Witness OCS - 3D

BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE JOINT NOTICE AND APPLICATION OF QUESTAR GAS COMPANY AND DOMINION RESOURCES, INC. OF PROPOSED MERGER OF QUESTAR CORPORATION AND DOMINION RESOURCES, INC.	**))))))**	**DOCKET NO. 16-057-01**

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

OFFICE OF CONSUMER SERVICES

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

JULY 7, 2016

DIRECT TESTIMONY OF RICHARD A. BAUDINO

QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ____(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Utah Office of Consumer Services ("OCS").

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to address the credit quality and service quality risks to customers resulting from the proposed merger between Dominion Resources, Inc. ("Dominion") and Questar Gas Company ("Questar") and to present my conclusions and recommendations regarding certain customer protections in the form of conditions that should be ordered by the Public Service Commission of Utah ("Commission") if it approves the merger. The risks and conditions that I address are a subset of the risks and conditions that have been identified by the OCS and that are addressed more generally by OCS witness Mr. Lane Kollen.

Q. Please summarize your testimony.

A. Consistent with the Direct Testimony of OCS witness Mr. Kollen, I recommend that the Commission deny the proposed merger unless it imposes necessary conditions to protect ratepayers from adverse consequences in the areas of credit quality and service quality. I recommend that the Commission order the following conditions if it approves the proposed merger:

1. Questar Gas Company shall not pass through any increases in credit costs caused by the proposed merger. Credit Costs shall be defined as incremental costs of common equity, costs of new issuances of long-term debt, and costs of short-term debt due to any downgrading in corporate wide credit and/or utility-specific credit rating(s) within ten years after announcement of merger as well as the effects of any increases in common equity as a percentage of capitalization.
2. Questar Gas Company's cost of equity shall be determined using a comparable group gas utilities with A bond ratings regardless of whether Questar Gas Company is rated A or is downgraded.
3. Dominion shall continue to provide no less than the same access to short-term debt, commercial paper, and other liquidity that Questar currently has in place. Questar's total liquidity through its current arrangements is $750 million.
4. Questar Gas Company shall continue to comply with the Commission's service quality guidelines adopted in Docket No. 02-057-02. The Commission and Division of Public Utilities (DPU) will continue to monitor current service quality measures as reported by Questar Gas Company. The "Annual Goals" currently contained in Questar's customer satisfaction standards shall be changed to "Minimum Service Metrics". The Commission should also impose financial penalties if Dominion fails to achieve the Minimum Service Metrics.

CREDIT QUALITY RISKS AND PROTECTIONS

Q. Please describe how the applicants intend to finance the proposed merger.

A. Applicants witness Fred Wood described the proposed financing for the merger beginning on line 70 of his Direct Testimony. Initially, Dominion will rely on bridge and term loans with various financial institutions and its own credit facility. These resources are expected to provide the entire $4.4 billion needed to fund the exchange of Questar Corporation for cash. Mr. Wood further testified that Dominion plans to use the proceeds from permanent financings "to preclude the need for or replace any funds borrowed under these existing credit facility, bridge and term loan agreements."

Questar Corporation and its subsidiaries' existing indebtedness, which total $1.7 billion as of December 31, 2015, will remain outstanding at Questar Corporation, Questar Gas, and Questar Pipeline, all of which will become direct or indirect subsidiaries of Dominion.

The Applicants provided additional information about the merger financing on page 19 of their presentation at the Utah Technical Conference dated April 28, 2016. Please refer to Exhibit ____(RAB-2) for the referenced page from this presentation. The contemplated permanent financing after closing the proposed merger transaction will consist of $1.45 billion of Dominion senior notes, $1.25 billion of Mandatory Convertible securities, $0.50 billion of Dominion equity, and $1.20 million of Master Limited Partnership drop proceeds.

Q. Have the major bond rating agencies responded to the proposed merger?

A. Yes. The Applicants provided rating agency reports from Fitch, Standard and Poor's ("S&P"), and Moody's that addressed the proposed merger with the attendant effects on Dominion's and Questar's ratings outlooks. Mr. Wood summarized the Applicants' credit and bond ratings and the ratings outlooks on pages 5 and 6 of his Direct Testimony.

Dominion's credit rating was lowered from A- to BBB+ by S&P after the merger announcement. S&P's rating outlook for Dominion is now stable. Fitch affirmed Dominion's Issuer Default Rating of BBB+. Moody's affirmed Dominion's corporate credit rating of Baa2.

Questar Corporation currently has an A credit rating from S&P. Questar Gas has an A2 rating from Moody's and an A rating from S&P. After the merger announcement, Questar Corporation's ratings were put on a review for downgrade from Moody's and were placed on a negative credit watch from S&P. Questar Gas' credit rating was affirmed by Moody's but was placed on a negative credit watch from S&P.

Q. What were the reasons expressed by S&P with respect to the credit rating outlook for Questar as a result of the proposed merger?

A. As Mr. Wood noted in his Direct Testimony, the negative outlook is associated with S&P's use of a group rating methodology for Questar once it becomes part of the Dominion corporate family. S&P stated that it expected to view Questar as "core to

Dominion and therefore Questar's issuer credit rating would be aligned with Dominion's ‘BBB+’ group credit profile". S&P went on to state the following:

The ratings on Questar, QGC, and QPC are on CreditWatch with negative implications, reflecting the prospect for a two-notch downgrade of Questar's issuer credit rating to 'BBB+' due to the company's agreement to be acquired by DRI. We expect to resolve the CreditWatch listing by the date of the transaction's closing, which could be by year-end 2016.

We could lower our ratings on Questar, QGC, and QPC to align them with our ratings on DRI. (Joint Application, Exhibit 1.14, page 9 of 12)

Q. Mr. Baudino, what is your conclusion with respect to the credit risks for Questar from the proposed merger?

A. S&P's comments with respect to the negative outlook for Questar suggest that Questar Gas may lose it’s A credit rating once the merger is completed. This would be due to the way that S&P employs its group rating methodology. Such a downgrading would be the direct result of the merger and Dominion’s lower credit quality.

Q. If Questar Gas lost its A rating from S&P, is it possible that the Company's cost of capital would increase?

A. Yes. With a lower credit rating Questar Gas could face an increased cost of debt and equity. BBB-rated debt costs are higher than A-rated debt cost. For example, the Mergent Bond Record showed that the May 2016 yield on Baa public utility bonds was 4.60% compared to the A-rated public utility bond yield of 3.93%, a difference of 67 basis points.

In addition, since BBB/Baa rated utilities are perceived as riskier than A/A rated companies by investors, the required return on equity would also be higher. Thus, if Questar Gas is downgraded by S&P, the cost of equity would likely increase as well.

Q. Given the risk of downgrading and the attendant increase in the cost of capital for Questar, do you recommend that the Commission include measures to protect Utah ratepayers in the event that Questar's credit ratings are lowered due to the proposed merger?

A. Yes. I recommend that the Commission condition its approval of the proposed merger such that neither Questar nor Dominion may pass through to Utah customers any increases in the cost of debt and/or equity that result from the proposed merger. Absent such a condition with attendant credit protection measures, the Commission should deny the proposed merger.

Q. How could the Commission implement the credit risk protection that you recommend?

A. In the event of credit rating downgrades for Questar wherein the rating agency cites the merger as a factor in the downgrade, I recommend the Commission implement the following conditions:

1. For new long-term debt issued by Questar and/or Dominion on behalf of Questar, the Commission should use the lower of (1) an imputed debt cost with a rating

equal to the rating before the downgrade, or (2) the actual debt cost. For Questar, the current bond rating is A/A from S&P and Moody's.

2. For all short-term debt, the Commission should use the lower of (1) an imputed A-rated debt cost, or (2) the actual debt cost, whichever is lower.

3. Questar's return on equity should be based on a comparison group of A-rated gas utilities.

Utah ratepayers must be protected from any resulting higher cost of debt that results from the proposed merger. Tying the cost of any new debt to the lower of actual debt cost or the pre-merger debt rating cost ensures adequate and reasonable protection for ratepayers.

This is also true for any increases in Questar's cost of equity resulting from a rating downgrade from the merger. If, for example, Questar's credit rating were lowered to BBB/Baa from its current A/A rating, the cost of equity would also rise as investors would consider Questar a higher risk company and, in turn, require a higher cost of equity. Utah ratepayers must be protected from this adverse outcome. Imputing a cost of equity based on A/A rated utilities would provide such a protection.

Q. Should this protection be extended to short-term debt cost?

A. Yes. After the closing, Questar Gas Company will obtain its short term financing through the Dominion credit facility and other Dominion sources of capital instead of through Questar Corporations' credit facility and other sources of capital. A credit downgrade of Dominion could affect the cost of short-term borrowing for Questar Gas. For example, Dominion has $4.5 billion of commercial paper, letters of credit, and additional capacity available under credit facilities as of December 31, 2015. Dominion's credit facilities and short-term debt are described on page 51 of its 2015 10-K Report that was included as Exhibit 1.10 in the Applicants' Joint Application. If the cost of borrowings under these credit facilities is negatively affected from bond downgrades, ratepayers should be protected from any such increased costs.

Q. Turning to short-term debt, what changes will the proposed merger cause with respect to Questar's access to short-term debt and other liquidity?

A. On page 12, lines 298 through 300 of his Direct Testimony Mr. Wood testified that Questar "will continue to benefit from access to the commercial paper market in the same manner that it currently utilizes to finance short-term capital needs on a cost-advantaged and efficient basis." Mr. Wood further testified that Dominion Questar Corporation would provide liquidity to Questar Gas "for seasonal working capital and other needs in a manner consistent with Questar Corporation's past practice."

Q. Please describe Questar's current liquidity resources.

A. Questar's 2015 10-K Report described its short-term financing capabilities on page 42 as follows:

> Questar issues commercial paper to meet short-term financing requirements. The commercial-paper program is supported by revolving credit facilities with various banks that provides back-up credit liquidity. Credit commitments under the revolving credit facilities totaled $500 million under the multi-year credit facility and $250 million under the 364-day facility at December 31, 2015, with no amounts borrowed. The credit facilities expire upon a change of control such as the proposed Merger with Dominion Resources. However, the Company has amended its credit facilities to extend through the closing of the proposed Merger with Dominion Resources. Commercial paper outstanding amounted to $457.6 million at December 31, 2015, compared with $347.0 million a year earlier. Availability under the revolving credit facilities is reduced by outstanding commercial paper amounts, resulting in net availability under the facilities of

$292.4 million at December 31, 2015. Under the facilities, consolidated funded debt cannot exceed 70% of consolidated capitalization.

In summary, Questar has a total of $750 million of short-term debt and credit facilities to meet short-term financing requirements, which include working capital.

Q. What is your recommendation with respect to assuring that Questar continues to have adequate access to needed liquidity, including working capital needs, if the Commission approves the proposed merger?

A. I recommend that the Commission order Dominion to provide Questar no less than the same access to liquidity it currently has under its existing short-term debt and commercial paper arrangements, which currently stands at $750 million. Questar and its customers must be assured that Questar will have sufficient access to liquidity after the merger with Dominion is consummated.

Q. Did the Applicants propose any consumer protections with respect to the cost of capital as part of their Application in this case?

A. In the aforementioned April 28, 2016 presentation, the Applicants outlined a number of so-called "ring fencing" provisions for Questar on page 18. Please refer to Exhibit ____(RAB-2) for this page. With respect to cost of capital protections, the Applicants proposed the following:

- Maintain status as a standalone issuer of long-term debt
- Maintain current debt and equity capital ratios
- Maintain credit metrics that support strong investment-grade credit ratings

- Maintain issuer credit ratings from independent credit rating agencies

Q. What is ring fencing and what is the purpose of ring fencing?

A. In this case, ring fencing refers to protections provided to a regulated utility company that shield that company from risks from its affiliates and/or parent company. These risks may take the form of operational risks and credit risks. A primary goal of ring fencing is to protect the regulated utility company from harm due to the financial risk, including bankruptcy risk, of its affiliates and/or parent company. Ring fencing also protects the regulated utility from having its assets depleted or compromised by an affiliate. Ring fencing also ensures that customers are not harmed from the results of corporate restructurings, such as the costs that are or may be incurred due to the transaction proposed in this proceeding.

Q. Are the Applicants' proposed ring fencing provisions for cost of capital sufficient for Commission approval of the merger?

A. No. The Applicants' ring fencing provisions are not specific enough and do not go far enough to protect Utah ratepayers. Tying cost of capital protections to Questar's credit and bond ratings before the merger announcement is critical to protect ratepayers from the adverse consequences of a downgrade of Questar's debt securities.

I do agree that the Commission should maintain the currently approved debt and equity ratios for Questar. It is my understanding that Questar will be filing a rate case soon and the Commission should order that its decision on the ratemaking capital structure for Questar in that docket be maintained after the proposed merger is completed.

I also agree with Dominion's commitment to maintain Questar's status as a standalone issuer of debt.

With respect to Dominion's commitment to maintain issuer credit ratings, it appears that there is a strong likelihood that S&P will downgrade Questar's credit rating as a result of the proposed merger. Thus, this stated commitment from Dominion likely cannot be upheld without the additional protections that I recommend.

Q. Are you aware of credit quality protections that were part of other merger proceedings before the Commission?

A. Yes. In Docket No. 98-2035-04 the Commission Report and Order dated November 23, 1999 approved a Stipulation among the parties to that case as part of its approval of a merger between Scottish Power PLC and PacifiCorp. Among other things, the Commission's Report and Order provided the following on page 8:

Financial Issues. Applicants agree that any reduction in the cost of capital will be reflected in rates in Utah, but any increase in the cost of capital of electric operations of PacifiCorp that is a direct result of the merger will be borne by shareholders (Condition 25). Applicants also agree that a hypothetical capital structure based on A-rated electric utilities comparable to PacifiCorp should be used to determine the correct cost of capital for ratemaking purposes (Condition 19). In addition, Applicants agree to maintain separate long-term debt (Condition 21) and to apply to the Commission for approval of debt issuances (Condition 22).

In Docket No. 05-035-54 the Commission's Report and Order dated June 5, 2006 adopted a Stipulation as part of its approval for a merger between PacifiCorp and MidAmerican Energy Holdings Company. Paragraph 21 of that Stipulation provided for the following:

> 21) MEHC and PacifiCorp, in future Commission proceedings, will not seek a higher cost of capital than that which PacifiCorp would have sought if the transaction had not occurred. Specifically, no capital financing costs should increase by virtue of the fact that PacifiCorp was acquired by MEHC.

SERVICE QUALITY ISSUES AND PROTECTIONS

Q. Does the Commission currently monitor the quality of service for Questar?

A. Yes. Questar currently files annual Customer Satisfaction Standards ("CSS") reports on a variety of service quality indices with the Commission. This comprehensive set of service quality standards resulted from a Settlement agreed to by members of the Service Standards Task Force in Docket No. 02-057-02. The Applicants included the 2015 CSS report as Exhibit 2.2 attached to the Joint Application.

Q. What are the service quality measures reported by Questar in its CSS reports?

A. Questar's CSS reports cover a broad range of customer service and satisfaction components in the following general areas:

- Overall impression of Questar Gas Company
- Customer care

- Customer affairs
- Service Calls - Ask-A-Tech
- Service Calls
- Billing

Each component within the broad areas listed above have Annual Goals associated with performance. Please refer to Exhibit ____(RAB-3) for a summary of the customer service and satisfaction Annual Goals and Questar's annual performance associated with each service quality goal for the years 2010 through 2015.

Q. How has Questar performed with respect to the Annual Goals contained in the CSS reports?

A. With three exceptions, Questar has met or exceeded every one of the Annual Goals for each service quality component for the six-year period shown in Exhibit ____(RAB-3). I highlighted the three instances in which Questar did not meet the Annual Goals.

Q. Did the applicants submit testimony with respect to the effect of the proposed merger on Questar's service quality?

A. Applicants' witness Diane Leopold addressed customer service beginning on page 13 of her Direct Testimony. Ms. Leopold testified at lines 330 through 331 that Dominion "intends to maintain Dominion Questar Gas' customer service at or better than current levels and will strive for continued improvements thereto."

Q. How does Dominion intend to maintain or improve Questar's customer service after the merger?

A. The OCS asked Dominion to explain how Dominion intended to maintain customer service after the merger in its Data Request 2.67. The Applicants' response is included in my Exhibit ____(RAB-4). In its response, the Applicants stated that Dominion "plans to continue to monitor and evaluate the customer service standards and metrics currently approved by the Utah Public Service Commission."

Q. Is it enough for Dominion to simply "monitor and evaluate" the customer service standards currently in place for Questar?

A. No. Dominion should be held to a higher standard of performance than a simple monitoring and evaluating of current performance goals.

Utah ratepayers must be assured that Questar's current customer satisfaction performance will not deteriorate after the proposed merger is completed. The risk for customers post-merger is that customer service could decline if Dominion were to reduce staffing levels in an effort to cut its costs and pass the savings on to shareholders. The DPU, OCS (when it was previously known as The Committee), and the other parties worked to carefully construct a suite of customer satisfaction goals in order to assure Utah ratepayers excellent levels of service from Questar. That commitment must be carried forward by Dominion and continue to be monitored by the Commission.

Q. How should the Commission ensure that Questar's service quality and satisfaction

does not decline if it approves the proposed merger?

A. First, I recommend that the Commission order Dominion to continue its commitment to the currently effective CSS reporting requirements for Questar. In this regard, I further recommend that Dominion be required to submit reports quarterly, rather than annually. Questar had been filing quarterly CSS reports until 2014, when the Commission allowed Questar to file annual reports. If the Commission approves the merger, it would be prudent and reasonable to return to quarterly reporting for Dominion Questar so that the Commission and DPU can closely and regularly monitor the impact of the merger on the CSS standards established by the Commission in Docket 02-057-02.

Second, I recommend that the "Annual Goals" for each service criterion in the CSS report be renamed "Minimum Service Metrics". Simply having a goal to shoot for is insufficient incentive for Dominion to maintain service quality and satisfaction for Utah customers after the merger. The currently effective Annual Goals must now be considered minimum achievable service metrics to which Dominion must adhere. Dominion should be required by the Commission to maintain these minimum service metrics.

Third, the Commission should assess penalties against Dominion for failing to achieve the Minimum Service Metrics.

Q. Please explain why the Commission should assess penalties against Dominion for failing to maintain Minimum Service Metrics.

A. Dominion should have a strong financial disincentive to allow customer service and satisfaction to decline after the merger. Instituting a penalty for lack of performance will provide an additional inducement for Dominion not to cut back on service quality to Utah ratepayers after completion of the proposed merger.

Q. What is your recommendation with respect to penalties for failing to achieve the Minimum Service Metrics?

A. I recommend that the Commission assess Dominion a $200,000 penalty for failure to achieve one or more of the individual CSS Minimum Service Metrics within each of the six categories of customer satisfaction metrics of the CSS reports.

The penalty would work in the following manner. Within the Customer Care category, if Dominion failed to achieve one of more of the individual performance metrics, the Commission would assess a $200,000 penalty. The recommended penalty would work in a similar fashion for each of the other categories. If, for example, Dominion failed to achieve one or more of the performance metrics in the Service Calls category in addition to the failure to achieve performance metrics in the Customer Care category, then the Commission would assess a total penalty of $400,000.

Penalties would be based on Dominion's performance over a calendar year. Penalties for a particular calendar should then be flowed back to Questar's customers in the following year as a 1-month credit to customer bills and allocated based on dekatherm ("dth") consumption to all customers. Across the six customer satisfaction categories, the maximum total penalty amount would be $1.2 million per year.

Q. Has the Commission approved penalties for lack of customer service quality in prior cases?

A. Yes. In the aforementioned Docket 98-2035-04 the Commission-approved Stipulation included penalties associated with certain customer service guarantees from PacifiCorp. Please refer to Exhibit ____(RAB-5), which includes the customer service standards, performance metrics, and penalties that were contained in an attachment to the Stipulation.

In the aforementioned Docket No. 05-035-04, MidAmerican Energy Holdings Company and PacifiCorp agreed to continue the customer service guarantees and performance standards after its acquisition of PacifiCorp. This agreement was attached to the Commission's Report and Order dated June 5, 2006. Please refer to Exhibit ____(RAB-6) for the relevant page from this agreement.

Q. Does this complete your testimony?

A. Yes.

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570 Colonial Park Drive, Suite 305
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JULY 7, 2016

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

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of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues

HOW WILL DOMINION QUESTAR GAS BE "RING-FENCED"?

- DRI and affiliates will not be able to borrow funds from Dominion Questar Gas ("IRCA")
- Maintain status as a standalone issuer of long-term debt
- Maintain current debt and equity capital ratios
- Maintain credit metrics that support strong investment-grade credit ratings
- Maintain issuer credit ratings from independent credit rating agencies
- Standalone audited financial statements (books and records maintained in SLC)
- Maintain as a separate and distinct legal entity
- Maintain Utah Commission oversight of Dominion Questar Gas dividends
- Appoint a member of Questar's Board of Directors to Dominion's Board of Directors

Exhibit ___ (RAB-2)
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HOW WILL DOMINION FINANCE THE MERGER?

At Announcement	Prior to Closing	At Closing	Permanent Financing
Existing Credit Facility $0.50	DRI Senior Notes **$1.45**	DRI Senior Notes **$1.45**	DRI Senior Notes **$1.45**
Bridge Commitment $2.70	Mandatory Convertible *(converts to equity)* $1.25	Mandatory Convertible *(converts to equity)* $1.25	Mandatory Convertible *(converts to equity)* $1.25
	D equity (complete) $0.50	D Equity (complete) $0.50	D Equity (complete) $0.50
Term Loan Commitment $1.20	Term Loan Commitment $1.20	<u>**Funded**</u> Term Loan (364 day) $1.20	MLP Drop Proceeds *(Equity funded)* $1.20

Note: All amounts in $ billion

Equity content of 67%

SUMMARY OF ANNUAL SERVICE QUALITY PERFORMANCE
QUESTAR GAS COMPANY

	2015 Annual Goal	2015	2014	2013	2012	2011	2010
Overall Impression of QGC							
How satisfied are you with the product and services you receive?	5.9	6.3	6.3	6.2	6.3	6.2	6.2
Delivers Natural gas to my home/good value for price paid	4.9	5.8	5.7	5.7	5.5	5.6	5.6
Keeps me informed when/why natural gas rates change before it happens	5.0	5.4	5.4	5.4	5.5	5.4	5.4
Consistently delivers natural gas to my home without disruption	6.5	6.7	6.6	6.7	6.7	6.7	6.7
Is honest and open in its dealings	5.5	6.0	5.9	5.9	6.1	5.9	5.9
Safely delivers natural gas to my home	6.5	6.6	6.6	6.6	6.6	6.6	6.6
Demonstrates case and concern for people like me	5.0	5.8	5.8	5.7	5.8	5.7	5.7
Customer Care							
Pct. Of call answered within 60 seconds after customer chooses menu option	40%	91.6%	94.2%	82.7%	96.0%	85.3%	88.5%
Pct. Of energency calls answered within 60 seconds by agent	95%	99.3%	99.4%	99.3%	99.6%	99.5%	99.6%
Average wait for customer after menu selection	less than 60 secs.	29	19	70	14	48	35
Callers that hang up after menu choice is made	less than 10%	1.0%	0.7%	2.5%	2.5%	2.4%	2.0%
Amount of time talking with customer and completing request	less than 5 mins.	4.8	4.8	4.8	4.2	4.6	4.4
The phone staff was courteous	6.0	6.7	6.6	6.5	6.5	6.5	6.4
The phone staff was knowledgeable	6.0	6.5	6.4	6.4	6.4	6.5	6.4
My call was answered quickly	5.5	6.2	6.2	6.0	6.0	6.1	6.0
The person I spoke with was able to resolve my issue	6.0	6.4	6.3	6.3	6.3	6.4	6.3
The automated manu was easy to use	5.7	5.9	5.9	5.9	5.8	5.9	5.7
How satisfied are you with the actions taken by Questar Gas in response to your call	5.8	6.4	6.2	6.1	6.3	6.3	6.2
Customer Affairs							
Respond to customer regarding any PSC complaint within 6 business days	100%	100%	100%	100%	100%	100%	100%
Service Calls - Ask-A-Tech							
The technician was courteous	6.2	6.8	6.7	6.8	6.8	6.7	6.7
The technician was knowledgeable	6.2	6.7	6.7	6.7	6.7	6.7	6.6
The technician was able to help me quickly	5.9	6.6	6.6	6.6	6.5	6.4	6.4
The technician was able to help me resolve my issue	5.9	6.6	6.6	6.6	6.6	6.6	6.6
The automated menu was easy to use	5.7	6.3	6.3	5.3	6.3	6.1	6.1
How satisfied are you with the technicians overall performance	6.0	6.8	6.6	6.6	6.6	6.6	6.6
Service Calls							
The service technician was courteous	6.4	6.8	6.9	6.8	6.9	6.8	6.8
The service technician was knowledgeable	6.4	6.7	6.8	6.8	6.8	6.7	6.8
The service technician was able to help me quickly	6.2	6.7	6.6	6.7	6.7	6.7	6.7
The service technician was able to help me resolve my issue	6.2	6.6	6.6	6.7	6.7	6.6	6.7
How satisfied are you with the service technician's overall performance	6.3	6.7	6.7	6.7	6.7	6.7	6.8
Energency calls - company representative is onsite within 1 hour of call	90%	98%	98.50%	97.5%	94.1%	94.4%	95.3%
Remove master seal within 1 business day requested by customer for activation	90%	100%	100%	100%	100.0%	98.5%	99.8%
Activate or reactivate customers' gas service within 3 business days	90%	100%	100%	100%	98.8%	100.0%	100.0%
Keeping customer appointments	90%	97.7%	98.50%	98.3%	99.5%	97.9%	96.2%
Restore interrupted service casued by system failure w/n 1 business day	24 hours	100%	100%	100%	100.0%	100.0%	100.0%
Billing							
Read each meter monthly	99%	97.3%	99%	99.2%	99.7%	99.5%	99.9%
Percent of adjustments	5% Annual	2.45%	2.09%	2.49%	1.99%	2.30%	3.51%
Send corrected statement to customer	7 bus. Days	2.33	2.33	2.25	1.28	1.70	0.23
Percentage of billing inquiries requiring investigation responded to w/n 7 bus. Days	90%	99.9%	99.7%	99.1%	100%	99.5%	99.9%
Response time to investigate meter problems and notify customer w/n 16 business days	90%	100%	100%	99%	100%	100%	100%

P.S.C.U. Docket No. 16-057-01
Data Request No. 2.67
Requested by Office of Consumer Services
Date of QGC Response May 20, 2016

Service Quality

OCS 2.67 Please refer to the Direct Testimony of Diane Leopold, page 13, lines 330 - 331.

a. Please explain in detail how Dominion "intends to maintain Dominion Questar Gas' customer service at or better than current levels and will strive for continued improvements thereto."

b. Will Dominion follow certain customer service quality standards and measures with respect to maintaining and improving Questar's service quality? If so, please provide all such standards and the metrics or goals associated with each standard.

c. Has Dominion identified any areas of Questar's customer service quality that could be improved? If so, please identify each area and explain how Dominion intends to improve service in that area.

Answer:

a. The main factors that drive customer service levels are resources, procedures and training. Dominion has indicated that it plans to operate Dominion Questar Gas in the same manner as it is currently operated, and that includes maintaining the Operator Qualified staffing and other resources needed to deliver the same or better level of customer service. Dominion is also committed to ensuring that employees continue to receive the training needed to be proficient in the customer service tasks they perform. In addition, Dominion has stated that it will also identify and share best practices among its operating companies. That exchange will contribute to continuous improvement in processes and procedures, some of which may improve Dominion Questar Gas customer service levels once evaluated and deployed.

b. Dominion plans to continue to monitor and evaluate the customer service standards and metrics currently approved by the Utah Public Service Commission. For a more detailed discussion of these metrics please see OCS 2.68.

c. Dominion and Questar have not engaged in analysis and best practice sharing to the level of detail needed to identify specific areas of Questar's customer service quality that can be improved.

Prepared by: Jeffrey A. Murphy, Vice President and General Manager, Dominion East Ohio and Dominion Hope

ScottishPower, Richardson
Ex. SP ___ (AVR-1), p. 1
No. 98-2035-04
Supplemental Testimony

BENEFITS TO CUSTOMERS FROM THE TRANSACTION

I.CUSTOMER SERVICE

A. Network Performance

1. System Availability. On the five-year anniversary of the completion of the transaction,[1] the underlying System Average Interruption Duration Index (SAIDI) for PacifiCorp customers in the State of Utah will have been reduced by 10%.

2. System Reliability. On the five-year anniversary of the completion of the transaction, the underlying System Average Interruption Frequency Index (SAIFI) for PacifiCorp customers in the State of Utah will have been reduced by 10%.

