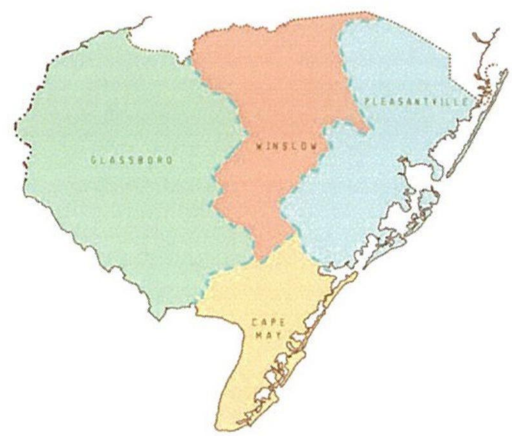

Figure 1: Atlantic City Electric Service Area

2.2 OVERHEAD AND UNDERGROUND NETWORK CONFIGURATION

A review of ACE's overhead and underground infrastructure shows that a majority of customers within the Company's service territory are currently served by overhead circuits. Within the Cape May, Glassboro, Pleasantville and Winslow Districts, there are [redacted] distribution circuits, of which [redacted] have greater than [redacted] underground construction and [redacted] have greater than [redacted] underground construction. Therefore, many customers supplied from an underground circuit may also have significant exposure to the overhead system. Many studies have been performed to evaluate the feasibility of converting overhead facilities to underground in order to improve reliability during storms. However, the cost of undergrounding large portions of the overhead system would place ACE outside of industry norms from a cost standpoint and would not meet the test of reasonableness to impose additional costs on customers for the return in increased reliability.

2.3 SYSTEM DESIGN

The Company's practices surrounding placement and maintenance of system design components such as substations, transformers and feeders are well within industry practices; there are, however, some areas of opportunity. ACE is taking advantage of current technologies that will improve service reliability. For instance, ACE continues to install state-of-the-art microprocessor-controlled line reclosers on its system, replacing mechanical switches and one-time fuses. Reclosers can often clear temporary faults avoiding outages altogether or limit permanent faults to smaller line segments. Reclosers can significantly improve reliability during lightning and wind storms where many momentary faults typically occur.

In addition, ACE is progressively expanding a new wireless network that will enable automation of the distribution system. Distribution Automation or DA, is typically comprised of a master logic controller, a communication system, and the actual distribution switching devices. Upon operation of a device due to a detected fault on a feeder, the master logic controller analyzes system conditions and determines which automated switches to open and which ones to close in order to safely and effectively isolate the faulted line segment and restore service to the maximum number of customers. Since the faulted line segment is now readily identified, line workers can quickly locate and effect repairs to damaged or failed equipment. The DA communications network will also enable future real-time communication with other line devices (line reclosers, line voltage regulators, capacitors, switches, etc.), thus providing status, alarming, and control capability enabling system optimization and decreased response time to problems on the distribution system.

2.4 SYSTEM OPERATIONS

For daily operations, ACE maintains sufficient staffing of utility employees and contractor resources to address routine maintenance and construction activities, and most storm events, on the electric distribution system. In the event of significant outages, resource requirements may exceed normal staffing levels. For such events, the Company follows accepted business practices and participates in several mutual assistance groups that pool resources during significant outage events and allocates them, by mutual agreement, for the most effective deployment. Periodically, member utilities meet to review restoration procedures, mutual assistance and operating best practices. The 2016 merger with Exelon has provided an even greater body of Exelon branded resources from Philadelphia Electric Company (PECO), Baltimore Gas & Electric (BGE), and Commonwealth Edison (ComEd) to assist ACE in major storm restoration. The employment of common dispatch tools and safety practices among the Exelon peer companies promotes significant synergies in storm restoration, enabling seamless deployment of assisting resources for faster and more efficient service restoration.

3. RELIABILITY

The reliability of an electrical system is directly related to implementing the appropriate design principles and construction practices, along with the proper deployment of distribution assets and equipment comparable to the demands placed upon the system by its users. ACE is sensitive to evolving trends in the industry and employs best practices in planning, design and operation of the system.

3.1 SYSTEM DESIGN – OVERHEAD VS. UNDERGROUND

There are solid arguments for both underground and overhead electric distribution systems. In general, overhead systems are less costly to install, are longer-lasting, and easier to maintain, since problems are easily located and repaired. Underground systems, while costlier to install and maintain, are also less susceptible to damage from storms, falling trees, and other exposures, which typically cause outages. Making the proper choices between overhead and underground facilities requires balancing cost against the amount of potential for environmental impacts on reliability.

ACE uses overhead conductors for the main trunk of its distribution feeders. This design philosophy enables faster location of faults affecting large numbers of customers and is far less expensive than fully undergrounded feeder designs, especially in long feeders such as those typically found in the ACE system. Some branch circuits and primary services for commercial customers may be underground for various reasons. For the past fifty years, virtually all residential developments have been designed using underground conductors. Typically, underground residential distribution (URD) systems use loop schemes so that service can be quickly restored in the event of a primary cable failure.

The graphic below depicts the distribution of overhead and underground primary conductors on ACE's system:

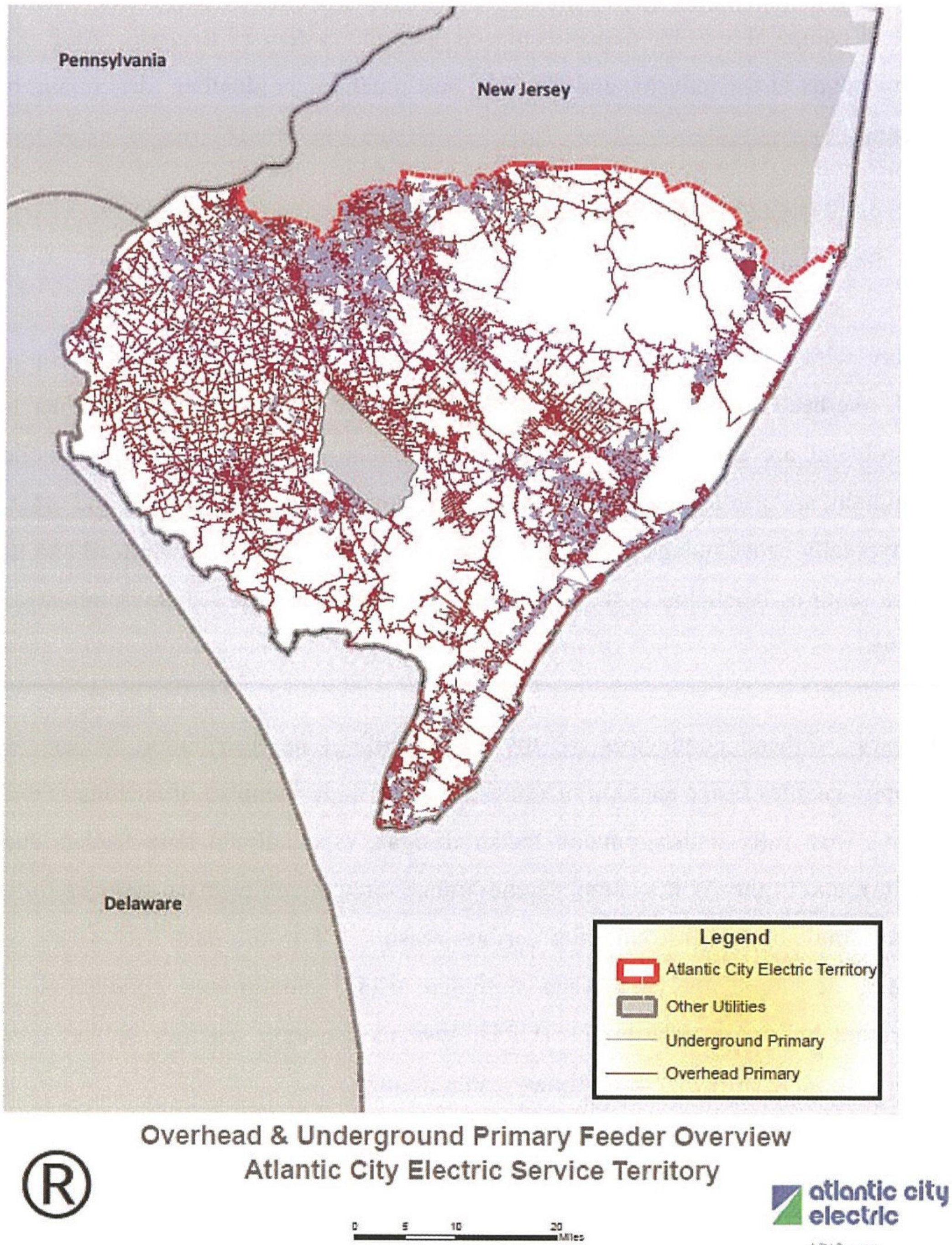

Figure 2 – ACE Service Territory Overhead and Underground

3.2 ACE RELIABILITY TRENDS

As evidenced by the charts below, since the inception of the Reliability Improvement Plan (RIP) in 2011, ACE has maintained an impressive and significant improvement trend in its reliability indices. The RIP is based on accelerated and incremental investments since 2011 in projects critical to reliability improvement. With the exception of vegetation management, which is expensed at ACE, the reliability improvement principles, processes, and capital projects embodied in the RIP serve as the basis for the ACE IIP. ACE looks to begin winding down the RIP after 2022 as it will have substantially completed its build out of Distribution Automation schemes. However, continued investments in proactive infrastructure renewal will be required in order to maintain the reliability gains achieved in the RIP over the ensuing decade.

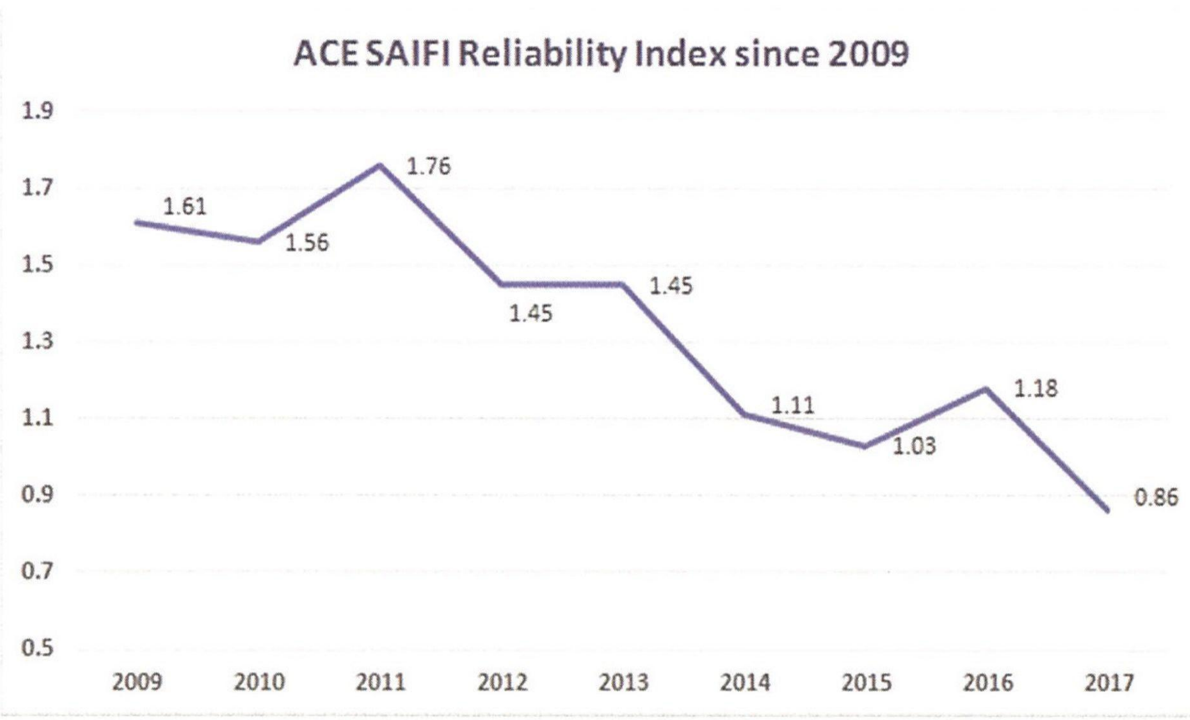

Figure 3 – ACE SAIFI Trend

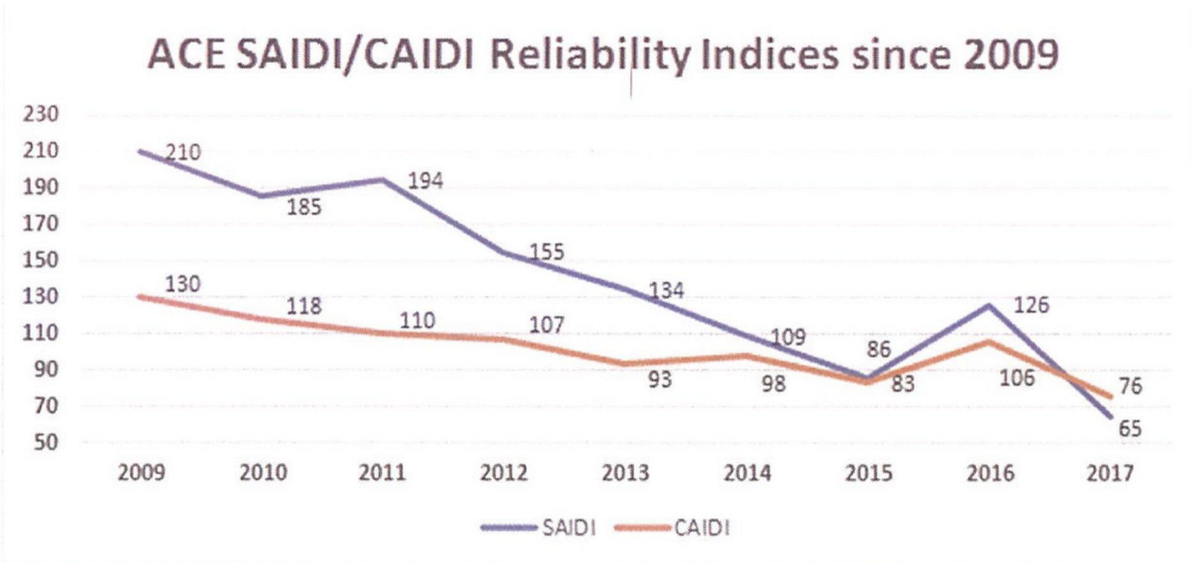

Figure 4 – ACE SAIDI and CAIDI trends

4. THE ACE INFRASTRUCTURE INVESTMENT PLAN

The Infrastructure Investment Program features a series of distribution capital projects that serve to improve ACE's reliability performance. Overall the four-year plan for distribution capital projects totals $338.2 million over five different categories of projects: Targeted Reliability Improvement, Distribution Automation, Infrastructure Renewal, Emergency, and Facilities. This project work includes replacement of infrastructure, distribution automation projects that aid in modernizing the grid, feeder reliability improvements, emergency restoration projects, and facility improvements, among other work.

These interrelated projects are needed to replace aging infrastructure, implement distribution automation and provide corrective maintenance, among other system improvements, and they will only be successful provided they have the appropriate supporting infrastructure, including properly maintained buildings, communication systems, and IT systems. Inherent in a more reliable distribution system is a safer distribution system for both customers and crews.

The five categories of the IIP are:

1. Targeted Reliability Improvements
2. Distribution Automation / Telecommunications
3. Infrastructure Renewal
4. Emergency
5. Facilities

The forecasted investments in each of these categories appears below in Table 1.