3. Momentary Interruptions. On the five-year anniversary of the completion of the transaction, the Momentary Average Interruption Frequency Index (MAIFI) for PacifiCorp customers in the State of Utah will have been reduced by 5%.

4. Worst Performing Circuits. The 5 worst performing circuits in the State of Utah will be selected annually on the basis of the Circuit Performance Indicator (CPI),[2] as calculated over a three-year average excluding extreme events. Corrective measures will be taken within 2 years of implementation of the performance targets to reduce the CPI by 20%.

5. Supply Restoration. For power outages because of a fault or damage on PacifiCorp's system, PacifiCorp will restore supplies on average to 80% of customers within 3 hours.

6. Penalties. For each of the standards not achieved in the State of Utah at the end of the five-year period, ScottishPower will pay a financial penalty equal to $1.00 for every customer served by PacifiCorp in Utah.

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[1] Reference to "completion of the transaction" throughout this document means the closing of the transaction pursuant to the Amended Merger Agreement.

[2] The CPI is a weighted, composite index based on the following four factors: (1) MAIFI, (2) SAIDI, (3) SAIFI, and (4) number of lockouts.

7. Implementation. Specific terms and conditions relating to the implementation of the Network Performance Standards are set forth in Appendix A.[3]

B. Customer Service Performance

1. Telephone Service Levels. Within 120 days after completion of the transaction, 80% of calls to PacifiCorp's Business Centers will be answered within 30 seconds. This target will be increased to 80% in 20 seconds by January 1, 2001 and 80% in 10 seconds by January 1, 2002.

2. Complaint Resolution.

a. Non-Disconnect Complaints. Within 90 days after completion of the transaction, PacifiCorp will investigate and provide a response to all complaints referred by the Commission within 3 business days.[4]

b. Disconnect Complaints. Within 90 days after completion of the transaction, complaints related to service disconnection will be responded to within 4 business hours.[5]

c. Commission Complaints. Within 90 days after completion of the transaction, ninety percent of complaints referred to PacifiCorp by the Commission will be resolved within 30 days. This percentage will be increased to 95 percent by 2001.

3. Implementation. Specific terms and conditions relating to the implementation of the Customer Service Performance Standards are set forth in Appendix A.

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[3] Initial benchmarks for SAIDI, SAIFI and MAIFI will be established based upon PacifiCorp's historical performance, adjusted as necessary where the change in measurement and monitoring accuracy results in a change in the reported (but not actual) reliability indices, as discussed in Mr. Moir's testimony at page 7.

[4] Business days are defined as Monday through Friday excluding company holidays.

[5] Business hours are defined as 8:00 a.m. to 5:00 p.m.

C. Customer Service Guarantees

1. Restoring the Customer's Supply.

a. Guarantee. If the customer loses electricity supply because of a fault in PacifiCorp's system, PacifiCorp will restore the customer's supply as soon as possible.

b. Penalty. If power is not restored in 24 hours, customers can claim $50 for residential customers and $100 for commercial and industrial customers. For each extra period of 12 hours the customer's supply has not been activated, the customer can claim $25.

2. Appointments.

a. Guarantee. PacifiCorp will keep all mutually agreed appointments with the customer, whether over the phone or in writing. Beginning in the year 2001, PacifiCorp will offer the customer a morning appointment, between 8 AM and 1 PM, or an afternoon appointment, between 12 Noon and 5 PM.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50.

3. Switching On the Customer's Power.

a. Guarantee. Upon customer request, PacifiCorp will activate the power supply within 24 hours provided no construction is required and all government requirements are met.

b. Penalty. If PacifiCorp fails to meet its guarantee, it will automatically pay the customer $50. In addition, for each extra period of 12 hours the customers power supply has not been activated, PacifiCorp will automatically pay-out $25 to the customer.

4. Estimates for Providing a New Supply.

a. Guarantee. Upon request by a customer for new power supply, PacifiCorp will call the customer back within 2 business days of the customer's initial call and schedule a mutually agreed appointment with an estimator. If PacifiCorp needs to change its network, it will provide a written estimate to the customer within

15 business days of the customer's initial meeting with the estimator. If PacifiCorp does not need to change its network, it will provide an estimate to the customer within 5 business days of the customer's initial meeting with the estimator.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

5. Response to Bill Inquiry.

a. Guarantee. PacifiCorp will investigate and respond within 15 business days of a customer's inquiry about its electric bill.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

6. Problems with the Customer's Meter.

a. Guarantee. PacifiCorp will investigate and report back to the customer within 15 business days if the customer suspects a problem with its meter.

b. Penalty. If PacifiCorp fails to meet its guarantee, PacifiCorp will automatically pay the customer $50 for each failure.

7. Planned Interruptions.

a. Guarantee. PacifiCorp will give the customer at least 2 days notice if it is necessary to turn the customer's power supply off for planned maintenance work or testing.

b. Penalty. If PacifiCorp fails to meet its guarantee, customers can claim $50 for residential customers and $100 for commercial and industrial customers.

8. Power Quality Complaints.

a. Guarantee. Upon notification from a customer about a problem with the quality of electric supply, PacifiCorp will either initiate an investigation within 7 days or explain the problem in writing within 5 business days.

b. Penalty. If PacifiCorp fails to meet its guarantee, it will automatically pay the customer $50.

9. Implementation. Specific terms and conditions relating to the implementation of the Customer Service Guarantees are set forth in Appendix B. Data calculations to measure performance will be audited by the company and an outside auditor.

10. Reporting.

a. To Customers. PacifiCorp will issue a report to the customer by June 30 of each year regarding its record in improving Performance Standards and how well it has performed against its Customer Guarantees. Each report will contain an overview of standards, targets and guarantees and describe the performance results for that year. The report will also discuss any new targets PacifiCorp will be applying in the coming year.

b. To Commission. PacifiCorp will provide an annual report to the Commission by May 31 of each year that will discuss implementation of ScottishPower's programs and procedures for providing improved performance. The report will provide a general summary of how PacifiCorp performed according to the standards, targets and guarantees. The report will: (i) provide performance results for each standard, target or guarantee; (ii) identify excluded exceptions; (iii) explain any historical and anticipated trends and events that affected or will affect the measure in the future; (iv) describe any technological advancements in data collection that will significantly change any performance indicator; (v) discuss any "phase in" of new standards, targets or guarantees; and (vi) include the name and telephone numbers of contacts at PacifiCorp to whom inquiries should be addressed. If the company is not meeting a standard, target or guarantee, the report will: (i) provide an analysis of relevant patterns and trends; (ii) describe the cause or causes of the unacceptable performance; (iii) describe the corrective measures undertaken by the company; (iv) set a target date for completion of the corrective measures; and (v) provide details of any penalty payments due.

II.REGULATORY OVERSIGHT

A. Access to Books and Records

1. PacifiCorp will maintain its own accounting system, separate from ScottishPower's accounting system. All PacifiCorp financial books and records will be kept in Portland, Oregon, and will continue to be available to the Commission upon request at PacifiCorp's offices in Portland, Salt Lake City, Utah, and elsewhere in

accordance with current practice.

B. Cost Allocation, Affiliated Interest Transactions

1. By the end of the third year following the completion of the transaction, ScottishPower will have achieved a net reduction of $10 million annually in PacifiCorp's corporate costs ($15 million of annual cost savings in corporate costs which, when offset by $5 million of cost increases, will produce a net reduction of $10 million annually in corporate costs). ScottishPower will commit to reflecting this reduction in PacifiCorp's results of operations filed with the Commission.

2. ScottishPower will provide an analysis of its proposed allocation of corporate costs within ninety days after completion of the transaction.

3. To determine the reasonableness of allocation factors used by ScottishPower to assign costs to PacifiCorp and amounts subject to allocation or direct charges, the Commission or its agents may audit the records of ScottishPower which are the bases for charges to PacifiCorp. ScottishPower will cooperate fully with such Commission audits.

4. ScottishPower and PacifiCorp will provide the Commission access to all books of account, as well as all documents, data and records of their affiliated interest, which pertain to any transactions between PacifiCorp and its affiliated interests.

5. ScottishPower and PacifiCorp agree to comply with all existing Commission statutes and regulations regarding affiliated interest transactions, including timely filing of applications and reports.

6. ScottishPower will not subsidize its activities by allocating to or directly charging PacifiCorp expenses not authorized by the Commission to be so allocated or directly charged.

7. Neither ScottishPower nor PacifiCorp will assert in any future Commission proceeding that the provisions of the Public Utility Holding Company Act of 1935 preempt the Commission's jurisdiction over affiliated interest transactions.

C. Transaction Costs

1. ScottishPower and PacifiCorp will exclude all costs of the transaction from PacifiCorp's utility accounts.

D. Financial Issues

1. ScottishPower intends to achieve an actual capital structure equivalent to that of comparable, A-rated electric utilities in the U.S., with a common equity ratio for PacifiCorp of not less than 47%.

2. PacifiCorp will maintain separate debt and, if outstanding, preferred stock ratings.

3. ScottishPower and PacifiCorp will provide the Commission with unrestricted access to all written information provided to common stock, bond, or bond rating analysts, which directly or indirectly pertains to PacifiCorp.

III.COMMITMENT TO THE ENVIRONMENT

A. Renewable Resources

1. PacifiCorp will develop an additional 50 MW of renewable resources (wind, solar and/or geothermal) at an anticipated cost of approximately $60 million within five years after completion of the transaction.

2. Within 60 days after completion of the transaction, PacifiCorp will file applications in each state for a "green resource" tariff.

3. PacifiCorp will contribute $100,000 to the Bonneville Environmental Foundation for use in the development of new renewable resources and fish mitigation projects.

B. Environmental Management

1. PacifiCorp will have environmental management systems in place that are self-certified to ISO 14001 standards at all PacifiCorp operated thermal generation by the end of 2000.

2. ScottishPower will include PacifiCorp operations in ScottishPower's comprehensive annual environmental report with appropriate specific goals.

3. ScottishPower will include a PacifiCorp officer on the Environmental

Policy Advisory Committee.

4. ScottishPower will develop a process to gather outside input on environmental matters, such as the establishment of an Environmental Forum.

IV.COMMITMENT TO COMMUNITIES

A. Financial Contribution

1. ScottishPower will contribute $5 million to the PacifiCorp Foundation upon completion of the transaction.

2. ScottishPower will maintain the existing level of PacifiCorp's other community-related contributions, both in terms of monetary and in-kind contributions.

B. Programs

1. ScottishPower will develop, in consultation with the appropriate Utah state educational authorities and the local business community, a "School to Work" initiative. Skill development opportunities will be made available through the Open Learning Centers, work experience mentoring, and work shadowing.

2. ScottishPower will maintain the existing Regional Advisory Boards.

C. Low-Income Customers

1. ScottishPower will commit $1.5 million per year (in addition to PacifiCorp's existing commitment of $1.5 million annually) to programs that encourage the economic well-being of communities, including the following:

a. ScottishPower will double the number of customers assisted by the heat assistance funding program for those customers who qualify under the Federal Low Income Energy Assistance Program and will reintroduce the matching concept with PacifiCorp matching customer donations to heat assistance programs annually.

b. ScottishPower will establish a debt counseling service for those customers who have difficulty in paying their monthly electric bills.

c. ScottishPower will expand the commitment to educate customers regarding energy efficiency in order to help customers with payment difficulties, and to promote electricity safety for all customers.

V.COMMITMENT TO EMPLOYEES

A. Existing Labor Agreements

1. ScottishPower will honor existing labor contracts with all levels of staff.

B. New Programs

1. ScottishPower will introduce the following programs in the PacifiCorp service territory, upon completion of the transaction, at a start-up cost of approximately $3 million and estimated annual expenditures of approximately $1 million:

a. ScottishPower will develop one "best-in-class" training center in each of Oregon and Utah. These centers will provide employees with opportunities to improve their work-related skills.

b. ScottishPower will phase in the introduction of the ScottishPower Open Learning centers. At these Open Learning centers, employees will be able to supplement their work-related skills with other skills designed to enhance their overall knowledge.

c. ScottishPower will establish partnerships with local colleges and universities to develop management training programs.

C. Occupational Health

1. ScottishPower will examine the appropriateness of introducing for PacifiCorp employees its successful programs already adopted in the U.K. to encourage a healthy lifestyle for employees.

ScottishPower/PacifiCorp
Proposed Treatment of Merger Related Costs

Cost Item	$	Above the line	Below the line	Ref.	Comment
Goodwill	1,800m (£1124.7m)		X	SP Listing Particulars page 107	Goodwill represents the difference between the purchase price and fair value of the net assets of PacifiCorp. Goodwill is sometimes referred to as the acquisition adjustment for accounting purposes. The calculation of goodwill varies with fluctuations in ScottishPower share price.
Acquisition Costs 1)Share Issue Costs 2)Preferred Stock Redemption 3)Investment, legal, accounting etc **Total Acquisition Cost**	 104m (£65m) 26m (£15m) 109m **239m**		 X X X X	SP Listing Particulars pages 107 & 145	This is an estimate only. However, all such costs incurred directly in completing the acquisition will be charged below the line.
Preferred Stockholder Merger Approval Payments	2.5m (maximum)		X	PC Proxy Statement page 138	Special payments made to preferred Stockholders of 1% to obtain merger approval.
Payments to Directors	0.4m		X	SP Listing Particulars page 166	$50,000 payment made to non-executive directors.
Change in Control 1)Enhanced Executive Severance 2)PacifiCorp Stock Plans 3)Supplemental Executive Retirement Plan (SERP)	 8.3m (maximum) minimal cost 2.6m		 X X X	SP Listing Particulars page 163-165	Only enhanced payments resulting from the application of change in control conditions are included. To the extent that a net benefit in costs going forward can be demonstrated then such costs will be treated above the line. Final change in control costs can only be determined 24 months after closure. Numbers quoted are upper limit amounts if all eligible employees receive maximum amounts due. They include payments due to two executives who have already retired. There is no material cost associated with PacifiCorp employee stock option provisions.
Retention Incentive Payments	7m (maximum)		X	SP Listing Particulars page 166, WIEC 3.5	Payments to retain key employees during period prior to merger completion.
Bonus Pool- Merger related portion	Not known		X	SP Listing Particulars page 166	To the extent that any such payments are made in connection with "extraordinary efforts" to accomplish the successful completion of the merger only. No quantification of this portion can be determined at this time.

-APPENDIX: COMPILATION OF COMMITMENTS-

MEHC Acquisition of PacifiCorp
Utah Docket No. 05-035-54

Consolidated List of Amended and Additional Commitments from Most-Favored States Process

Extension of Existing Commitments – (reference Gale's Exhibit UP&L (BEG-1)

1) MEHC and PacifiCorp affirm the continuation (through March 31, 2008) of the existing customer service guarantees and performance standards in each jurisdiction. MEHC and PacifiCorp will not propose modifications to the guarantees and standards prior to March 31, 2008. Refer to Commitment 45 for the extension of this commitment through 2011.

2) Penalties for noncompliance with performance standards and customer guarantees shall be paid as designated by the Commission and shall be excluded from results of operations. PacifiCorp will abide by the Commission's decision regarding payments.

3) PacifiCorp will maintain its own accounting system, separate from MEHC's accounting system. All PacifiCorp financial books and records will be kept in Portland, Oregon. PacifiCorp's financial books and records and state and federal utility regulatory filings and documents will continue to be available to the Commission, upon request, at PacifiCorp's offices in Portland, Oregon, Salt Lake City, Utah, and elsewhere in accordance with current practice.

4) MEHC and PacifiCorp will provide the Commission access to all books of account, as well as all documents, data, and records of their affiliated interests, which pertain to transactions between PacifiCorp and its affiliated interests or which are otherwise relevant to the business of PacifiCorp. This commitment is also applicable to the books and records of Berkshire Hathaway, which shall retain its books and records relevant to the business of PacifiCorp consistent with the manner and time periods of the Federal Energy Regulatory Commission's record retention requirements that are applicable to PacifiCorp's books and records.

5) MEHC, PacifiCorp and all affiliates will make their employees, officers, directors, and agents available to testify before the Commission to provide information relevant to matters within the jurisdiction of the Commission.

6) The Commission or its agents may audit the accounting records of MEHC and its subsidiaries

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

IN RE:		
JOINT REQUEST OF ATLANTA GAS LIGHT COMPANY, AGL RESOURCES INC., AND THE SOUTHERN COMPANY FOR A FINDING THAT SOUTHERN COMPANY'S MERGER WITH AGL RESOURCES INC. COMPLIES WITH APPLICABLE LAW	))))))	**DOCKET NO. 39971**
AND	))	
SOUTHSTAR ENERGY SERVICES LLC d/b/a GEORGIA NATURAL GAS; APPLICATION FOR A NATURAL GAS MARKETER CERTIFICATE OF AUTHORITY	))))	**DOCKET NO. 9574**

PUBLIC DISCLOSURE

DIRECT TESTIMONY
AND EXHIBITS
OF

RICHARD A. BAUDINO

ON BEHALF OF THE
GEORGIA PUBLIC SERVICE COMMISSION

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

APRIL 4, 2016

BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF RICHARD A. BAUDINO

QUALIFICATIONS AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a consultant to Kennedy and Associates.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ____(RAB-1) summarizes my expert testimony experience.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Georgia Public Service Commission ("Commission") Staff.

Q. PLEASE STATE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is twofold. First, my testimony supports the proposed settlement ("Stipulation") agreed to by Staff, Southern Company, Georgia Power Company, Atlanta Gas Light Resources, Atlanta Gas Light Company, True Natural Gas and Fireside Natural Gas, LLC, specifically paragraph 4 of the Stipulation. Second, I provide an evaluation of the potential impact on credit quality and service quality of the proposed merger between Southern Company and AGL Resources, Inc.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Staff concludes that the proposed merger between Southern Company and AGL Resources, Inc. is in the public interest and should be approved by the Commission subject to certain ratepayer protection conditions. With respect to credit quality and service quality, I recommend that the Commission adopt the Stipulation.

In the event that the Commission elects to resolve the issues raised in this proceeding in a manner other than adoption of the Stipulation, I recommend that the Commission order the following conditions in connection with its approval of the proposed merger:

1. Georgia Power and Atlanta Gas Light Company shall not pass through any increases in the cost of equity or debt if the proposed merger results in a downgrading of either company's debt.
2. The Commission and Staff should continue to monitor current service quality measures as reported by Georgia Power and Atlanta Gas Light Company. If these measures deteriorate from 2015 levels, the Commission should open an investigation into service quality for purposes of determining whether any penalties should be assessed against Georgia Power and/or Atlanta Gas Light Company.

These conditions are more fully discussed in the section of my testimony captioned “Credit Quality Issues and Protections”.

THE STIPULATION

Q. PLEASE DESCRIBE THE STIPULATION.

A. On March 30, 2016, Staff forwarded to all parties a proposal designed to resolve the issues raised in this proceeding. I understand that as of the date of this testimony, Southern Company, Georgia Power Company, Atlanta Gas Light Resources, Atlanta Gas Light Company, True Natural Gas and Fireside Natural Gas, LLC have agreed to execute the Stipulation. The Stipulation addresses issues related to accounting, savings and competitive issues. These issues are addressed more completely in the testimony of Mr. Bond and Mr. Kollen.

Q. DOES THE STIPULATION ALSO ADDRESS ISSUES RELATED TO INCREASES IN CREDIT COSTS?

A. Yes, it does. Specifically, paragraph 4 of the Stipulation provides:

> 4. Increases in Credit Costs directly related to the merger shall not be recovered through ratemaking process. Georgia Power and Atlanta Gas Light shall report any future downgrades in their credit quality, or the credit quality of Southern, within 20 days of such a downgrade, along with an explanation of the basis for such downgrade, for the Commission to evaluate under the circumstances at the time.

Credit Costs are defined as incremental costs of common equity, costs of new issuances of long-term debt, and short-term debt due to any down rating in corporate wide credit and/or utility-specific credit rating(s) within ten years after announcement of merger as well as the effects of any increases in common equity as a percentage of capitalization. These are measured solely on the impact of the cost of capital to the utility where it is clearly linked to the current merger transaction.

Q. IN THE SECTION OF YOUR TESTIMONY TITLED "CREDIT QUALITY ISSUES AND PROTECTIONS" YOU DISCUSS THE RISKS TO GEORGIA RATEPAYERS IN THE EVENT THAT SOUTHERN COMPANY'S AND/OR GEORGIA POWER'S CREDIT RATINGS ARE LOWERED DUE TO THE PROPOSED MERGER. DOES PARAGRAPH 4 OF THE STIPULATION PROVIDE APPROPRIATE PROTECTIONS TO RATEPAYERS IN THE EVENT THAT THE CREDIT RATINGS ARE LOWERED?

A. Yes, it does. As I discuss later in my testimony, issues such as Southern Company's use of debt to finance the merger in 2016 will substantially increase its leverage and, thus, its financial risk. Also, Southern Company provided a detailed description of the risks of the merger in its 2015 10-K Report. Given these risks, it is reasonable and appropriate that ratepayers be protected against increases in credit costs and that Georgia Power Company and Atlanta Gas Light Company not pass through to ratepayers any increases in credit costs directly related to the proposed merger. Paragraph 4 of the Stipulation provides such protection to ratepayers, and I recommend that the Commission adopt the Stipulation.

<u>CREDIT QUALITY ISSUES AND PROTECTIONS</u>

Q. PLEASE DESCRIBE HOW THE APPLICANTS INTEND TO FINANCE THE PROPOSED MERGER.

A. According to Southern Company's 2015 10-K Report, page II-12, the Company expects to fund the acquisition of AGL Resources through the issuance of $8 billion of new debt prior to the closing along with a total of $1.4 billion of new equity in calendar year 2016. Southern Company stated in its 10-K Report that this capital "is expected to provide funding for the Merger, Southern Power growth opportunities, and other Southern Company system capital projects." Southern Company also noted that it had entered into an $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the proposed merger "in the event long-term financing is not available."

In addition, Southern Company will assume the outstanding AGLR debt of approximately $4 billion. The combination of new debt and assumed debt will add more than $12 billion of debt to Southern Company's consolidated capital structure.

Q. WILL THE MANNER IN WHICH THE MERGER IS FINANCED SIGNIFICANTLY AFFECT SOUTHERN COMPANY'S LEVERAGE?

A. Yes. The expected debt and equity split for 2016, including the $4.0 billion of AGLR debt, means that Southern Company will finance the acquisition of AGLR with about 90% debt and only 10% equity. Southern Company's present debt leverage is approximately 52%, based on its financial statements at year end 2015, so the highly leveraged financing the Company intends to use this year will increase the debt ratio for 2016 and beyond.

Q. HOW HAVE THE MAJOR BOND RATING AGENCIES RESPONDED TO THE

PROPOSED MERGER?

A. Southern Company noted in its 2015 10-K Report, page II-45, that on August 24, 2015 Standard & Poor's ("S&P") revised the credit rating outlook for Southern Company, the traditional operating companies, and Southern Power Company from stable to negative following the announcement of the merger. Georgia Power was included along with Southern Company in the negative credit outlook from S&P. Southern Company also noted that on the aforementioned date, Moody's revised its credit outlook from stable to negative and that Fitch placed its ratings on credit watch negative. Georgia Power's issuer credit outlook was not lowered by Moody's and Fitch.

AGL Resources reported on page 37 of its 2015 10-K Report that during the third quarter of 2015, S&P revised AGL Resources' rating outlook to positive from stable and that Fitch revised its outlook to positive. These revised outlooks were due to the agencies' favorable evaluations of the merger's effect on AGL Resources and Atlanta Gas Light Company.

Q. WHAT WERE SOME OF THE CONCERNS EXPRESSED BY THE RATING AGENCIES WITH RESPECT TO THE CREDIT OUTLOOK FOR SOUTHERN COMPANY AS A RESULT OF THE PROPOSED MERGER?

A. In an article dated August 24, 2015, S&P stated [redacted]

[redacted]

Moody's also published an article on August 24, 2015 in which it affirmed Southern Company's credit ratings, but changed the credit outlook to negative.[1] The article stated the following:

[redacted].

The Moody's article also stated that [redacted]

Q. HAS MOODY'S ISSUED MORE RECENT STATEMENTS REGARDING THE FINANCIAL RISKS OF THE PROPOSED MERGER?

A. Yes. On March 22, 2016, Moody's issued an announcement entitled "Moody's: Benefits of electric utilities acquiring natural gas assets offset by higher debt." This announcement explained that the additional financial risk undertaken by Southern Company, Duke Energy Corp., and Dominion Resources to acquire natural gas

1 https://www.moodys.com/research/Moodys-affirms-Southern-Company-ratings-changes-outlook-to-negative--PR_333158

distribution assets has offset the financial benefits of diversifying their businesses.[2] [redacted]

Q. WHAT ARE THE CURRENT BOND RATINGS FOR SOUTHERN COMPANY AND GEORGIA POWER COMPANY?

A. S&P's current ratings for Southern Company and Georgia Power are A-. Moody's current ratings for Southern Company and Georgia Power are Baa1 and A3, respectively. Fitch's ratings for Southern Company and Georgia Power are A. Atlanta Gas Light Company's current ratings are BBB+ from S&P and Fitch and Baa1 from Moody's. The credit ratings for Southern Company, Georgia Power, and Atlanta Gas Light Company are all considered investment grade. Investment grade ratings fall within the range of BBB/Baa to AAA. The cost of debt and equity follow these ratings. The higher the credit rating, the lower the cost of debt and equity. Alternatively, the lower the credit rating, the higher the cost of debt and equity.

Q. DID SOUTHERN COMPANY DESCRIBE THE RISKS OF THE PROPOSED MERGER IN ITS 10-K REPORT?

A. Yes. Southern Company provided a detailed description of the risks of the merger on pages I-32 through I-34 of its 2015 10-K Report. I have included these pages in Exhibit

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2 https://www.moodys.com/research/Moodys-Benefits-of-electric-utilities-acquiring-natural-gas-assets-offset--PR_345914#

___(RAB-2). In summary, Southern Company noted the following acquisition risks from the merger:

- Difficulties in satisfying the conditions for the completion of the merger, including receipt of all required regulatory approvals, which could delay the completion of the merger, or impose conditions that could have a material adverse effect on the combined company or that could cause the parties to abandon the merger.
- Failure to complete the merger could negatively impact Southern Company's stock price and Southern Company's future business and financial results.
- If completed, the merger may not achieve its intended results.
- The Southern Company system will be subject to business uncertainties while the merger is pending that could adversely affect Southern Company's financial results.
- Southern Company is obligated to complete the merger whether or not it has obtained the required financing.
- Following the merger, stockholders of Southern Company will own equity interests in a company whose subsidiary owns and operates a natural gas business.
- Southern Company expects to record goodwill that could become impaired and adversely affect its operating results.

Q. MR. BAUDINO, WHAT IS YOUR CONCLUSION WITH RESPECT TO THE CREDIT RISKS FOR SOUTHERN COMPANY AND GEORGIA POWER FROM

THE PROPOSED MERGER WITH AGL RESOURCES?

A. First, Southern Company's use of debt to finance the merger in 2016 will substantially increase its leverage and, thus, its financial risk. All three of the major rating agencies clearly recognized this in their opinions of the proposed transaction. [redacted] Southern Company itself clearly delineated additional risks from the merger in its 2015 10-K report. Without question, Southern Company's credit risk has increased due to the proposed merger.

Second, S&P lowered Georgia Power's credit outlook to negative from stable. Thus, at least one rating agency concluded that Southern Company's utility subsidiaries could be at risk from the proposed merger. In my opinion, this is particularly the case for Georgia Power, which is the largest of the utility subsidiaries and also faces financial risk from the ongoing construction of the Vogtle power plant.

Third, the proposed merger will likely have a beneficial credit impact on Atlanta Gas Light Company, whose credit outlook improved after the merger announcement.

Q. GIVEN THE ADDITIONAL RISKS DESCRIBED BY THE BOND RATING AGENCIES AND BY SOUTHERN COMPANY IN ITS 2015 10-K REPORT, DO YOU RECOMMEND THAT THE COMMISSION INCLUDE MEASURES TO PROTECT GEORGIA RATEPAYERS IN THE EVENT THAT SOUTHERN

COMPANY'S AND/OR GEORGIA POWER'S CREDIT RATINGS ARE LOWERED DUE TO THE PROPOSED MERGER?

A. Yes. Given the additional risks I describe earlier, I recommend that the Commission condition its approval of the proposed merger such that Southern Company, Georgia Power Company, and Atlanta Gas Light Company shall not pass through to ratepayers any increases in the cost of debt and equity that result from the proposed merger.

Q. MR. BAUDINO, HOW COULD THE COMMISSION IMPLEMENT THE CREDIT RISK PROTECTION THAT YOU RECOMMEND?

A. In the event of credit rating downgrades for Southern Company, Georgia Power, and/or Atlanta Gas Light Company wherein the rating agency cites the merger as a factor in the downgrade, I recommend the Commission implement the condition as follows:

1. For new long-term debt issued by Georgia Power or Atlanta Gas Light Company, the Commission should use the lower of (1) an imputed debt cost with a rating equal to the rating before the downgrade, or (2) the actual debt cost. For Georgia Power, the current bond rating is A/A from S&P and Moody's. For Atlanta Gas Light Company, the current bond rating is BBB/Baa from S&P and Moody's.

2. For all short-term debt, the Commission should use the lower of (1) an imputed A-rated debt cost, or (2) the actual debt cost, whichever is lower.

3. Georgia Power's return on equity should be based on a comparison group of A-rated electric utilities. Atlanta Gas Light Company's return on equity

should be based on a comparison group of gas distribution companies with investment grade bond ratings.

If either Georgia Power or Atlanta Gas Light Company issue new debt that reflects a lower rating due to adverse consequences from the proposed merger transaction, then Georgia ratepayers must be protected from any resulting higher cost of debt. Tying the cost of any new debt to the lower of actual debt cost or the pre-merger debt rating cost ensures adequate and reasonable protection for ratepayers.

Q. SHOULD THIS PROTECTION BE EXTENDED TO SHORT-TERM DEBT COST?

A. Yes. A credit downgrade of Southern Company could affect the cost of short-term borrowing for both Georgia Power and Atlanta Gas Light. For example, Georgia Power has $1.75 billion of bank credit agreements as of December 31, 2015, as well as commercial paper and short-term bank loans available. These are described on page II-276 of Southern Company's 2015 10-K Report. If the cost of borrowings under these credit facilities are negatively affected from bond downgrades, ratepayers should be protected from any such increased costs.

Q. ON PAGE 13, LINE 24 THROUGH PAGE 14 LINE 2 OF HER DIRECT TESTIMONY, MS. DAISS TESTIFIED THAT "THERE IS NOTHING TO SUGGEST THAT AFFILIATING GEORGIA POWER AND ATLANTA GAS LIGHT, TWO FINANCIALLY SOUND COMPANIES IN THEIR OWN RIGHT,

WILL CAUSE EITHER TO HAVE INCREASED MARKET RISK OR COMPANY OPERATIONAL RISK SUCH THAT THEIR COST OF CAPITAL WOULD INCREASE." PLEASE RESPOND TO MS. DAISS' TESTIMONY.

A. If Ms. Daiss is correct, then I don't believe that Southern Company or AGL Resources should object to the Commission requiring the cost of capital protection condition that I recommend. However, if the risks that the bond rating agencies identified do indeed come to pass and if those risks increase the cost of capital for Southern Company, Georgia Power, and Atlanta Gas Light Company, then Georgia ratepayers will be well served by the Commission ordering the ratepayer credit protection conditions.

SERVICE QUALITY ISSUES AND PROTECTIONS

Q. DID THE APPLICANTS SUBMIT TESTIMONY WITH RESPECT TO THE EFFECT OF THE PROPOSED MERGER ON SERVICE QUALITY?

A. Yes. The panel testimony submitted by witnesses Sherwood, Morley, and Cogburn stated on page 10 that AGLC customers "should experience no reduction in safety, quality, reliability, service continuity, call center access, emergency responses, and related utility services." Mr. Roberts also testified on pages 14 and 15 of his Direct Testimony that there would be no effect on Georgia Power's provision of safe and reliable service at just and reasonable rates and that no conditions are necessary to ensure the provision of such service.

Q. DOES THE COMMISSION CURRENTLY MONITOR THE QUALITY OF SERVICE FOR GEORGIA POWER AND ATLANTA GAS LIGHT COMPANY?

A. Yes. Both Georgia Power and AGLC submit service quality reports to the Commission pursuant to Orders in Docket Nos. 11941-U (Georgia Power) and 15295-U (AGLC).

Q. WHAT ARE THE SERVICE QUALITY MEASURES REPORTED BY GEORGIA POWER?

A. Georgia Power reports two reliability indices: System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"). SAIDI is a measure of the length of time (duration) during a year that the average customer experienced an outage. For 2014, Georgia Power's SAIDI was 102.76, which means that the average customer on Georgia Power's system experienced 102.76 minutes of interrupted service during the year. SAIFI is a measure of how frequently customers were interrupted during the year. For 2014, Georgia Power's SAIFI was 1.20, meaning that the average customer was interrupted 1.2 times during 2014. Lower SAIDI and SAIFI indices indicate interruptions of shorter duration and fewer interruptions, respectively.

Georgia Power also provides Customer Value Benchmark Survey Results that report customer opinions of the Company's reliability and overall satisfaction. Georgia Power provides its rank in these areas of customer service quality compared to 16 peer electric utilities.

Q. PLEASE SUMMARIZE THE SAIDI AND SAIFI RESULTS FOR THE LAST FIVE YEARS.

A. Table 1 below provides the most recent five year values for SAIDI and SAIFI reported by Georgia Power.

TABLE 1
GPC SERVICE QUALITY MEASURES

	SAIDI	SAIFI
2010	109.99	1.25
2011	113.65	1.18
2012	119.31	1.37
2013	102.17	1.17
2014	102.76	1.20

Table 1 shows that Georgia Power's SAIDI and SAIFI values rose from 2010 through 2013, then declined from 2013 through 2014.

Q. WHAT ARE THE RESULTS OF THE CUSTOMER SATISFACTION SURVEYS THAT GEORGIA POWER CONDUCTED OVER THE LAST 5 YEARS?

A. Exhibit **___**(RAB-3) contains the most recent customer satisfaction survey reports from Georgia Power that were filed from 2011 through 2015.

Generally speaking, Georgia Power scored in the upper quartile of reliability results for General and Large Business Customers. With respect to Residential reliability, Georgia Power scored in the upper quartile in 2010, 2011, and 2104 and was near the middle of the group of companies in 2012 and 2013. Georgia Power scored in the upper quartile in overall satisfaction for all customer classes in 2010. In 2011, the Company stayed in the upper quartile for Large Business customers, but dropped out of that quartile for Residential and General Business customers. In 2012 and 2013, Georgia Power dropped into the lower half of the group with respect to Residential customer satisfaction. However, the Company rose into the upper half of the group for Residential customer satisfaction in 2014.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS WITH RESPECT TO GEORGIA POWER COMPANY'S SERVICE QUALITY AND RELIABILITY REPORTS?

A. Georgia Power's SAIDI and SAIFI indices have been relatively consistent over the last five years and have even shown improvement from prior years in 2013 and 2014. This suggests that Georgia customers have received consistently safe and reliable service from Georgia Power during that period. However, with respect to Residential customer satisfaction there are opportunities for the Company to improve its score in comparison to the peer group of utilities. I recommend that in its Rebuttal Testimony in this proceeding, Georgia Power provide an explanation for the decline in Residential customer satisfaction since 2010 and provide a detailed explanation to the Commission as to the Company's efforts to improve its standing within the peer group of companies.

Q. WHAT ARE THE SERVICE QUALITY MEASURES REPORTED BY AGLC?

A. Exhibit ___(RAB-4) provides a five-year summary of the service quality measures that AGLC provides to the Commission. All of these measures were approved by the Commission in Docket No. 15295-U pursuant to the Joint Recommendation of Commission Staff and Atlanta Gas Light Company ("Joint Recommendation"). Exhibit ___(RAB-5) contains a copy of this Joint Recommendation dated February 28, 2003.

Please note that the values reported in Exhibit ____(RAB-4) are yearly averages with the exception of meter reading accuracy, which presents the average from January through October. On an annual basis, AGLC exceeded the customer service benchmarks provided in the Joint Recommendation.

Q. SHOULD GEORGIA POWER AND AGLC CONTINUE TO PROVIDE THESE SERVICE QUALITY REPORTS AFTER THE MERGER IS COMPLETED?

A. Yes. The Companies should continue to file these reports with the Commission pursuant to the aforementioned Orders so that the Commission and Staff can continue to monitor service quality after the merger is completed.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of March 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

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Richard A. Baudino
As of March 2016

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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As of March 2016

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
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Richard A. Baudino
As of March 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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As of March 2016

Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

Expert Testimony Appearances
of
Richard A. Baudino
As of March 2016

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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of
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As of March 2016

Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-31737	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

the reduction of risk. These transactions may also affect the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.

These transactions also involve risks, including:

- any acquisitions may not result in an increase in income or provide an adequate return on capital or other anticipated benefits;
- any acquisitions may not be successfully integrated into the acquiring company's operations and internal controls processes;
- the due diligence conducted prior to an acquisition may not uncover situations that could result in financial or legal exposure or the acquiring company may not appropriately evaluate the likelihood or quantify the exposure from identified risks;
- any disposition may result in decreased earnings, revenue, or cash flow;
- use of cash for acquisitions may adversely affect cash available for capital expenditures and other uses; or
- any dispositions, investments, or acquisitions could have a material adverse effect on the liquidity, results of operations, or financial condition of Southern Company or its subsidiaries.

Southern Company and AGL Resources may encounter difficulties in satisfying the conditions for the completion of the Merger, including receipt of all required regulatory approvals, which could delay the completion of the Merger or impose conditions that could have a material adverse effect on the combined company or that could cause either party to abandon the Merger.

Consummation of the Merger remains subject to the satisfaction or waiver of certain closing conditions, including, among others, (i) the approval of the California Public Utilities Commission, Georgia PSC, Illinois Commerce Commission, and Maryland PSC, New Jersey Board of Public Utilities, and other approvals required under applicable state laws, and the approval of the Federal Communications Commission (FCC) for the transfer of control over the FCC licenses of certain subsidiaries of AGL Resources, (ii) the absence of a judgment, order, decision, injunction, ruling, or other finding or agency requirement of a governmental entity prohibiting the consummation of the Merger, and (iii) other customary closing conditions, including (a) subject to certain materiality qualifiers, the accuracy of each party's representations and warranties and (b) each party's performance in all material respects of its obligations under the Merger Agreement.

Southern Company completed the required state regulatory filings in the fourth quarter 2015 and the required FCC filings in February 2016. On February 24, 2016, a stipulation and settlement agreement between Southern Company, AGL Resources, the Maryland PSC Staff, and the Maryland Office of People's Counsel was filed with the Maryland PSC. The proposed settlement remains subject to the approval of the Maryland PSC. Additionally, Southern Company received the approval of the Virginia State Corporation Commission in February 2016.

These governmental entities may decline to approve the Merger or may impose conditions on the completion, or require changes to the terms, of the Merger, including restrictions or conditions on the business, operations, or financial performance of the combined company following the Merger.

Satisfying the conditions to completion of the Merger may take longer, and could cost more, than Southern Company expects. Any delay in completing the Merger or any additional conditions imposed in order to complete the Merger may materially adversely affect the benefits that Southern Company expects to achieve from the Merger and the integration of the companies' respective businesses.

In addition, conditions to the completion of the Merger may fail to be satisfied. Subject to certain limitations, either party may terminate the Merger Agreement if the Merger is not consummated by August 23, 2016, which date may be extended by either party to February 23, 2017 if, on August 23, 2016, all conditions to closing other than those relating to (i) regulatory approvals and (ii) the absence of legal restraints preventing consummation of the Merger (to the extent relating to regulatory approvals) have been satisfied.

Any delay in completing the Merger, conditions imposed by governmental entities, or failure to complete the Merger could have a material adverse effect on the financial condition, net income, and cash flows of Southern Company.

Failure to complete the Merger could negatively impact Southern Company's stock price and Southern Company's future business and financial results.

Completion of the Merger is not assured and is subject to risks, including the risks that approval of the transaction by governmental entities will not be obtained or that certain other closing conditions will not be satisfied. If the Merger is not completed, Southern Company's ongoing businesses and financial results may be adversely affected and Southern Company will be subject to a number of risks, including the following:

- Southern Company will be required to pay significant costs relating to the Merger, including legal, accounting, and financial advisory costs, whether or not the Merger is completed;
- matters relating to the Merger (including integration planning) may require substantial commitments of time and resources by Southern Company management, which could otherwise have been devoted to other opportunities that may have been beneficial to Southern Company; and
- negative publicity and a negative impression of Southern Company in the investment community.

The occurrence of any of these events, individually or in combination, could cause the share price of Southern Company to decline if and to the extent that the current market prices reflect an assumption by the market that the Merger will be completed.

If completed, the Merger may not achieve its intended results.

Southern Company entered into the Merger Agreement with the expectation that the Merger would result in various benefits. Achieving the anticipated benefits of the Merger is subject to a number of uncertainties, including whether the business of AGL Resources is integrated in an efficient and effective manner, conditions imposed on the Merger by federal and state public utility, antitrust, and other regulatory authorities prior to approval, general market and economic conditions, and general competitive factors in the marketplace. Failure to achieve these anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company, and diversion of management's time and energy and could have an adverse effect on the combined company's financial condition, net income, and cash flows.

The Southern Company system will be subject to business uncertainties while the Merger is pending that could adversely affect Southern Company's financial results.

Uncertainty about the effect of the Merger on employees, suppliers, and customers of the Southern Company system may have an adverse effect on Southern Company. These uncertainties may impair the Southern Company system's ability to attract, retain, and motivate key personnel until the Merger is completed and for a period of time thereafter and could cause customers, suppliers, and others that deal with the Southern Company system to seek to change existing business relationships.

Employee retention and recruitment may be particularly challenging prior to the completion of the Merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If key employees depart or fail to accept employment with the Southern Company system because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, Southern Company's financial results could be adversely affected.

The pursuit of the Merger and the preparation for the integration of AGL Resources into the Southern Company system may place a significant burden on management and internal resources. The diversion of management attention away from day-to-day business concerns and any difficulties encountered in the transition and integration process could adversely affect Southern Company's financial condition, net income, and cash flows.

Southern Company is obligated to complete the Merger whether or not it has obtained the required financing.

Southern Company intends to initially fund the cash consideration for the Merger using a mix of debt and equity. Southern Company finances its capital needs on a portfolio basis and expects to issue approximately $8.0 billion in debt prior to closing the Merger and approximately $1.2 billion in equity during 2016. This capital is expected to provide funding for the Merger, Southern Power growth opportunities, and other Southern Company system capital projects. In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available. The Bridge Agreement is subject to various conditions contained in the Bridge Agreement and the issuance of long-term debt and equity sales to finance the Merger will be subject to future market conditions.

Following the Merger, stockholders of Southern Company will own equity interests in a company whose subsidiary owns and operates a natural gas business.

AGL Resources is an energy services holding company whose primary business is the distribution of natural gas through natural gas distribution utilities. AGL Resources is involved in several other businesses that are mainly related and complementary to its primary business including: retail operations including the provision of natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice, wholesale services including natural gas storage, gas pipeline arbitrage, and natural gas asset management and/or related logistics services, and midstream operations including high deliverability natural gas storage facilities and select pipelines. As a result, the combined company will be subject to various risks to which Southern Company is not currently subject, including risks related to transporting and storing natural gas. As stockholders of the combined company following the Merger, Southern Company stockholders may be adversely affected by these risks.

Southern Company expects to record goodwill that could become impaired and adversely affect its operating results.

In accordance with GAAP, the Merger will be accounted for using the acquisition method of accounting whereby the assets acquired and liabilities assumed are recognized at fair value as of the acquisition date. The excess of the purchase price over the fair values of AGL Resources' assets and liabilities will be recorded as goodwill.

The amount of goodwill, which is expected to be material, will be allocated to the appropriate reporting units of the combined company. Southern Company is required to assess goodwill for impairment at least annually by comparing the fair value of reporting units to the carrying value of those reporting units. To the extent the carrying value of any of those reporting units is greater than the fair value, a second step comparing the implied fair value of goodwill to the carrying amount would be required to determine if the goodwill is impaired. Such a potential impairment could result in a material charge that would have a material impact on Southern Company's future operating results and consolidated balance sheet.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Georgia Power
Company Comparison of Customer/Reliability Survey Results
(GPC and other Southern Company Operating Companies Compared to 16 Peer Utilities)

2010 Customer Value Benchmark Survey Results

Residential Reliability	General Business Reliability	Large Business Reliability	Residential Overall Satisfaction	General Business Overall Satisfaction	Large Business Overall Satisfaction
8.66	9.38	9.38	8.13	**9.26 (GPC)**	9.30
8.57	9.36	9.34	8.08	9.23	9.20
8.53 (GPC)	9.36	9.28	8.04	9.20	9.16
8.50	**9.35 (GPC)**	9.24	**8.03 (GPC)**	9.01	**8.93 (GPC)**
8.49	9.17	**9.20 (GPC)**	7.98	9.00	8.91
8.44	9.12	9.17	7.95	8.98	8.54
8.34	9.05	9.01	7.94	8.94	8.53
8.34	9.03	8.91	7.85	8.94	8.50
8.29	8.97	8.90	7.83	8.89	8.48
8.25	8.95	8.83	7.79	8.89	8.43
8.10	8.94	8.81	7.78	8.88	8.32
8.09	8.92	8.80	7.58	8.83	8.20
8.08	8.87	8.54	7.53	8.72	8.20
8.03	8.86	8.52	7.48	8.69	8.18
8.01	8.85	8.48	7.47	8.57	8.11
7.95	8.78	8.44	7.44	8.57	7.92
7.94	8.59	8.33	7.37	8.53	7.78
7.93	8.48	8.31	7.31	8.33	7.61
7.85	8.46	8.15	6.87	8.32	7.57
7.39	8.44	7.95	6.80	8.31	7.37

Please rate your overall satisfaction with the reliability of your electric supply	Please rate your overall satisfaction with the reliability of electric supply	Overall how satisfied are you with the reliability of electric power?	How do you rate your overall satisfaction with your power company?	Please rate your overall satisfaction with your current power company	Overall how satisfied are you with the full package of electrical services provided by your utility

Georgia Power 2011 Customer Value Benchmark Survey Results*

Reliability			Overall Satisfaction		
Residential	General Business	Large Business	Residential	General Business	Large Business
8.57	9.28	9.40	8.12	9.24	9.40
8.47	9.27	9.40	8.08	9.24	9.29
8.41	9.19	9.29	8.04	9.09	9.18
8.40 (GPC)	9.17	9.24 (GPC)	8.00	9.02	8.93
8.33	9.13 (GPC)	9.19	7.88	9.02	8.90 (GPC)
8.28	9.06	8.93	7.87 (GPC)	8.99	8.54
8.28	9.05	8.87	7.86	8.97	8.50
8.23	9.05	8.85	7.81	8.93	8.48
8.21	8.94	8.76	7.79	8.93	8.45
8.19	8.93	8.70	7.79	8.91	8.42
8.15	8.93	8.65	7.79	8.90 (GPC)	8.25
8.13	8.86	8.61	7.77	8.82	8.17
8.02	8.80	8.60	7.58	8.82	8.15
8.02	8.79	8.44	7.52	8.79	8.03
8.01	8.75	8.44	7.50	8.76	7.98
8.00	8.55	8.35	7.41	8.73	7.80
7.96	8.53	8.27	7.41	8.52	7.65
7.90	8.52	8.27	7.36	8.48	7.64
7.55	8.45	8.25	7.23	8.35	7.63
7.08	8.29	7.96	6.09	8.25	7.46

Respondent Question

Please rate your overall satisfaction with the reliability of your electric supply	Please rate your overall satisfaction with the reliability of electric supply	Overall how satisfied are you with the reliability of electric power?	How do you rate your overall satisfaction with your power company?	Please rate your overall satisfaction with your current power company	Overall how satisfied are you with the full package of electrical services provided by your utility

***Company Comparison of Customer Satisfaction/Reliability Survey Results (GPC and other Southern Company Operating Companies Compared to 16 Peer Utilities)**

Georgia Power 2012 Customer Value Benchmark Survey Results*

Reliability			Overall Satisfaction		
Residential	General Business	Large Business	Residential	General Business	Large Business
8.74	9.46	9.59	8.41	9.43	9.51
8.67	9.35	9.56	8.37	9.28	9.44
8.67	9.21 (GPC)	9.29	8.36	9.17	9.14
8.64	9.20	9.27 (GPC)	8.28	9.17	9.06 (GPC)
8.64	9.14	9.14	8.28	9.12	8.82
8.62	9.13	9.08	8.27	9.08	8.72
8.57	9.09	8.90	8.23	9.07 (GPC)	8.65
8.43	9.04	8.87	8.18	9.07	8.62
8.43	9.02	8.77	8.15	9.03	8.48
8.40 (GPC)	8.97	8.75	8.05	9.02	8.34
8.39	8.96	8.74	7.95	9.02	8.28
8.36	8.96	8.68	7.85	8.98	8.20
8.36	8.89	8.56	7.78 (GPC)	8.96	8.15
8.36	8.87	8.52	7.73	8.95	8.10
8.29	8.79	8.46	7.73	8.87	8.00
8.23	8.79	8.40	7.70	8.85	7.97
8.10	8.78	8.37	7.56	8.84	7.87
8.06	8.75	8.28	7.52	8.81	7.65
7.99	8.64	8.05	7.46	8.67	7.61
7.55	8.23	7.81	6.77	8.37	7.45

Respondent Question

Please rate your overall satisfaction with the reliability of your electric supply	Please rate your overall satisfaction with the reliability of electric supply	Overall how satisfied are you with the reliability of electric power?	How do you rate your overall satisfaction with your power company?	Please rate your overall satisfaction with your current power company	Overall how satisfied are you with the full package of electrical services provided by your utility

***Company Comparison of Customer Satisfaction/Reliability Survey Results (GPC and other Southern Company Operating Companies Compared to 16 Peer Utilities)**

Georgia Power 2013 Customer Value Benchmark Survey Results*

Reliability			Overall Satisfaction		
Residential	General Business	Large Business	Residential	General Business	Large Business
8.96	9.34	9.66	8.44	9.20	9.54
8.70	9.27	9.48	8.42	9.11	9.52
8.69	9.15	9.44	8.35	9.06	9.25 (GPC)
8.67	9.07	9.37 (GPC)	8.09	9.05	9.13
8.63	9.03 (GPC)	9.05	8.02	8.93	8.87
8.60	9.00	9.00	7.98	8.92 (GPC)	8.83
8.52	8.99	8.97	7.97	8.92	8.79
8.51	8.95	8.96	7.94	8.90	8.71
8.50 (GPC)	8.90	8.78	7.93	8.85	8.61
8.37	8.89	8.77	7.91	8.81	8.41
8.36	8.88	8.76	7.85	8.78	8.37
8.35	8.86	8.72	7.79	8.76	8.37
8.29	8.83	8.71	7.77	8.76	8.37
8.23	8.71	8.68	7.76 (GPC)	8.68	8.13
8.21	8.71	8.58	7.74	8.67	8.06
8.11	8.68	8.45	7.73	8.63	8.02
7.98	8.64	8.31	7.58	8.61	7.69
7.94	8.54	8.14	7.27	8.59	7.45
7.80	8.50	7.86	6.88	8.57	7.15
7.55	8.48	7.80	6.83	8.52	7.08

Respondent Question

Please rate your overall satisfaction with the reliability of your electric supply	Please rate your overall satisfaction with the reliability of electric supply	Overall how satisfied are you with the reliability of electric power?	How do you rate your overall satisfaction with your power company?	Please rate your overall satisfaction with your current power company	Overall how satisfied are you with the full package of electrical services provided by your utility

***Company Comparison of Customer Satisfaction/Reliability Survey Results (GPC and other Southern Company Operating Companies Compared to 16 Peer Utilities)**

Georgia Power
2014 System Average Interruption Duration Index (SAIDI)
and
2014 System Average Interruption Frequency Index (SAIFI)

$$\text{2014 SAIDI} = \frac{\sum \text{Customer Minutes Interrupted}}{\text{Total Number of Customers Served}} = \frac{\mathbf{239,824,841}}{\mathbf{2,333,921}} = \mathbf{102.76}$$

$$\text{2014 SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}} = \frac{\mathbf{2,805,736}}{\mathbf{2,333,921}} = \mathbf{1.20}$$

Georgia Power 2014 Customer Value Benchmark Survey Results*

Reliability			**Overall Satisfaction**		
Residential	General Business	Large Business	Residential	General Business	*Large Business*
9.10	9.34	9.69	8.80	9.11	9.63
8.73	9.25	9.58	8.40	9.09	9.52
8.70	9.25	9.51	8.36	9.09	9.40
8.68 (GPC)	9.15	9.39 (GPC)	8.35	9.07	9.25 (GPC)
8.67	9.12 (GPC)	9.23	8.32	9.00	9.08
8.66	9.08	9.19	8.19	8.98	9.01
8.65	9.03	9.18	8.18	8.88	8.81
8.41	9.03	9.03	8.14 (GPC)	8.87	8.78
8.37	9.00	8.86	8.09	8.87 (GPC)	8.63
8.34	8.97	8.86	7.95	8.86	8.58
8.32	8.93	8.67	7.95	8.76	8.53
8.32	8.92	8.63	7.90	8.76	8.42
8.30	8.92	8.57	7.86	8.74	8.27
8.29	8.88	8.48	7.86	8.69	8.20
8.25	8.88	8.46	7.81	8.69	8.04
8.23	8.86	8.38	7.78	8.51	8.04
8.18	8.82	8.33	7.75	8.38	7.89
8.10	8.67	8.15	7.74	8.37	7.81
8.04	8.66	8.00	7.67	8.36	7.61
7.72	8.60	7.89	7.29	8.18	7.41
Respondent Question					
Please rate your overall satisfaction with the reliability of your electric supply	Please rate your overall satisfaction with the reliability of electric supply	Overall how satisfied are you with the reliability of electric power?	How do you rate your overall satisfaction with your power company?	Please rate your overall satisfaction with your current power company	Overall how satisfied are you with the full package of electrical services provided by your utility

***Company Comparison of Customer Satisfaction/Reliability Survey Results (GPC and other Southern Company Operating Companies Compared to 16 Peer Utilities)**

ATLANTA GAS LIGHT COMPANY
SERVICE QUALITY MEASURES

	2011	2012	2013	2014	2015	Benchmark
Meter Reading Accuracy	99.7%	99.8%	99.8%	99.8%	99.9%	98.5%
Meter Reading Timeliness	99.8%	99.9%	99.7%	99.8%	99.9%	98.5%
Appointment Attainment	97.0%	97.8%	97.7%	97.9%	97.3%	90.0%
EBB Availability						
Customer Information System	100.0%	100.0%	100.0%	100.0%	100.0%	95.0%
Gas Operating System	100.0%	100.0%	100.0%	100.0%	100.0%	98.0%
Marketer Interface Application	100.0%	99.9%	100.0%	100.0%	100.0%	98.5%
Eneract	100.0%	99.8%	99.9%	100.0%	100.0%	97.0%
Responsiveness To the Commission	100.0%	100.0%	100.0%	100.0%	100.0%	99.0%
Call Center Response Time	98.3%	97.9%	95.3%	94.7%	95.3%	80.0%
Forecasting	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Average FSR Leak Response Time	30.90	28.90	29.50	29.50	30.35	35.00
Average Distribution Leak Response Time	38.00	40.80	42.10	36.60	35.84	60.00

Note: Meter reading accuary percentage is the average from January through October. All other measures represent 12-month averages.

Source: AGLC Service Quality Measures Compliance Reports

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:
Service Quality Standards for the Electing Distribution Company)) **Docket No. 15295-U**

JOINT RECOMMENDATION OF
COMMISSION STAFF AND ATLANTA GAS LIGHT COMPANY

COMES NOW, Atlanta Gas Light Company (AGLC) and the Staff of the Georgia Public Service Commission (Staff) and hereby jointly recommend that the Commission approve and adopt the following service quality benchmarks and penalty structure for Electing Distribution Companies in the above-referenced matter:

1. Meter Reading Accuracy

"Meter Reading Accuracy" shall be defined as "the total of all firm cycle meter reads issued during the cycle month minus the cancelled cycle readings minus NCONS divided by the total of all firm cycle meter readings issued during the cycle month."

$$\frac{\text{Total of all firm cycle meter reads issued during the cycle month} - \text{cancelled cycle readings} - \text{NCONS}}{\text{Total of all firm cycle meter reads issued during the cycle month}}$$

"Cancelled cycle readings" means "all actual and estimated meter reads that the EDC cancels during the cycle month." The average two-month EDC Meter Reading Accuracy shall be no less than 98.5%.

2. Meter Reading Timeliness

"Meter Reading Timeliness" shall be defined as "the number of meter reads in a given one-month period issued by the EDC within the three-day cycle meter-reading window that applies to each respective meter divided by the total number of active meters that the EDC is responsible to read." The average two-month EDC Meter Reading Timeliness shall be no less than 98.5%.