	2019	2020	2021	2022	2019-2022
Targeted Reliability Improvements	$18.60	$19.70	$14.70	$13.40	$66.30
Distribution Automation & Telecom	$32.90	$30.40	$17.00	$12.90	$93.10
Infrastructure Renewal	$26.90	$19.10	$23.80	$33.40	$103.20
Emergency	$16.90	$17.70	$5.60	$6.00	$46.20
Facilities	$13.30	$14.70	$0.00	$1.40	$29.30
Total	$108.60	$101.40	$61.10	$67.10	$338.20

Table 1 – ACE IIP Investment Forecast

All five of the project categories are designed to address reliability, resiliency and safety. Targeted Reliability Improvements and Distribution Automation/Telecommunications categories are intended to strengthen ACE's distribution system by further modernizing the grid and strategically targeting opportunities for reliability improvements. Infrastructure Renewal will accelerate the replacement of equipment that is nearing the end of its useful life and is more likely to fail due to age or condition-based issues. Facilities will provide infrastructure that aids in personnel maintaining the distribution system, and Emergency will restore customers efficiently during unforeseen system scenarios. Further discussion on each of these project categories follows.

4.1 TARGETED RELIABILITY IMPROVEMENTS

The category Targeted Reliability Improvements features projects that, once installed, will provide significant reliability improvements to ACE's distribution system. Priority feeder and comprehensive feeder improvements will be significant drivers of this category, and there will be other investments as well, such as single phase recloser improvements, installation of capacitors for enhanced voltage control [redacted], and other planned substation improvements as a result of past operational events.

The benefits of projects in this category are both quantitative and qualitative. The reduction in fault sources from known past causes results in fewer future outages and improvements in reliability metrics. The increases in overhead equipment reliability will also provide resilience benefits during major storms. These projects also serve to reduce O&M expense and result in greater customer satisfaction. Finally, the increased operational flexibility afforded by several substation-based projects in this category will lead to fewer and/or shorter outages as well as increased ability to maintain equipment.

4.1.1 Priority Feeder Program

The objective of the Priority Feeder Program [redacted] is to identify the least reliable distribution feeders in each operating district, analyze and prioritize those feeders, and initiate corrective actions to improve individual and overall distribution feeder reliability. ACE conducts annual system performance reviews of its [redacted] distribution feeders and ranks these feeders from the most reliable to the least reliable, based on high frequency and extended duration outages using data from a rolling 12-month period from October 1 to September 30. Across ACE's four operating districts, [redacted] feeders are selected based on their overall reliability performance and targeted for improvements under the BPU supported program.

Based on the field inspection results and historical outage data, the information for each selected feeder is reviewed, evaluated and analyzed to recommend appropriate corrective actions. Proposed corrective actions may include but are not limited to the following activities:

- Perform infrared thermal scanning of lines and equipment to remediate poor connections, overloads, and defective equipment.
- Install animal guards.
- Replace blown lightning arresters and defective grounds.
- Replace deteriorated structures: poles, cross-arms, braces, down guys, etc.
- Re-tension conductors with excessive slack, re-pull guys, install conductor spacers, etc.
- Replace defective insulators.

- Replace or repair transformers and other distribution equipment based on observed condition.
- Install new lateral tap fuses.
- Install sectionalizing and reclosing devices.
- Trim trees to provide sufficient clearances to lines and equipment.
- Verify protective device coordination to ensure effective fault isolation with minimum customer impact.
- Reconfigure overhead lines to avoid or minimize physical hazards such as large trees, motor vehicle hazards, etc.

In an effort to reduce overall SAIFI, ACE is emphasizing the importance of reducing feeder lockouts with added emphasis on the priority feeders. Since 2011, the first feeder line segment(s), defined as the feeder segment originating at the substation feeder breaker or riser terminal pole and extending to the first major protective device (usually a recloser), have received extra scrutiny with the objective to remediate moderate to high level outage risk factors. Additional remedial work is justified for the critical line segments of a feeder. For example, ensuring all lighting arresters are either fused or equipped with ground fault isolators may make sense for the first line segment, but perhaps may not be the best use of funds for the last segment.

4.1.2 Comprehensive Feeder Improvements [redacted]

ACE's feeder improvement strategy is focused on addressing equipment, vegetation, weather and animal related interruptions which negatively impact reliability performance. This effort concentrates on feeders not included in the Priority Feeder Program.

The primary goal of feeder improvement is to minimize conditions on the distribution system, which could lead to interruptions of service. Equipment upgrades, line section rebuilds, conversion of spans to tree wire and installation of animal guards are several of the tactics employed by ACE to eliminate potential fault causing conditions.

The secondary goal of feeder improvement is to minimize the impact of interruptions. Minimizing the impacts of faults is accomplished by adding or improving sectionalization on distribution lines. This mitigation tactic can include significant measures such as deployment of automatic reclosing equipment when applicable.

Unlike the Priority Feeder Program, which looks at feeder performance on an operating district level, the comprehensive feeder reliability improvements initiative identifies feeders which exhibit poor performance based on the feeder's individual reliability indices as well as the feeder's contribution to overall system reliability. Those feeders that exhibit the best opportunity for improvement of the overall system reliability are targeted for improvements. Additionally, sections of feeders that exhibit multiple interruptions for ostensibly avoidable causes are addressed.

While ACE has been very aggressive in utilizing main-trunk line reclosers to improve feeder reliability performance, its use of single-phase reclosers has been limited. Presently, most single-phase branch circuits and laterals are protected by fuses. Beginning in 2009, ACE began experimenting with an economical single-phase reclosing device that is designed to install in a standard type "C" cutout frame. This is a very practical and cost-effective way to implement single-phase reclosing and since the device mimics standard fuse cures used by ACE, there are virtually no coordination issues. Since 2009, under the comprehensive feeder improvement model, hundreds of single phase electronic reclosing fuses (TripSaverII) have been installed on formerly fused taps, reducing unnecessary fuse blows due to transient or temporary fault conditions. ACE continues to deploy TripSavers where appropriate to help reduce permanent outages in both storm and non-storm conditions.

Although ACE continues to register relatively low CEMI (customers experiencing multiple interruptions) statistics in its service area, ACE continues an initiative to reduce its CEMI indices further as a driver of customer satisfaction. The initiative includes improved detection and internal reporting on the operation of protective devices experiencing repeated interruptions as well as timelier investigation and remediation of conditions contributing to repetitive outages. ACE will continue to closely monitor distribution feeder performance in an effort to improve customer satisfaction and overall system reliability. As a result of increased funding for feeder reliability work under the RIP, ACE has achieved significant reductions in CEMI at all levels.

4.1.3 Substation Transformer Projects

[redacted] projects in the Targeted Reliability category are focused on substations where past operational events have driven the need for modifications or upgrades at the subject stations. In the case of [redacted] and [redacted] substations, [redacted] In the cases of [redacted] and [redacted] substations, the [redacted]

4.2 DISTRIBUTION AUTOMATION & TELECOMMUNICATIONS

Distribution automation involves installing advanced intelligent electronic devices in the substation and in the field. Facilitated via an established telecom network, these devices work in concert with an automation control program to carry out the automatic sectionalizing and restoration (ASR) DA function. This "self-healing" concept is the heart of DA. Feeders are designed with good segmentation using reclosers and smart switches and utilize one or more feeder tie switches to provide alternate power sources. Should a permanent fault occur, the appropriate protective device locks out as expected. In a conventional radially designed feeder, all customers beyond a locked out protective device experience a sustained outage. However, with ASR, the faulted segment is isolated by opening additional switches, and the non-faulted portion of the feeder is quickly restored by closing one or more available feeder tie switches. This automatic isolation and restoration process normally takes less than two minutes.

DA does not prevent faults or reduce their likelihood of occurring. However, a well performing DA system can minimize the number of customers experiencing sustained outages and reduce restoration times by positively identifying and isolating the faulted line segment. Knowing the location of the fault reduces patrol times and speeds up the restoration process for the customers impacted by the faulted section.

By the end of 2017, through legacy programs as well as the RIP, ACE had [redacted] three-phase line reclosers installed on its distribution system. Many remain in series configurations on radial feeders, but the DA system build out will connect a large amount of reclosers in ASR schemes in the future. Current plans call for an estimated [redacted] of ACE's distribution feeders to be part of ASR schemes by 2023. ACE plans to install approximately [redacted] new reclosers during 2018 as well as an additional estimate of [redacted] over the 2019-2022 IIP period. This plan will essentially complete the recloser installation initiative by 2023, leaving the integration of reclosers into ASR schemes as the final element of the DA build out.

Projects included in the DA portion of the DA / Telecom category include:

1. [redacted] – This is the project for upgrade of older non-DA capable reclosers to more modern DA capable devices.
2. [redacted] - Control Install Replace ACE - This project installs new DA capable reclosers on the ACE system to build out the DA system capabilities, a precursor to integration of those reclosers into DA schemes.
3. [redacted] – This project adds remote control capability to ACE feeder breakers, enabling remote operation of the breakers' reclosing functionality.
4. [redacted] – This project upgrades older mechanical relays in substations to modern microprocessor relays. This capability is foundational in the establishment of ASR schemes in ACE's DA design.

There are many other potential benefits of DA. For example, one of the challenges distribution engineers face is maintaining acceptable time-current coordination as feeder segmentation is increased for reliability. For a conventional radial design feeder, poor device coordination results in the sustained interruption of more customers than is necessary and makes it more difficult to locate faulted equipment, thereby increasing restoration times. However, since the DA master controller receives input from all devices, it can quickly determine which devices or sensors have "seen" fault current and which ones have not. Therefore, should an over-trip occur, the DA master controller can open the correct devices and close back in the mis-tripped device(s), thereby isolating only the faulted line segment. By closing one or more feeder ties, all customers are quickly restored except those served by the faulted line segment. In addition, the DA devices are able to be controlled remotely by the control center operators. This capability can improve the time efficiency of scheduled maintenance work as well as the service restoration work discussed.

Also a part of DA, ACE is upgrading the controls at [redacted] capacitor banks, which includes replacing [redacted] fixed capacitor banks with switched capacitor banks. These capacitor banks will be upgraded with two-way communications and control from a state-of-the-art Volt-VAR Control Program, which will maintain an acceptable voltage profile along the distribution feeders throughout the day and also reduce power losses by correcting the feeder power factor.

Incumbent in any DA buildout is the necessity to provide infrastructure for the smart devices to communicate and coordinate with control systems. The Telecom projects in this category serve to collectively construct the necessary communications system to enable effective distribution automation technologies. Part of the challenge in ACE, absent AMI communications infrastructure, is to establish reliable communications for the DA system on an ad hoc basis as opposed to connecting to an established AMI mesh network, which is the case in many modern DA implementations.

Projects to upgrade or install telecommunications infrastructure to enable DA functionality include:

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]

5. [redacted]
6. [redacted]
7. [redacted]
8. [redacted]
9. [redacted]
10. [redacted]
11. [redacted]
12. [redacted]
13. [redacted]
14. [redacted]
15. [redacted]
16. [redacted]
17. [redacted]
18. [redacted]
19. [redacted]

The benefits of distribution automation are well established, and many utilities have or are currently executing sophisticated DA implementations. As indicated previously, DA generally does not prevent outages, but does have the ability to minimize the impacts of outages by automatically limiting the number of customers involved as well as reducing outage time by automated isolation of faulted sections of the distribution system, enabling faster location and repair of faults.

4.3 INFRASTRUCTURE RENEWAL

The Infrastructure Renewal category of the IIP includes an array of projects to upgrade, replace, or repair system infrastructure. The projects in this category are primarily focused on the replacement of infrastructure at or near substations, which can have a significant effect on reliability for many customers. The category also includes projects to convert feeders to higher operating voltages, enabling the implementation of distribution automation schemes as well as creating greater hosting capacity for distributed energy resources (DERs). Naturally, as infrastructure ages, it becomes more prone to failures and less resilient and reliable. Therefore, the replacement of common infrastructure such as poles, substation switchgear, substation transformers, and other mission critical equipment is required and prudent to maintain system level reliability improvements to date, avoid future high impact failures, and provide increased resiliency in significant weather events.

As part of its infrastructure renewal strategy, ACE plans the proactive replacement of equipment that exhibits signs of reduced reliability and/or impending failure. Distribution infrastructure is periodically inspected and evaluated on its ability to perform as required in normal and stressed conditions. In addition, as part of the Equipment Condition Assessment (ECA) protocol, critical substation components are periodically assessed and tracked for indications of impending failures. Equipment which exhibits poor physical condition, permanently impaired operations, or more frequent and costly required maintenance is scheduled for replacement. The coastal environments age equipment and enclosures more quickly than other regions typically experience. By replacing equipment proactively that is trending towards failure, ACE avoids potential future outages impacting large numbers of customers and improves long term reliability, especially along the coast line such as in the Wildwood and Atlantic City areas.

The benefits of these projects are critical to large customer populations as failures of some elements of the distribution system, such as substations, often result in large and lengthy customer outages. The criticality of substation equipment in the overall reliability of the system cannot be overstated, and despite effective condition based maintenance protocols, it is generally more prudent to proactively replace critical equipment in poor condition as opposed to running it to failure and incurring an emergency replacement, which can result in significantly larger costs to remediate than planned replacements.

4.3.1 Substation Upgrades

This grouping of [redacted] projects within the Infrastructure Renewal category is focused on the replacement of critical substation equipment such as transformers, breakers, switchgear, or other substation based components due to age and physical condition. Examples include:

1. [redacted].
2. [redacted].
3. [redacted].
4. [redacted].
5. [redacted].
6. [redacted].
7. [redacted].
8. [redacted].
9. [redacted].
10. [redacted].
11. [redacted].
12. [redacted].

13. [redacted].

14. [redacted].

15. [redacted].

16. [redacted].

17. [redacted].

18. [redacted].

19. [redacted].

4.3.2 Distribution Upgrades

This subset of projects within the Infrastructure Renewals category consists of [redacted] projects to upgrade distribution lines associated with line reconfigurations, substation retirements, poor physical condition, and switchgear upgrades.

1. [redacted]

2. [redacted]

3. [redacted]

4. [redacted]

5. [redacted].
6. [redacted].
7. [redacted].
8. [redacted].
9. [redacted].
10. [redacted].
11. [redacted].
12. [redacted].
13. [redacted].
14. [redacted].
15. [redacted].

4.3.3 Retirements

Numerous ACE substations are being retired due to age, condition, and obsolescence. These projects are required to remove equipment, secure facilities, or restore locations to greenfield condition. These projects disconnect and station components from the distribution system and remove them from the facility in order to responsibly alleviate potential public safety, theft, and environmental issues associated with retired facilities. The projects in this subset include:

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]
5. [redacted]
6. [redacted]
7. [redacted]
8. [redacted]
9. [redacted]
10. [redacted]

4.3.4 Relocations

ACE performs numerous relocations of existing facilities on public or private rights of way when requested by NJ DOT or other governing authorities. When relocations are required, ACE rebuilds the relocated infrastructure to the latest standards as governed by the National Electrical Safety Code or ACE distribution standards. The costs to relocate these facilities is variable year over year. The [redacted] project is the placeholder for these funds.

4.4 EMERGENCY

The Emergency category of projects includes two projects which provide funding as needed for the emergent restoration of overhead and critical underwater facilities.

1. [redacted].
2. [redacted].

These projects are reactive in nature, and the funds are utilized for the capital replacement of facilities as a result of system damage or failures resulting in outages. The future benefits of projects in this category result from the effective replacement of affected facilities as a result of the emergency restoration, thus alleviating future outages for the same cause.

4.5 FACILITIES

The Facilities category includes projects that provide vital physical and logistical support facilities utilized by ACE personnel to design, build, operate, and maintain the distribution system. [redacted]

Modern facilities also contribute to employee safety and productivity. [redacted]

[redacted]

[redacted]

.