The EDC shall be prohibited from sending, for any particular meter, any more than two consecutive no-reads or estimated reads, in any combination, to marketers, unless the EDC cannot read a meter due to interference by a customer or other such event that is beyond the EDC's control. In such an instance, the EDC shall make a good faith effort to notify the affected marketer within a reasonable time frame that the meter was not read due to circumstances beyond the EDC's control. The EDC shall implement computer-programming changes to ensure compliance.

3. Appointment Attainment

(Meter Reconnections, Meter Turn-ons, and Meter Turn-offs)

The EDC shall meet 90.0% of all scheduled appointments, measured on an average 2-month basis.

(Disconnection requests from marketers)

No standard shall be set in this proceeding but the EDC shall comply with Commission Rule 515-3-3-.08(a).

4. Call Center Response

The EDC must answer 80% of all calls to the call center within 180 seconds of a request to speak with an agent, measured over one calendar month. For purposes of this service quality benchmark, "calls" shall include calls in queue terminated by the calling party prior to speaking with an agent. The EDC will begin the remediation process as described in Attachment 2 if it fails to meet the benchmark twice during any 12-month period.

The EDC shall provide a wait-time notification message for all calls in the call center queue.

The Commission should issue a Notice of Proposed Rulemaking for the purpose of amending Commission Rules 515-7-7-.04(d) and .05(f) by deleting the phrase "average speed of answer."

5. Forecasting

The EDC shall follow its 12-step forecasting process 100% of the time that it receives weather forecasts from the service provider and its information and communication systems required to perform the task are functioning properly, unless the EDC cannot do so for events beyond the EDC's control. Also, the firm demand forecast shall be within 6.25% of the actual firm demand measured on a monthly net percentage basis.

"Monthly net percentage" is defined as:

$$\frac{\text{Total monthly firm forecast} - \text{Actual monthly firm demand}}{\text{Total monthly firm forecast}}$$

Should the EDC fail to meet these benchmarks for 2 consecutive quarters, it shall file a remediation plan with the Commission. Should the EDC fail to meet this benchmark for 3 consecutive quarters, a party may petition the Commission to initiate a proceeding to determine if AGLC should be relieved of its obligation to perform forecasting and the petitioning party shall bear the burden of proof.

6. Lost and Unaccounted For Gas ("L&U")

No standard shall be set in this proceeding but the EDC shall comply with the L&U standard of 1.6% of a 16-year rolling average as established in Docket No. 15527–U.

7. Electronic Bulletin Board ("EBB")

Components of the EBB shall be available as set forth as summarized below and in more detail on Attachment 1, measured on an average 2-month basis:

Customer Information System (CIS):	95.0% Availability;
Gas Operating System (GOS):	98.0% Availability;
Marketer Interface Application (MIA):	98.5% Availability; and
Eneract:	97.0% Availability.

These percentages shall be reevaluated following substantial changes to the EDC's EBB system.

"Availability" is defined for a month as:

$$\frac{\text{Total hours in month - hours of scheduled maintenance} - \text{hours of unplanned outages}}{\text{Total hours in month} - \text{hours of scheduled maintenance}}$$

8. Acquiring and Managing Interstate Capacity

The EDC must comply with OCGA 46-4-155 (e) and the Commission's approved capacity plan.

9. Accurate and Timely Customer Data Sent to Marketers

No benchmark shall be established at this time. The Commission should issue a Notice of Proposed Rulemaking for the purpose of amending Commission Rule 515-7-7-.05 by deleting subsection (g) in its entirety.

10. Leak Response Time

Service Leak Call Standard - The EDC shall respond on average over a given calendar year within 35 minutes from the time the EDC's Customer Information System time stamps a leak call to the time the EDC's Field Service Representative arrives on site.

Distribution Leak Call Standard – The EDC shall respond on average over a given calendar year within 60 minutes from the time the EDC's distribution personnel are notified by EDC dispatch of a distribution leak call to the time distribution personnel arrive on site.

The EDC would be subject to a penalty of $100,000 per year whenever the EDC's actual average annual response time for either the service or distribution calls exceeds 105% of the respective standards.

The EDC shall provide monthly to Commission Staff in a mutually acceptable format the leak response summary for each service area beginning January 1, 2003.

11. Response to the Commission

(Consumer Affairs Complaints)

Over a given two-month period, the EDC shall 99 % of the time acknowledge receipt within 1 business day of receiving complaints marked "urgent", and acknowledge receipt within 5 business days of receiving non-urgent complaints. Provided, however, that the EDC shall be deemed to have met this benchmark if its number of untimely responses does not exceed 2 in a given month. Resolution of the complaint is not measured in this standard.

Definition of Urgent Complaints– A complaint may be marked "urgent" if it involves a request for reconnection of service resulting from an erroneous disconnection; a situation where the consumer has indicated that an appointment for reconnection of service had been missed or states that the bill was paid prior to disconnection; failure to respond to a complaint after two referrals; or if it appears that the complaint is a result of the EDC's failure to act in accordance with any Commission rules. In all cases that a complaint is made with the Commission the Commission retains the discretion to mark that complaint as "urgent". However, the EDC may challenge the urgent status of any particular complaint when it is apparent from the face of the complaint that the EDC is not the proper party to handle the complaint or the complaint does not satisfy any of the requirements listed above for the complaint being marked "urgent".

(Data Requests, Orders, Reports)

No standards shall be established in this proceeding. The Commission should issue a Notice of Proposed Rulemaking for the purpose of amending Commission Rule 515-7-7-.06 by deleting subsections (a), (c), and (d) in their entirety.

12. General

The EDC standards shall not include any "deadband" compliance zone or "credit" for meeting or exceeding any benchmark.

In each instance in which the EDC's performance is to be measured over a 2-month period, such 2-month period shall be determined for each calendar year as follows: January/February, March/April, May/June, July/August, September/October and November/December.

Compliance with the performance standards being set for meter reading accuracy and timeliness, appointment attainment for meter turn/ons, turn/offs and reconnections, electronic bulletin board availability, and responsiveness to complaints shall be measured on a bi-monthly basis with the remediation process described in Attachment 2. Call center response time compliance shall be measured on a monthly basis, but otherwise the remediation process described in Section 4 and the Rebuttal testimony of Thebert and LeLash shall apply. As set forth in said testimony, and as qualified by force majure events, for a period of one year after the filing of a Remediation Report, the EDC will remain subject to quarterly penalties if the deficiency remains or reoccurs, and the EDC will not be given remediation opportunities again until such time as the EDC has demonstrated compliance with the benchmark for one year. All penalties will be subject to Commission discretion and a party may petition the Commission to increase or decrease penalties. In making the decision to increase or decrease penalties the Commission may consider factors including but not limited to, the impacts to consumers and marketers of AGLC's failure to meet a standard, any mitigating or aggravating circumstances, or the amount of any cost avoided by AGLC as a result of failing to meet a standard.

NOTE: AGLC and Staff reached agreement on all issues in this Docket except for one, the amount of the penalty for non-compliance with standards established in this proceeding. As such, Staff and AGLC offer the following independent recommendations:

<u>Staff Proposal</u>: a presumptive $50,000 penalty to be paid within 35 days after the filing of the Remediation Report demonstrating that deficiencies were not eliminated and benchmarks had not been met as referenced in Section 4 of this joint recommendation and Attachment 2 or after filing a Monthly Performance Data that demonstrates the EDC failed to meet the benchmark during the twelve consecutive month period following the remediation period;

<u>AGLC Proposal</u>: a recommended $25,000 penalty to be consistent with the penalty Staff recommended for the marketer non-compliance with the standards being established in Docket No. 15296-U.

13. Reporting

The EDC and Staff shall discuss the appropriate format for reports that need to be made to implement the Commission's final order in this proceeding and the EDC shall submit to the Commission the reporting formats within 60 days of such final order.

14.

Each of the undersigned authorized representatives of the parties to this Joint Recommendation acknowledges that he has read this Joint Recommendation and understands its contents. The undersigned representatives acknowledge that the undersigned parties freely, knowingly and voluntarily enter into this Joint Recommendation.

This 28th day of February, 2003.

Agreed to:

Alan Jenkins (w/permission by JS)

Alan Jenkins
On Behalf of Atlanta Gas Light Company

Jeffrey C. Stair

Jeffrey C. Stair
On Behalf of the Staff of the Georgia Public Service Commission

STATE OF VERMONT
PUBLIC SERVICE BOARD

Petition of Vermont Gas Systems, Inc. for change in rates, and for use of the System Reliability and Expansion Fund in connection therewith	)))	Docket No. 8710

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE
VERMONT DEPARTMENT OF PUBLIC SERVICE

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

AUGUST 22, 2016

Summary: Mr. Baudino provides an opinion as to the overall fair rate of return or cost of capital for the regulated electric utility operations of Vermont Gas Systems Inc. and evaluates Vermont Gas's rate of return testimony in this proceeding.

Exhibit List

EXHIBIT DPS-RAB-1	Resume of Richard A. Baudino
EXHIBIT DPS-RAB-2	Average Public Utility Bond vs. 20-Year Treasury Bond
EXHIBIT DPS-RAB-3	Gas Distribution Company Group – Dividend Yields
EXHIBIT DPS-RAB-4	Gas Distribution Company Group – Growth Rate Analysis and DCF Return on Equity Calculation
EXHIBIT DPS-RAB-5	Gas Distribution Company Group – Capital Asset Pricing Model (CAPM) Analysis
EXHIBIT DPS-RAB-6	CAPM Analysis – Historic Market Premium
EXHIBIT DPS-RAB-7	Coyne Gas Distribution Company Group – Dividend Yields
EXHIBIT DPS-RAB-8	Coyne Gas Distribution Company Group – Growth Rate Analysis and DCF Return on Equity Calculation
EXHIBIT DPS-RAB-9	2017-2020 Capital Expenditures as a Percent of 2014 Net Plant

STATE OF VERMONT
PUBLIC SERVICE BOARD

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STATE OF VERMONT
PUBLIC SERVICE BOARD

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DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service,

rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

DPS-RAB-1 summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Vermont Department of Public Service ("DPS").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the allowed return on equity for Vermont Gas Systems, Inc. ("Vermont Gas" or "Company"). I will also address the Company's requested capital structure and the cost of short-term and long-term debt. Finally, I will respond to the Direct Testimony of Mr. James Coyne and Ms. Eileen Simollardes, witnesses for the Company.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows.

First, I recommend that the Vermont Public Service Board ("Board") adopt a fair rate of return on equity of 9.0% for Vermont Gas. My recommended return on equity ("ROE") is based on a Discounted Cash Flow analysis using a comparison group of regulated gas distribution companies. My recommended 9.0% ROE is completely consistent with current stock market data, expected growth rates, and today's low interest rate environment.

Second, I recommend that Vermont Gas' cost of short-term debt be reduced to 1.50% from the Company's requested 2.01%. This cost of short-term debt is supported by the current London Interbank Offered Rate ("LIBOR") and is consistent with the Company's 2015 short-term debt cost.

Third, I recommend that the Board adopt Vermont Gas' requested capital structure and cost of long-term debt.

Fourth, my recommended adjusted weighted cost of capital for Vermont Gas is 6.84%.

Fifth, I recommend that the Board reject Mr. Coyne's recommended 9.70% cost of equity. For reasons that I shall explain in Section IV of my testimony, a cost of equity of 9.70% is overstated, inconsistent with current market required returns, and would result in an excessive revenue requirement for Vermont Gas.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Generally speaking, interest rates have declined over the last few years. DPS-RAB-2 presents a graphic depiction of the trend in interest rates from January 2008 through May 2016. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. In January 2008, the average public utility bond yield was 6.08% and the 20-year Treasury Bond yield was 4.35%. As of May 2016 the average public utility bond yield was 4.06%, representing a decline of 202 basis points, or 2.02 percentage points, from January 2008. Likewise, the 20-year Treasury bond declined to 2.22% in May 2016, a decline of 2.13 percentage points (213 basis points) from January 2008.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in DPS-RAB-2?

A. Yes. In response to the 2007 financial crisis and severe recession that followed in December 2007, the Federal Reserve ("Fed") undertook a series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets."[1]

QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases.

QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury securities by the second quarter of 2011.[2]

Beginning in September 2011, the Federal Reserve initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist" was designed by the Federal Reserve to lower long-term interest rates and support the economic recovery.

QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities. On June 19,

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[1] http://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm

[2] http://www.federalreserve.gov/newsevents/press/monetary/20101103a.htm

2013, the Federal Open Market Committee ("FOMC") issued a press release indicating that it intended to extend "Operation Twist." In its press release, the Federal Reserve stated:

> To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.

More recently, the Federal Reserve began to pare back its purchases of securities. For example, on January 29, 2014 the Federal Reserve stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Federal Reserve continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October.[3]

Q. Since the Federal Reserve's announcements of scaling back and finally ending its purchases of long-term Treasury securities, what has the trend been in long-term Treasury yields from 2014 through 2016?

[3] http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm

A. The yield on the 20-year Treasury bond has actually declined since the beginning of 2014. The January 2014 yield on the 20-year Treasury bond was 3.52%. The closing yield for June 2016 was 2.02%, a decline of 150 basis points since January 2014.

Q. Has the Federal Reserve recently indicated any important changes to its monetary policy?

A. Yes. Recently the Federal Reserve raised its target range for the federal funds rate to 1/4% to 1/2% from 0% to 1/4%. The Federal Reserve also issued a press release dated June 15, 2016 from the Federal Open Market Committee stating the following:

> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will strengthen. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of past declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to closely monitor inflation indicators and global economic and financial developments.
>
> Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.

Note that the stance of the Federal Reserve is one of accommodation and that it decided to maintain short-term interest rates at their present levels. This continues to favor lower expected returns on the part of investors for lower risk and higher yielding regulated utility stocks.

Q. Why is it important to understand the Fed's actions with respect to monetary policy since 2007?

A. The Fed's monetary policy actions since 2007 were deliberately undertaken to lower interest rates and support economic recovery. The Fed's actions have been quite successful in lowering interest rates given that the 20-year Treasury Bond yield in June 2007 was 5.29% and the public utility bond yield was 6.34%. The U.S. economy is currently in a low interest rate environment that, in my opinion, will likely continue at least through this year. As I will demonstrate later in my testimony, low interest rates have also significantly lowered investors' required return on equity for the stocks of regulated utilities.

Q. Are current interest rates indicative of investor expectations regarding future policy actions by the Federal Reserve?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> "A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information."[4]

I acknowledge that the U.S. economy is operating in a low interest rate environment. It is likely at some point in the near future that the Federal Reserve will raise short-term interest rates further. However, the timing and the level of any such move are not known at this time. It is important to realize that investor expectations of higher

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4 Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.

interest rates, if any, are already embodied in current securities prices, which include debt securities and stock prices.

The current low interest rate environment favors lower risk regulated utilities. As I shall demonstrate in Section III, all the market evidence I examined suggests that investors require lower rates of return on equity on regulated utility stocks.

Q. How does the investment community regard the regulated gas distribution industry as a whole?

A. The Value Line Investment Survey's June 3, 2016 summary report on the Natural Gas Utility industry noted the following:

> Stocks within the Natural Gas Utility Industry ought to attract the interest of income-focused investors with a conservative bent, given that a number of these issues are ranked favorably for Safety and boast high marks for Price Stability. Those seeking outstanding short-term investment performance should find something to like here, too, such as Atmos Energy, Southwest Gas, UGI Corp. and Spire Inc. (formerly Laclede Group). It is important to mention that companies owning larger nonregulated operations might offer a higher potential for returns, but profits could be more volatile than for companies with a greater emphasis on the more stable utility segment.

Q. What do you conclude from the aforementioned quote from Value Line?

A. Utilities in general and gas utilities in particular continue to be safe, solid stock choices for investors. Even with uncertainty regarding the Federal Reserve's future moves on interest rates, utilities' prices have made solid gains since the beginning of 2016. For example, the Dow Jones utility average opened January 2016 at 574.51 and closed at 717.37 on July 8, 2016. This represents a gain of nearly 25% since the beginning of this year.

It appears that the Fed will continue a relatively accommodating stance with respect to monetary policy in 2016 and has signaled that it does not intend to raise short-term interest rates at this time. The volatile economic conditions that were present in the 2008 - 2009 period are over and the U.S. economy continues to recover from the recession that began in 2007.

Q. Briefly describe Vermont Gas Systems.

A. Vermont Gas Systems, Inc. is a wholly owned subsidiary of Northern New England Energy Corporation ("NNEEC). According to its audited financial statements for the period ending September 30, 2015 the Company serves more than 49,000 residential, commercial, and industrial customers in Northwestern Vermont. Vermont Gas reported total net plant in service for 2015 of $147.99 million, $76.6 million of Construction Work in Progress ("CWIP"), and total utility plant of $224.58 million.

The Company reported total operating revenues of $114.19 million in 2015 and $108.22 million in 2014. Due mainly to a write-off associated with the Company's investment in the Addison Natural Gas Project ("the Addison project"), net income declined from $7.9 million in 2014 to $3.26 million in 2015.

On page 4 of his Prefiled Testimony, Company witness Donald Rendall testified that in addition to the Addison project, the Company expects to invest $36 million over the next three years to maintain the safety and reliability of its system, expand service to more customers, and enhance customers' experience.

Vermont Gas receives its financing from equity infusions from its parent company, issuances of long-term debt, and engages in short-term debt and credit arrangements. Vermont Gas reported in its 2015 financial statements that it was in compliance with all restrictive covenants and limitations related to both its short-term and long-term debt agreements.

Q. Has the Board provided advantageous regulation for the Company over the last several years?

A. Yes, most definitely. As Vermont Gas noted on page 12 of its 2015 financial statements, the Company has been regulated under an Alternative Regulation Plan since October 1, 2006. This plan contains a Purchase Gas Adjustment Clause and an Earnings Sharing Mechanism ("ESM"). The Original Plan was modified through a Memorandum of Understanding ("MOU") with the Board on June 18, 2012. On August 26, 2015 the Board approved a one-year extension of the Successor Plan. It is my understanding that the current Successor Plan is being evaluated in this case.

The Company also operates under a System Expansion and Reliability Fund ("SERF"). This mechanism designed to support the Company's system expansion into unserved areas in Vermont. In this current proceeding, Mr. Rendall testified on page 4 of his Prefiled Testimony that the Company proposes to use the SERF in this case to lower the rate increase.

Q. On page 2 of his Prefiled Testimony, Mr. Rendall noted that Vermont Gas recognized a $10.3 million write-off associated with the Addison project. Please comment on the financial ramifications of the write-off and on the ongoing financial commitment of the Company to the Addison project.

A. The Addison project had a significant impact on the Company's net income, as I pointed out earlier. The MOU between Vermont Gas and the Public Service Department will indeed shield ratepayers from ongoing cost overruns from the Addison project, overruns that have been substantial and are ongoing. To the extent that Vermont Gas' continued involvement in the Addison project places financial stress on the Company, it is imperative that Vermont Gas ratepayers be shielded from any adverse impacts on the cost of capital that may result from that stress. This includes both the cost of debt and equity. In other words, the Company should not be allowed to earn a higher cost of equity due to any increase in its risk caused by the Addison project. My approach to the allowed return on equity will ensure such protection.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for Vermont Gas.

A. I employed a Discounted Cash Flow ("DCF") analysis using a group of regulated gas distribution utilities. In my opinion, they form a reasonable basis for estimating the investor required return on equity for Vermont Gas.

My DCF analysis is my standard constant growth form of the model that employs four different growth rate forecasts from the Value Line Investment Survey, IBES, and Zacks. I also employed Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data. Although I did not rely on the CAPM for my recommended 9.0% ROE for Vermont Gas, the results from the CAPM tend to support this recommendation.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) and Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many regulated utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the risk of a particular investment. The end result of their analyses is a bond and/or credit rating that reflect these risks.

Discounted Cash Flow ("DCF") Model

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I typically employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Embodied in this formula, it is assumed that "k" reflects the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for Vermont Gas?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to Vermont Gas. Vermont Gas itself is not a publicly traded company and, therefore, has no stock price and growth forecasts to use in a DCF analysis. Therefore, a group of natural gas distribution companies must be employed to estimate an investor required ROE for Vermont Gas. In this respect, my approach is similar to Mr. Coyne's DCF analysis.

Q. Did you make any adjustments to the group used by Mr. Coyne?

A. Yes. I included UGI Corporation in my natural gas distribution group. It is my understanding that Mr. Coyne excluded UGI because it did not meet all of his selection criteria listed on page 19 of his Direct Testimony. Even though UGI has significant unregulated operations, my review of its dividend yield and growth estimates suggest that it is reasonable to include UGI Corp. in my comparison group of gas distribution companies.

Q. What was your first step in determining the DCF return on equity for the comparison groups of regulated utilities?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from January through June 2016. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the gas distribution group is 2.92%. These calculations are shown in DPS-RAB-3.

Q. Having established the average dividend yield, how did you determine the **investors' expected growth rate for** the comparison groups?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and IBES. This is the method I typically use for estimating growth for my DCF calculations.

Q. Please briefly describe Value Line, Zacks, and IBES.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Plus Edition. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated gas utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, IBES also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance.

Q. Wh**y did you rely on analysts' forecasts in your analysis?**

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. Please explain how you used analysts' dividend and earnings growth forecasts in your constant growth DCF analysis.

Q. Columns (1) through (5) of DPS-RAB-4 shows the forecasted dividend, earnings, and retention growth rates from Value Line and the earnings growth forecasts from IBES and Zacks for the companies in the gas distribution group. In my analysis I used four of these growth rates: dividend and earnings growth from Value Line and earnings growth from Zacks and IBES. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows. Value Line is the only source of which I am aware that forecasts dividend growth and my approach gives this forecast equal weight with each of the three earnings growth forecasts.

Q. How did you proceed to determine the DCF return of equity for the two comparison groups?

A. To estimate the expected dividend yield (D_1), the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

DPS-RAB-4 presents my standard method of calculating dividend yields, growth rates, and return on equity for the gas distribution group of companies. The DCF Return on Equity Calculation section shows the application of each of four growth rates I used in my analysis to the current group dividend yield of 2.92% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. My DCF return on equity was calculated using two different methods. Method 1 uses the Average Growth Rates shown in the upper section of DPS-RAB-4. Method 2 utilizes the median growth rates shown in the upper section of DPS-RAB-4.

Q. What are the results of your constant growth DCF model?

A. The results for Method 1 range from 7.55% to 8.97%, with the average of these results being 8.42%. The results for Method 2 range from 6.73% to 9.27%, with the average of these results being 8.44%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing **Model ("CAPM") approach.**

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: *K* = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[5] There is evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a

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[5] For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206 - 211, 2007 edition.

wide variety of data in estimating investor-required returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for June 12, 2016. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of DPS-RAB-5. I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 9.88% to 11.0%. The average of these three market returns is 10.44%.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2015 Classic Yearbook*. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. DPS-RAB-6 presents the calculation of the market returns using the historical data.

Q. Please explain how this historical risk premium is calculated.

A. DPS-RAB-6 shows both the geometric and arithmetic average of yearly historical stock market returns over the historical period from 1926 - 2014. The average annual income return for 20-year Treasury bond is subtracted from these historical stocks returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The historical market risk premium range is 5.03% - 7.03%.

Q. Did you add an additional measure of the historical risk premium in this case?

A. Yes. Morningstar reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001.[6] Morningstar recommended adjusting this growth in the P/E ratio for stocks out of the historical risk premium because "it is not believed that P/E will continue to increase in the future." Morningstar's adjusted historical arithmetic market risk premium is 6.19%, which I have also included in DPS-RAB-6.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from January through June 2016. The 20-year Treasury

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6 *2015 Ibbotson SBBI Classic Yearbook,* Morningstar, pp. 156 - 158.

bond may be used as a proxy for the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM return on equity may be estimated.

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the gas distribution group from most recent Value Line reports. The average of the Value Line betas for the comparison group is 0.77.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 8.33% - 8.54%. Using historical risk premiums, the CAPM results are 6.10% - 7.64%.

ROE Conclusions and Recommendations

Q. Please summarize the cost of equity results for your DCF and CAPM analyses.

A. Table 1 below summarizes my return on equity results using the DCF and CAPM for my comparison group of companies.

TABLE 1

VERMONT GAS SYSTEMS
ROE RESULTS SUMMARY

<u>DCF Results:</u>	
Average Growth Rates, Gas Group	
- High	8.97%
- Low	7.55%
- Average	8.42%
Median Growth Rates, Gas Group	
- High	9.27%
- Low	6.73%
- Average	8.44%
CAPM:	
- 5-Year Treasury Bond	8.33%
- 20-Year Treasury Bond	8.54%
- Historical Returns	6.10% - 7.64%

Q. What is your recommended return on equity for Vermont Gas?

A. I recommend that the Commission adopt a 9.0% return on equity for Vermont Gas. My recommendation is consistent with the upper end of the range of DCF results that employed earnings growth forecasts for the gas distribution group (8.31% - 9.27%). Based on current market evidence, a 9.0% return on equity is fair and reasonable, even generous for a regulated natural gas distribution company such as Vermont Gas.

Q. Mr. Baudino, are you concerned that your recommended cost of equity is too low?

A. No, not at all. All of the market evidence I examined fully supports my ROE recommendation for Vermont Gas in this proceeding. As I described in Section II of my testimony, the U. S. economy is in a low interest rate environment, one that has been supported in a deliberate and considered fashion by Federal Reserve monetary policy. Both my DCF and CAPM ROE estimates show that the investor required ROE for Vermont Gas, as well as other regulated gas and water utilities, reflects this low interest rate environment. A 9.0% ROE recommendation for Vermont Gas is by no means too low in the current economic and financial environment and is higher than the average DCF results

Q. Please explain why you chose to move to the upper end of your range of DCF results in this particular proceeding.

A. There are good reasons for recommending the upper end of my DCF results for Vermont Gas at this time in this particular case.

First, the dividend growth forecasts for my gas company comparison group are significantly lower than the earnings growth forecasts at this point in time. Referring to DPS-RAB-4, the DCF ROE estimates using dividend growth range from 6.73% to 7.55%. If these rather low DCF estimates are excluded from the averages, then the average DCF for Method 1 is 8.72% and the average DCF for Method 2 is 9.02%.

Second, in my opinion it is likely that interest rates may increase at some point in the near future. One cannot say when or by how much rates will go up at this time, but the Federal Reserve has signaled its willingness to raise rates later this year and into next year if conditions warrant. For example Federal Reserve Chair Janet Yellen noted in a New York Times article dated June 6, 2016 that "if incoming data are consistent with labor market conditions strengthening and inflation making progress toward our 2 percent objective, as I expect, further gradual increases in the federal funds rate are likely to be appropriate." Of course, the Federal Reserve did not increase interest rates in June, but in my view it stands ready to do so if economic conditions warrant such an increase. Given this readiness on the part of the Federal Reserve to raise interest rates, I believe that a modest upward adjustment to my return on equity recommendation is reasonable in this case.

Taking these two points into consideration and using my professional judgment, a 9.0% ROE is a reasonable and appropriate recommendation for Vermont Gas in this case.

Cost of Short-Term Debt

Q. Please explain how you adjusted the Vermont Gas' cost of short-term debt.

A. Ms. Simollardes presented the Company's proposed cost of short-term debt on page 12, lines 2 through 5 of her Prefiled Testimony. Ms. Simollardes explained that the interest rate on short-term debt was determined using a forecasted 30-day LIBOR of 1.0% plus the basis point differential from the credit lines of 1.01% for a total short-term debt cost of 2.01%.

According to the Wall Street Journal, the current 30-day LIBOR is 0.467% as of June 30, 2016. I recommend that the Board use this current LIBOR, rather than the forecasted LIBOR recommended by Ms. Simollardes. I recognize that interest rates may rise later this year and into next year, but how much they will rise, if any, is speculative at this point. Rather than use a forecasted LIBOR, I believe it is reasonable to use the most current LIBOR for this proceeding. I also recommend that the rate be updated in Rebuttal Testimony so that the Board may use the latest possible current LIBOR for Vermont Gas' short-term debt rate.

For purposes of this case, I will round up the current LIBOR to 0.50%. Adding a 1.0% basis point differential to my recommended LIBOR results in my recommended cost of short-term debt of 1.50%.

Capital Structure and Weighted Cost of Capital

Q. What is your recommended weighted cost of capital for Vermont Gas?

A. My weighted cost of capital recommendation is 6.84%. It is based on the Company's adjusted equity ratio of 50.0%, an adjusted short-term debt cost of 1.50%, and my recommended ROE of 9.0%.

TABLE 2

VERMONT GAS SYSTEMS
WEIGHTED COST OF CAPITAL

	Percentage	Cost	Wtd. Cost
Long-term Debt	42.13%	5.27%	2.22%
Short-term Debt	7.87%	1.50%	0.12%
Common Equity	50.00%	9.00%	4.50%
Total	100.00%		6.84%

Q. How does the Company's proposed equity ratio compare to the equity ratios of your natural gas comparison group?

A. Table 3 presents the 2015 common equity ratios for the companies in the group, as well as the group average common equity ratio. The data in Table 3 was taken from the June 3, 2015 Value Line reports for each company.

TABLE 3

GAS UTILITY GROUP
2015 COMMON EQUITY RATIOS

Atmos Energy	56.5%
New Jersey Resources	56.8%
Northwest Natural Gas	57.5%
South Jersey Industries	50.8%
Southwest Gas	50.7%
Spire Inc.	47.0%
UGI Corp.	43.9%
WGL Holdings	56.1%
Average	52.4%

Source: Value Line Investment Survey

Table 3 shows that the imputed common equity ratio for Vermont Gas is somewhat lower than the comparison group average, although a 50% common equity ratio falls within the range of common equity ratios for the group. On balance, a 50% common equity ratio for Vermont Gas is reasonable in this proceeding.

IV. RESPONSE TO VERMONT GAS ROE TESTIMONY

Q. Have you reviewed the Direct Testimony of Mr. Coyne?

A. Yes.

Q. Please **summarize Mr. Coyne's testimony and approach to return on equity.**

A. Mr. Coyne employed three methods to estimate the investor required rate of return for Vermont Gas: (1) the constant growth DCF model, (2) the CAPM, and (3) the bond yield plus risk premium model.

For his constant growth DCF approach, Mr. Coyne used Value Line, First Call, and Zacks for the investor expected growth rate. Mr. Coyne's mean growth rate ROE results for his proxy group of companies ranged from 9.46% to 9.56%. Vermont Gas Witness Coyne Direct at 25, Figure 5.

With respect to the DCF model, Mr. Coyne used 30-day, 90-day, and 180-day average stock prices ending December 31, 2015 to estimate the dividend yield for the companies in his proxy group.

With respect to the CAPM, Mr. Coyne's results ranged from 9.09% to 11.39%. Witness Coyne Direct at 30, Figure 6.

Mr. Coyne's formulation of the bond yield plus risk premium approach resulted in a ROE estimate range of 9.65% - 10.31%. Witness Coyne Direct at 33, Figure 8.

Mr. Coyne also discussed making an adjustment for flotation costs to his recommended ROE, but did not make an explicit adjustment. Witness Coyne Direct at 42.

Based on the results of his analyses and judgment, Mr. Coyne recommended a ROE range for Vermont Gas of 9.70%.

Constant Growth DCF Analyses

Q. Are the stock prices Mr. Coyne used in his DCF analyses out of date?

A. Yes, they are quite dated. Mr. Coyne used stock prices ending December 31, 2015, making them over six months out of date. The Commission should not rely on ROE analyses that use such stale data.

Q. Did you update any of Mr. Coyne's DCF analyses using current stock prices and growth forecasts?

A. Yes. Mr. Coyne and I used similar data sources in our analyses, including earnings growth forecasts from Value Line, Yahoo! Finance, and Zacks. My exhibits DPS-RAB-7 and DPS-RAB-8 show updated return on equity calculations for Mr. Coyne's gas group, which excludes UGI Corp. I used my more recent 6-month stock price data, which would correspond to Mr. Coyne's 180-day average price approach, in DPS-RAB-7. DPS-RAB-8 shows the growth rates for this group and the resulting DCF results.

Using updated stock prices and earnings growth forecasts shows the following:

- Updated group dividend yield of 3.00%, compared to Mr. Coyne's group dividend yield of 3.47%.
- Updated average group growth rate of 5.64%, compared to Mr. Coyne's average group growth rate of 5.99%.
- Updated average DCF result of 8.73%, compared to Mr. Coyne's average DCF result of 9.50%.

Q. Does updating Mr. Coyne's 180-day DCF result support your recommendation of 9.0% for Vermont Gas?

A. Yes. Please note that on DPS-RAB-8, the median DCF result is 9.09%, which is quite close to my recommendation of 9.0%.

Q. On page 42 of his Prefiled Testimony, Mr. Coyne discussed adding an adjustment for flotation costs, though he made no explicit adjustment to his recommendation. Should the Commission add a flotation cost adjustment to the cost of equity for Vermont Gas?

A. No. In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. I do not believe that this is an appropriate assumption. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

CAPM

Q. **Briefly summarize the main elements of Mr. Coyne's CAPM approach.**

A. On page 28 of his Prefiled Testimony, Mr. Coyne testified that he used the projected yield on the 30-year Treasury bond from Blue Chip. This projected yield was 4.50%. Mr. Coyne did not consider any shorter maturity bonds, such as the 5-year Treasury note.

Mr. Coyne utilize two sources for the market risk premium portion of the CAPM: (1) an historical risk premium from the 2015 Ibbotson Classic Yearbook of 7.0% and (2) an ex-ante risk premium based on the total market return on the S&P 500 using data from Bloomberg. The total market return from Bloomberg was 13.62%. Exhibit Petitioner JMC-5.

Mr. Coyne used two different estimates for beta from Bloomberg and Value Line.

Q. Is it appropriate to use forecasted or projected bond yields in the CAPM?

A. Definitely not. Current interest rates and bond yields embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted bond yield used by Mr. Coyne is speculative at best and may never come to pass. Current interest rates provide tangible and verifiable market evidence of investor return requirements today, and these are the interest rates and bond yields that should be used in both the CAPM and in the bond yield plus risk premium analyses. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

Furthermore, Mr. Coyne's forcasted 30-year Treasury Bond yield is grossly excessive compared to current long-term bond yields. My 6-month average 20-year Treasury Bond yield is 2.24%. As of June 30, 2016 the yield on the 30-year Treasury Bond was 2.30%. Mr. Coyne's forecasted yield of 4.50% is nearly double the current yield for long-term Treasury bonds. Given how far off the Blue Chip forecast is from current yields, I strongly recommend that Mr. Coyne's CAPM results be rejected out of hand.

Q. What would Mr. Coyne's mean CAPM result be using the current yield on 30-year Treasury bonds?

A. Using the current yield on the 30-year Treasury bond requires a recalculation of Mr. Coyne's Market DCF Derived risk premium shown on Exhibit Petitioner JMC-5. Subtracting the current 30-year Treasury bond yield of 2.30% from Mr. Coyne's S&P 500 Market Return of 13.62% results is a market risk premium of 11.32%. Averaging this market premium with Mr. Coyne's historical risk premium of 7.0% results in an average market risk premium of 9.16%

The revised result for Mr. Coyne's CAPM would be as follows:

30-Year Risk-free Rate (June 30, 2016)	2.30%
Average Bloomberg and Value Line betas	.706
Average Market Risk Premium	9.16%
Revised CAPM Return on equity	***8.77%***

The revised CAPM result is somewhat higher than my CAPM results, but is still below my recommended ROE for Vermont Gas of 9.0%.

Q. Should Mr. Coyne have considered shorter-term Treasury yields in his CAPM analyses?

A. Yes. In theory, the risk-free rate should have no interest rate risk. 30-year Treasury Bonds do face this risk, which is the risk that interest rates could rise in the future and lead to a capital loss for the bondholder. Typically, the longer the duration of the bond, the greater the interest rate risk. The 5-year Treasury note has much less interest rate risk than 20-year or 30-year Treasury Bonds and may be considered one reasonable proxy for a risk-free security. My CAPM analysis shows that the ROE using a 5-year Treasury note would be only 8.33% using the expected market return. This is much lower than any of the CAPM estimates provided by Mr. Coyne.

Q. Is the S&P 500 a good proxy for the market when estimating a CAPM return on equity?

A. No. That is because the S&P 500 is limited to the stocks of the 500 largest companies in the United States. The market return portion of the CAPM should represent the most comprehensive estimate of the total return for all investment alternatives, not just a small subset of publicly traded stocks. In practice, of course, finding such an estimate is difficult and is one of the more thorny problems in estimating an accurate ROE when using the CAPM. If one limits the market return to stocks, then there are more comprehensive measures of the stock market available, such as the Value Line Investment Survey that I used in my CAPM analysis. Value Line's projected earnings growth used a sample of 2,209 stocks and its book value growth estimate used 1,527 stocks. Value Line's projected annual percentage return included 1,680 stocks. These are much broader samples than Mr. Coyne's limited sample of the S&P 500.

Q. Do the market returns you used in your CAPM suggest that Mr. Coyne's estimated market returns are excessive?

A. Yes. The market returns I estimated from Value Line ranged from 9.88% to 11.00%, far lower than Mr. Coyne's estimated returns on the S&P 500.

<u>Bond Yield Plus Risk Premium Analysis</u>

Q. **Please summarize Mr. Coyne's risk premium approach.**

A. Mr. Coyne developed a historical risk premium using Commission-allowed returns for regulated gas utility companies and 30-year Treasury bond yields from 1992 through December 31, 2015. He used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. Applying the regression coefficients to the average risk premium and using both current and projected 30-year Treasury yields I discussed earlier, Mr. Coyne's risk premium ROE estimate ranges from 9.65% to 10.31%. Witness Coyne Prefiled Testimony at 33.

Q. Please respond to Mr. Coyne's risk premium analysis.

A. First, the bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time. As such, this approach is a "blunt instrument" for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on a historical risk premium analysis over a certain period of time.

Second, I recommend that the Commission reject the use of the forecasted Treasury bond yields for the same reasons I described in my response to Mr. Coyne's CAPM approach. The Blue Chip Consensus 30-Year Treasury yield forecasts resulted in an ROE of 10.31%, the highest of the three results obtained from Mr. Coyne's analysis. Changing Mr. Coyne's analysis only to use the current 30-Year Treasury yield, without addressing other potential shortcomings of that analysis, would result in a ROE of 9.65%.

Capital Market Environment

Q. Beginning on page 12 of his Prefiled Testimony, Mr. Coyne presented an analysis of credit spreads that, in his view, suggested that the cost of equity is increasing. Please respond to Mr. Coyne's testimony on this point.

A. I disagree with Mr. Coyne's analysis and conclusions.

First of all, as I pointed out in Section II of my testimony, interest rates have fallen significantly so far in 2016 and have continued to stay at nearly historic lows. I also showed that the Dow Jones Utility Average gained about 25% so far this year. The current data suggests that investors are placing their money into safer investments and are willing to accept lower returns for that safety. This includes stocks of regulated public utilities, both electric and gas companies. Thus, it is safe to conclude that the

DCF and CAPM results I have presented in Section III are well supported by current stock and bond market data. My revisions and corrections to Mr. Coyne's DCF and CAPM analyses are also consistent with the current market environment.

Second, increasing credit spreads do not necessarily suggest that the cost of equity will increase. I analyzed the bond yield data contained in my DPS-RAB-2 and calculated monthly credit spreads between the 20-year Treasury bond and the average Mergent utility bond yield. My observations from this analysis are as follows:

- During the period from January 2008 through May 2016, the highest credit spread was 3.69% in December 2008.
- The 20-year Treasury bond yield rose from 3.18% in December 2008 to 4.51% in June 2009. Thus, the interest rate did rise over this 6-month period.
- The yield on the average public utility bond fell from 6.87% in December 2008 to 6.54% in June 2009. The resulting credit spread fell from 3.69% to 2.03%.
- The increasing yield on the 20-year Treasury bond was not predictive of the yield on the average utility bond yield, which actually declined over the six-month period.
- The average credit spread from January 2008 through May 2016 is 1.75%.
- The credit spread for May 2016 was 1.84%.
- As of July 1, 2016 the Moody's average public utility bond yield was 3.75%. The yield on the 20-year Treasury bond was 1.81%. The credit spread was 1.94%.

Based on these observations of the market, I do not necessarily agree that current credit spreads suggest a higher cost of equity going forward. Despite the changes in credit spreads over the period of January 2008 through July 2016, the trend was declining interest rates and, in my opinion, a lower required return on equity over time.

Small Size

Q. Beginning on page 34 of his Prefiled Testimony, Mr. Coyne discusses his view of how Vermont Gas' relatively small size affects its risk profile. Please respond to Mr. Coyne's testimony on this point.

A. I agree with Mr. Coyne that economic literature recognizes that smaller companies may be considered riskier by investors and command higher required returns as a result. However, the fact that Vermont Gas is a regulated utility would substantially reduce its risk compared to smaller, unregulated companies. Indeed, as I described earlier in my testimony the Board has approved regulatory mechanisms and rate treatment for Vermont Gas that reduces its risk of recovering its costs and its required return. The SERF, a weather normalization adjustment, and the Alternative Regulation Plan have all reduced risk for the Company. I would not recommend that the Board consider Vermont Gas' size relative to the companies in the gas comparison group when deciding its allowed return on equity. Mr. Coyne also declined to make a size adjustment in his recommended ROE.

<u>Capital Expenditure Program</u>

Q. On page 38 of his Prefiled Testimony, Mr. Coyne concluded that Vermont Gas has an above average risk profile due to its capital expenditure program. Please respond to Mr. Coyne's testimony on this point.

A. The ratio that Mr. Coyne calculated for expected capital expenditures to net utility plant for Vermont Gas is inflated by a very large capital expenditure of $103.5 million in 2016, according to the data presented in Exhibit Petitioner JMC-8.1. After 2016, the capital expenditures drop off dramatically for Vermont Gas, averaging about $14.1 million per year.

I recalculated the percentages of capital expenditures to net plant for the gas company group using Mr. Coyne's projected data for the period 2017 through 2020 and have included the results in DPS-RAB-9. The results of this analysis are rather striking and completely turn around the conclusions reached by Mr. Coyne. The important points from this analysis are:

- Vermont Gas' ratio of capital expenditures as a percentage of net plant falls to 29.24%, lower than any company in Mr. Coyne's gas distribution group.
- Vermont Gas as a percentage of the group median falls to 46% from 108% in Mr. Coyne's study.
- The annual average expenditure for Vermont Gas falls from $32.9 million in Mr. Coyne's study to $14.1 million during the period of 2017 through 2020.

The conclusion from my analysis of capital expenditures from 2017 through 2020 shows that relative to the gas company group, Vermont Gas' ongoing capital expenditure program is much smaller as a percentage of 2014 net plant. One should not conclude that this program places extra risk on the Company relative to the companies in the gas distribution group. If anything, the results suggest that Vermont Gas has lower risk than Mr. Coyne's gas distribution group with respect to its ongoing construction program.

Regulatory Risk

Q. Mr. Coyne presented an analysis of regulatory risk in his Exhibit Petitioner JMC-9. In your opinion, do the regulatory rankings shown in this exhibit suggest that the Board provide a higher ROE to Vermont Gas?

A. No, not at all. Vermont received an Average regulatory rank from the Regulatory Research Associates, albeit with a slightly lower number than the average ranking for the gas group. All things considered, the Board's regulation has been broadly constructive for Vermont Gas for the reasons I cited earlier in my testimony.

Q. Does this complete your Direct Testimony?

A. Yes.

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area
Vermont Department of Public Service

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
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Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

**Expert Testimony Appearances
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As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR- 09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E- GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009- 2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010- 2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010- 2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010- 2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts- Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010- 2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010- 2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010- 2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011- 2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

Expert Testimony Appearances
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Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

**Expert Testimony Appearances
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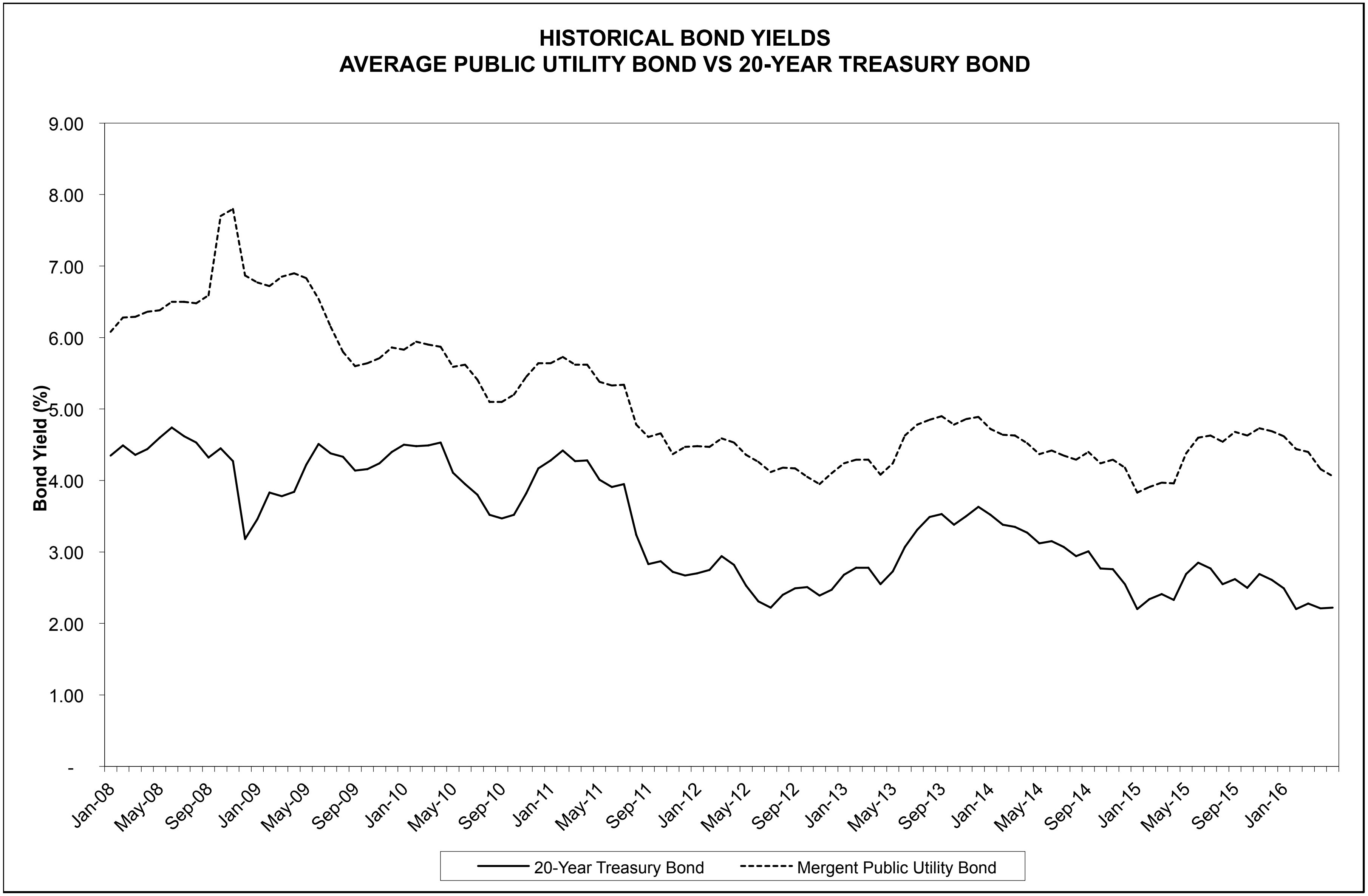
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
07/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital


HISTORICAL BOND YIELDS
AVERAGE PUBLIC UTILITY BOND VS 20-YEAR TREASURY BOND
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Bond Yield (%)
Jan-08
May-08
Sep-08
Jan-09
May-09
Sep-09
Jan-10
May-10
Sep-10
Jan-11
May-11
Sep-11
Jan-12
May-12
Sep-12
Jan-13
May-13
Sep-13
Jan-14
May-14
Sep-14
Jan-15
May-15
Sep-15
Jan-16
20-Year Treasury Bond
Mergent Public Utility Bond

VERMONT GAS SYSTEMS
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-16	May-16	Apr-16	Mar-16	Feb-16	Jan-16
Atmos Energy	High Price ($)	81.350	75.100	74.860	74.600	71.900	69.220
	Low Price ($)	72.420	70.840	70.410	68.600	67.940	60.000
	Avg. Price ($)	76.885	72.970	72.635	71.600	69.920	64.610
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.420
	Mo. Avg. Div.	2.19%	2.30%	2.31%	2.35%	2.40%	2.60%
	6 mos. Avg.	2.36%					
New Jersey Resources	High Price ($)	38.560	37.170	36.880	36.850	36.570	35.570
	Low Price ($)	35.140	33.910	34.550	33.320	33.370	32.320
	Avg. Price ($)	36.850	35.540	35.715	35.085	34.970	33.945
	Dividend ($)	0.240	0.240	0.240	0.240	0.240	0.240
	Mo. Avg. Div.	2.61%	2.70%	2.69%	2.74%	2.75%	2.83%
	6 mos. Avg.	2.72%					
Northwest Natural Gas	High Price ($)	64.840	57.950	54.290	54.510	53.880	52.010
	Low Price ($)	55.060	51.120	49.460	48.900	49.410	49.300
	Avg. Price ($)	59.950	54.535	51.875	51.705	51.645	50.655
	Dividend ($)	0.468	0.468	0.468	0.468	0.468	0.468
	Mo. Avg. Div.	3.12%	3.43%	3.61%	3.62%	3.62%	3.70%
	6 mos. Avg.	3.52%					
South Jersey Industries	High Price ($)	31.640	28.970	28.550	29.140	26.940	24.860
	Low Price ($)	28.520	26.290	27.170	25.270	24.540	22.060
	Avg. Price ($)	30.080	27.630	27.860	27.205	25.740	23.460
	Dividend ($)	0.264	0.264	0.264	0.264	0.264	0.264
	Mo. Avg. Div.	3.51%	3.82%	3.79%	3.88%	4.10%	4.50%
	6 mos. Avg.	3.93%					
Southwest Gas	High Price ($)	79.430	70.510	66.600	67.290	62.430	58.920
	Low Price ($)	69.180	64.390	62.750	59.490	58.070	53.510
	Avg. Price ($)	74.305	67.450	64.675	63.390	60.250	56.215
	Dividend ($)	0.450	0.450	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	2.42%	2.67%	2.50%	2.56%	2.69%	2.88%
	6 mos. Avg.	2.62%					
Spire Inc.	High Price ($)	70.870	66.200	68.400	68.790	66.430	63.940
	Low Price ($)	63.150	61.000	62.650	64.390	63.310	57.100
	Avg. Price ($)	67.010	63.600	65.525	66.590	64.870	60.520
	Dividend ($)	0.490	0.490	0.490	0.490	0.490	0.490
	Mo. Avg. Div.	2.92%	3.08%	2.99%	2.94%	3.02%	3.24%
	6 mos. Avg.	3.03%					

VERMONT GAS SYSTEMS
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-16	May-16	Apr-16	Mar-16	Feb-16	Jan-16
UGI Corp.	High Price ($)	45.250	43.720	41.430	40.850	37.210	34.370
	Low Price ($)	42.750	39.440	39.200	36.890	33.330	31.590
	Avg. Price ($)	44.000	41.580	40.315	38.870	35.270	32.980
	Dividend ($)	0.238	0.228	0.228	0.228	0.228	0.228
	Mo. Avg. Div.	2.16%	2.19%	2.26%	2.35%	2.59%	2.77%
	6 mos. Avg.	2.39%					
WGL Holdings	High Price ($)	70.810	70.090	72.840	74.100	69.200	66.810
	Low Price ($)	65.100	63.060	65.000	67.230	62.930	59.990
	Avg. Price ($)	67.955	66.575	68.920	70.665	66.065	63.400
	Dividend ($)	0.488	0.488	0.488	0.463	0.463	0.463
	Mo. Avg. Div.	2.87%	2.93%	2.83%	2.62%	2.80%	2.92%
	6 mos. Avg.	2.83%					
6-month Average Dividend Yield		2.92%					

Source: Yahoo! Finance

VERMONT GAS SYSTEMS
GAS DISTRIBUTION COMPANY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson/ IBES
Atmos Energy	6.50%	6.00%	5.00%	6.60%	7.00%
New Jersey Resources	3.00%	1.50%	5.00%	6.50%	6.50%
Northwest Natural Gas	2.00%	7.00%	3.50%	4.00%	4.00%
South Jersey Industries	6.50%	3.00%	2.00%	6.00%	6.00%
Southwest Gas	8.50%	7.00%	6.50%	5.00%	4.00%
Spire Inc.	3.50%	9.00%	4.50%	4.59%	4.52%
UGI Corp.	4.00%	4.00%	7.50%	6.87%	7.65%
WGL Holdings	2.50%	5.00%	4.50%	7.33%	8.00%
Average Growth Rates	4.56%	5.31%	4.81%	5.86%	5.96%
Median Growth Rates	3.75%	5.50%	4.75%	6.25%	6.25%

Sources: Zack's and Thomson Earnings Reports, retrieved July 1, 2016
Value Line Investment Survey, June 3, 2016

VERMONT GAS SYSTEMS
GAS DISTRIBUTION COMPANY GROUP
DCF RETURN ON EQUITY CALCULATION

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	2.92%	2.92%	2.92%	2.92%	2.92%
Average Growth Rate	4.56%	5.31%	5.86%	5.96%	5.42%
Expected Div. Yield	2.99%	3.00%	3.01%	3.01%	3.00%
DCF Return on Equity	***7.55%***	***8.31%***	***8.87%***	***8.97%***	***8.42%***
Method 2:					
Dividend Yield	2.92%	2.92%	2.92%	2.92%	2.92%
Median Growth Rate	3.75%	5.50%	6.25%	6.25%	5.44%
Expected Div. Yield	2.98%	3.01%	3.02%	3.02%	3.00%
DCF Return on Equity	***6.73%***	***8.51%***	***9.27%***	***9.27%***	***8.44%***

GAS DISTRIBUTION COMPANY GROUP
Capital Asset Pricing Model Analysis

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.44%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.24%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.20%
6	Comparison Group Beta	0.77
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.31%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	8.54%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.44%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.31%
4	Risk Premium	
5	(Line 1 minus Line 3)	9.13%
6	Comparison Group Beta	0.77
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	7.02%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	8.33%

GAS DISTRIBUTION COMPANY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
January-16	2.49%
February-16	2.20%
March-16	2.28%
April-16	2.21%
May-16	2.22%
June-16	2.02%
6 month average	2.24%

5 Year Treasury Bond Data

	Avg. Yield
January-16	1.52%
February-16	1.22%
March-16	1.38%
April-16	1.26%
May-16	1.30%
June-16	1.17%
6 month average	1.31%

Source: www.federalreserve.gov, Selected Interest Rates (Daily) - H.15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.84%
Estimated Market Return	9.88%
Value Line Projected 3-5 Yr. Median Annual Total Return	11.00%
Average of Projected Mkt. Returns	10.44%

Source: Value Line Investment Survey
for Windows retreived June 12, 2016

Comparison Group Betas:

Atmos Energy	0.75
New Jersey Resources	0.80
Northwest Natural Gas	0.65
South Jersey Industries	0.80
Southwest Gas	0.75
Spire, Inc.	0.70
UGI Corp.	0.95
WGL Holdings	0.75
Average	0.77

Source: Value Line Investment Survey,
June 3, 2016

CAPITAL ASSET PRICING MODEL ANALYSIS
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.07%	5.07%	
Historical Market Risk Premium	5.03%	7.03%	6.19%
Gas Distribution Group Beta, Value Line	0.77	0.77	0.77
Beta * Market Premium	3.87%	5.40%	4.76%
Current 20-Year Treasury Bond Yield	2.24%	2.24%	2.24%
CAPM Cost of Equity, Value Line Beta	**6.10%**	**7.64%**	**7.00%**

Source: *Ibbotson SBBI 2015 Classic Yearbook,* Morningstar, pp. 39, 40, 152, 157 - 158