5. BENEFITS / COST ANALYSIS

The estimation of quantitative benefits associated with the ACE IIP was achieved using the Interruption Cost Estimate (ICE) tool provided by the U.S. Department of Energy (DOE) at https://icecalculator.com/. History of the development and the theory behind the ICE tool can also be found on the same website. The ICE tool provides a reasonable estimate of the monetized benefits of reductions in outage frequency and duration for direct comparison to costs necessary to achieve the benefits. The ICE tool has been used to quantify project and portfolio benefits by ACE's sister company, Pepco in Maryland regulatory proceedings as well as by other NJ EDCs in NJ BPU regulatory filings.

Each category of projects within the IIP was evaluated for estimated reductions in future outage frequency and duration resulting from the body of projects within the category and modeled as a category within the ICE tool. These estimated reductions in SAIFI and SAIDI as a result of the projects undertaken were derived from ACE's engineering experience and in marked reliability. The resultant monetized benefits of each category were compared to the category costs to determine category level and IIP level benefits to cost ratio. The results of the benefits to cost analysis are shown in Table 2 below. Results reflected are nominal.

Category	Benefits	Cost	B/C Ratio
Targeted Reliability Improvement	$ 126.8	$ 66.3	1.9
Distribution Automation / Telecom	$ 198.1	$ 93.1	2.1
Infrastructure Renewal	$ 262.6	$ 103.2	2.5
Emergency	$ 19.0	$ 46.2	0.4
Facilities	$ 7.4	$ 29.3	0.3
Total IIP	$ 614.0	$ 338.2	1.8

Table 2 – ACE IIP Cost Benefit Ratio Summary - Nominal ($Millions)

As can be seen from the analysis, the Targeted Reliability Improvement, Distribution Automation/Telecom, and Infrastructure Renewal categories all yield favorable B/C ratios (greater than 1.0). This is expected given that these project categories specifically focus on outage frequency and duration reduction and are based on ACE's past reliability improvement success in the RIP. The Emergency and Facilities projects, under the ICE methodology, do not generate enough benefits in the form of outage frequency and duration reduction. This is also as expected as the nature of these project benefits is more qualitative than quantitative. However, on the whole, the IIP, as a body of projects still provides a favorable benefit to cost ratio and as such, presents a viable and wholistic approach to the improvement of reliability and resiliency at ACE.

6. CONCLUSION

The IIP represents ACE's continuing commitment to provide safe and reliable electric service to its customers at a reasonable cost. Therefore, each initiative undertaken in the IIP must consider the cost to obtain and the anticipated benefits to be realized. ACE believes the IIP is both qualitatively and quantitatively cost beneficial and as such, represents prudent investments on behalf of its customers, and extends the Company's continuous commitment to improving reliability and resiliency to its customers. As evidenced by past performance, ACE has delivered on previous commitments to reliability improvement and through the IIP, intends on continuing to exceed expectations for a safe, reliable and resilient electric distribution system.

ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES REBUTTAL TESTIMONY OF JOSEPH F. JANOCHA BPU DOCKET NO. EO18020196

Q1. Please state your name and position.

A1. My name is Joseph F. Janocha. I am the Manager of Retail Pricing for Pepco Holdings LLC. I am testifying on behalf of Atlantic City Electric Company (ACE or the Company).

Q2. What is the purpose of your Rebuttal Testimony?

A2. The purpose of my Rebuttal Testimony is to respond to the revenue requirement development issues raised by New Jersey Division of Rate Counsel (DRC) Witness Peterson.

Q3. Please describe the revenue requirement issue raised by DRC Witness Peterson to which you will respond.

A3. For the most part, DRC Witness Peterson concurs with the Company's approach to the development of the Infrastructure Investment Program (IIP) revenue requirement, the allocation of the revenue requirement to the different rate classes, and the Company's proposed rate design. He raises an issue with regard to the treatment of the retirement of existing assets that would result from the implementation of IIP projects. Specifically, he recommends that a credit be included in the development of the IIP revenue requirement to account for reduction in net plant in service associated with the retirement of existing plant.

Q4. Please respond to the approach proposed by DRC Witness Peterson.

A4. Since the retirement of existing plant would be driven by an investment included in the IIP program, the approach recommended by DRC Witness Peterson is conceptually correct. However, from a practical standpoint, unless the asset being retired is well short of its useful life, the difference in net plant should be small, as the adjustment to plant in service and depreciation reserve should be comparable.

Q5. Do the existing capital tracker mechanisms approved for New Jersey utilities include such an adjustment?

A5. A review of the approved tracker mechanisms listed below finds that none of them include such an adjustment.

Mechanism	Utility
Distribution System Improvement Charge (DSIC)	Water Utilities
Energy Strong	PSE&G
NJ Reinvestment in System Enhancement (RISE) Program	New Jersey Natural Gas
Safety Acceleration and Facility Enhancement Extension (SAFE) II	New Jersey Natural Gas
Storm Hardening and Reliability Program (SHARP)	South Jersey Gas

Q6. Does this conclude your Rebuttal Testimony?

A6. Yes, it does.

ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES DIRECT TESTIMONY OF ROBERT B. HEVERT DOCKET NO. OE18020196

I. INTRODUCTION

Q1. Please state your name, affiliation, and business address.

A1. My name is Robert B. Hevert. I am a Partner at ScottMadden, Inc. (ScottMadden). My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q2. On whose behalf are you submitting this testimony?

A2. I am submitting this direct testimony (Direct Testimony) before the New Jersey Board of Public Utilities (BPU or the Board) on behalf of Atlantic City Electric Company (ACE or the Company), a wholly owned operating subsidiary of Exelon Corp. (Exelon).

Q3. Please describe your educational background.

A3. I hold a Bachelor's degree in Business and Economics from the University of Delaware, as well as an MBA with a concentration in Finance from the University of Massachusetts. I also hold the Chartered Financial Analyst designation.

Q4. Please describe your experience in the energy and utility industries.

A4. I have worked in regulated industries for over 30 years, having served as an executive and manager with consulting firms, a financial officer of a publicly traded natural gas utility, and an analyst at a telecommunications utility. In my role as a consultant, I have advised numerous energy and utility clients on a wide range of financial and economic issues, including corporate and asset-based transactions, asset and enterprise valuation, transaction due diligence, and strategic matters. As an expert witness, I have provided testimony in more than 250 proceedings regarding various financial and regulatory matters before numerous state utility regulatory agencies, the Federal Energy Regulatory Commission, United States District Court, and the Alberta Utilities Commission. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included in Attachment R-(RBH)-A to my Direct Testimony.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q5. What is the purpose of your Direct Testimony?

A5. The purpose of my Direct Testimony is to respond to the direct testimony of Dr. Marlon F. Griffing, regarding the Cost of Equity (sometimes referred to as the Return on Equity or ROE), to be applied to the Company's Infrastructure Investment Program (IIP) assets. My analyses and conclusions are supported by the data presented in Schedule R-(RBH)-1 through Schedule R-(RBH)-3, which have been prepared by me or under my direction.

Q6. Please briefly summarize Dr. Griffing's recommended ROE, and the basis for his recommendation.

A6. Dr. Griffing recommends an ROE of 8.50%, 110 basis points below the Company's currently authorized ROE of 9.60%. Dr. Griffing argues his proposed reduction is reasonable for three reasons: (1) the timing of cost recovery for IIP investments is shortened relative to those made under "traditional rate regulation", thereby reducing risk to investors; (2) IIP investments face a "diminished" likelihood of disallowance relative to other (presumably non-IIP) investments[1]; and (3) the Cost of Equity for ACE, itself, is 9.00%.[2] In Dr. Griffing's view, those factors require the 9.00% Cost of Equity he believes is appropriate for ACE to be reduced by 50 basis points, to 8.50% for IIP investments.[3]

Q7. Please now summarize your response to Dr. Griffing on those points.

A7. Dr. Griffing's view that equity investors require a distinct and lower return on the Company's IIP investments is misplaced. Putting aside the fact that ACE does not finance its utility assets on a project basis,[4] Dr. Griffing has provided no evidence that equity investors see IIP treatment as so risk-mitigating that they would reduce their required returns by any amount; he certainly has not shown they would do so by 50 basis points.

In large measure, Dr. Griffing's misapplication is due to his view that the proper frame of reference is the Company's IIP investments relative to its "traditional" investments. It is not. Rather, because the Cost of Equity is based on the economic principle of "opportunity costs", the appropriate point of comparison is other utilities, and the appropriate analytical question is whether they, too, have infrastructure recovery mechanisms in place. That type of comparative analysis fully supports the position that the Company is no less risky than its peers because of the IIP, and its return should not be reduced in connection with it.

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1 *See*, Direct Testimony of Marlon F. Griffin, Ph.D., at 10 – 11.

2 Direct Testimony of Marlon F. Griffin, Ph.D., at 49-50.

3 Direct Testimony of Marlon F. Griffin, Ph.D., at 50.

4 That is, ACE does not raise equity capital for specific investments. Rather, the Company's assets are financed "on balance sheet", with the overall mix of permanent capital funding all investments in long-lived assets.

Second, even if credit ratings were direct measures of equity risk,[5] there is no reason to conclude the IIP enhances the Company's credit profile and reduces its cost of capital. Rather, Moody's and Standard & Poor's see the IIP as credit-supportive, maintaining the Company's financial profile as it would have been but for the IIP investments.

Third, Dr. Griffing's analysis does not consider that ACE has consistently and significantly under-earned its authorized ROE. As the Company's Verified Petition explains, as recently as 2016 its earned ROE was 2.09%, below even the yield on U.S. Treasury bonds.[6] Company Witness McGowan explains that much of the reason ACE has so significantly under-earned its authorized return is the Company's increased focus on reliability investments.[7]

Further, the Board's IIP regulations were purposefully designed to "encourage and support" sustained infrastructure investment, recognizing the critical relationship among reliability investments and sustained economic growth in New Jersey.[8] Dr. Griffing's recommendation, however, would cost the Company a significant portion of the return the Board has recognized should "encourage and support" reliability investments, and would frustrate the very objectives the Board seeks to achieve.

Dr. Griffing's recommendation also conflicts with the Board's decision in the Company's PowerAhead program. As Mr. McGowan notes in his Direct Testimony, the Board approved an overall Rate of Return for ACE's PowerAhead investments

5 As discussed later in my Direct Testimony, equity investors face risks beyond those faced by debt investors, and are exposed to those risks for periods longer than are debt investors.

6 Verified Petition, at 5, Table 3; the average yield on 30-Year Treasury Bonds was 2.60% in 2016. Source: Bloomberg Professional.

7 Verified Petition, at 3-4, Tables 1 and 2.

8 Verified Petition, at 6.

equal to its most recently authorized return.[9] That decision supports the point made earlier, that the return authorized for IIP investments should not frustrate the policy and economic objectives the Board and legislature hope to achieve.

Regarding Dr. Griffing's view that the Company's Cost of Equity is 9.00% (before any consideration of the IIP structure), there are several areas in which I disagree with his approaches and conclusions; I discuss those analytical differences in Section IV. Beyond differences in approach, I strongly disagree with Dr. Griffing's overall conclusion that the investor-required Return on Equity for an electric utility such as ACE is no more than 9.00%.

Q8. Did Dr. Griffing accept the Company's proposed capital structure and cost of debt?

A8. Yes, he did.[10] Consequently, my Direct Testimony will not address those issues.

Q9. How is the balance of your Direct Testimony organized?

A9. The remainder of my Direct Testimony is organized as follows:

- Section III – responds to Dr. Griffing's evaluation of the difference in risk of IIP-related investments and other utility capital expenditures;
- Section IV – responds to Dr. Griffing's Cost of Equity analyses;
- Section V – summarizes my conclusions and updated results.

[9] Verified Petition, at 19.
[10] Direct Testimony of Marlon F. Griffing, Ph.D., at 53-54.

III. IIP INVESTMENT RISK DIFFERENTIALS

Q10. Please briefly summarize your disagreements with Dr. Griffing's position regarding the IIP, and how it affects the Company's risk and Cost of Equity.

A10. There are several points on which I disagree with Dr. Griffing. First, Dr. Griffing reviews the IIP in isolation, not considering whether the Company's peers have similar rate structures in place. That type of partial analysis conflicts with the economic principle of "opportunity costs" and the *Hope* and *Bluefield* "comparable risk" standard[11], which require that a utility and its investors should be allowed the opportunity (not a guarantee) to earn a return comparable to those they could expect to achieve on investments of similar risk. Under those principles, if we are going to consider the IIP's effect on the Cost of Equity, we must consider whether its peers have similarly supportive rate mechanisms in place. As shown on Schedule R-(RBH)-1, that is the case for the companies in Dr. Griffing's peer group. On that basis alone, we cannot say the IIP reduces ACE's risk relative to its peers.

Q11. Has the Board addressed the relationship between infrastructure recovery mechanisms and the Cost of Equity?

A11. Yes, it has. Although Dr. Griffing is correct that the Board approved a stipulation regarding PSE&G's "Energy Strong" program, his testimony dismisses the applicability of stipulations in setting ROE. In his "Authorized ROEs Comparison" discussion, Dr. Griffing states that he "...rejected outcomes of settled cases because settlements can reflect tradeoffs parties make to reach agreement." Dr. Griffing went on to argue that "...an authorized ROE in a settled case may reflect compromise

[11] *See*, Direct Testimony of Marlon F. Griffing, PhD, at 16.

rather than strictly analysis."[12]

I agree with Dr. Griffing that settlements may not strictly reflect the results of ROE models and analyses. In my experience, that is because settlements are viewed in their entirety, not on the basis of an individual element. Consequently, the stipulated return in one case may not reasonably apply to another. Therefore, I do not believe a stipulated ROE for another company, in another proceeding, should be considered effectively precedent-setting in this case.

Regarding ACE specifically, in May 2017 the Board authorized cost recovery for a five-year capital investment/grid resiliency investment program (the PowerAhead Program) using semi-annual revenue requirement calculations and the Company's most recently authorized rate of return: "[t]he rate of return shall be calculated based on the overall rate of return approved in ACE's most recent base rate case."[13]

Because Dr. Griffing has not provided any evidence that the IIP reduces ACE's risk relative to its peers, and knowing that (1) infrastructure cost recovery mechanisms are common among the proxy companies, and (2) the Board did not adopt a downward adjustment for the Company's PowerAhead investments, I do not believe the Company's ROE should be reduced in connection with the IIP.

Q12. Are there other fundamental reasons why Dr. Griffing's recommendation to reduce the ROE for IIP investments is incorrect?

A12. Yes. The position that a reduction in volatility (whether of revenues, income, or cash flow) or the timing of cash flows necessarily requires a reduction in the Cost

[12] Direct Testimony of Marlon F. Griffing, Ph.D., at 46.
[13] Docket No. ER16030252, Order Approving Stipulation (May 31, 2017), at 6.

of Equity runs counter to Modern Portfolio Theory, which is the fundamental basis of the CAPM. Under Modern Portfolio Theory, risk is defined as the uncertainty, or variability, of returns. Modern Portfolio Theory was advanced by recognizing that total risk may be separated into two distinct components: non-diversifiable risk, which is that portion of risk that can be attributed to the market as a whole; and non-systematic (or diversifiable) risk, which is attributable to the idiosyncratic nature of the subject company, itself.

Any reduction in the Cost of Equity therefore depends critically on the type of risk that is reduced; if the risk assumed to be mitigated by the Company's rate structures is diversifiable, there would be no reduction in the Cost of Equity even if total risk (diversifiable plus non-diversifiable risk) has been reduced. If the rate structures mitigate increased systematic risk associated with the factors that drove the Company to implement them in the first place, there likewise would be no effect on the Cost of Equity.

As Dr. Griffing points out, non-diversifiable risk is measured by the Beta coefficient within the CAPM structure.[14] By recommending a specific downward adjustement, Dr. Griffing has assumed the IIP reduces the Company's non-diversifiable risk, in some cases by a considerable amount. As Table 1 (below) demonstrates, for the CAPM and ECAPM results to fall by 50 basis points, the implied Beta coefficient falls by as much as 13.00% (from Dr. Griffing's assumed Beta coefficient of 0.67 to 0.58). Dr. Griffing has not explained, however, why the Company's diversifiable risk would fall by such a considerable amount.

[14] *See*, Direct Testimony of Marlon G. Griffing, Ph.D., at 37.

Table 1: Implied Reduction in Beta Coefficients[15]

	CAPM			ECAPM		
As Filed						
Risk Free Rate	3.08%	3.08%	3.08%	3.08%	3.08%	3.08%
Market Risk Premium	12.37%	7.68%	7.10%	12.37%	7.68%	7.10%
Beta Coefficient	0.67	0.67	0.67	0.67	0.67	0.67
Cost of Equity	11.37%	8.23%	7.84%	12.39%	8.86%	8.42%
Revised						
Risk Free Rate	3.08%	3.08%	3.08%	3.08%	3.08%	3.08%
Market Risk Premium	12.37%	7.68%	7.10%	12.37%	7.68%	7.10%
Implied Beta Coefficient	0.63	0.60	0.60	0.62	0.58	0.58
Revised Cost of Equity	10.87%	7.73%	7.34%	11.89%	8.36%	7.92%
Cost of Equity Difference	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Beta Coefficient Difference	0.04	0.07	0.07	0.05	0.09	0.09

Q13. At page 11 of his Direct Testimony, Dr. Griffing refers to reports from Moody's and Standard & Poor's (S&P) to support his view that the IIP significantly reduces the Company's risk. Do you agree with Dr. Griffing's conclusion?

A13. No, I do not. First, Moody's did not raise the Company's credit rating. Rather, its Issuer Rating remains Baa2 (with a "positive" outlook), toward the lower end of Dr. Griffing's proxy companies' ratings (see Schedule R-(RBH)-2). Further, although Dr. Griffing points to Moody's discussion of the IIP's positive credit implications, Moody's also explained that the IIP is one part of the improving regulatory environment in New Jersey, and it is the improving regulatory and economic environments that support the Company's "positive" ratings outlook.[16] The factors that would lead to a ratings upgrade include:

- Continuing improvements in the regulatory environment;
- The IIP is implemented in an investor friendly manner; and

[15] Source: Exhibit MFG-19, Schedule 9.
[16] *See*, Exhibit MFG-3.

- Improving financial metrics, including a CFO pre-working capital to debt ratio in the high-teens, on a sustained basis.[17]

In summary, Moody's did not increase ACE's credit rating, and the Company's "positive" outlook principally is related to the overall improving regulatory and economic environment in New Jersey. Any potential future upgrade is contingent on further improvements in both. Consequently, I disagree with Dr. Griffing's view that the Moody's report supports a reduction in the ROE associated with the Company's IIP investments.

Q14. If those conditions, and the Company's credit metrics, were to improve such that Moody's were to upgrade ACE, would its issuer credit rating be higher than those of its peers?

A14. No, it would not. As noted earlier, Moody's currently assigns ACE an issuer credit rating of Baa2, which falls toward the lower end of Dr. Griffing's peer group. If ACE were to be upgraded by one "notch" to Baa1, it still would only be at about the peer group average. Consequently, even if we assume the IIP was solely responsible for a future upgrade (which, as Moody's explains, is not likely to be the case), the Company would be only as risky as its peers.[18] It would not be materially less risky, as Dr. Griffing's position assumes and requires.

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[17] Exhibit MFG-3, Page 2 of 3.

[18] Assuming credit ratings are full measures of equity risk. As discussed later in my Direct Testimony, that is not the case.

Q15. At pages 11 and 12 of his testimony, Dr. Griffing points to the fact that S&P affirmed its ratings for Exelon Corporation and its subsidiaries and revised its outlook to "positive". Do you believe that change in outlook supports Dr. Griffing's 8.50% ROE for the Company's IIP investments?

A15. No, I do not. As Dr. Griffing's Exhibit MFG-14 notes, ACE's current issuer credit rating from S&P is BBB+. Of the 19 companies in that Exhibit, 13 are rated BBB+ or A-. Therefore, even if the Company's issuer credit rating were to be increased to A-, it would not be distinguishable from the majority of its peers.

Further, S&P makes clear that its positive outlook relates to Exelon Corporation reducing its overall business risk by increasing the proportion of utility operations (to about 75.00% consolidated operations, as measured by EBITDA[19]), and less volatile Zero Emission Credits. S&P also explains it could increase Exelon's (and its subsidiaries') rating by one notch if utility operations and Zero Emission Credits consistently represent 75.00% of consolidated operations, regulatory risk is effectively managed, and financial metrics support the rating.[20] Any future ratings increase from S&P therefore depends on Exelon moving away from businesses considered more risky than utility operations, and on Exelon's ability to effectively manage the risks associated with utility operations. As with Moody's, a ratings increase, if it were to occur, simply would indicate the Company has become more like its peers, not less.

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[19] *See*, Exhibit MFG-4, Page 2 of 2. EBITDA refers to Earnings Before Interest, Taxes, Depreciation and Amortization.

[20] Exhibit MFG-4, Page 2 of 2

Q16. Dr. Griffing further argues the IIP reduces the Company's Cost of Equity because it would limit the lag period to nine months.[21] Do you agree with Dr. Griffing on that point?

A16. No, I do not. Although Dr. Griffing points to comments by Moody's to support his position, as discussed in more detail below, Dr. Griffing's data and analyses do not support the position that the relationship between credit ratings and Cost of Equity estimates is such that we can draw firm conclusions regarding one from the other. In large measure, that is because of the differences in risk faced by debt investors on one hand, and equity investors on the other.

Further, rating agencies may view the reduction in lag resulting from the IIP as credit-supportive, but not necessarily credit-enhancing. That is, but for the IIP the Company's reliability investments would dilute its earnings and cash flow, putting downward pressure on cash flow-related credit metrics.[22] In that respect, the IIP supports the Company's credit rating but as discussed above, does not necessarily enhance it.

Lastly, Dr. Griffing has not considered whether the proxy companies have similar structures in place, and whether those structures likewise reduce lag periods. To that point, since 2017 the average lag period for electric utility rate cases was nine months.[23] Because the Cost of Equity is inherently comparative, we cannot say the reduction in lag for IIP investments is materially risk-reducing relative to other

[21] Direct Testimony of Marlon F. Griffing, Ph.D., at 9-10.
[22] As discussed earlier, the Company has consistently and significantly under-earned its authorized ROE.
[23] Source: Regulatory Research Associates

electric utilities, and we cannot conclude the IIP lag period supports the 8.50% ROE Dr. Griffing recommends.

Q17. Even if Moody's and S&P were to upgrade ACE's credit rating, does that mean its Cost of Equity should be reduced?

A17. No, it does not. Debt and equity are entirely different securities with different risk/return characteristics, different lives, and different investors with different risk/return requirements. Although both are exposed to business and financial risks, debt investors have a senior, contractual claim on cash flows not available to equity investors, and a liquidation preference senior to equity investors. As such, equity investors bear the residual risk of ownership. In addition, debt has a finite life, which limits debt investors' risk exposure to a definite, pre-determined period. Equity, on the other hand, has an indefinite life, exposing equity investors to residual risk in perpetuity. Debt and equity may have common considerations, but only to a point, and we cannot draw firm inferences for one from the other.

A visible measure of difference in risk to debt and equity investors is the difference in their respective Beta coefficients. For example, whereas Dr. Griffing reports an average Beta coefficient of 0.67 for his proxy group[24] Duff & Phelps notes that as of December 2017, the Beta coefficient for A-rated debt was 0.04.[25] In fact, a debt Beta coefficient of 0.47 is associated with "B" rated debt, which is considered below investment grade.[26] Consequently, I do not believe credit ratings, or

[24] Exhibit MFG-19, Schedule 2.
[25] Duff & Phelps 2018 Valuation Handbook, at 5-18.
[26] *Ibid.* Debt Beta coefficients for Baa-rated companies were 0.19.

discussions of possible one-notch changes in those ratings, support Dr. Griffing's view that 8.50% is a sensible ROE for the Company's IIP investments.

Q18. Has Dr. Griffing demonstrated that changes in credit rating notches are measures of changes in the Cost of Equity?

A18. No, he has not. To assess that relationship, I began with the credit ratings and DCF results provided in Dr. Griffing's Exhibits MFG-14 and MFG-18, Schedule 3.[27] Because the credit rating scores are ordinal (they are discrete measures of relative creditworthiness) and DCF estimates are continuous, I converted both to ordinal ranks, and analyzed the relationship between the ranks. To do so, I assigned numerical values to each proxy company's credit rating and calculated the rank order for the group. I then calculated the rank order for each proxy company's DCF result (again, relative to the proxy group). That way, I was able to calculate the correlation between credit rating ranks and DCF estimate ranks. If Dr. Griffing's view held, the two would move in opposite directions and the correlation between them would approach negative 1.00.

Based on Dr. Griffing's full proxy group (that is, before removing outliers), the correlation was 23.77%, which is rather weak, and the relationship was statistically insignificant. Applying the same approach to the proxy group with DCF outliers removed, the correlation was negative 13.65% (contrary to the view that higher credit ratings would be associated with lower DCF results), and also weak and statistically insignificant.[28]

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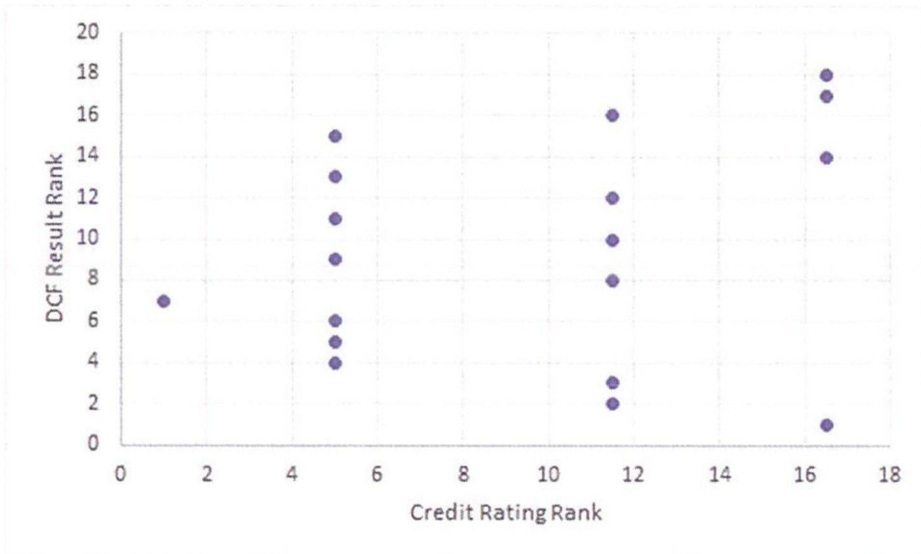
[27] Credit ratings for OGE Energy Corporation and Portland General Electric were updated based on data from S&P Global Market Intelligence (from "A-" to "BBB+" and from "BBB" to "BBB+", respectively).

[28] *See*, Schedule R-(RBH)-3.

That there is no meaningful relationship between the two can be seen visually, in Chart 1, below. As that Chart indicates, the companies with the lowest credit rating ranking (BBB companies, which ranked 16th) had both the lowest and highest DCF estimate rank.

Chart 1: DCF Estimates vs. Credit Rating (ranks)



Q19. Given that Dr. Griffing views the IIP in the context of credit ratings, have you considered how many credit rating "notches" are implied by his proposed 50 basis point ROE reduction?

A19. Yes, I have. Since 2012, the average difference in yields between the Moody's Utility Baa Index, and the Utility A Index has been about 61 basis points.[29] If we assume the average difference is spread evenly across the three notches within a letter grade, a one-notch upgrade would be associated with about a 20-basis point reduction in yields. Under the very conservative assumption that differences in the cost of debt are one-to-one measures of differences in the Cost of Equity, Dr.

[29] Source: Bloomberg Professional, as of September 2018.

Griffing's recommendation implies the IIP, on its own, would cause the Company's credit rating to be increased by two to three ratings notches.

Clearly, that has not been the case; as noted above ACE's credit rating is consistent with its peers'. Even though the rating agencies may consider the IIP to be credit supportive, there is no suggestion that ACE's credit rating will be increased by two to three ratings notches solely because of it. In fact, there is no suggestion that ACE's credit rating will be increased by even one notch on account of the IIP. On that basis alone, Dr. Griffing's proposed 50-basis point reduction is unsupported and unwarranted.

Q20. Lastly, does ACE separately finance its IIP investments?

A20. No, the Company finances its capital investments "on balance sheet", not with discrete issuances of debt and equity supporting individual investments. The Company's overall Cost of Capital therefore reflects the average risk of the projects that constitute its invested capital. If credit ratings are relevant measures of business and financial risk, as Dr. Griffing believes, they reflect the average risk of those assets. As discussed above, ACE's credit rating is within one notch of the proxy group average; that would remain the case even if the Company were to be upgraded. From that perspective, the average risk of the Company's assets and operations is not far removed from its peers.

Q21. What is your conclusion regarding Dr. Griffing's proposed 50-basis point reduction to the Company's ROE for IIP investments?

A21. There is no support, in theory or in practice, for Dr. Griffing's proposal. The fact that rating agencies may view IIP investments as credit supportive does not mean those investments significantly reduce ACE's equity risk relative to other utilities. Even if we assume (incorrectly) that changes in credit ratings are direct measures of changes in equity risk, Dr. Griffing's proposal implies a two to three credit notch increase in the Company's credit rating. There is no company of which I am aware that saw its credit rating increased even one credit notch solely because of a specific rate structure; two to three notches are even less probable. On balance, it is my view that Dr. Griffing's proposed 50-basis point reduction is unsupported, unwarranted, and should be rejected.

IV. DR. GRIFFING'S COST OF EQUITY ANALYSES

Authorized ROEs

Q22. Do recently authorized returns for electric utilities support Dr. Griffing's position that ACE's allowed ROE should be reduced to 9.00% from the stipulated 9.60% return authorized on September 22, 2017?

A22. No. Over the last five years most authorized ROEs for electric utilities have been well above Dr. Griffing's 9.00% recommendation. In fact, the majority have been in the mid 9.00% range to 10.00% (*see* Chart 2, below), which alone demonstrates the Stipulation ROE of 9.60% is reasonable. Dr. Griffing's recommendation, however, falls in the bottom 8th percentile of those returns.[30]

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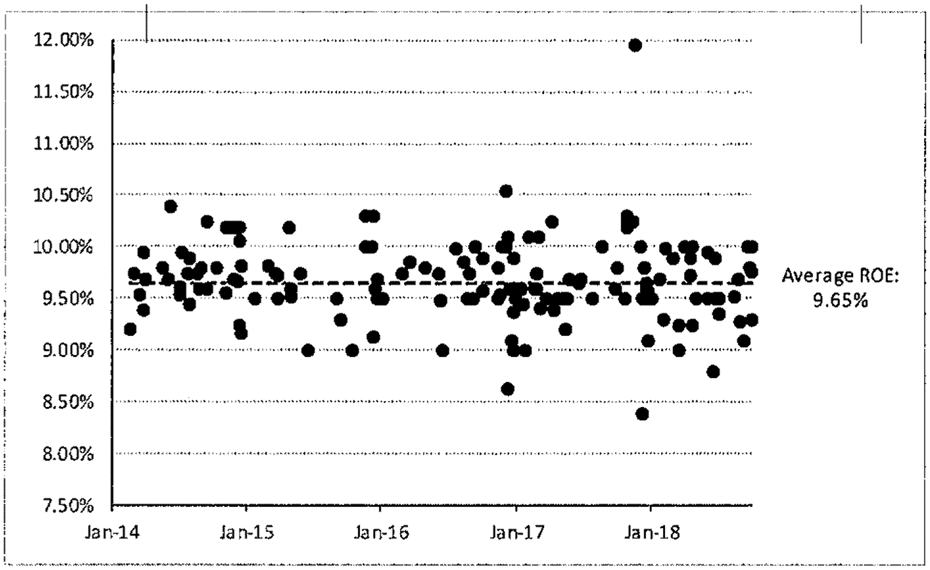
[30] Source: Regulatory Research Associates.