COYNE GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-16	May-16	Apr-16	Mar-16	Feb-16	Jan-16
Atmos Energy	High Price ($)	81.350	75.100	74.860	74.600	71.900	69.220
	Low Price ($)	72.420	70.840	70.410	68.600	67.940	60.000
	Avg. Price ($)	76.885	72.970	72.635	71.600	69.920	64.610
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.420
	Mo. Avg. Div.	2.19%	2.30%	2.31%	2.35%	2.40%	2.60%
	6 mos. Avg.	2.36%					
New Jersey Resources	High Price ($)	38.560	37.170	36.880	36.850	36.570	35.570
	Low Price ($)	35.140	33.910	34.550	33.320	33.370	32.320
	Avg. Price ($)	36.850	35.540	35.715	35.085	34.970	33.945
	Dividend ($)	0.240	0.240	0.240	0.240	0.240	0.240
	Mo. Avg. Div.	2.61%	2.70%	2.69%	2.74%	2.75%	2.83%
	6 mos. Avg.	2.72%					
Northwest Natural Gas	High Price ($)	64.840	57.950	54.290	54.510	53.880	52.010
	Low Price ($)	55.060	51.120	49.460	48.900	49.410	49.300
	Avg. Price ($)	59.950	54.535	51.875	51.705	51.645	50.655
	Dividend ($)	0.468	0.468	0.468	0.468	0.468	0.468
	Mo. Avg. Div.	3.12%	3.43%	3.61%	3.62%	3.62%	3.70%
	6 mos. Avg.	3.52%					
South Jersey Industries	High Price ($)	31.640	28.970	28.550	29.140	26.940	24.860
	Low Price ($)	28.520	26.290	27.170	25.270	24.540	22.060
	Avg. Price ($)	30.080	27.630	27.860	27.205	25.740	23.460
	Dividend ($)	0.264	0.264	0.264	0.264	0.264	0.264
	Mo. Avg. Div.	3.51%	3.82%	3.79%	3.88%	4.10%	4.50%
	6 mos. Avg.	3.93%					
Southwest Gas	High Price ($)	79.430	70.510	66.600	67.290	62.430	58.920
	Low Price ($)	69.180	64.390	62.750	59.490	58.070	53.510
	Avg. Price ($)	74.305	67.450	64.675	63.390	60.250	56.215
	Dividend ($)	0.450	0.450	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	2.42%	2.67%	2.50%	2.56%	2.69%	2.88%
	6 mos. Avg.	2.62%					
Spire Inc.	High Price ($)	70.870	66.200	68.400	68.790	66.430	63.940
	Low Price ($)	63.150	61.000	62.650	64.390	63.310	57.100
	Avg. Price ($)	67.010	63.600	65.525	66.590	64.870	60.520
	Dividend ($)	0.490	0.490	0.490	0.490	0.490	0.490
	Mo. Avg. Div.	2.92%	3.08%	2.99%	2.94%	3.02%	3.24%
	6 mos. Avg.	3.03%					

COYNE GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jun-16	May-16	Apr-16	Mar-16	Feb-16	Jan-16
WGL Holdings	High Price ($)	70.810	70.090	72.840	74.100	69.200	66.810
	Low Price ($)	65.100	63.060	65.000	67.230	62.930	59.990
	Avg. Price ($)	67.955	66.575	68.920	70.665	66.065	63.400
	Dividend ($)	0.488	0.488	0.488	0.463	0.463	0.463
	Mo. Avg. Div.	2.87%	2.93%	2.83%	2.62%	2.80%	2.92%
	6 mos. Avg.	2.83%					
6-month Average Dividend Yield		3.00%					

Source: Yahoo! Finance

VERMONT GAS SYSTEMS
COYNE GAS DISTRIBUTION COMPANY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson/ IBES
Atmos Energy	6.50%	6.00%	5.00%	6.60%	7.00%
New Jersey Resources	3.00%	1.50%	5.00%	6.50%	6.50%
Northwest Natural Gas	2.00%	7.00%	3.00%	4.00%	4.00%
South Jersey Industries	6.50%	3.00%	2.00%	6.00%	6.00%
Southwest Gas	8.50%	7.00%	6.50%	5.00%	4.00%
Spire Inc.	3.50%	9.00%	4.50%	4.59%	4.52%
WGL Holdings	2.50%	5.00%	4.50%	7.33%	8.00%
Average Growth Rates	4.64%	5.50%	4.36%	5.72%	5.72%
Median Growth Rates	3.50%	6.00%	4.50%	6.00%	6.00%

Sources: Zack's and Thomson Earnings Reports, retrieved July 1, 2016
Value Line Investment Survey, June 3, 2016

VERMONT GAS SYSTEMS
COYNE GAS DISTRIBUTION COMPANY GROUP
DCF RETURN ON EQUITY CALCULATION

	(1) Value Line Earnings Gr.	(2) Zack's Earning Gr.	(3) IBES Earning Gr.	(4) Average of All Gr. Rates
Method 1:				
Dividend Yield	3.00%	3.00%	3.00%	3.00%
Average Growth Rate	5.50%	5.72%	5.72%	5.64%
Expected Div. Yield	3.08%	3.09%	3.09%	3.09%
DCF Return on Equity	***8.58%***	***8.81%***	***8.81%***	***8.73%***
Method 2:				
Dividend Yield	3.00%	3.00%	3.00%	3.00%
Median Growth Rate	6.00%	6.00%	6.00%	6.00%
Expected Div. Yield	3.09%	3.09%	3.09%	3.09%
DCF Return on Equity	***9.09%***	***9.09%***	***9.09%***	***9.09%***

2017-2020 CAPITAL EXPENDITURES AS A PERCENT OF 2014 NET PLANT
($ Millions)

		[1] 2014	[2] 2016	[3] 2017	[4] 2018	[5] 2019	[6] 2020	[7] 2017-20 Cap. Ex. / 2014 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			$9.80	$9.90	$10.00	$10.00	$10.00	
Common Shares Outstanding			107.00	$113.50	120.00	120.00	120.00	
Capital Expenditures			$1,048.6	$1,123.7	$1,200.0	$1,200.0	$1,200.0	70.23%
Net Plant		$6,725.9						
Laclede Group, Inc. (The)	LG							
Capital Spending per Share			$7.00	$6.83	$6.65	$6.65	$6.65	
Common Shares Outstanding			43.00	$44.00	45.00	45.00	45.00	
Capital Expenditures			$301.0	$300.3	$299.3	$299.3	$299.3	43.41%
Net Plant		$2,759.7						
New Jersey Resources Corporation	NJR							
Capital Spending per Share			$1.70	$1.75	$1.80	$1.80	$1.80	
Common Shares Outstanding			85.00	$85.00	85.00	85.00	85.00	
Capital Expenditures			$144.5	$148.8	$153.0	$153.0	$153.0	32.26%
Net Plant		1884.1						
Northwest Natural Gas Company	NWN							
Capital Spending per Share			$6.15	$6.48	$6.80	$6.80	$6.80	
Common Shares Outstanding			27.75	$27.88	28.00	28.00	28.00	
Capital Expenditures			$170.7	$180.5	$190.4	$190.4	$190.4	35.43%
Net Plant		$2,121.6						
South Jersey Industries, Inc.	SJI							
Capital Spending per Share			$4.50	$4.75	$5.00	$5.00	$5.00	
Common Shares Outstanding			72.00	$74.00	76.00	76.00	76.00	
Capital Expenditures			$324.0	$351.5	$380.0	$380.0	$380.0	69.89%
Net Plant		$2,134.1						
Southwest Gas Corporation	SWX							
Capital Spending per Share			$9.80	$10.68	$11.55	$11.55	$11.55	
Common Shares Outstanding			49.00	$50.50	52.00	52.00	52.00	
Capital Expenditures			$480.2	$539.1	$600.6	$600.6	$600.6	63.99%
Net Plant		$3,658.4						
WGL Holdings, Inc.	WGL							
Capital Spending per Share			$16.70	$18.35	$20.00	$20.00	$20.00	
Common Shares Outstanding			50.00	$50.00	50.00	50.00	50.00	
Capital Expenditures			$835.0	$917.5	$1,000.0	$1,000.0	$1,000.0	118.20%
Net Plant		$3,314.4						
Vermont Gas	VT Gas							
Capital Expenditures [2]			103.525	14.808	21.707	10.207	9.571	29.24%
Net Plant [3]		$192.5						

VT Gas Total	$56.3
VT Gas as % Proxy Group Median	46%
Annual Average	$14.1

Notes:
[1] Source: Value Line, at December 1, 2015.
[2] Source: Vermont Gas % year Strategic Plan, at 1, for 2016-2020, Vermont Gas Systems, Inc. Financial Report, Sept 30, 2015, at 9 for 2015.
[3] Source: VT Gas Systems, 2015 FERC Form 2, at 110.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission	**:**	
As to the Rates, Charges, Rules and	**:**	
Regulations of Keyspan Gas East Corp.	**:**	**Case No. 16-G-0058**
dba Brooklyn Union of L.I.	**:**	
for Gas Service	**:**	

Proceeding on Motion of the Commission	**:**	
As to the Rates, Charges, Rules and	**:**	
Regulations of the Brooklyn Union Gas	**:**	**Case No. 16-G-0059**
Company for Gas Service	**:**	

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

THE CITY OF NEW YORK

J. KENNEDY AND ASSOCIATES, INC.

MAY 20, 2016

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission As to the Rates, Charges, Rules and Regulations of Keyspan Gas East Corp. dba Brooklyn Union of L.I. for Gas Service	:	**Case No. 16-G-0058**
Proceeding on Motion of the Commission As to the Rates, Charges, Rules and Regulations of the Brooklyn Union Gas Company for Gas Service	:	**Case No. 16-G-0059**

DIRECT TESTIMONY OF RICHARD A. BAUDINO ON BEHALF OF THE CITY OF NEW YORK

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ____(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the City of New York.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address cost and revenue allocation, rate design, and service quality issues for Brooklyn Union Gas Company ("KEDNY") and KeySpan Gas East Corporation ("KEDLI"). In so doing, I will address the Direct Testimony of the Companies' Rate Design Panel and Shared Services Panel.

Q. Please summarize your conclusions and recommendations to the Public Service Commission of the State of New York ("Commission").

A. My conclusions and recommendations with respect to cost and revenue allocation and rate design are as follows:

1. The Companies' filed embedded cost of service study ("ECOSS") should be accepted for purposes of revenue allocation.
2. Regarding the Temperature Controlled ("TC") classes, despite their expressed intent to move to cost-based rates, the Companies' proposed revenue allocation and rate design for the TC classes fails to accomplish a cost-based rate for these classes. In fact, the Companies' proposed revenue allocation results in excessive rates and revenue for the KEDNY's TC classes. Therefore, the proposed revenue allocation and rate design for KEDNY's TC customers should be rejected.
3. Although the KEDNY TC classes should have their rates and revenue reduced significantly, I recommend that the current level of delivery

revenues for KEDNY's TC customers remain constant, i.e., no increase in TC class revenues. This will assist the Commission in limiting rate shock to those customer classes that already are facing significant increases in their rates and bills I am not recommending any changes to the KEDLI revenue allocation or rate design for TC customers at this time.

4. The Companies' proposed average commodity cost of gas includes TC customers. This is a change from the current practice of charging TC customers the incremental cost of gas on the system. This change should be approved.

5. The Companies' proposal to apply certain portions of the Merchant Function Charge ("MFC") to TC customers should be rejected. The Companies failed to support the applicability of this charge to TC customers. Moreover, KEDNY's TC customers' current revenues are already so far in excess of their cost to serve that imposing the MFC as an additional charge is unreasonable and burdensome.

6. I recommend that the Commission reject the Companies' proposal to close the TC classes to new customers. The Companies failed to provide any substantive reasons to close the TC class service offerings at this time. The Companies also failed to provide any time frame for the proposed collaborative or how the results of any such collaborative would be included in the future.

7. The Companies' tariffs should be modified to provide TC and IT customers the option of paying a surcharge, in lieu of a lump sum payment, for any infrastructure upgrades that are required in connection with a request to convert from TC/IT service to firm service.

Regarding service quality issues, my conclusions and recommendations are as follows:

1. The Companies' revised customer service quality program for KEDNY and KEDLI should be rejected. In particular, the Commission should reject any monetary incentive payments for so-called superior performance above established targets. The Commission should continue the currently effective penalty structure for the Companies.
2. The Companies propose to keep the four current service quality metrics, with some modifications. Regarding the currently effective Adjusted Customer Bills metric, the Companies propose to exclude the following situations from this metric: (1) an estimated bill replaced by a bill based on the actual reading and (2) a customer reading replaced with an actual or estimated reading. I recommend that the Commission continue to include these two items in the calculation of Adjusted Customer Bills. The City of New York has been experiencing a high number of estimated readings

resulting in numerous bill adjustments from KEDNY. Adjustments due to estimated bills being replaced by actual bills should continue to be part of this service metric in order to limit the number of such adjustments in the future.

3. The Companies also propose several new service quality metrics, including two new incentive-only metrics. I recommend that the Commission require the Companies to report these new metrics along with the current service quality metrics but reject any new incentives. No new penalties should be established for these new metrics at this time.

<u>COST AND REVENUE ALLOCATION</u>

Q. Have you reviewed the ECOSS study presented by the Companies?

A. Yes. The Companies' ECOSS and proposed revenue allocation was presented by the Rate Design Panel.

Q. Does the ECOSS study conform to generally accepted cost allocation principles?

A. Generally, yes. The Company’s ECOSS is a traditional study wherein revenue requirements are allocated among customer classes on the basis of cost causation.

Q. Why is an ECOSS important?

A. An ECOSS illustrates the costs a utility incurs to serve each customer class. It is widely accepted that costs should be allocated among customer classes on the basis of cost causation. That principle is perhaps the most universally accepted tenet of allocating costs that cannot be directly assigned to a particular customer class. As such, costs should be allocated to those classes on the basis of how or why those costs are incurred by the utility. The results of such studies are normally used in assigning cost and revenue responsibilities to various customer classes.

Q. Do you support the premise that cost causation principles should guide the allocation of costs to the customer classes?

A. Yes. Rates that are based on consistently applied cost causation principles are fair and reasonable and further the cause of stability, conservation and efficiency. Other factors such as simplicity, gradualism, economic development and ease of administration may also be taken into consideration when determining the final allocation of the revenue requirement among classes, but the fundamental starting point and guideline should be the cost of serving each customer class produced by the ECOSS.

Q. Please explain the purpose and development of a class cost of service study.

A A class cost of service study allocates and assigns the total cost of providing utility service to the classes of customers receiving that service. The development of a class cost of service study consists of three steps: functionalization, classification, and allocation. Functionalization refers to the process by which the Company's investments and expenses are identified and segregated into different cost categories. For natural gas utilities such as KEDNY and KEDLI, these categories include storage, transmission, and distribution functions.

Once functionalization is complete, the utility's costs are classified into categories of demand-related, energy related and customer-related costs in order to facilitate the allocation of costs by applying cost causation principles. In general, all distribution costs are either responsive to increases in natural gas demand or to the number of customers. Demand-related costs are those that are needed to serve the winter peak demands of distribution customers. Demand-related costs are fixed and do not vary with the monthly and annual commodity consumption of the utility's customers. Customer-related costs are associated with the number of customers and are costs that are incurred to connect customers to the system independent of the customer's demand and energy requirements. Primary examples of customer-related costs are investments in meters, services, and a portion of main investment incurred to extend the distribution system to the customer's premises and conform to local and national codes and standards. In addition, such accounting functions as meter reading, bill preparation and revenue accounting are generally considered customer-related costs.

Lastly, the functionalized and classified costs are allocated to the various customer classes based on each class' contribution to the respective cost classifications. In general, demand-related costs are allocated based on each class' contribution to the maximum demand placed on the system by the classes or by the customers within the classes. Customer related costs are allocated based upon the number of customers in each class, weighted to account for the complexity of servicing the needs of the different classes of customers.

Q. How did the Companies' ECOSS classify distribution mains?

A. The KEDNY Rate Design Panel (page 16) described the method used by the Companies to classify and allocate the costs of distribution mains. The Companies used a minimum size study that classified the customer portion of mains as 37.91% and the remaining 62.09% as demand related. The customer portion of mains was then allocated based on the number of customers and the demand portion was allocated based class contribution to design-day demand.

Q. Do you agree with the Companies' classification and allocation of distribution mains?

A. Yes. As the Rate Design Panel pointed out, distribution mains are installed to connect customers to the distribution system and to provide capacity to meet the winter peak. The Companies' ECOSS appropriately utilized a minimum size system study to estimate which portions of distribution mains are demand related and customer related and allocated costs to customer classes based on that relationship.

Q. Do you recommend that the Commission rely upon the Companies' ECOSS for purposes of revenue allocation?

A. Yes. The Companies' ECOSS provides a reasonable basis for cost and revenue allocation in this proceeding and is consistent with prior Commission decisions that adopted an allocation of distribution mains on a demand and customer basis.[1]

<u>Revenue Allocation and Rate Design</u>

Q. What were the results of the ECOSS study as filed by KEDNY?

A. Table 1 below summarizes the class rate of return results of the ECOSS for KEDNY. Table 1 shows the current class rates of return and the relative rates of

1 *See* Case 08-G-0609, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Gas Service*, Order Adopting the Terms of a Joint Proposal and Implementing a State Assessment Surcharge (issued May 15, 2009) at 6; Case 08-G-0888, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*, Order Adopting Recommended Decision with Modifications (issued June 22, 2009) at 47-48.

return at current rates.

Table 1

KEDNY
Current Class Rates of Return

	Return %	Relative ROR %
SC1A - Res NonHeat	-5.38%	(2.25)
SC-1B Res Heat	2.44%	1.02
SC-1DG Res DG	-6.32%	(2.65)
SC-2-1 Non-Res NonHeat	13.78%	5.77
SC-2-2 Non-Res Heat	-0.24%	(0.10)
SC-3 Multiple Family	-1.20%	(0.50)
SC-4A High Load Factor	20.95%	8.78
SC-4A CNG	35.37%	14.81
SC-4B Year Round AC	15.48%	6.49
SC-18-5A OnSys Lg. Vol Sales	95.20%	39.87
SC-6C Temp. Controlled Comm/Ind	48.07%	20.13
SC-6G Temp. Controlled Gov't	35.92%	15.04
SC-6M Temp Controlled Multi-Fmly.	27.30%	11.44
SCX-7 Seasonal	19.18%	8.03
SC-21 DG Sales	0.00%	0.00
Total	2.39%	1.00

Table 1 shows that SC1A, SC-1DG, SC 2-2, and SC-3 are actually earning negative returns currently. The TC service classes and SC-18 are significantly overearning, which means that the rates these classes are currently paying are significantly greater than the cost based rates that they should be paying.

Q. How did KEDNY propose to allocate its requested revenue increase in this

proceeding?

A. Table 2 presents the Rate Design Panel's recommended percentage revenue increases by service class. This Table also presents the percentage revenue increases and decreases that would be necessary to bring each service class to the overall system average return of 7.24%.

Table 2

KEDNY
Revenue Allocation

Schedule	Full ECOSS Increase	Company Propsed Inct.
SC1A - Res NonHeat	65.5%	31.5%
SC-1B Res Heat	30.6%	31.5%
SC-1DG Res DG	100.0%	31.5%
SC-2-1 Non-Res NonHeat	-7.1%	31.5%
SC-2-2 Non-Res Heat	46.4%	31.5%
SC-3 Multiple Family	49.9%	31.5%
SC-4A High Load Factor	-18.3%	25.0%
SC-4A CNG	-44.3%	25.0%
SC-4B Year Round AC	-13.1%	25.0%
SC-18-5A OnSys Lg. Vol Sales	-61.6%	0.0%
SC-6C Temp. Controlled Comm/Ind	-56.9%	6.4%
SC-6G Temp. Controlled Gov't	-45.6%	14.6%
SC-6M Temp Controlled Multi-Fmly.	-34.3%	17.1%
SCX-7 Seasonal	-13.3%	25.0%
SC-21 DG Sales	-	-
Total	30.1%	30.1%

Table 2 follows the relationships shown in Table 1 and shows the rate increases/decreases that would be necessary to move each class to its cost service. For example, service classes 1A, 1DG, 2-2, and 3 would require large rate increases to achieve cost based rates at KEDNY's proposed revenue requirement. Alternatively, SC 4 and 18 and the TC classes would require large rate decreases to achieve cost based rates.

Q. What conclusion do you draw from KEDNY's proposed revenue allocation?

A. The Rate Design Panel relied primarily upon the principle of gradualism given the rather large system-wide increase the Company is seeking in base delivery revenues (30.1%). As demonstrated in Table 2, the Company’s proposed class-specific increases/decreases are nowhere near what is needed to eliminate the interclass subsidies that the ECOSS reveals. Thus, the Company’s approach results in very slow, incremental progress in moving classes toward cost based rates in this proceeding.

Q. What is your recommendation for class revenue allocation in this proceeding?

A. Given the very large delivery service rate increase the Company seeks in this case, I appreciate that the Company is constrained in reallocating revenue responsibility so that the service classes that are below their cost to serve do not experience rate shock. However, customers paying 10-40 times their cost of service should not be increased. Therefore, I recommend that KEDNY's revenue allocation proposal be modified so that the TC classes do not receive any increases in current delivery revenues. I recommend that, as is proposed for SC-18-5A, the TC classes should have rates designed so that the current level of revenues forecasted by KEDNY remain constant. I also recommend that the SC-4 classes receive no increase, given their excessive current revenue levels.

Table 3 below presents my recommended revenue increase by service class with the TC classes receiving no increase in current forecasted delivery service rate revenues. I spread the dollar increases to the other service classes that were receiving increases in proportion to the increases recommended by the Rate Design Panel.

Table 3

City of New York
Proposed Revenue Allocation

Schedule	$ Increase (000s)	Pct. Increase
SC1A - Res NonHeat	35,708	33.4%
SC-1B Res Heat	137,867	33.4%
SC-1DG Res DG	1	33.4%
SC-2-1 Non-Res NonHeat	13,608	33.4%
SC-2-2 Non-Res Heat	20,391	33.4%
SC-3 Multiple Family	28,871	33.4%
SC-4A High Load Factor	-	0.0%
SC-4A CNG	-	0.0%
SC-4B Year Round AC	-	0.0%
SC-18-5A OnSys Lg. Vol Sales	-	0.0%
SC-6C Temp. Controlled Comm/Ind	-	0.0%
SC-6G Temp. Controlled Gov't	-	0.0%
SC-6M Temp Controlled Multi-Fmly.	-	0.0%
SCX-7 Seasonal	-	0.0%
SC-21 DG Sales	-	0.0%
Total	236,445	30.1%

Table 3 shows that holding the TC and SC-4 classes to no increase had a minimal effect on the increases to the classes that are receiving increases under the Rate Design Panel's revenue allocation proposal. For example, the increase for SC-1B Residential Heating increased by about 2% over the Company's proposed increase. This translates into an additional $1.30 per month for a typical monthly bill for a residential heating customer.[2]

Q. Are you recommending that the Commission adopt the Company's proposed revenue requirement?

A. No. I have not evaluated the reasonableness of the Company's proposed revenue requirement.

Q. If the Commission approves a lower revenue requirement increase than KEDNY is seeking in this case, how should this lower increase be spread among the Company's service classes?

A. If the Commission approves a lower revenue increase for KEDNY, then I recommend that the service class increases shown in Table 3 be scaled back proportionately. In essence, my recommendation in this regard allocates all of the benefits of the lower revenue requirement to the classes that are receiving increases. Although the SC-4, SC-5, and SC-6 classes should receive decreases in this case, I believe that the principles of gradualism and avoidance of rate shock should also be considered given the sheer magnitude of the delivery service increase being sought by KEDNY.

[2] This estimate was made based on the typical bill impacts shown on Exhibit ____(RDP-4), Schedule 4, page 1 of 15.

Q. Have you prepared a Table demonstrating how your proposed revenue allocation would work with a reduced revenue requirement?

A. Yes. Table 4 below illustrates the resulting service class increases at a system average increase of 15%. By allocating the entire benefit of any reduction to the SC1-SC3 classes, the impacts on those classes are scaled back approximately 50% (15.0% / 30%) to reflect the lower overall system increase.

Table 4

City of New York
Proposed Revenue Allocation - 15% Increase

Schedule	$ Increase (000s)	Pct. Increase
SC1A - Res NonHeat	17,854	16.7%
SC-1B Res Heat	68,933	16.7%
SC-1DG Res DG	0	16.7%
SC-2-1 Non-Res NonHeat	6,804	16.7%
SC-2-2 Non-Res Heat	10,196	16.7%
SC-3 Multiple Family	14,435	16.7%
SC-4A High Load Factor	-	0.0%
SC-4A CNG	-	0.0%
SC-4B Year Round AC	-	0.0%
SC-18-5A OnSys Lg. Vol Sales	-	0.0%
SC-6C Temp. Controlled Comm/Ind	-	0.0%
SC-6G Temp. Controlled Gov't	-	0.0%
SC-6M Temp Controlled Multi-Fmly.	-	0.0%
SCX-7 Seasonal	-	0.0%
SC-21 DG Sales	-	0.0%
Total	118,223	15.0%

Q. Did you review KEDLI's proposed revenue allocation for its service classes?

A. Yes. I reviewed the Rate Design Panel’s ("RDP") proposed revenue allocation for KEDLI. While the proposal will result in rates for the TC/IT classes that continue to be above cost of service, at this time I have no proposed changes or revisions to KEDLI's proposed revenue allocation.

Q. Please summarize the Rate Design Panel's proposed rate design for the TC classes.

A. Beginning on page 65 of its KEDNY Direct Testimony and on page 69 of its KEDLI Direct Testimony, the RDP set forth its proposed rate design for the TC and Interruptible Service ("IT") classes. The Companies proposed to move TC customers from a value of service pricing method to cost based rates by pricing volumetric rates at parity with the corresponding firm service class. The RDP also proposed the following changes:

- Updated demand charge for TC/IT customers
- Application of portions of the MFC charge to TC/IT customers
- Initiating a collaborative and inviting TC customers and Staff to "discuss and explore options for non-firm service.” (KEDNY RDP page 68; KEDLI RDP page 70).

The RDP also revised the minimum charge for TC customers to a fixed customer-type charge.

Q. What are your conclusions and recommendations with respect to the rate design for KEDNY's TC classes?

A. I recommend that the Commission approve moving the TC classes to a cost-based rate design. However, as explained above, that the RDP's proposed rate design does not yield a cost based rate for the TC classes. KEDNY's proposed rates for the TC classes are still greatly in excess of the true cost to serve these classes, as KEDNY's ECOSS clearly shows.

I recommend that the Commission approve the monthly fixed charges proposed by the RDP. I also recommend that the volumetric rate proposed by the RDP be reduced such that the total revenues from the TC classes do not exceed current revenues. Please refer to Exhibit **____**(RAB-2) for my proposed TC class rate design. For example, the volumetric rate for the TC-G class would be $0.30 per therm under my revenue allocation recommendation, compared to KEDNY's proposed volumetric charge of $0.35 per therm.

Q. Are you making similar recommendations with respect to KEDLI's proposed fixed charges and volumetric rates?

A. No, not at this time. However, as discussed below, I am recommending other rate design changes that would apply to both KEDNY and KEDLI.

Q. Do you have any further concerns with respect to KEDNY's proposed rate design and billing impact for TC customers?

A. Yes. The City of New York has a number of TC accounts with KEDNY. Currently, KEDNY bills the City's TC accounts based on a minimum charge that includes 10 therms of consumption and a therm charge based on value of service pricing based on the cost of alternative fuels as described by the RDP in its Direct Testimony. Given this current bill presentation, it was impossible to determine the billing impact on the City's TC accounts since the current therm rate is not broken out into the cost of gas and delivery service component. Please refer to Exhibit ____(RAB-3), which contains a copy of a monthly bill for one of the City's TC-G2 accounts, with customer-specific account information redacted. This bill shows the minimum charge and the therm charge as they are currently applied to TC-G accounts.

Although I agree with the RDP's proposal to move the TC classes to a cost based rate, it is imperative that the bill presentation for TC customers be clarified so that TC customers understand exactly what they are being charged for.

Q. What are your recommendations regarding KEDNY's bill presentation for TC customers?

A. I recommend that the customer charge, the delivery service therm charge, and cost of gas per therm be stated separately on the TC customer's bill. KEDNY should also show how these charges are applied to consumption to arrive at the final bill. I understand that this information is currently displayed on electronic billing data provided by KEDNY; there is no reason for KEDNY to exclude it from the bill presentation.

Q. How does KEDNY propose to charge TC sales customers for the cost of gas?

A. According to KEDNY's Gas Tariff, 33. Monthly Cost of Gas Surcharge, B. The Monthly Cost of Gas (Leaf 74), TC sales customers are charged the average commodity cost of gas. The RDP also provided an updated demand charge for TC customers of $0.034 per therm. TC customers would not be assessed average monthly hedging costs / credits or the average fixed cost of gas.

Q. During your analysis in this case, did you discover any inconsistencies in how KEDNY intends to charge TC sales customers for their cost of gas?

A. Yes. KEDNY's response to City of New York Request 127 indicated that both KEDNY and KEDLI intend to continue charging TC customers the incremental cost of gas on the system. The Companies' response is included in Exhibit

___(RAB-4).

Q. What is your recommendation regarding the cost of gas for TC customers?

A. I recommend that both Companies follow their proposed Monthly Cost of Gas calculation and charge TC customers the average commodity cost of gas, not the incremental cost of gas. This is consistent with the Companies' proposal to move TC customers to a cost based rate. I also recommend that the Companies' application of the fixed cost component, or demand charge, be clarified. Regarding the cost of gas, TC customers should only be charged for the average commodity cost of gas and the demand charge of $0.034 per therm. No other gas costs should be allocated to and paid for by TC customers. This recommendation applies to both KEDNY and KEDLI TC customers.

Q. Should the MFC be applied to KEDNY's and KEDLI's TC customers in this proceeding?

A. No, it should not. The RDP proposed to apply certain parts of the MFC to TC customers based on the proposed move to a cost based rate. However, as I demonstrated earlier in my testimony KEDNY’s proposed rates for the TC service classes are by no means cost based. Even under my revenue allocation proposal, KEDNY's TC rates are still significantly above the cost to serve TC customers.