Chart 2: Electric Utility Authorized ROEs (2014 – 2018) [31]



As Chart 2 also demonstrates, since the Company's last rate case, there has been no discernible downward trend in authorized ROEs for electric utilities that would support Dr. Griffing's recommendation. The average ROE since January 2014 is 9.65%, and the average ROE since September 22, 2017 also is 9.65%. Excluding Illinois formula-based rates the averages are 9.69% and 9.70%, respectively.

The difference between Dr. Griffing's recommendation and the returns available to other utilities raises two concerns. First, ACE must compete with other companies, including utilities, for the long-term capital needed to provide utility service. Given the choice between two similarly situated utilities, one with a return that falls far below industry averages and another with a return that more closely aligns with industry averages, investors will choose the latter.

Second, although no regulatory commission sets returns solely by reference to

[31] Source: Regulatory Research Associates (RRA). Authorized ROEs for electric utilities from January 1, 2014 through September 30, 2018. ROEs authorized for limited issue rate riders are excluded.

those authorized elsewhere, authorized returns do provide observable and measurable benchmarks against which return recommendations may be assessed. In my experience, regulatory commissions generally consider the same types of market, methodological, and risk factors at issue in this proceeding. They recognize that financial models are important tools in determining returns, and appreciate that because all models are subject to assumptions, no one method is most reliable at all times, and under all conditions. Even if we focus on a single method, it remains critically important to apply reasoned judgment to determine where the Cost of Equity falls within that model's range of results. Just as investors consider company-specific and general market factors, we should do the same. Those considerations, and that judgment, leads to the conclusion that Dr. Griffing's ROE recommendations are unduly low.

Capital Market Conditions

Q23. How has Federal Reserve monetary policy changed since the Board's September 22, 2017 Order in Docket No. ER17030308?

A23. The Federal Reserve has continued to move forward on its path of policy "normalization,"[32] raising the Federal Funds rate four times since the Board issued its order in that docket,[33] such that the top end of the Federal Funds target rate is 100 basis points higher than it had been (from a range of 1.00%-1.25% to a range of

[32] Normalization refers to the removal of the extraordinary monetary policy initiatives adopted in response to the 2008-2009 financial crisis. The Federal Reserve has stated that the two main components of its policy normalization will be "gradually raising its target range for the federal funds rate to more normal levels and gradually reducing the Federal Reserve's securities holdings." *See:* https://www.federalreserve.gov/monetarypolicy/policy-normalization.htm.

[33] The Federal Reserve increased the target Federal Funds rate 100 basis points over the past twelve months, with increases of 25 basis points on December 13, 2017, March 21, 2018, and June 13, 2018, and September 26, 2018 respectively.

2.00%-2.25%). 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.[34] In a press conference following the June 2018 Federal Open Market Committee meeting, Chairman Powell discussed the recent increases in the Federal Funds rate and expectations for continued rate increases, noting a strong labor market and increases in household spending and business fixed investment.[35]

Q24. Have long-term interest rates and utility company dividend yields also increased?

A24. Yes, they have. As shown in Chart 3 below, 30-year Treasury yields have increased by nearly 40 basis points while Dr. Griffing's proxy group dividend yield has increased by nearly 30 basis points.

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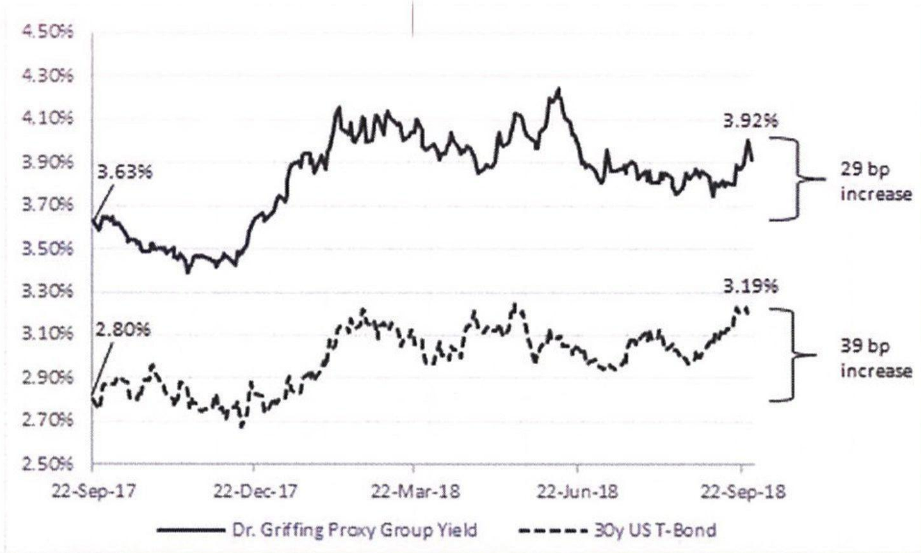
[34] *See:* https://www.federalreserve.gov/monetarypolicy/policy-normalization.htm and Federal Open Market Committee (FOMC) Press Release, June 14, 2017.

[35] Transcript of Chairman Powell's Press Conference, June 13, 2018.

Chart 3: Proxy Group Dividend Yield and 30-Year Treasury Yield [36]



Over the same period, the one-year Treasury yield increased from 1.30% to 2.59% (129 basis points) and the ten-year Treasury yield increased from 2.26% to 3.05% (79 basis points). That is, the cost of short-term debt now is higher than the cost of long-term debt at the time of the Company's last rate case. Those increases suggest the Cost of Equity has been increasing, not decreasing as Dr. Griffing suggests.

Q25. Does market-based data indicate that investors see a probability of increasing interest rates?

A25. Yes, observable market data demonstrate investors expect interest rates to increase in the near future. Data compiled by CME Group indicates that investors see a near certainty of further Federal Funds rate increases, even after three increases in 2018. As shown in Table 2 below, the market expects at least one additional rate hike (99.10% probability) and possibly two or three (89.40% and 59.70% probability,

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[36] Source: Regulatory Research Associates (RRA) and Bloomberg Professional. Proxy group measured as an index.

respectively) over the next year.

Table 2: Probability of Federal Funds Rate Increase[37]

Target Rate (bps)	Federal Reserve Meeting Date								
	Nov-18	Dec-18	Jan-19	Mar-19	May-19	Jun-19	Jul-19	Sep-19	Oct-19
200-225 (current)	98.7%	13.7%	13.1%	4.3%	3.8%	1.6%	1.5%	1.0%	0.9%
225-250	1.3%	85.2%	82.1%	35.8%	32.0%	16.0%	14.5%	10.3%	9.7%
250-275		1.1%	4.7%	56.7%	54.2%	41.6%	39.0%	31.1%	29.7%
275-300				3.2%	9.6%	34.9%	35.6%	36.7%	36.3%
300-325					0.4%	5.6%	8.6%	17.3%	18.6%
325-350						0.2%	0.8%	3.3%	4.2%
350-375								0.3%	0.5%

Similarly, consensus near-term forecasts of the 30-year Treasury yield reported by *Blue Chip Financial Forecast* indicate the market expects long-term rates to rise by another approximately 40 basis points by the first quarter of 2020.[38] Importantly, the potential for rising rates represents risk for utility investors.

Q26. Are there other capital market developments that call into question Dr. Griffing's position that the Cost of Equity has fallen since the Board issued its Order in the Company's last case?

A26. Yes, there are. On December 22, 2017, the President signed into law the "Tax Cuts and Jobs Act" (TCJA). The rating agencies have observed that a reduction in utilities' revenue associated with lower income taxes and the potential return of excess accumulated deferred income taxes also may reduce utilities' cash flow. Leading up to and subsequent to the signing of the TCJA, utilities underperformed the market, which resulted in higher dividend yields, as rating agencies and investors re-

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[37] Source: http://www.cmegroup.com/trading/interest-rates/countdown-to-fomc.html, accessed October 4, 2018.

[38] *Blue Chip Financial Forecast,* Vol. 37, No. 10, October 1, 2018, at 2.

evaluated utilities relative to other market sectors. To the extent investors now view utilities as less attractive relative to other sectors, investors will require a higher return to remain invested in the proxy companies. As that occurs, the proxy companies' prices will fall, and their dividend yields will increase. Because rating agencies have begun to discuss the consequences of the TCJA for utilities' cash flow, we reasonably can assume equity investors also have begun to recognize those concerns.

Q27. Has Moody's recently updated its review of the utility sector?

A27. Yes. On June 18, 2018 Moody's changed its outlook on the U.S. regulated utility 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."[39] 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). Moody's also noted that "[m]anagement teams' defensive efforts and a few initial signs of supportive regulatory responses to tax reform are important first steps in addressing the sector's increased financial risk," and explained that in its view, "it will take longer than 12-18 months for the sector to exhibit a material financial improvement from these actions."[40]

[39] Moody's Investors Service, *Announcement: Moody's changes the US regulated utility sector outlook to negative from stable*, June 18, 2018.
[40] *Ibid.*

Q28. Are there analytical methods that may be applied to determine whether the TCJA likely affected utility stock prices?

A28. Yes, there are. A method frequently used to assess the implications of a given event on stock prices is to calculate "abnormal returns" before and after the event. In this approach, "abnormal returns" are defined as the difference between actual and expected returns. To the extent the cumulative abnormal returns deviate significantly from pre-event levels, we can conclude the event affected market price performance, and was meaningful to investors.

In applying this approach, I defined the abnormal return on a given day as $A_t = R_{I,t} - R_{m,t}$ Equation [1], where A_t is the Abnormal Return on day t, $R_{i,t}$ is the actual return for Dr. Griffing's proxy group,[41] on day t, and $R_{m,t}$ is the expected return for the proxy group. The expected return (sometimes referred to as the "market-adjusted return") is based on a regression equation in which the proxy group's daily returns are the dependent variable, and the market's daily return (measured by the S&P 500) is the explanatory variable (that is, $R_{m,t} = \alpha_t + \beta_{m,t}$ Equation [2]) Consistent with Value Line's approach for calculating Beta coefficients, I ran the regression (*i.e.*, Equation [2]) over five years, using daily (rather than weekly) returns. The equation and slope coefficient both were statistically significant (see Table 3, below). Because it relies on market-adjusted returns, the approach controls for factors that, like the TCJA, affect companies across market sectors.

To determine whether the TCJA likely affected the proxy companies' stock valuations, I considered the "event date" to be December 1, 2017. Because it pre-

[41] Calculated as an index. Source: S&P Global Market Intelligence.

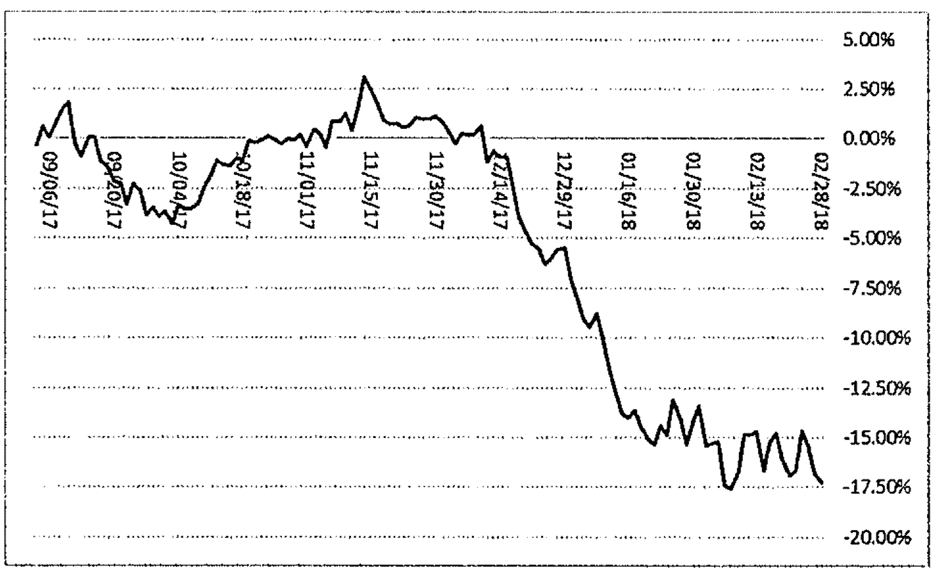
dates the TCJA's enactment, the event date provides for the likelihood that investors were aware of, and began to consider how the TCJA may affect utility risks before the TCJA became law. I then calculated the cumulative abnormal return for each day over a window that spanned from September 1, 2017 to March 1, 2018 (that is, approximately three months before and after December 1, 2017). Chart 4 (below) provides the cumulative abnormal return over that period.

Table 3: Market Model Regression Statistics

	SLOPE	INTERCEPT
Coefficient	0.3831	0.0001
Std. Err.	0.0316	0.0002
R-Square	0.1045	
F-Stat	146.9226	
t-stat	12.1212	0.4824

Because it relies on market-adjusted returns, the approach controls for factors that, like the TCJA, affect companies across market sectors.

Chart 4: Cumulative Abnormal Return



Q29. What conclusions do you draw from Chart 4?

A29. In the pre-event window (September 1, 2017 to December 1, 2017), the cumulative abnormal return was about 1.12%; during the post-event window (from December 1, 2017 to March 1, 2018), it was negative 18.39%. Simply, even when controlling for market-wide events, the TCJA clearly has had a strong negative effect on Dr. Griffing's proxy company valuation levels. We therefore reasonably can conclude that aside from actions taken by rating agencies, the TCJA meaningfully – and negatively – has affected utility stock prices.

We cannot conclude that the TCJA, together with other changes in the capital market discussed throughout my Direct Testimony, has caused the Company's Cost of Equity to fall below its currently authorized ROE of 9.60%, as Dr. Griffing's recommendation suggests.

Proxy Group Selection

Q30. Please summarize the criteria by which Dr. Griffing developed his proxy group.

A30. Dr. Griffing began with the Value Line Electric Utility Industry and eliminated companies that:

1. Are not based in the continental 48 states;
2. Are not traded on a public stock exchange;
3. Have not paid consistent or growing dividends for at least three years;
4. Are party to a merger or acquisition, or unusual regulatory proceedings;
5. Derive less than 75.00% of three-year average operating revenues, operating income or net income from regulated electric utility operations;

6. Do not have a credit rating of at least BBB- from S&P; and
7. Do not have positive growth rate estimates from industry analysts.[42]

Q31. Do you believe that geographical location is a relevant screening criterion in developing a proxy group for this proceeding?

A31. No, I do not. In my view, geographic proximity does not necessarily demonstrate comparable financial or business risk, since there can be significant disparities in regulation, market circumstances, and other important factors even within regional boundaries. Second, I am not aware of any analyst reports or literature from the financial community indicating that investors limit their universe of investment alternatives by reference to geography. In my view, therefore, Dr. Griffing erred by excluding Hawaiian Electric Industries from the proxy group solely because it is not part of the 48 contiguous states.

Q32. Do you agree with Dr. Griffing's decision to exclude Avangrid (AGR) from the proxy group?[43]

A32. No, I do not. Dr. Griffing excluded AGR because that company has not paid consecutive quarterly dividends for three years. AGR, however, was formed in 2015 through a merger between Iberdrola USA, Inc. and UIL Holdings Corporation. The company has paid quarterly dividends since the second quarter of 2016 (two and one half years). To that point, Value Line (which is one of the sources relied upon by Dr. Griffing to estimate proxy companies' dividend yields and growth rates) projects steady increases in AGR's dividend through 2023.

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[42] Direct Testimony of Marlon F Griffing, Ph.D., at 21-22.

[43] *Ibid.*, at 23.

Estimating the Cost of Equity is a forward-looking exercise that relies on a group of fundamentally comparable proxy companies. In my view, the availability of three-years of historical dividend data is overly restrictive for a newly-formed company such as AGR, and does not distinguish suitable from unsuitable proxy companies.[44] Consequently, I do not believe AGR should have been excluded from the proxy group.

Q33. Do you have any concerns with the inclusion of IDACORP, Inc. (IDA) in Dr. Griffing's proxy group?[45]

A33. Yes. Dr. Griffing notes it is important to exclude companies that are party to mergers or acquisitions because the resulting volatility in stock prices may undermine the reliability of DCF analysis.[46] I agree with Dr. Griffing on that point. Stock prices that are affected by merger and acquisition activity can skew dividend yields and, therefore DCF, results. As to IDA, Value Line notes:

> This stock is expensively priced. The recent quotation is above our 3- to 5-year Target Price Range. We think this reflects takeover speculation, as IDACORP is one of the few remaining mid-cap utility holding companies. However, we advise against purchasing this equity in the hope of an acquisition agreement. Finally, the dividend yield is low, by utility standards.[47]

As seen on Exhibit MFG-18, Schedule 1, IDA's Discounted Cash Flow result of 5.61% is well below those of Dr. Griffing's other proxy companies. Although Dr. Griffing ultimately excludes IDA from his ROE analyses because the company's

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[44] UIL Holdings had consistently paid dividends for the five years ended 2014. *See*, UIL Holdings Corporation SEC Form 10-K For the fiscal year ended December 31, 2014, at 25.

[45] Direct Testimony of Marlon F Griffing, Ph.D., Exhibit MFG-15.

[46] *Ibid.*, at 23-24.

[47] Value Line company report, IDACORP, Inc., July 27, 2018.

ROE result is below 6.85%,[48] there is sufficient reason to exclude the company even if its ROE result were above that threshold.

Q34. Do you have any concerns with Dr. Griffing's criteria that requires proxy companies to have at least 75.00% of operating revenue and income from regulated electric operations?

A34. Yes, I find Dr. Griffing's 75.00% requirement overly restrictive. The selection of any proxy group requires the balancing of two practical objectives: selecting companies that are fundamentally comparable to the subject; and ensuring a group of sufficient size to have confidence in the analytical results. Black Hills Corporation (BKH), DTE Energy Company (DTE), NextEra Energy, Inc. (NEE), and Wisconsin Electric Corporation (WEC) are all included in Value Line's Electric Utility Industry category. They all derive the majority of their operating income from regulated utility service and, as shown in Table 4 (below), their credit ratings, and Value Line Beta coefficients and Safety Ratings are similar to Dr. Griffing's other proxy companies.

Table 4: Risk Measures[49]

	S&P Credit Rating	Value Line Beta Coefficient	Value Line Safety Rating
Black Hills	BBB+	0.85	2
DTE Energy	BBB+	0.60	2
NextEra Energy	A-	0.60	1
Wisconsin Electric	A-	0.55	1
Dr. Griffing's Proxy Group Range	BBB to A+	0.45 to 0.95	1 to 3
Dr. Griffing's Proxy Group Average	BBB+	0.67	2

48 Direct Testimony of Marlon F Griffing, Ph.D., at 34.

49 Sources: MFG Exhibit-19, Schedule 2, Bloomberg Professional and Value Line, as of September 28, 2018. Proxy group average is the median for credit rating and Safety Rating, and the mean for Beta coefficient.

Because they are considered electric utilities by Value Line and have risk metrics consistent with his other proxy companies, BKH, DTE, NEE, and WEC should not have been excluded from Dr. Griffing's ROE analyses.

Discounted Cash Flow Analysis

Q35. Do you have any concerns with how Dr. Griffing applied the Constant Growth Discounted Cash Flow model?

A35. I do not disagree with the fundamental structure of Dr. Griffing's model. Rather, my concerns lie in how Dr. Griffing applied the model, his interpretation of its results, and the weight he gives to it.

Q36. Turning to your last point, how much weight did Dr. Griffing give his DCF analysis in arriving at his conclusion that the Cost of Equity for IIP investments is 8.50%?

A36. It appears he gave that method considerable weight. As Dr. Griffing explains, he considered the CAPM, ECAPM, and returns authorized in other jurisdictions only as checks on the reasonableness of his DCF estimates.[50]

Q37. Do you agree with that approach?

A37. No, I do not. In my experience, each model used to estimate the Cost of Equity is subject to assumptions that may become more, or less, applicable as market conditions change. The use of multiple methods in estimating the Cost of Equity is well-supported in academic literature. As Dr. 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

[50] Direct Testimony of Marlon F Griffing, Ph.D., at 18.

> 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 measurement difficulties and vagaries in individual companies' market data.[51]

As Dr. Morin points out, although many empirical models have been developed to estimate the Cost of Equity, all are subject to limiting assumptions or other constraints. As a practical matter, no individual model is more reliable than all others under all market conditions. Therefore, it is both prudent and appropriate to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. Professor Eugene Brigham, a widely respected finance scholar, 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.[52]

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[51] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 428.
[52] *Ibid.*, at 430-431, citing Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice.

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.[53]

Although Dr. Griffing considered other methods as checks on his DCF estimates, they did not change his conclusion that his DCF results were reasonable. Consequently, it appears Dr. Griffing's 9.00% base ROE recommendation relies heavily on his DCF analyses.

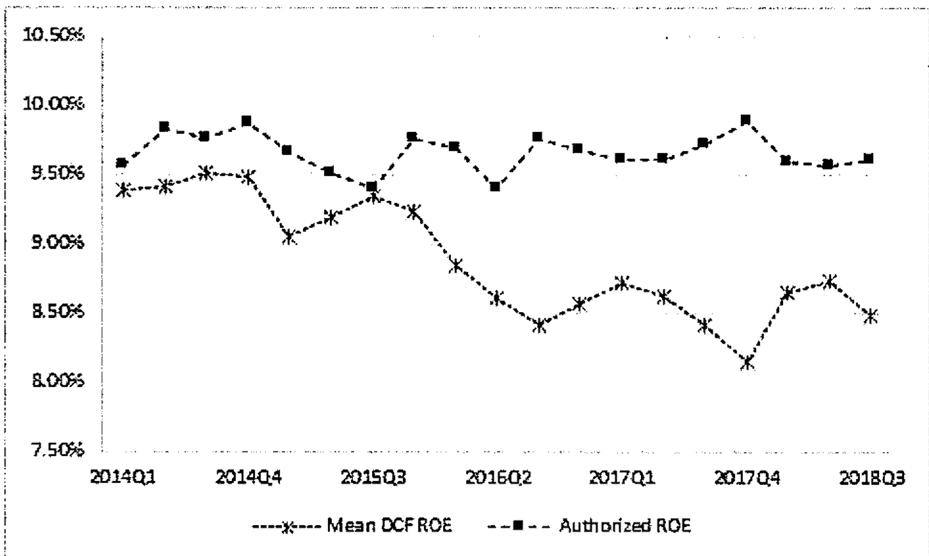
Q38. Have utility commissions authorized ROEs consistent with the Constant Growth DCF model's results?

A38. Not for several years. As Chart 5 (below) demonstrates, since 2014 the Constant Growth DCF model has produced ROE estimates consistently and meaningfully below returns then-authorized by regulatory commissions. The difference between the two widened from 2016 – 2018, when (on average) DCF

[53] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 430-431.

results were as much as 174 basis points below authorized returns. Even with the recent increase in utility dividend yields, the difference remains about 112 basis points. Simply, for several years, the DCF method has produced unreasonably low estimates of the Cost of Equity and regulatory decisions have reflected that understanding.

Chart 5: Authorized ROEs vs. DCF Estimates[54]



Q39. In your view, is the Constant Growth DCF model currently the most reliable measure of utilities' Cost of Equity?

A39. No, I do not believe it is. In large measure that is because the model's fundamental assumptions continue to be misaligned with actual market conditions. As Dr. Griffing explains,[55] the Constant Growth DCF model often is given as $k = \frac{D_1}{P_0} + g$ Equation [3]. That form is a simplified version of the full Discounted

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[54] DCF results based on quarterly average stock prices, Earnings Per Share growth rates from Value Line, Zacks, and First Call; assumes Griffing proxy group. Authorized ROEs are quarterly averages for electric utilities excluding limited issue riders and Illinois formula returns; source: S&P Global Market Intelligence. Please note that 2015 Q3 included only two ROE decisions.

[55] Direct Testimony of Marlon F. Griffing, Ph.D., at 19.

Cash Flow model, $P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty}$ Equation [4], where P_0 is the current price, D_1 through D_∞ are annual dividends, and k is the Cost of Equity. The Constant Growth form (that is, Equation [3]) assumes investors apply the present value analysis described in Equation [4] to determine the "intrinsic value", or the price they are willing to pay, for a share of common stock. The simplified version explained in Dr. Griffing's testimony (Equation [3]) therefore will not produce accurate estimates of the market-required ROE if the market price diverges from intrinsic value.

Differences between market prices and intrinsic value can and do arise for various reasons. First, the DCF model (including both forms) requires several strict, often limiting assumptions, including: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) the dividend payout ratio remains constant in perpetuity; (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. To the extent those assumptions do not align with market conditions, intrinsic value may deviate from the market price and the Constant Growth DCF model will give unreliable results.

We know, for example, that the Federal Reserve now is in the process of unwinding nearly $4 trillion of assets it purchased during its Quantitative Easing initiatives. Those asset purchases were made with the explicit intent of reducing long-term interest rates.[56] Because those asset purchases are in the process of being unwound, their effect on interest rates will diminish over time. We therefore cannot assume the Cost of Equity estimate produced by the Constant Growth DCF model today will be the fundamentally consistent with the estimate it produces going forward.

Differences between market prices and intrinsic valuations also may arise when investors take short-term trading positions to hedge risk (*e.g.*, a "flight to safety"), to speculate (*e.g.*, momentum trades), or as temporary position to increase current income (*i.e.*, a "reach for yield"). Those motivations, including a "reach for yield", also may be related to evolving Federal monetary policy. It is difficult, therefore, to have a reasonable degree of confidence that the Constant Growth DCF model's fundamental assumptions so fully align with current market conditions, and that its results are so reasonable that it should be given principal weight in determining the Company's Cost of Equity. That concern is made more clear when we consider that Dr. Griffing's 8.90% to 9.01% DCF estimate falls 60 to 70 basis points below the Company's currently authorized ROE.

Capital Asset Pricing Model (CAPM) and the Empirical CAPM (ECAPM)

Q40. Please briefly summarize Dr. Griffing's CAPM and ECAPM analyses.

A40. Dr. Griffing uses a four-week average Treasury yield (3.08%), a proxy group average Value Line Beta coefficient (0.67), and three separate Market Risk Premium (MRP) estimates (ranging from 7.10% to 12.37%) to derive CAPM estimates of

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[56] *See* Federal Reserve Press Release, dated June 19, 2013.

7.84%, 8.23% and 11.37%, and ECAPM estimates of 8.42%, 8.86% and 12.39%.[57]

Dr. Griffing's first MRP estimate (12.37%) is derived from a Constant Growth DCF analysis that uses the average dividend yield and average growth rate for the 1,019 dividend paying public companies in the Value Line Universe who have positive earnings growth rate estimates.[58] Dr. Griffing's second MRP estimate (7.68%) is calculated in a similar manner, but excludes companies whose individual DCF results are below 6.85% or above 13.30%.[59] His third MRP estimate (7.10%) subtracts the 5.00% arithmetic average historical yield on long-term Government bonds from the 12.10% arithmetic average return on large-cap stocks, as reported by Duff & Phelps.

As noted above, Dr. Griffing only uses the CAPM and ECAPM results as a check on the reasonableness of his DCF analysis. In Dr. Griffing's view, the CAPM approach has questionable value in directly estimating the Cost of Equity becaue it requires "extensive" judgment in selecting its inputs.[60]

Q41. Do you agree with Dr. Griffing's assessment of the limited-value of the CAPM approach?

A41. No, I do not. In my experience, the CAPM is commonly considered by regulatory commissions in determining the ROE for public utilities. Brigham, Shome, and Vinson also addressed methods used to estimate the Cost of Equity for regulated utilities, noting that:

In the mid-1960s, Myron Gordon and others began applying the

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57 Direct Testimony of Marlon F Griffing, Ph.D., Exhibit MFG-19, Schedule 9.
58 Direct Testimony of Marlon F Griffing, Ph.D., at 39-41.
59 *Ibid.*
60 *Ibid.*, at 38.

> theory of finance to help estimate utilities' costs of capital. Previously, the standard approach in cost of equity studies was the "comparable earnings method," which involved selecting a sample of unregulated companies whose investment risk was judged to be comparable to that of the utility in question, calculating the average return on book equity (ROE) of these sample companies, and setting the utility's service rates at a level that would permit the utility to achieve the same ROE as the comparable companies. This procedure has now been thoroughly discredited...and it has been replaced by three market-oriented (as opposed to accounting-oriented) approaches: (i) the DCF method, (ii) the bond-yield-plus-risk-premium method, and (iii) the CAPM, which is a specific version of the generalized bond-yield-plus-risk-premium approach.[61]

As to its use in practice, an article published in Financial Analysts Journal surveyed financial analysts to determine the analytical techniques that are used in practice, and this included the CAPM.[62] That survey, which was conducted by Stanley Block, clearly indicated that the CAPM is used by practitioners. Similarly, a 2001 article by Professors Graham and Harvey demonstrated that industry practitioners are far more likely to use the CAPM than the DCF model.[63]

Lastly, all ROE models are subject to limiting assumptions and other constraints. Importantly, however, the CAPM is not subject to the same limiting assumptions as DCF-based methods, and provides the ability to reflect additional information regarding investors' views of relative risk and expected market conditions. The CAPM, therefore provides useful additional information to inform the assessment of the required ROE and is consistent with equity analysts' and investors' use of multiple models to develop their return requirements.

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[61] 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.

[62] Stanley B. Block, *A Study of Financial Analysts: Practice and Theory*, Financial Analysts Journal, July/August, 1999.

[63] John R. Graham, Campbell R. Harvey, *The Theory and Practice of Corporate Finance: Evidence from the Field*, Journal of Financial Economics, 2001.

Q42. Do you agree with Dr. Griffing's use of the 30-year Treasury yield as the risk-free rate?

A42. I agree with Dr. Griffing that the yield on 30-year Treasury bonds is an appropriate measure of the risk-free rate. However, as Dr. Griffing acknowledges,[64] the Cost of Equity is forward-looking and, as such, it would have been appropriate for Dr. Griffing to consider consensus forecasts for long-term Treasury yields. *Blue Chip Financial Forecasts*, which provides consensus estimates from over 50 business economists, projects 30-year Treasury yields to steadily rise from their current approximately 3.00% level to 3.70% by the end of next year.[65]

Q43. Do you agree with Dr. Griffing's use of *ex-ante* market DCF analyses to estimate the required MRP?

A43. Although I agree with Dr. Griffing that the DCF model is a reasonable means of calculating the expected market return when estimating the MRP, I have several concerns with the inputs and assumptions on which Dr. Griffing relies to calculate the MRP, including: (1) excluding non-dividend paying companies; (2) excluding companies with negative earnings per share growth rates; (3) the use of an equal-weighted average return as opposed to a market capitalization weighted return; and (4) in the case of his second DCF-based MRP estimate, excluding companies with DCF results below 6.85% or above 13.30%.