Furthermore, the RDP failed to adequately support the application of the MFC to TC customers, which is essential since the MFC was not applied to this class in the past. In fact, on page 33, lines 8 through 16 of its Direct Testimony the KEDNY RDP testified that the MFC is designed to recover expenses associated with gas procurement functions for firm sales customers, transportation customers taking service under SC-17, and ESCOs that participate in the Company's Purchase of Receivables program. The RDP made no mention of incurring any MFC-related expenses on behalf of TC and IT customers. TC and IT customers are not firm service customers.

Q. Did the City of New York propound discovery seeking additional explanation as to why the MFC should now be applied to TC and IT customers?

A. Yes. City of New York data request 106 asked for a detailed explanation as to why components of the MFC should be applied to TC and IT customers. Please refer to Exhibit ____(RAB-5), which contains KEDNY's response to this data request. KEDNY replied that it is proposing to recover the costs associated with gas supply procurement and a return requirement on working capital because these are costs that the Company incurs to purchase supply on behalf of all its sales customers. This response conflicts with the RDP’s testimony, which states that these costs are incurred on behalf of firm sales customers. This inconsistency calls into question whether any MFC-related costs should be allocated to or paid by TC/IT customers.

The response continues that because the Company is proposing to move TC and IT customers to a cost based rate, TC and IT customers "would avoid paying a portion of the costs allocated to them in the Embedded Cost of Service Study, which is inconsistent with how the Company treats all other customers whose rates are cost based." However, the Companies' proposed rates for TC/IT customers are above the cost of service. This means that, under the Companies' proposal, TC customers are not avoiding paying any costs that are allocated to them and, in fact, are paying far more than their allocated cost to serve.

Q. Please comment on the Companies' proposed collaborative on TC/IT service offerings.

A. It is my understanding that this proposed collaborative would begin after the close of the current proceeding for KEDNY and KEDLI, and is connected with the proposal to close TC service to new customers. While I do not oppose collaborative discussions with a goal of improving to TC/IT service offerings, I disagree with the Companies proposal to close their TC tariffs to new customers. I discuss this in more detail below.

Q. The Companies proposed to close their TC tariffs to new customers. Should

the Commission approve this proposal?

A. No. The Companies failed to provide any good reason to close the TC service offerings to new customers. The RDP provided no support whatsoever that TC service should be closed due to any problems or shortcomings associated with that service. The RDP's proposal to close the TC service classes to new customers appears rather arbitrary at this point and, thus, should be rejected by the Commission.

Q. On page 6 of the RDP's KEDNY Corrections and Updates Testimony, lines 3 through 13, the RDP clarified that the Company's consolidated billing charge should be applied to TC and IT customers based on the proposed move to a cost based rate design. Should the Commission approve the application of the consolidated billing charge to TC/IT customers?

A. No. The consolidated billing charge should not be applied to TC/IT customers at this time. I base this recommendation on the fact that the rates that would be paid under my revenue allocation proposal are still greatly in excess of the cost to serve TC customers. Moreover, the proposed TC rates under the RDP's proposed rate design are even further away from the true cost to serve those customers. In my view, any costs associated with consolidated billing are already being collected in the rates being paid by TC customers and should not be added as an additional charge in this proceeding.

Q. On page 7 of the RDP's KEDNY Corrections and Updates Testimony, lines 13 and 14, the RDP proposed including SC 6 under the Company's customer billing charge. Should this change be approved at this time?

A. No. My recommendation here relates to my answer to the prior questions regarding the fact that the current and proposed TC rates are not cost based.

Q. On page 7 of the RDP's Corrections and Updates Testimony, line 18, the RDP proposed revising the language in the SC 6 tariff to reflect how new customers would be put on the SC 6 rate. Should this revised language be adopted?

A. No. My recommendation on this point relates to my previous testimony regarding keeping the TC service classes open to new customers at this time. KEDNY and KEDLI failed to support closing or limiting access to the TC service classes in their Direct Testimony. If the Commission finds good cause to convene a collaborative after this docket is closed, then this issue could be discussed and evaluated at that time.

<u>**Surcharge for Main Reinforcements**</u>

Q. Are you proposing any changes to the Companies' rules regarding contributions in aid of construction for new or upgraded gas service?

A. Yes. The Companies' should modify their tariffs to provide TC or IT customers with an option to pay for a CIAC associated with system reinforcement through either a lump sum payment or through an ongoing surcharge.

Q. What is required under the current tariff?

A. Under the current tariffs, large TC or IT customers that want to upgrade to firm service are required to pay for any gas system reinforcements that might be required as a result of the service upgrade. For example, Special Provisions (b) and (c) of KEDNY's Service Classification No. 2 provide that a "contribution payment" is required for system reinforcement:

> (b) New gas service will be supplied under this Service Classification upon determination by the Company that the total rated hourly Btu input to supply the gas-fired equipment installed for such use does not exceed 2,500,000 Btu per hour. Process and feedstock requirements are exempt from the conditions for gas service set forth in this Special Provision (b).
>
> (c) Exemption from the limitation provision set forth in Special Provision (b) hereof will be granted by the Company provided that a contribution payment necessary for required service laterals and/or system reinforcement is submitted prior to the commencement of gas service by the applicant for such gas service.

Q. Do the Companies' tariffs provide customers with an option to pay the "contribution payment" through a monthly surcharge?

A. No. As demonstrated above, KEDNY's tariff does not offer a surcharge option for customers to pay for a system reinforcement required under Special Provisions

(b) and (c), and thus such customers are forced to make an upfront, lump sum payment covering the cost of the necessary system reinforcement.

Q. What are you proposing?

A. I recommend that the Companies' tariffs be revised to allow TC/IT customers the option to make a surcharge payment in lieu of a lump sum contribution, when gas system reinforcements are required in connection with a service upgrade. I recommend that this surcharge be calculated and administered similar to the existing surcharge payments that are available to new firm customers when new distribution main is required in excess of the main that is required to be provided by the Companies without charge.

Q. Is the change you are requesting allowed under the Commission's regulations?

A. Yes. First, the Companies' position may actually conflict with existing regulations, specifically 16 NYCRR § 203.3, which requires gas corporations to impose a surcharge to recover the costs of mains and appurtenant facilities in excess of those costs required to be provided without charge to the customer. There is nothing in § 203.3 that excludes this surcharge from TC/IT customers that trigger main upgrades as part of an upgrade to firm service.

Moreover, Part 230 of the Commission's regulations establish "the minimum obligations of gas corporations with respect to the facilities required to be provided without charge to applicants for…firm, nondual-fuel nonresidential service. <u>Each corporation may, in its tariff schedules, extend such obligation, to the extent the provision of additional facilities without charge is cost-justified. Each corporation's obligations with respect to applicants for interruptible or dual-fuel nonresidential service shall be governed by tariffs approved by the commission.</u>" *See* 16 NYCRR § 230.2(f) (emphasis added). Thus, even if the Commission determines that its regulations do not explicitly require the Companies' to offer the surcharge option, the regulations are flexible enough to allow utilities to extend the surcharge option to TC/IT customers through their tariffs.

Q. Are you proposing to include any restrictions on a customer's ability to select the new surcharge option?

A. Yes. As noted above, I propose that the surcharge be calculated and administered similar to the existing surcharge for new firm, nondual-fuel nonresidential customers. Under the Companies' exiting tariffs, new customers are required to sign a "Main Extension Agreement" that sets forth the customer obligation to pay the surcharge, and it provides a number of provisions to ensure that a surcharge payment, as opposed to a lump sum, is cost-justified.

For example, as part of this Agreement, there is a representation that the customer has assured the Company that it will be "a reasonably permanent customer." *See* KEDNY Tariff at Leaf No. 428. TC/IT customers that are upgrading to firm service should be required to provide similar assurances, so that the Companies' can have confidence that the gas delivery revenues generated by the customer will be long-term and thus pay back the Company investment in the upgraded gas main.

CUSTOMER SERVICE QUALITY PROGRAMS

Q. Please summarize the proposed service quality standards as set forth in the Direct Testimony of the Shared Services Panel ("SSP").

A. The SSP provided Direct Testimony regarding customer service quality programs beginning on page 38 of its KEDNY testimony, though this testimony applied to both KEDNY and KEDLI. The SSP described the current service quality programs, which consist of the following:

- Annual Commission complaint rate per 100,000 customers
- Residential customer transaction satisfaction
- Percent of calls answered in 30 seconds
- Adjusted customer bills

On page 41, the SSP reported that KEDNY had met all of its performance targets since 2008. KEDLI failed to meet its customer satisfaction target in 2013 and the complaint rate and customer satisfaction targets in 2014. However, the SSP also testified that both Companies are "on track" to meet all service quality targets in 2015.

Also on page 41, the SSP proposed a "new, innovative" service quality program. This program would include:

- The current service quality metrics with more stringent targets for some metrics
- New metrics that better measure customer satisfaction
- A mechanism that would allow the Companies to offset underperformance in one area with "superior" performance in another.

On page 43, the SSP presented the new service quality metrics that include:

- Payment processing - percent of payments avoiding exception processing
- Interactive Voice Response ("IVR") self-service rate
- Percent of appointments kept
- Percent of payments made through the web and mobile (incentive only)
- Low income outreach and assistance program engagement (incentive only)

Q. What are your conclusions and recommendations with respect to the SSP's proposed customer service quality programs?

A. First, I recommend that the SSP's proposed new service quality program structure be rejected. The Company should not be allowed to offset poor performance in one area with better performance in other areas. Furthermore, the Company should not be provided any monetary incentives for performance above certain targets. The Commission's current approach that relies on penalties for failing to maintain service quality standards should be continued.

Second, I recommend that the Commission continue the current customer service quality programs with more stringent metrics. The Companies' proposed change to the adjusted customer bills metric should be rejected. The existing penalties for all existing programs should be maintained.

Third, I recommend that the Commission approve the following new proposed metrics with the Companies adding these metrics to the reports they file on the currently effective service quality metrics. I do not recommend adding new penalties to these metrics at this time. The Commission should reject any incentive payments to the Companies.

<u>Proposed Customer Driven Service Metrics and Levels</u>

Q. Have you reviewed the SSP's proposed service metrics and proposed offsets?

A. Yes. The SSP's proposed new approach to its customer service metrics, including penalties, incentives, and offsets are contained in Exhibit ____(SSP-9).

In summary, the proposed new collection of customer service metrics are weighted with associated penalty amounts, a penalty floor that cannot be offset, a penalty threshold that can be offset, and resulting dollar amounts of offsets that may be used to offset poor performance in one area with better performance in other areas. For KEDNY, the total yearly offset amount would be $5.85 million and for KEDLI the total yearly offset amount would be $4.95 million. The incentive-only metrics would allow the Companies to collect an additional $2.16 million, $1.17 million for KEDNY and $0.99 million for KEDLI.

Q. Should the Companies be allowed to offset poor performance in one customer service metric with offsets from other service metrics?

A. No. I strongly recommend that the Commission reject the Companies' proposed customer service metric offsets.

Customer service quality metrics are all equally important in terms of how the Commission monitors and assesses the Companies' level of service quality to its customers. The Commission's currently approved approach of evaluating several service quality measures should be continued and augmented with the new metrics I recommend be adopted. The Commission should also continue the penalties for lack of performance in these areas. Penalties for each service quality metric will help ensure that the Companies do not allow deterioration in the quality of service. Allowing the offsets proposed by the SSP would indeed be a step backward in terms of the Companies' and the Commission's commitment to the highest quality of service that customers deserve.

Q. Should the Companies be allowed to earn incentives for performance above certain levels?

A. No. KEDNY and KEDLI should not be allowed to earn any special monetary incentives if their customer service performance exceeds certain preset levels. Customers should be entitled to excellent service from their regulated utility service providers and should not have to pay additional money for that service in addition to the rates they are already paying. This is an especially important regulatory principle given the large rate increases proposed by the Companies in this proceeding. Given these very substantial rate increases, customers should expect high quality service for the additional money they are being asked to spend each month for their gas service. Moreover, it is reasonable that the Companies be penalized for failing to provide that level of service.

<u>Existing Service Quality Metrics</u>

Q. Briefly describe the SSP's proposal for the percent of calls answered in 30 seconds.

A. The SSP proposed to move to a more stringent performance target for KEDNY, increasing the current target from 59.0% to 62.2%. KEDLI would have the same performance target. The SSP testified on page 45 that these higher targets assume the Companies' proposal to add incremental call center staffing and to load balance calls.

Q. What is your recommendation with respect to the proposed performance target for the percentage of call answered within 30 seconds?

A. I recommend that the Commission adopt the proposed new performance standards, but without them being contingent on adopting the Companies' proposals to add staffing and to load balance calls.

The service quality performance reports provided in Exhibit **____**(SSP-8) show that over the period from 2009 through 2014, KEDNY was below the 62.2% performance standard in only 2 years: 2011 (58.96%) and 2014 (60.61%). KEDNY’s performance has been as high as 70.9% in 2009, 66.03% in 2010, 65% in 2012, and 63.40% in 2013. The new performance target of 62.2% appears to be well within KEDNY’s ability to achieve based on historical results and without the additional proposals described by the SSP.

Q. Briefly describe the SSP's proposal for the adjusted customer bills metric.

A. On page 46 of their Direct Testimony, the SSP proposed adjusting the calculation of adjusted customer bills to exclude certain items, among them being (1) estimated bill replaced by a bill based on an actual reading and (2) a customer reading replaced with an actual or estimated reading. Based on the proposed revisions, the SSP proposed revised targets of 0.58% for KEDNY and 1.24% for KEDLI.

Q. Should the Companies be allowed to make the two exclusions you mentioned?

A. No. In particular, estimated bills being replaced by a bill based on actual readings should continue to be included in the calculation of percentage of adjusted bills. The City of New York, in particular, is concerned over the number of adjusted TC account bills it receives from KEDNY. These numerous adjustments from prior periods based on estimated-to-actual meter reads have caused monthly bills to fluctuate for the City's TC accounts. It is also my understanding that the City of New York has engaged in discussions with KEDNY over trying to decrease the number of billing adjustments, but so far no resolution has been reached. Through the City's February 2016 billings, there has been no improvement in the number of estimated reads. According to City personnel, March billings did show an improvement in estimated readings, but this does not indicate a positive trend as yet.

Q. Do you have any additional information related to the number of estimated meter readings that the City receives from KEDNY?

Yes. Please refer to Exhibit ____(RAB-6). This exhibit contains a graph developed by City of New York personnel that shows the percentage of City accounts with estimated readings from May 2014 through February 2016. The percentage of estimated reads ranges from 17% to 40% over this period. This is an unacceptably high number of estimated meter readings from the City's perspective. The City is currently targeting 10% or less estimated reads but, as I previously mentioned, no resolution has yet been reached with KEDNY.

Q. Are there other potential issues with respect to estimated meter readings of which the Commission should be aware?

A. Yes, there are two additional issues.

First, discussions I have had with City of New York personnel indicate that some estimated meter readings after some length of time may not be trued up to actual readings. If such circumstances occur in which estimated readings are considered to be actual readings, those estimated readings should continue to count as estimated readings for purposes of the adjusted billings metric. Simply because an estimated meter reading is deemed to be final does not mean it is a true actual reading.

Second, the Commission should ensure that all meter readings are considered as separate readings and not aggregated if a customer has multiple meters and/or multiple accounts. In other words, every estimated meter reading should be considered separately so that the Commission and its Staff have a full accounting of all estimated meter readings.

Q. Should the Companies' revised performance targets for adjusted bills be accepted, including the two items you recommend continuing to include in the calculation of the metric?

A. Yes. The Companies should have an incentive to lower the number of estimated bills being replaced by actual bills and more stringent performance standards would assist with performance in this area. Therefore, the revised targets should be accepted without the exclusions proposed by the Companies.

Q. Briefly describe the Companies' proposal for the PSC complaint rate.

A. The SSP proposed lowering the current target for KEDNY from 1.1 per 100,000 to 1.05 per 100,000. KEDLI's current target of 1.1 per 100,000 would continue.

Q. What is your recommendation with respect to the performance target for the PSC complaint rate?

A. Based on the Companies' performance from 2009 through 2014, I recommend that the performance target for both Companies be lowered to 0.90 complaints per 100,000. From 2009 through 2014, KEDNY has performed significantly below this metric except for 2009 (0.91). KEDLI has exceeded 0.90 only once, which was 2014 (1.29). My proposed performance target of 0.90 for both Companies is reasonable, even generous, considering their performance since 2009.

Q. Is the SSP proposing to change the performance target for residential customer transaction satisfaction?

A. No. The SSP proposed to retain the current targets of 84.8% for KEDNY and 83.4% for KEDLI.

Q. What has the performance of the Companies been from 2009 through 2014?

A. KEDNY's performance has ranged from 88.3% in 2009 to 91.8% in 2014. KEDLI's performance ranged from 81.3% in 2013 to 87% in 2009.

First, it is clear that KEDNY has easily exceeded the current performance target in every year since 2009. Second, it is also clear that KEDLI has some work to do to in terms of residential transaction satisfaction. KEDLI's performance has actually declined since 2009.

Q. What is your recommendation with respect to the performance targets for residential customer transaction satisfaction?

A. I recommend that the Commission consider raising KEDNY's performance target for this metric. In my opinion, the Commission could reasonably raise KEDNY's target to 88%, which is the lowest performance level since 2009. Based on the reports contained in Exhibit ____(SSP-8), this target is achievable by KEDNY and represents a reasonable floor for performance in this area.

For KEDLI, I recommend that the Commission raise KEDLI's performance target from 83.4% to 85%. KEDLI achieved this metric in the past and should be held accountable for better performance for its residential customers. Increasing the target should provide the incentive for this performance.

Q. Should the Commission continue the existing level of penalties for the four current customer service metrics you discussed?

A. Yes. I recommend that the Commission continue the current penalties for all four metrics.

New Service Quality Metrics

Q. Please summarize the new service quality metrics proposed by the SSP.

A. The new service quality metrics proposed by the Companies include the following:

- Payment processing
- IVR Self-Service Rate
- Appointments kept
- Web/mobile payments
- Low income outreach and assistance programs

Exhibit ____(SSP-9) shows how the Companies propose that these new metrics be included into the existing service quality metrics. The first three new metrics along with the current metrics are assigned weights and the total current penalty amounts for each Company are multiplied by the percentage weighting to determine the new penalty amounts for each metric. There is also a performance matrix that includes a penalty floor, a penalty threshold that can be offset, and potential offset. The SSP also provided work papers in Exhibit ___(SSP-11) that support the development of the proposed performance targets, including the new service quality metrics.

Q. Should the Commission approve the performance matrix for the new service

quality metrics proposed by the SSP?

A. No. The Commission should also reject any monetary performance incentives associated with these newly proposed metrics for the reasons I stated earlier in my testimony.

Q. Should the Commission monitor the proposed new performance metrics?

A. Yes. In particular, the payment processing and appointments kept metrics are very important customer service quality metrics and the Company should include these new metrics in its regular service quality reports to the Commission.

Regarding the appointments kept metric, the Companies proposed a floor performance target of 91.9% for KEDNY and 87.9% for KEDLI. My review of Exhibit ____(SSP-11) indicates that these levels are too low for both Companies. KEDLI has been consistently performing between 90% - 95% for the years 2012 through 2015. KEDNY began reporting for this metric in 2013 and has been performing near the mid 90% level since then. I recommend that the Commission continue to monitor this metric to ensure no degradation of service in this area over time.

Q. Do you recommend the imposition of penalties for these new service metrics?

A. I do not recommend any new penalties at this time. Instead, the Company should report these new service metrics along with the current service quality metrics that do have penalties. If the Staff notices any decline in these new metrics, such declines should be reported to the Commission and the Companies should be responsible for implementing procedures to correct any problems.

Q. Do you have any comments with regard to the proposed web/mobile payments metric?

A. Yes. It is not clear that this is a relevant performance metric, though it may be an interesting trend for the Companies to monitor. With increased use of the web and mobile devices, this metric may simply reflect growing customer preferences to use the web and other devices to electronically pay their bills. In my view, the Companies should make this process as easy as possible for customers who choose to pay in this manner. It is unnecessary to give the Companies extra money for something that reflects growing use of new technologies for customers to pay their bills.

Q. Please comment on the proposed low income outreach and assistance program.

A. Like the prior metric I just discussed, it is not clear why this program should be considered a service quality metric. The cost of this activity is likely already included in the Companies' cost of service and appears to be the kind of service beneficial to low income customers. The Companies should certainly continue this activity to the extent its costs are included in rates. No additional monetary incentive is required.

<u>Service Termination Performance Incentive</u>

Q. On pages 36 through 37 of its KEDNY testimony, the SSP proposed establishing a performance incentive metric for residential service terminations for KEDNY and KEDLI. Should the Companies receive any monetary incentives for reducing service terminations to residential customers?

A. No. The Public Service Law, Commission regulations, and Company tariffs establish the terms under which service to residential customers may be terminated. The Companies should use all reasonable efforts to work with residential customers who are having difficulties paying their bills without having to receive additional money from ratepayers to do so. To the extent the Companies are able to work with customers in this manner, the more distribution revenues the Companies will receive when compared to terminating service to customers. Thus, the Companies already have an incentive to reduce service termination to residential customers.

Q. Does this conclude your Direct Testimony?

A. Yes.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission	**:**	
As to the Rates, Charges, Rules and	**:**	
Regulations of Keyspan Gas East Corp.	**:**	**Case No. 16-G-0058**
dba Brooklyn Union of L.I.	**:**	
for Gas Service	**:**	

Proceeding on Motion of the Commission	**:**	
As to the Rates, Charges, Rules and	**:**	
Regulations of the Brooklyn Union Gas	**:**	**Case No. 16-G-0059**
Company for Gas Service	**:**	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

THE CITY OF NEW YORK

J. KENNEDY AND ASSOCIATES, INC.

MAY 20, 2016

EXHIBIT ___ (RAB-1)

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor

Expert Testimony Appearances
of
Richard A. Baudino
As of May 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of May 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042-000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR- 09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E- GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009- 2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010- 2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010- 2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010- 2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts- Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010- 2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010- 2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010- 2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011- 2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011- 2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012- 2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012- 2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues

EXHIBIT ___ (RAB-2)

Exhibit ____(RAB-2)

PROPOSED TEMPERATURE CONTROLLED RATE DESIGN

			Sales	Transport	Total
TC-C	Cust		96	36	132
	Billed Sales (Dth)		1,274,691	787,593	2,062,284
	Customers under		60	26	86
				Block 1 therms	10
	Tariff Rates				
	Block 1-Under	All TC's	$ 300.0000	$ 300.0000	
	Block 1-Over	All TC's	$ 375.0000	$ 375.0000	
	Block 2 (bef Disc)	SC 2-2 Blk 4	$ 0.3300	$ 0.3300	
				Discount	0.0%
	Billed Margin ($000)				
	Block 1		$ 378	$ 136	$ 514
	Block 2		$ 4,168	$ 2,585	$ 6,753
	Billed Delivery Rev		$ 4,546	$ 2,721	$ 7,268
TC-G	Cust		353	20	373
	Billed Sales (Dth)		3,650,912	69,386	3,720,298
	Customers under		170	1	171
				Block 1 therms	10
	Tariff Rates				
	Block 1-Under	All TC's	$ 300.0000	$ 300.0000	
	Block 1-Over	All TC's	$ 375.0000	$ 375.0000	
	Block 2 (bef Disc)	SC 2-2 Blk 4	$ 0.3000	$ 0.3000	
				Discount	0.0%
	Billed Margin ($000)				
	Block 1		$ 1,436	$ 91	$ 1,526
	Block 2		$ 10,826	$ 201	$ 11,026
	Billed Delivery Rev		$ 12,261	$ 292	$ 12,553
TC-M	Cust		2,263	300	2,563
	Billed Sales (Dth)		11,742,044	1,519,861	13,261,905
	Customers under		1,901	148	2,049
				Block 1 therms	10
	Tariff Rates				
	Block 1-Under	All TC's	$ 300.0000	$ 300.0000	
	Block 1-Over	All TC's	$ 375.0000	$ 375.0000	
	Block 2 (bef Disc)	SC 3 Blk 3	$ 0.2740	$ 0.2740	
				Discount	0.0%
	Billed Margin ($000)				
	Block 1		$ 8,473	$ 1,217	$ 9,689
	Block 2		$ 31,429	$ 4,066	$ 35,495
	Billed Delivery Rev		$ 39,902	$ 5,283	$ 45,184

Source: Exhibit ___(RDP-4), Schedule 3

EXHIBIT ___ (RAB-3)

2015118

[redacted]

Exhibit___(RAB-3)

**C 017
BROOKLYN COLLEGE CUNY Y
DCAS
1 CENTRE STREET, 17FL
NEW YORK, NY 10007

Please Pay
Upon Receipt
213,994.63 H

[redacted]

BROOKLYN COLLEGE CUNY
1325 OCEAN AVE SCH
BROOKLYN,NY
11230

[redacted]

TC Government

May 26 '15 Apr 27 '15

6G2

CURRENT BILL ITEMIZED

In 29 days you used 308467 therms:

Mar 25 2015 reading ACTUAL	263859
Feb 24 2015 reading ACTUAL	234397
Meter multiplier is 10.0 -CCF used	29462
CCF Used for METER# 13002946	294620
Thermal Factor	x1.0470
Total therms used	308467

Your Cost is determined as follows:

Minimum Charge (First 9.7 therms or less)	$291.72
Next 308457.3 @ $.6916	213,329.07
MTA Surcharge	373.84
SUB-TOTAL	$213,994.63
MTA Surcharge	.00
Sales Tax	.00
.0000 % Sales Tax on Gas Delivery	.00
TOTAL CURRENT CHARGES	**$213,994.63**

SUMMARY OF CHARGES

Total Current Charges	$213,994.63
Amount Due Last Bill	67,891.96
Your Total Payments Since Last Bill. Thank You!	-67,891.96
Please Pay Upon Receipt	**$213,994.63**

IMPORTANT MESSAGES

[redacted] your balance, submit meter readings. The code above provides free, instant access with "My Account" - visit www.nationalgridus.com. Many automated services are also available at the telephone number above.

The amount due shown above is included as part of the balance shown on your Summary Bill, which combines multiple bills into one convenient statement. Please refer to your Summary Bill account number [redacted] for the total due at this time. Thank You!

Nothing beats the reliability of natural gas. It's always there when you need it. Over 90% of our supply is produced right here in North America. It's the clean, efficient, and safe choice for cooking, heating and many other uses.

We sincerely appreciate the prompt way you pay your bills.

An electronic meter reading device provides us with your actual meter reading.

[redacted]

EXHIBIT ___ (RAB-4)

Date of Request: March 31, 2016 City of New York Request No. CNY-127 KS-127
Due Date: April 11, 2016 KEDNY/ KEDLI Req. No. BULI-382

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: CNY, Kimberly Schaffer

TO: National Grid, Rate Design Panel

Request:

Note: In these interrogatories, any request for workpapers or supporting calculations should be construed as requesting any Excel or other computer spreadsheet models in electronic format with all formulae intact.

KEDNY AND KEDLI:

127. For the following questions, please refer to page 3 of the Order Regarding Tariff Filings issued on August 20, 2008 in Case Nos. 06-G-1185 and 06-G-1186.

a. Is KEDNY proposing to continue charging TC/Interruptible customers "the incremental cost of gas"?

b. If the answer to part a. is yes, please explain why such a charge is justified.

c. If the answer to part a. is no, please explain how KEDNY intends to charge for the cost of gas to TC/Interruptible customers.

d. Is KEDLI proposing to continue charging TC/Interruptible customers "the incremental cost of gas"?

e. If the answer to part d. is yes, please explain why such a charge is justified.

f. If the answer to part d. is no, please explain how KEDLI intends to charge for the cost of gas to TC/Interruptible customers.

Response:

127. a. KEDNY is proposing to continue to charge TC/IT customer "the incremental cost of gas."

b. The commodity cost of gas is a pass through charge, meaning the Company charges the customer for the cost it incurs for gas on behalf of the customer.

c. N/A

d. KEDLI is proposing to continue to charge TC/IT customer "the incremental cost of gas."

e. The commodity cost of gas is a pass through charge, meaning the Company charges the customer for the cost it incurs for gas on behalf of the customer.

f. N/A

Name of Respondent:	Date of Reply:
Dawn Herrity	April 8, 2016

EXHIBIT ___ (RAB-5)

Date of Request: March 24, 2016
Due Date: April 4, 2016

City of New York Request No. CNY-106 KS-106
KEDNY/ KEDLI Req. No. BULI-318

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: CNY, Kimberly Schaffer

TO: National Grid, Rate Design Panel

Request:

Note: In these interrogatories, any request for workpapers or supporting calculations should be construed as requesting any Excel or other computer spreadsheet models in electronic format with all formulae intact.