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[64] Direct Testimony of Marlon F Griffing, Ph.D., at 28.

[65] *Blue Chip Financial Forecast*, Vol. 37, No. 10, October 1, 2018, at 2.

Q44. Please explain your concerns with Dr. Griffing's decision to exclude non-dividend paying companies and companies with negative growth rates in calculating the expected market return.

A44. My first concern is that the expected market return is meant to reflect all companies in the market. Investors recognize the market includes both dividend and non-dividend paying companies, companies with relatively strong current growth, and those negative current growth. Under Dr. Griffing's approach of excluding non-dividend paying companies, some of the largest companies in the market (based on market capitalization) would be not be considered part of the investible universe. For example, Alphabet Inc., Berkshire Hathaway Inc.[66], Amazon.com Inc., and Facebook Inc., do not pay dividends. As of September 2018 their combined market capitalization is approximately $2.81 trillion, which is over 10.00% of the entire S&P 500.[67] Excluding just those companies therefore could have a significant effect on the calculated Market Risk Premium. Equally important, the resulting estimate would not represent an estimate of the market, as a whole.[68]

Beyond that, my methodological concern with excluding non-dividend paying companies and companies with negative growth rates is with internal consistency in the model's application. A fundamental assumption of the CAPM is that the required return is proportional to the risk of the investment. In the CAPM structure, the Beta coefficient is the measure of risk, and is calculated by comparing the subject security's returns to the overall market returns. Because the Beta coefficient is

[66] Including Class A and Class B.
[67] Based on data from Bloomberg Professional.
[68] Excluding companies with negative growth introduces a degree of "survivorship bias".

calculated relative to the overall market, which includes both non-dividend paying companies and companies who currently have negative growth, it is important that the expected market return also reflects the overall market. As such, I do not believe it is appropriate to combine Beta coefficients calculated relative to the entire market with a Market Risk Premium calculated using only a subset of the market (*i.e.*, dividend paying companies with.

If Dr. Griffing chooses to remove non-dividend paying companies and companies with negative growth rates from his calculation of the expected market return, he likewise should remove them from the index used to calculate the Beta coefficient. Because Beta coefficients are a positive function of the correlation of returns between the subject company and the index, removing non-dividend paying companies and companies with negative growth rates may increase the correlation of the proxy companies, thereby increasing the Beta coefficient.[69] In addition, dividend paying companies may have lower volatility than non-dividend paying companies and companies with negative growth rates. And, because the Beta coefficient also reflects relative volatility (*i.e.*, subject company relative to the index), if the volatility of the index falls, the relative volatility will increase, again increasing the Beta coefficient. Dr. Griffing's position inherently assumes the proxy companies' correlation coefficients and relative volatility would remain constant, and their Beta coefficients

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[69] The Beta coefficient is defined as: $\beta_j = \frac{\sigma_j}{\sigma_m} \times \rho_{j,m}$ where σ_j is the standard deviation of returns for company "*j*," σ_m is the standard deviation of returns for the broad market, 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.

would not change if we remove non-dividend paying companies from the market index. But he has not shown that to be the case.

Q45. Please explain your concern with the averaging convention Dr. Griffing's uses to calculate his market return estimate.

A45. Dr. Griffing's market DCF analysis relies on the simple average of the reported dividend yield and the expected growth rate for each of the companies in his selected market universe. That approach gives the same weight to the smallest companies in the market as it does to the largest, and therefore does not reflect the overall earned return expected for the average investor. Rather, the overall market return for the average investor will be the market capitalization weighted average return. In the extreme, Dr. Griffing's approach could produce a negative market return estimate even if the overall market was expected to perform well (and conversely, a relatively high return estimate even if the overall market was expected to perform poorly.)

Moreover, the indices used by financial data providers such as Bloomberg and Value Line to calculate Beta coefficient estimates, such as the S&P 500 and New York Stock Exchange, are market capitalization weighted. Dr. Griffing's use of a simple average, therefore, creates an additional inconsistency between the calculation of the Beta coefficient (the measure of risk) and the MRP (the incremental required return from investing in the market), which can bias the CAPM result.

Q46. Please explain your concern with Dr. Griffing's removal of companies with DCF results below 6.85% and above 13.30% to calculate his second DCF-based market return estimate.

A46. The market return estimate used to calculate the MRP component of the CAPM should reflect the forward-looking return expected from the overall market. Industries, and individual companies within those industries, face constantly evolving business and financial opportunities (and risks). As such, it is entirely reasonable for a broad market index to contain companies with relatively high and relatively low expected returns at any given time. As discussed above, although the calculation of the required return involves calculating individual component company returns, the end result should be the market capitalization weighted return for all companies in the market. Excluding specific companies based on their individual DCF estimates without making a corresponding adjustment to the Beta coefficient would be inappropriate.

V. SUMMARY AND CONCLUSIONS

Q47. What is your conclusion regarding Dr. Griffing's proposed reduction in the Company's ROE for its IIP-related investments?

A47. First, I disagree with Dr. Griffing that there is any reasonable basis to conclude that the return required by equity investors in ACE has fallen by 60 basis points since the Board authorized the Company's 9.60% ROE in September 2017. That position is not supported by the average return authorized in other regulatory jurisdictions, which has remained approximately 9.65% (9.70% excluding Illinois formula-based returns). In fact, if the required ROE has changed over the past twelve months, rising interest rates and new cashflow pressures resulting from TCJA legislation suggest it has increased, not decreased.

I also disagree with Dr. Griffing's argument that a lower ROE should be authorized for IIP-related investments. Estimating the Cost of Equity is a comparative exercise and cost recovery mechanisms such as infrastructure recovery riders are common among the proxy group. There is no reason to conclude that ACE's IIP investments are so much less risky than the regulated utility operations of its peers that investors would require a lower return. IIP-related investments are not guaranteed, and ACE continues to face regulatory lag even with the mechanism in place. And, importantly, a reduction in the ROE for IIP investments would run counter to the Board's stated objective of encouraging and supporting reliability investments.

Q48. Does this conclude your Direct Testimony?

A48. Yes, it does.

Attachment R-(RBH)-A

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Resume of:

Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Area 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 Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
Cook Inlet Natural Gas Storage Alaska, LLC	06/18	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. U-18-043	Return on Equity
ENSTAR Natural Gas Company	06/16	ENSTAR Natural Gas Company	Matter No. TA 285-4	Return on Equity
ENSTAR Natural Gas Company	08/14	ENSTAR Natural Gas Company	Matter No. TA 262-4	Return on Equity
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	10/17	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	2018 General Cost of Capital, Proceeding ID. 22570	Rate of Return
EPCOR Energy Alberta G.P. Inc.	01/17	EPCOR Energy Alberta G.P. Inc.	Proceeding 22357	Energy Price Setting Plan
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/16	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2016 General Cost of Capital, Proceeding ID. 20622	Rate of Return
Arizona Corporation Commission				
Southwest Gas Corporation	05/16	Southwest Gas Corporation	Docket No. G-01551A-16-0107	Return on Equity
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
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)
Xcel Energy, Inc.	12/12	Public Service Company of Colorado	Docket No. 12AL-1268G	Return on Equity (gas)

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Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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-TBD	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
Potomac Electric Power Company	07/11	Potomac Electric Power Company	Formal Case No. 1087	Return on Equity

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Testimony Listing of:
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Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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				
Maui Electric Company, Limited	10/17	Maui Electric Company, Limited	Docket No. 2017-0150	Return on Equity
Hawaiian Electric Company, Inc.	12/16	Hawaiian Electric Company, Inc.	Docket No. 2016-0328	Return on Equity
Hawai'i Electric Light Company, Inc.	09/16	Hawai'i Electric Light Company, Inc.	Docket No. 2015-0170	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Maui Electric Company, Limited	12/14	Maui Electric Company, Limited	Docket No. 2014-0318 RP15-1322-000	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				
Kansas City Power & Light Company	05/18	Kansas City Power & Light Company	Docket No. 18-KCPE-480-RTS	Return on Equity
Westar Energy	02/18	Westar Energy	Docket No. 18-WSEE-328-RTS	Return on Equity
Great Plains Energy, Inc. and Kansas City Power & Light Company	01/17	Great Plains Energy, Inc. and Kansas City Power & Light Company	Docket No. 16-KCPE-593-ACQ	Response to Direct Testimony by Commission Staff-related to the ratemaking capital structure processes

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Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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				
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				
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

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

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Testimony Listing of:
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Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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				
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)

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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

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Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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	08/18	Atlantic City Electric Company	Docket No. ER18080925	Return on Equity
Atlantic City Electric Company	06/18	Atlantic City Electric Company	Docket No. ER18060638	Return on Equity
Atlantic City Electric Company	03/17	Atlantic City Electric Company	Docket No. ER17030308	Return on Equity
Pivotal Utility Holdings, Inc.	08/16	Elizabethtown Gas	Docket No. GR16090826	Return on Equity
The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	04/16	The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	BPU Docket No. GM15101196	Merger Approval
Atlantic City Electric Company	03/16	Atlantic City Electric Company	Docket No. ER16030252	Return on Equity
Pepco Holdings, Inc.	03/14	Atlantic City Electric Company	Docket No. ER14030245	Return on Equity
Orange and Rockland Utilities	11/13	Rockland Electric Company	Docket No. ER13111135	Return on Equity
Atlantic City Electric Company	12/12	Atlantic City Electric Company	Docket No. ER12121071	Return on Equity
Atlantic City Electric Company	08/11	Atlantic City Electric Company	Docket No. ER11080469	Return on Equity
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EM06090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process
New Mexico Public Regulation Commission				
Public Service Company of New Mexico	12/16	Public Service Company of New Mexico	Case No. 16-00276-UT	Return on Equity (electric)
Public Service Company of New Mexico	08/15	Public Service Company of New Mexico	Case No. 15-00261-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 14-00332-UT	Return on Equity (electric)

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

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

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Dominion North Carolina Power	03/16	Dominion North Carolina Power	Docket No. E-22, Sub 532	Return on Equity
Duke Energy Carolinas, LLC	02/13	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1026	Return on Equity
Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	10/12	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	Docket No. E-2, Sub 1023	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/12	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 479	Return on Equity (electric)
Duke Energy Carolinas, LLC	07/11	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 989	Return on Equity (electric)
North Dakota Public Service Commission				
Otter Tail Power Company	11/17	Otter Tail Power Company	Docket No. 17-398	Return on Equity (electric)
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/16	CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	Cause No. PUD201600094	Return on Equity
Oklahoma Gas & Electric Company	12/15	Oklahoma Gas & Electric Company	Cause No. PUD201500273	Return on Equity
Public Service Company of Oklahoma	07/15	Public Service Company of Oklahoma	Cause No. PUD201500208	Return on Equity
Oklahoma Gas & Electric Company	07/11	Oklahoma Gas & Electric Company	Cause No. PUD201100087	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Cause No. PUD200900055	Return on Equity
Pennsylvania Public Utility Commission				
Pike County Light & Power Company	01/14	Pike County Light & Power Company	Docket No. R-2013-2397237	Return on Equity (electric & gas)
Veolia Energy Philadelphia, Inc.	12/13	Veolia Energy Philadelphia, Inc.	Docket No. R-2013-2386293	Return on Equity (steam)
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a National Grid	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				
South Carolina Electric & Gas	12/17	South Carolina Electric & Gas	Docket No. 2017-305-E	Return on Equity

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

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				
Atmos Energy Corporation – West Texas Division	06/18	Atmos Energy Corporation – West Texas Division	GUD 10743	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/18	Atmos Energy Corporation – Mid-Texas Division	GUD 10742	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	11/17	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10669	Return on Equity
Atmos Pipeline - Texas	01/17	Atmos Pipeline - Texas	GUD 10580	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	12/16	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10567	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	03/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10432	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/12	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10182	Return on Equity
Atmos Energy Corporation – West Texas Division	06/12	Atmos Energy Corporation – West Texas Division	GUD 10174	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/12	Atmos Energy Corporation – Mid-Texas Division	GUD 10170	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	12/10	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline – Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity
Vermont Public Service Board				
Central Vermont Public Service Corporation; Green Mountain Power	02/12	Central Vermont Public Service Corporation; Green Mountain Power	Docket No. 7770	Merger Policy
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)
Virginia State Corporation Commission				
Virginia Electric and Power Company	03/17	Virginia Electric and Power Company	Case No. PUR-2017-00038	Return on Equity
Virginia Natural Gas, Inc.	03/17	Virginia Natural Gas, Inc.	Case No. PUE-2016-00143	Return on Equity
Virginia Electric and Power Company	10/16	Virginia Electric and Power Company	Case No. PUE-2016-00112; PUE-2016-00113; PUE-2016-00136	Return on Equity
Washington Gas Light Company	06/16	Washington Gas Light Company	Case No. PUE-2016-00001	Return on Equity
Virginia Electric and Power Company	06/16	Virginia Electric and Power Company	Case Nos. PUE-2016-00063; PUE-2016-00062; PUE-2016-00061; PUE-2016-00060; PUE-2016-00059	Return on Equity
Virginia Electric and Power Company	12/15	Virginia Electric and Power Company	Case Nos. PUE-2015-00058; PUE-2015-00059; PUE-2015-00060; PUE-2015-00061; PUE-2015-00075; PUE-2015-00089; PUE-2015-00102; PUE-2015-00104	Return on Equity
Virginia Electric and Power Company	03/15	Virginia Electric and Power Company	Case No. PUE-2015-00027	Return on Equity
Virginia Electric and Power Company	03/13	Virginia Electric and Power Company	Case No. PUE-2013-00020	Return on Equity
Virginia Natural Gas, Inc.	02/11	Virginia Natural Gas, Inc.	Case No. PUE-2010-00142	Capital Structure
Columbia Gas of Virginia, Inc.	06/06	Columbia Gas of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies

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Rates, Regulation and Planning Practice Area Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy

Expert Reports

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

Schedule R-(RBH)-1

Summary of Adjustment Clauses & Alternative Regulation/Incentive Plans

Company	Parent	State	Adjustment Clauses: Fuel/ Purchased Power	Decoupling (F/P) [1]	Capital Investment (New and Replacement) [2]	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]
Ameren Illinois Company	AEE	IL	✓		✓	✓	✓	✓	✓
Union Electric Company	AEE	MO	✓	P		✓		✓	✓
Southwestern Electric Power Company	AEP	AR	✓	P	✓	✓		✓	✓
Indiana Michigan Power Company	AEP	IN	✓	P	✓	✓	✓	✓	✓
Kentucky Power Company	AEP	KY	✓	P	✓	✓		✓	✓
Southwestern Electric Power Company	AEP	LA	✓	P	✓	✓		✓	✓
Indiana Michigan Power Company	AEP	MI	✓	P		✓	✓	✓	✓
Ohio Power Company	AEP	OH	✓	F	✓	✓	✓		✓
Public Service Company of Oklahoma	AEP	OK	✓	P		✓			✓
Kingsport Power Company	AEP	TN	✓						✓
AEP Texas Central Company	AEP	TX	NA		✓	✓		✓	✓
AEP Texas North Company	AEP	TX	NA		✓	✓			✓
Southwestern Electric Power Company	AEP	TX	✓		✓	✓	✓		✓
Appalachian Power Company	AEP	VA	✓		✓	✓	✓	✓	✓
Appalachian Power/Wheeling Power	AEP	WV	✓		✓	✓			✓
ALLETE (Minnesota Power)	ALE	MN	✓			✓	✓	✓	✓
Superior Water, Light and Power Company	ALE	WI	✓						
Consumers Energy Company	CMS	MI	✓			✓	✓		✓
Duke Energy Florida, LLC	DUK	FL	✓			✓		✓	✓
Duke Energy Indiana, LLC	DUK	IN	✓	P	✓	✓	✓	✓	✓
Duke Energy Kentucky, Inc.	DUK	KY	✓	P		✓		✓	✓
Duke Energy Carolinas, LLC	DUK	NC	✓	P		✓	✓	✓	✓
Duke Energy Progress, LLC	DUK	NC	✓		✓	✓	✓		
Duke Energy Ohio, Inc.	DUK	OH	✓	P	✓	✓	✓		✓
Duke Energy Carolinas, LLC	DUK	SC	✓	P		✓	✓	✓	✓
Duke Energy Progress, LLC	DUK	SC	✓			✓	✓	✓	✓
Rockland Electric Company	ED	NJ	✓			✓	✓		✓
Consolidated Edison Company of New York, Inc.	ED	NY	✓	F	✓	✓	✓	✓	✓
Orange and Rockland Utilities, Inc.	ED	NY	✓	F	✓	✓	✓		✓
El Paso Electric Company	EE	NM	✓			✓			✓
El Paso Electric Company	EE	TX	✓			✓			✓
Connecticut Light and Power Company	ES	CT	✓	F		✓		✓	✓
NSTAR Electric Company	ES	MA	✓	F	✓	✓	✓		✓
Western Massachusetts Electric Company	ES	MA	✓	F	✓	✓	✓		✓
Public Service Company of New Hampshire	ES	NH	✓	P		✓			✓
Idaho Power Co.	IDA	ID	✓	F		✓			✓
Idaho Power Co.	IDA	OR	✓			✓	✓	✓	✓
Interstate Power and Light Company	LNT	IA	✓			✓	✓	✓	✓
Wisconsin Power and Light Company	LNT	WI	✓						
NorthWestern Corporation	NWE	MT	✓			✓			✓
NorthWestern Corporation	NWE	SD	✓			✓		✓	✓
Oklahoma Gas and Electric Company	OGE	AR	✓	P	✓	✓		✓	✓
Oklahoma Gas and Electric Company	OGE	OK	✓	P		✓			✓
Otter Tail Power Company	OTTR	MN	✓		✓	✓	✓	✓	✓
Otter Tail Power Company	OTTR	ND	✓		✓		✓	✓	✓
Otter Tail Power Company	OTTR	SD	✓		✓	✓		✓	✓
Public Service Company of New Mexico	PNM	NM	✓			✓	✓		✓
Texas New Mexico Power	PNM	TX	NA		✓	✓			✓
Arizona Public Service Company	PNW	AZ	✓	P		✓	✓	✓	✓
Portland General Electric Company	POR	OR	✓	P		✓	✓	✓	✓
Alabama Power Company	SO	AL	✓		✓			✓	✓
Gulf Power Company	SO	FL	✓			✓		✓	✓
Georgia Power Company	SO	GA	✓		✓	✓		✓	✓
Mississippi Power Company	SO	MS	✓	P		✓	✓	✓	✓
Public Service Company of Colorado	XEL	CO	✓	P	✓	✓	✓	✓	✓
Northern States Power Company - WI	XEL	MI	✓			✓			
Northern States Power Company - MN	XEL	MN	✓	F	✓	✓	✓	✓	✓
Northern States Power Company - MN	XEL	ND	✓		✓		✓		✓
Southwestern Public Service Company	XEL	NM	✓			✓	✓		✓
Northern States Power Company - MN	XEL	SD	✓	P	✓	✓		✓	✓
Southwestern Public Service Company	XEL	TX	✓		✓	✓			✓
Northern States Power Company - WI	XEL	WI	✓						

Note: Texas electric T&D-only, do not have retail provider of last resort obligations, therefore fuel/power recovery is not applicable. A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category.

[1] Full or partial decoupling (such as Straight-Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs).

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

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

[4] Recovers costs associated with renewable energy projects, clean energy, Distributed Energy Resources, REC purchases, net metering, RPS expense, and renewable PPAs.

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

[6] Pension expenses, bad debt costs, storm costs, vegetation management, RTO/Transmission Expense, capacity costs, transmission costs, government & franchise fees and taxes, economic development, and low income programs.

Company	Parent	State	Alternative Regulation / Incentive Plans: Formula-Based Rates	Price Freeze/ Cap	Earnings Sharing	Formula-Based ROE	Service Quality/ Performance	Merger Savings
Ameren Illinois Company	AEE	IL	✓		✓	✓	✓	
Union Electric Company	AEE	MO						
Southwestern Electric Power Company	AEP	AR						
Indiana Michigan Power Company	AEP	IN						
Kentucky Power Company	AEP	KY						
Southwestern Electric Power Company	AEP	LA	✓	✓	✓			
Indiana Michigan Power Company	AEP	MI						
Ohio Power Company	AEP	OH		✓	✓			
Public Service Company of Oklahoma	AEP	OK						
Kingsport Power Company	AEP	TN						
AEP Texas Central Company	AEP	TX						
AEP Texas North Company	AEP	TX						
Southwestern Electric Power Company	AEP	TX						
Appalachian Power Company	AEP	VA			✓	✓	✓	
Appalachian Power/Wheeling Power	AEP	WV						
ALLETE (Minnesota Power)	ALE	MN						
Superior Water, Light and Power Company	ALE	WI						
Consumers Energy Company	CMS	MI						
Duke Energy Florida, LLC	DUK	FL		✓				
Duke Energy Indiana, LLC	DUK	IN		✓				
Duke Energy Kentucky, Inc.	DUK	KY						
Duke Energy Carolinas, LLC	DUK	NC		✓				
Duke Energy Progress, LLC	DUK	NC						
Duke Energy Ohio, Inc.	DUK	OH			✓			
Duke Energy Carolinas, LLC	DUK	SC		✓				
Duke Energy Progress, LLC	DUK	SC						
Rockland Electric Company	ED	NJ						
Consolidated Edison Company of New York, Inc.	ED	NY			✓			
Orange and Rockland Utilities, Inc.	ED	NY		✓	✓			
El Paso Electric Company	EE	NM						
El Paso Electric Company	EE	TX						
Connecticut Light and Power Company	ES	CT		✓	✓			
NSTAR Electric Company	ES	MA		✓			✓	
Western Massachusetts Electric Company	ES	MA		✓			✓	
Public Service Company of New Hampshire	ES	NH		✓	✓			
Idaho Power Co.	IDA	ID			✓			
Idaho Power Co.	IDA	OR						
Interstate Power and Light Company	LNT	IA		✓				
Wisconsin Power and Light Company	LNT	WI		✓	✓			
NorthWestern Corporation	NWE	MT						
NorthWestern Corporation	NWE	SD						
Oklahoma Gas and Electric Company	OGE	AR						
Oklahoma Gas and Electric Company	OGE	OK						
Otter Tail Power Company	OTTR	MN						
Otter Tail Power Company	OTTR	ND						
Otter Tail Power Company	OTTR	SD						
Public Service Company of New Mexico	PNM	NM						
Texas New Mexico Power	PNM	TX						
Arizona Public Service Company	PNW	AZ		✓				
Portland General Electric Company	POR	OR						
Alabama Power Company	SO	AL	✓					
Gulf Power Company	SO	FL						
Georgia Power Company	SO	GA		✓	✓			
Mississippi Power Company	SO	MS	✓			✓	✓	
Public Service Company of Colorado	XEL	CO		✓	✓			
Northern States Power Company - WI	XEL	MI						
Northern States Power Company - MN	XEL	MN						
Northern States Power Company - MN	XEL	ND						
Southwestern Public Service Company	XEL	NM		✓				
Northern States Power Company - MN	XEL	SD		✓				
Southwestern Public Service Company	XEL	TX		✓				
Northern States Power Company - WI	XEL	WI						

Sources: Company SEC Form 10-Ks; Operating company tariffs as of September 2018; Regulatory Research Associates, *Alternative Regulation/Incentive Plans: A State-by-State Overview*, November 19, 2013; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview, September 28, 2018*.

Schedule R-(RBH)-2

Moody's Issuer Ratings for Dr. Griffing's Proxy Group

Company	Issuer Rating	Rank	Outlook
ALLETE, Inc.	A3	1	Negative
Alliant Energy Corporation	Baa1	2	Negative
Ameren Corporation	Baa1	2	Stable
American Electric Power	N/A	N/A	
CMS Energy Corporation	N/A	N/A	
Consolidated Edison, Inc.	A3	1	Negative
Duke Energy	Baa1	2	Stable
El Paso Electric	Baa1	2	Negative
Eversource Energy	Baa1	2	Stable
IDACORP, Inc.	Baa1	2	Stable
NorthWestern Corporation	N/A	N/A	
OGE Energy Corp.	N/A	N/A	
Otter Tail Corp.	Baa2	3	Stable
Pinnacle West Capital Corporation	A3	1	Stable
PNM Resources, Inc.	Baa3	4	Stable
Portland General Electric Company	A3	1	Stable
Southern Co.	N/A	N/A	
Xcel Energy Inc.	A3	1	Stable
Proxy Group Average:	A3 / Baa1	1.8	
Proxy Group Median:	Baa1	2.0	
Atlantic City Electric Company	Baa2	3	Positive

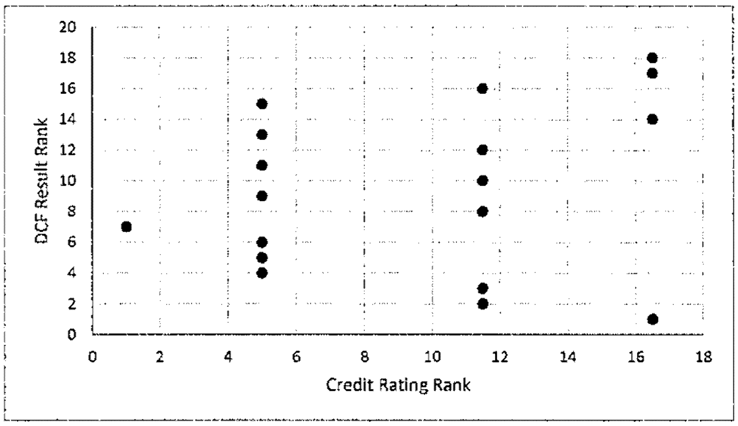
Source: S&P Global Market Intelligence

Schedule R-(RBH)-3

Sources: Exhibits MFG-14 and MFG-18, Schedule 3
(S&P Global Intelligence for updated OGE and POR issuer ratings)

Correlation	23.77%
R-Square	5.65%
Count	18
Degrees of Freedom	16
alpha	5.00%
Critical Value	46.83%
Significant?	NO
p-value	34.22%
Significant?	NO

Company	Ticker	Credit Rating	Credit Rating (Numerical)	Rank	DCF Result	Rank
ALLETE, Inc.	ALE	BBB+	3	11.5	8.73%	10
Alliant Energy Corporation	LNT	A-	4	5	9.24%	5
Ameren Corporation	AEE	BBB+	3	11.5	10.04%	2
American Electric Power	AEP	A-	4	5	8.91%	9
CMS Energy Corporation	CMS	BBB+	3	11.5	9.87%	3
Consolidated Edison, Inc.	ED	A-	4	5	6.87%	15
Duke Energy	DUK	A-	4	5	9.55%	4
El Paso Electric	EE	BBB	2	16.5	7.04%	14
Eversource Energy	ES	A+	6	1	9.08%	7
IDACORP, Inc.	IDA	BBB	2	16.5	5.61%	18
NorthWestern Corporation	NWE	BBB	2	16.5	6.54%	17
OGE Energy Corp.	OGE	BBB+	3	11.5	9.01%	8
Otter Tail Corp.	OTTR	BBB	2	16.5	11.25%	1
Pinnacle West Capital	PNW	A-	4	5	7.99%	13
PNM Resources, Inc.	PNM	BBB+	3	11.5	8.38%	12
Portland General Electric	POR	BBB+	3	11.5	6.77%	16
Southern Co.	SO	A-	4	5	8.40%	11
Xcel Energy Inc.	XEL	A-	4	5	9.16%	6
Average					8.47%	
Median					8.82%	



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.237703044
R Square	0.056502737
Adjusted R Square	-0.002465842
Standard Error	5.345117071
Observations	18

ANOVA

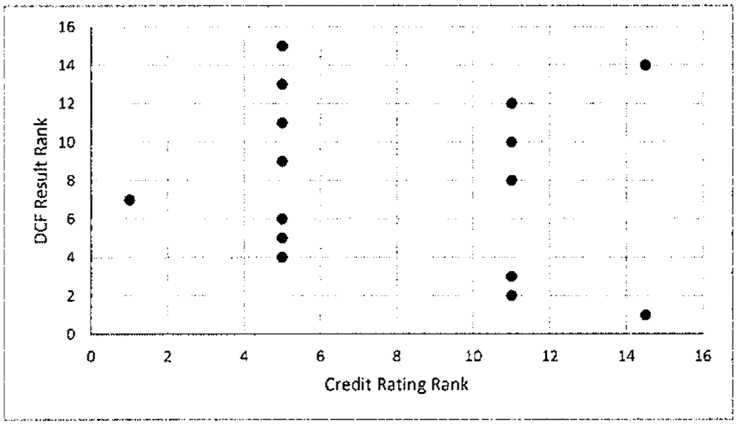
	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	27.37557604	27.375576	0.9581838	0.3422148
Residual	16	457.124424	28.5702765		
Total	17	484.5			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	7.114055	2.743794	2.592780	0.019626	1.297471	12.930639	1.297471	12.930639
Credit Rating Rank	0.251152	0.256574	0.978869	0.342215	-0.292760	0.795064	-0.292760	0.795064

Sources: Exhibits MFG-14 and MFG-18, Schedule 3
(S&P Global Intelligence for updated OGE and POR issuer ratings)

Correlation	-13.65%
R-Square	1.86%
Count	15
Degrees of Freedom	13
alpha	5.00%
Critical Value	51.40%
Significant?	NO
p-value	62.76%
Significant?	NO

Company	Ticker	Credit Rating	Credit Rating (Numerical)	Rank	DCF Result	Rank
ALLETE, Inc.	ALE	BBB+	3	11	8.73%	10
Alliant Energy Corporation	LNT	A-	4	5	9.24%	5
Ameren Corporation	AEE	BBB+	3	11	10.04%	2
American Electric Power	AEP	A-	4	5	8.91%	9
CMS Energy Corporation	CMS	BBB+	3	11	9.87%	3
Consolidated Edison, Inc.	ED	A-	4	5	6.87%	15
Duke Energy	DUK	A-	4	5	9.55%	4
El Paso Electric	EE	BBB	2	14.5	7.04%	14
Eversource Energy	ES	A+	6	1	9.08%	7
OGE Energy Corp.	OGE	BBB+	3	11	9.01%	8
Otter Tail Corp.	OTTR	BBB	2	14.5	11.25%	1
Pinnacle West Capital	PNW	A-	4	5	7.99%	13
PNM Resources, Inc.	PNM	BBB+	3	11	8.38%	12
Southern Co.	SO	A-	4	5	8.40%	11
Xcel Energy Inc.	XEL	A-	4	5	9.16%	6
Average					8.90%	
Median					9.01%	



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.136518268
R Square	0.018637238
Adjusted R Square	-0.056852206
Standard Error	4.597504118
Observations	15

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5.218426501	5.2184265	0.24688535	0.62757332
Residual	13	274.7815735	21.1370441		
Total	14	280			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	9.175983	2.647767	3.465555	0.004181	3.455830	14.896137	3.455830	14.896137
Credit Rating Rank	-0.146998	0.295845	-0.496876	0.627573	-0.786131	0.492135	-0.786131	0.492135

I/M/O Petition of Atlantic City Electric Company for Approval of an Infrastructure Investment Program, and Related Cost Recovery Mechanism, Pursuant to N.J.A.C. 14:3-2A.1 *et seq.*
BPU Docket No. EO18020196
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