Rate Design Panel (KEDNY):

106. Please refer to page 42, lines 1 through 8, of the Panel's pre-filed direct testimony. For each of the four listed components of the MFC charge, please provide a detailed explanation as to why the Company proposes to apply each component to TC and IT rates.

Response:

The Company is proposing to recover four components of the MFC from TC and IT customers: gas supply procurement, return requirement on working capital, commodity related uncollectible costs, and commodity related credit and collections expenses.

The Company is proposing to recover the costs associated with gas supply procurement and a return requirement on working capital because these two components are costs that the Company incurs to purchase supply on behalf of all of its sales customers. The gas supply procurement component includes both direct and allocated costs associated with the procurement of supply. The return requirement on working capital related to purchased gas expense reflects the number of days between the time the Company pays its suppliers for gas purchases and the time the Company receives payments from its customers.

In addition, the Company is proposing to recover commodity related uncollectible costs and commodity credit and collections costs from the TC and IT customers. The Company incurs commodity related costs for its sales customers that are either in arrears or are subsequently written off as uncollectible.

As explained previously in the Company's response to CNY-10, MFC costs are removed from the revenue requirement for each service class before base delivery rates are designed. The MFC is recovered outside of base delivery rates and is only paid by customers that take supply from the Company. Because the Company is proposing to move TC and IT customers to a cost based rate, TC and IT customers would avoid paying a portion of the costs allocated to them in the Embedded Cost of Service Study, which is inconsistent with how the Company treats all other customers whose rates are cost based. For these reasons, it is appropriate to charge the four components of the MFC described on page 42 of the Rate Design Panel's direct testimony to recover the total costs to serve these customers.

Name of Respondent:	Date of Reply:
Pamela Dise	April 4, 2016

EXHIBIT ___ (RAB-6)

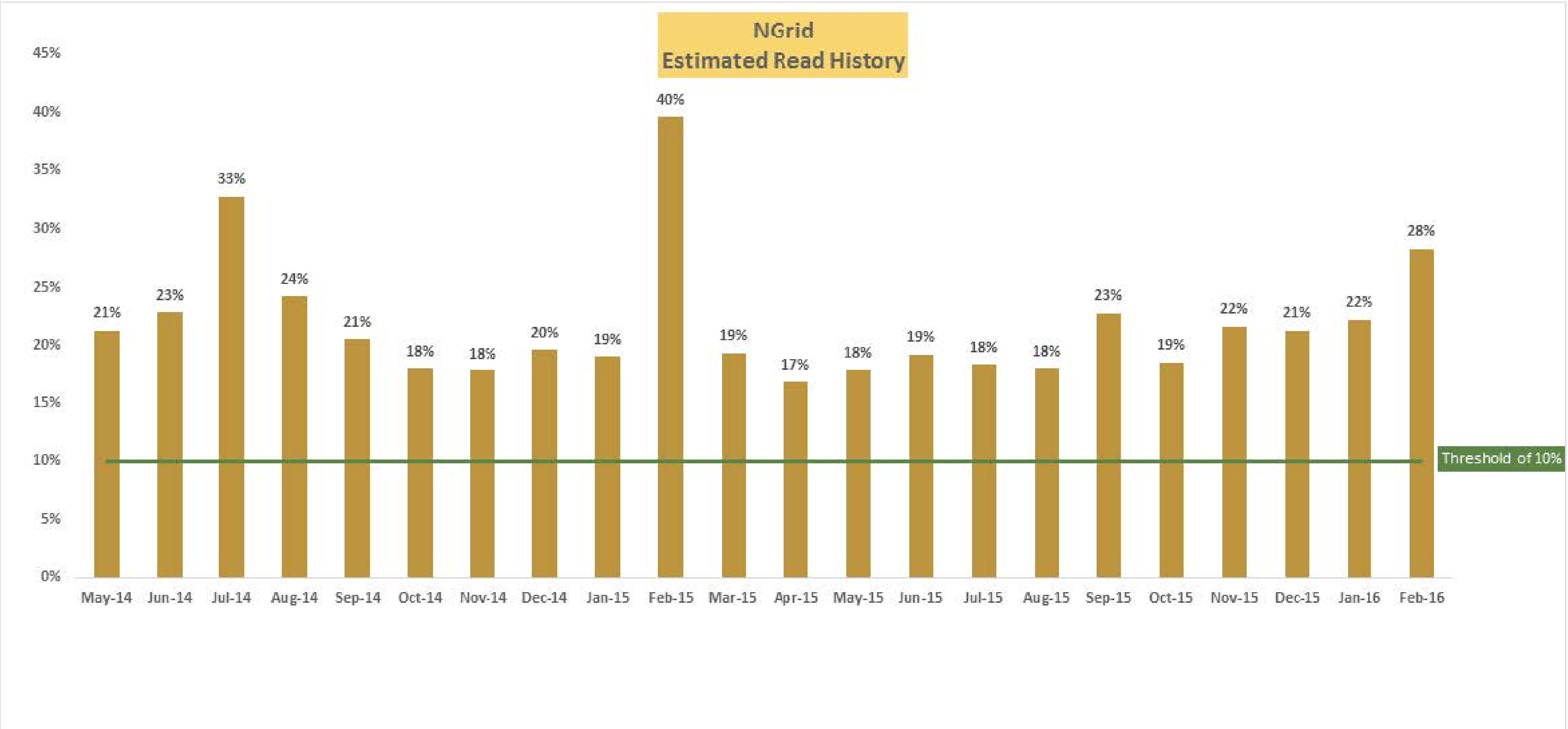

Exhibit ___(RAB-6)

SPILMAN THOMAS & BATTLE, PLLC
ATTORNEYS AT LAW

Susan J. Riggs
304.340.3867
sriggs@spilmanlaw.com

August 18, 2016

VIA HAND DELIVERY
Ms. Ingrid Ferrell
Executive Secretary
Public Service Commission of West Virginia
201 Brooks Street
Charleston, WV 25301

04:32 PM AUG 18 2016 PSC EXEC SEC DIV

Re: CASE NO. 16-0073-E-C
CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC, Complainant, v. APPALACHIAN POWER COMPANY, a public utility, Defendant.

Dear Ms. Ferrell:

Pursuant to the August 17, 2016, Order issued by the Public Service Commission of West Virginia, please find enclosed for filing in the above-referenced case, on behalf of Constellium Rolled Products Ravenswood, LLC ("Constellium-Ravenswood"), an original and twelve (12) copies of the **REVISED** "*Direct Testimony and Exhibits of Richard A. Baudino*" and the **REVISED REDACTED VERSIONS** of the *"Direct Testimony and Exhibit of Victus Rose,"* and *"Direct Testimony of Derek Scantlin."*

Please contact me if you have any questions concerning this filing.

Sincerely,

Susan J. Riggs

Lee F. Feinberg (WV State Bar No. 1173)
Susan J. Riggs (WV State Bar No. 5246)
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Counsel to Constellium Rolled Products Ravenswood, LLC

SJR.sds.8744146
c: Certificate of Service

CERTIFICATE OF SERVICE

I, Susan J. Riggs, counsel to Constellium Rolled Products Ravenswood, LLC, do hereby certify that on this 18th day of August, 2016, a copy of the foregoing **REVISED** "*Direct Testimony and Exhibits of Richard A. Baudino*" and **REVISED REDACTED VERSIONS** of the *"Direct Testimony and Exhibit of Victus Rose"* and *"Direct Testimony of Derek Scantlin"* was served upon the parties and/or counsel of record in this proceeding as follows:

VIA E-MAIL & HAND DELIVERY

Leslie Anderson, Esquire
Legal Division
Public Service Commission of West Virginia
201 Brooks Street
Charleston, WV 25301
landerson@psc.state.wv.us
Counsel for Commission Staff

04:32 PM AUG 18 2016 PSC EXEC SEC DIV

VIA E-MAIL & U.S. MAIL

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Counsel for Appalachian Power Company

Susan J. Riggs

Susan J. Riggs (WV State Bar No. 5246)

Constellium-Ravenswood Exhibit RAB-D [REVISED]

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

DIRECT TESTIMONY AND EXHIBITS OF RICHARD A. BAUDINO [REVISED]

ON BEHALF OF

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

J. KENNEDY AND ASSOCIATES, INC.

JUNE 28, 2016

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

DIRECT TESTIMONY OF RICHARD A. BAUDINO [REVISED]

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to J. Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit__(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Constellium Rolled Products Ravenswood, LLC ("Constellium-Ravenswood").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the attempt by Appalachian Power Company ("APCo" or "Company") to assess a security deposit of $1,766,000 on Constellium-Ravenswood.

Q. Please summarize your conclusions and recommendations to the Commission.

A. The Public Service Commission of West Virginia ("Commission") should order APCo to withdraw its demand for Constellium-Ravenswood to pay the Company a security deposit. As I shall demonstrate, APCo's demand is arbitrary and capricious, violates certain Commission Rules governing security deposits, and violates the current contract between APCo and Constellium-Ravenswood. APCo's proposed security deposit is an onerous financial obligation for Constellium-Ravenswood and APCo's threatened service termination would harm Constellium-Ravenswood's West Virginia operations as well as threaten the economic wellbeing of the employees that work for Constellium-Ravenswood. APCo's attempt to extract a $1.8 million security deposit from Constellium-Ravenswood is therefore unjust and unreasonable.

Q. Please provide a brief description of the Constellium-Ravenswood operation in West Virginia.

A. Constellium-Ravenswood is a West Virginia corporation with its principal place of business located at 859 Century Road, P.O. Box 68, Ravenswood, West Virginia, 26164-0068. Constellium-Ravenswood began operations in Ravenswood in 1957, and is currently one of the largest rolled aluminum products facilities in the world, producing plate, sheet, and coil aluminum products for a wide range of industrial uses, including aerospace, defense, transportation, and marine. Constellium-Ravenswood currently has approximately 1,100 employees, the majority of whom are members of the United Steelworkers union, and annual payroll of approximately $78.4 million. In addition to the significant workforce that Constellium-Ravenswood employs in the State of West Virginia, Constellium-Ravenswood also contributes to the economy of West Virginia through the payment of over $5 million annually in state and local taxes.

Q. **Briefly summarize the events that led to Constellium-Ravenswood filing its Complaint.**

A. I understand that on November 10, 2015, after periodic discussions and refusals by Constellium-Ravenswood to remit a security deposit, that APCo conveyed to Constellium-Ravenswood a demand for payment of $1,776,000 as a security deposit. APCo claimed that Constellium-Ravenswood represents a financial risk to APCo. APCo's demand failed to include any indication of how long the security deposit would be held or under what terms, if any, it would be released. As part of its demand, APCo threatened to issue a Discontinue Notice to terminate service if Constellium-Ravenswood did not pay the security deposit within twenty (20) days of any invoiced due date.

Q. Mr. Baudino, does APCo have any grounds for assessing its proposed $1,776,000 security deposit on Constellium-Ravenswood?

A. No, it has no grounds whatsoever to assess its proposed security deposit on Constellium-Ravenswood. The remainder of my Direct Testimony will show that APCo's proposed security deposit (1) violates certain Commission Rules and (2) violates the currently effective Service Contract ("Special Contract") between APCo and Constellium-Ravenswood. As a result, APCo's proposed security deposit under threat of termination is unjust and unreasonable.

Q. Please summarize Commission Rule 4.2.a.1.

A. Rule 4.2.a.1. of the Commission's Rules for the Government of Electric Utilities (the "Electric Rules") establishes the standards by which electric utilities may collect security deposits from customers. 150 CSR 3, § 4.2.a.1. Under Rule 4.2.a.1., the only standard necessary for a customer to demonstrate that it meets appropriate financial security and responsibility is the timely payment of twelve (12) consecutive utility bills for service.

Q. Has Constellium-Ravenswood made timely payment of 12 consecutive bills for service?

A. Yes. In fact, Constellium-Ravenswood has now made timely payment to APCo of well over 36 consecutive monthly bills for its electric service. Constellium-Ravenswood has not only met, but has significantly surpassed the minimum number of consecutive bill payments necessary under Commission Rule 4.2.a.1. to demonstrate its financial fitness in relation to security deposit requirements.

Q. Does APCo's demand for a security deposit of $1.8 million from Constellium-Ravenswood constitute a violation of Commission Rule 4.2.a.1.?

A. Yes, in my opinion, APCo's demand is clearly contrary to Commission Rule 4.2.a.1., and the Commission should reject it on this basis alone.

Q. Please describe Commission Rule 4.2.a.6.

A. Rule 4.2.a.6. states, "All utilities that collect security deposits must do so in a non-discriminatory manner."

Q. Does APCo's demand for a security deposit of $1.8 million from Constellium-Ravenswood constitute a violation of Commission Rule 4.2.a.6.?

A. Based on my review of the evidence in this case and of the evidence in the proceeding on APCo's recent request for new terms and conditions of service related to non-residential security deposits at Case No. 15-1673-E-T, I believe that it does. APCo has acknowledged in Case No. 15-1673-E-T that it has requested security deposits from certain large non-residential customers on the basis of assessments of the credit-worthiness of those customers using the criteria proposed in that proceeding. APCo further acknowledged in that proceeding that these efforts are targeted specifically at non-residential customers with over $3 million in annual revenues, despite also claiming that bad debt charge-offs are a system-wide problem.

In my opinion, it is unduly discriminatory to target a small, select group of customers for security payments intended to address an alleged system-wide bad debt charge-off problem. APCo's attempt to extract a security deposit from Constellium-Ravenswood is clearly rcflective of that unduly discriminatory conduct. Furthermore, the evidence in Case No. 15-1673-E-T shows that such efforts to avoid bad debt charge-offs from large non-residential customers like Constellium-Ravenswood is simply not needed, as these customers continue to subsidize the bad debt of other rate classes.

Q. Please describe Commission Rule 4.2.b.

A. Rule 4.2.b. of the Commission's Electric Rules establishes the standards by which electric utilities may obtain a guaranty agreement signed by a financially responsible guarantor of a customer. 150 CSR 3, § 4.2.b. Rule 4.2.b.2. specifically states, in part, that such a guaranty agreement "shall terminate after the customer has satisfactorily paid bills for service for twelve consecutive months," and provides that electric utilities may only require a new guaranty agreement or cash deposit "<u>where experience indicates</u> that a cash deposit or a new guaranty agreement is reasonably necessary to secure the utility from loss." (Emphasis added.)

Q. How would Rule 4.2.b apply to Constellium-Ravenswood, if at all.

A. In my view, this Rule does not apply due to the special contract that exists between APCo and Constellium-Ravenswood; however, if APCo relied on this Rule in an attempt to extract a security deposit from Constellium-Ravenswood, then the Company did so in violation of the Rule. Constellium-Ravenswood has submitted timely payment of its bills for 36 consecutive months, which far surpasses the 12-month requirement of the Rule.

Furthermore, there is no experience cited by APCo that indicates that a cash deposit or new guaranty agreement is reasonable and/or necessary, as required by Rule 4.2.b.2. Indeed, the only relevant experience between Constellium-Ravenswood and APCo demonstrably proves that Constellium-Ravenswood is a customer in good standing and, as I mentioned earlier, has remitted payments for its APCo bills for well over 36 consecutive months.

Q. Are you familiar with the Special Contract between APCo and Constellium-Ravenswood?

A. Yes, I have reviewed the Special Contract. I will now address certain Articles of this Special Contract that bear on the current situation with respect to APCo's demand for a security deposit. These are Articles 11, 12.3, 14.2, and 16.2.

Q. Briefly describe Article 11 of the Special Contract.

A. Article 11 of the Special Contract details all of the various components that are to be used to determine the monthly bill paid by Constellium-Ravenswood to APCo. This article does not contemplate or include any computation of a security deposit.

Q. Does Article 11 contain any provision for the collection of a security deposit from Constellium-Ravenswood?

A. No, it does not. I conclude from this fact that APCo's attempt at extracting a security deposit from Constellium-Ravenswood violates the terms of Article 11 of the Special Contract.

Q. Briefly describe Article 12.3 of the Special Contract.

A. Article 12.3 of the Special Contract specifies the basis upon which APCo may terminate or suspend service to Constellium-Ravenswood if Constellium-Ravenswood fails or refuses to pay the monthly bill conveyed by APCo under Article 11.2 of the Special Contract.

Q. Does Article 12.3 contain any provision for the collection of a security deposit from Constellium-Ravenswood?

A. No, it does not. I conclude from this fact that APCo's attempt at extracting a security deposit from Constellium-Ravenswood violates the terms of Article 12.3 of the Special Contract.

Q. Briefly describe Article 14.2 of the Special Contract.

A. Article 14.2 of the Special Contract states, "To the extent not specifically modified by this Special Contract, APCo's Terms and Conditions of Service, on file with the Commission, are incorporated herein by reference and made a part hereof."

Article 14.2 of the Special Contract also states, "In the event of a conflict between the provisions of this Special Contract and the provisions of the Company's [APCo's] Terms and Conditions of Service, the provisions of this Special Contract shall control."

Q. Do APCo's Terms and Conditions of Service currently on file with the Commission require a customer to demonstrate credit worthiness?

A. No. APCo's Terms and Conditions of Service (as referenced in Article 14.2 of the Special Contract) currently on file with the Commission do not require a customer to demonstrate credit-worthiness or to establish any other metric of financial stability beyond the timely payment of twelve (12) consecutive bills for service.

Q. How does the second section you quoted from Article 14.2 of the Special Contract apply with respect to APCo's attempt to extract a security deposit from Constellium-Ravenswood?

A. Constellium-Ravenswood's Special Contract with APCo does not require payment of a security deposit by Constellium-Ravenswood. At the time that Constellium-Ravenswood and APCo entered into the Special Contract, APCo did not demand a security deposit nor did APCo apply the security deposit criteria that it now attempts to apply to Constellium-Ravenswood's service. At no time during the initial term of the Special Contract or in relation to renewal of the Special Contract did APCo ever demand payment of a security deposit. Since there is no language regarding a security deposit in the Special Contract, APCo cannot attempt to use the Commission Rules against Constellium-Ravenswood to demand a security deposit that was not contemplated in the Special Contract.

However, as I demonstrated earlier, even if APCo is attempting to use the Commission Rules to obtain a security deposit from Constellium-Ravenswood, then no security deposit could be applied to Constellium-Ravenswood because it has submitted over 36 months of consecutive timely bill payments to APCo.

Q. Briefly describe Article 16.2 of the Special Contract.

A. Article 16.2 of the Special Contract states that "[t]he Company [APCo] and the Customer [Constellium-Ravenswood] agree that this Special Contract reflects the steps required to insure adequate service to the Customer[.]"

There is no other provision within the Special Contract requiring Constellium-Ravenswood to provide APCo with any other assurance or consideration to insure adequate electric service. This includes providing a security deposit from Constellium-Ravenswood to APCo.

Q. Did APCo apply is credit worthiness standards and analyses to the Constellium-Ravenswood operations?

A. No, it did not. In its correspondence with personnel at Constellium-Ravenswood dated July 17, 2015, the Company stated that it had reviewed "assessments . . . made by commercial ratings agencies . . . such as Moody's, Standard and Poor's and other[]" commercial rating agencies of Constellium-Ravenswood's indirect parent company, Constellium N.V. APCo also stated that it relied on an unspecified "tool developed to forecast the probability of bankruptcy" by Constellium N.V. APCo admits that it "took action" in demanding a security deposit from Constellium-Ravenswood "based on these analyses," which were analyses of Constellium N.V. Please refer to Exhibit___(RAB-2) for a copy of this communication.

Q. Is it reasonable for APCo to evaluate the credit worthiness of Constellium-Ravenswood based on assessments of its indirect parent company?

A. No, it is not reasonable. Constellium-Ravenswood itself is not a publicly traded corporation and does not have independent credit ratings. Constellium N.V. is the indirect parent of Constellium-Ravenswood and is removed from Constellium-Ravenswood by three intermediate tiers of corporate hierarchy. Absent an analysis specific to the Constellium-Ravenswood operation, there is no way for APCo to determine the credit worthiness of the Constellium-Ravenswood operations based on Constellium N.V.'s credit ratings.

Furthermore, APCo failed to provide any specific, objective and transparent tests that it applied as the basis of its demand for a security deposit from Constellium-Ravenswood. The lack of any specific, objective, and transparent tests lends itself to the unfettered discretion of APCo to subjectively apply its so-called assessments in whatever manner and at any time of its choosing, and to do so without any procedural recourse by a customer, short of filing a Motion for Stay and/or a Complaint as Constellium-Ravenswood has done in this proceeding. APCo's customers cannot know if or when new security deposits will be demanded, on what basis deposits will be retained, or for how long they will be retained. The absence of the specific criteria and transparent methodology means that APCo could, on its own volition, collect and retain deposits indefinitely, or serially collect and refund deposits indefinitely. In other words, APCo would have free rein to assess and retain security deposits with no Commission review for reasonableness.

To make matters worse, in its July 17, 2015, correspondence to Constellium-Ravenswood, APCo also stated and claimed that it could require a security deposit "at any time, from any customer, for any reason." The fact of the matter is that APCo ***cannot*** require a security deposit "for any reason" any time its wishes. APCo's actions with respect to security deposits must be governed by the Commission's Rules regarding security deposits. APCo's rules governing customer security deposits are outlined on Sheet No. 3-1 of APCo's current Commission-approved tariff. According to Sheet No. 3-1, the only standard necessary for a customer to demonstrate that it meets appropriate financial security and responsibility is the timely payment of twelve (12) consecutive utility bills for service. Nothing in APCo's current Commission-approved tariff permits APCo to require a customer to demonstrate financial security or responsibility through the use of financial information, credit worthiness, or other measurements of either a customer or a customer's parent corporation. Sheet 3-1 does not allow for APCo to assess security deposits at any time and for any reason it wishes. As a regulated monopoly provider of electric service in West Virginia, APCo simply cannot charge anything it wants for any reason it comes up with.

Q. Is it appropriate to use a parent company to ascertain the credit worthiness of a subsidiary or division within a larger company, such as Constellium N.V.?

A. It most definitely is not appropriate. Circumstances within a larger parent company may affect that parent company's financial performance in many different ways that have nothing to do with a subsidiary or operating division within that parent. A holding company may be in bankruptcy while its subsidiaries are financially healthy and have investment grade credit ratings.

For example, I was recently involved in a proceeding in Texas that involved a proposed restructuring of Oncor and its parent, Energy Future Holdings ("EFH").[1] EFH is a holding company that owns, among other things, Oncor, the largest transmission and distribution utility in Texas. EFH filed for bankruptcy protection in 2014; however, Oncor is a financially healthy operating company with current bond ratings of A from Standard and Poor's and Baa1 from Moody's. These are solid investment grade bond ratings. Even in the utility industry, it is abundantly clear that one should not make assumptions about the credit worthiness of a subsidiary based on the financial condition of the parent company.

Q. Are you aware of any information with respect to the economic viability of the Constellium-Ravenswood operations?

A. Yes. Please refer to the Fourth Quarter and Full Year 2015 – Earnings Call document contained in Exhibit__(RAB-3). On page 7, Constellium stated that 2015 was a record year for Adjusted EBITDA (Earnings Before Interest, Taxes, Depreciation, and Amortization) for Ravenswood.

[1] Public Utility Commission of Texas Docket No. 45188.

Q. Could APCo's demand of a $1.8 million security deposit have adverse consequences for Constellium-Ravenswood and its West Virginia employees?

A. Yes. Other Constellium-Ravenswood witnesses will testify to the economic impact of the proposed security deposit. It is certainly not economically justified given the fact that Constellium-Ravenswood has now made well over 36 months of consecutive timely payments to APCo, and is still doing so to my knowledge.

A more chilling aspect of APCo's demand is its threat to discontinue service to Constellium-Ravenswood if the Company does not receive its $1.8 million security deposit. In such an event, APCo would be responsible for working a hardship not only on a customer in good standing such as Constellium-Ravenswood, but on the 1,100 West Virginia employees who work for the company. Obviously, Constellium-Ravenswood would not be able to continue its operations if APCo shut off its electricity. This could throw 1,100 West Virginia employees out of work indefinitely. In this regard, APCo's threat is astoundingly draconian and dangerously insensitive to the potentially devastating economic consequences of its actions. Utilities in the state of West Virginia, or in the entire United States for that matter, should not be allowed to operate in this manner.

I strongly recommend that the Commission order APCo to drop its demanded security deposit in order to protect the interests not only of Constellium-Ravenswood, but to protect the people of West Virginia as well.

Q. **In its Order dated June 2, 2016, the Commission noted on page 4: "It is not unusual for the Commission, in carrying out its legislative duties, to face statutory or regulatory language that does not offer specific guidance as to how it is to be interpreted or applied. When we encounter those situations, we typically use reasonableness as the test." Is APCo's attempt to demand a security deposit with the threat of service termination reasonable, particularly when balanced against the potential harm to Constellium-Ravenswood?**

A. No. APCo's demand for a security deposit under threat of service termination is unreasonable and unjust for all of the reasons I have explained previously in my Direct Testimony, especially considering Constellium-Ravenswood's impeccable payment history and the potential that APCo's security deposit could adversely impact Constellium-Ravenswood's business, employees, customers, vendors, suppliers, and the West Virginia economy, as further outlined by Constellium-Ravenswood witness Mr. Derek Scantlin. I strongly recommend that the Commission reject APCo's attempt to assess its proposed $1.8 million security deposit on Constellium-Ravenswood.

Q. **Does this conclude your Direct Testimony?**

A. Yes.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

EXHIBITS

OF

RICHARD A. BAUDINO

[REVISED]

ON BEHALF OF

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

J. KENNEDY AND ASSOCIATES, INC.

JUNE 28, 2016

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

EXHIBIT__(RAB-1)

OF

RICHARD A. BAUDINO

[REVISED]

ON BEHALF OF

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

J. KENNEDY AND ASSOCIATES, INC.

JUNE 28, 2016

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor

Expert Testimony Appearances
of
Richard A. Baudino
As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
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As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestem Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

**Expert Testimony Appearances
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As of June 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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As of June 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

Expert Testimony Appearances
of
Richard A. Baudino
As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

EXHIBIT__(RAB-2)

OF

RICHARD A. BAUDINO

[REVISED]

ON BEHALF OF

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

J. KENNEDY AND ASSOCIATES, INC.

JUNE 28, 2016

Looney, Bryan

From:	Alan D Bragg <adbragg@aep.com>
Sent:	Friday, July 17, 2015 2:22 PM
To:	Looney, Bryan; Scantlin, Derek
Cc:	Brent L Busch
Subject:	FW: Follow up on Account Security

Dear Bryan:

We have upmost respect for Mr. Williamson, and we certainly understand the basis for his thoughts, however, Company attorneys have a different interpretation of the tariff language. We believe that the Deposit language in APCo's current Terms and Conditions of Service (T&Cs) is very clear: *"Applicant or customer may be required to make a deposit as a guarantee for the payment of electricity used."; and "Such deposits shall not be more than one-twelfth (1/12) of the estimated annual charge for service for any Residential customer and not more than one-sixth (1/6) of the estimated annual charge for service for any other customer."* There are no other stipulations or qualifications in this language that would prevent or deny APCo from collecting account security at any time, from any customer, for any reason. As such, APCo is not taking action based on proposed changes, nor is this a new interpretation of the tariff.

To the contrary, APCo's proposed deposit changes revolve around the language that requires the Company to refund deposits after 12 months of on-time payments. We do not believe this refund requirement is reasonable based on the risk imposed on both APCo and its other customers, by customers who are in financial distress and perhaps face bankruptcy. Regarding the Commission's action on this matter, they have not yet ruled on this proposal, but merely deferred discussion of proposed T&C changes to a General Investigation to be conducted at a later date. Regardless, consideration of the refund issue does not preclude us from collecting a deposit now, and hopefully, the refund issue will be ruled upon soon.

APCo does appreciate Constellium's past payment history, and APCo has not made a "unilateral assessment" of Constellium's going-forward credit-worthiness. Those assessments were made by commercial rating agencies, upon whom financial institutions depend, such as Moody's, Standard and Poor's and others. APCo merely read them and took action based on these analyses. As an example, a tool developed to forecast the probability of bankruptcy occurring within the next 12 months rates Constellium as a "1", which they define as their highest level of bankruptcy risk over the next 12 months, and the score trajectory has declined sharply over the past 12 months. Constellium currently has a "B" rating from Standard & Poor's and "B1" by Moody's, both of which are several steps below investment grade.

As we discussed in our face-to-face meeting, based on the commercially available credit information, serving your facility without security is not an option, and therefore, APCo is requiring that Constellium provide full account security equivalent to 1/6 of the annual billings, or $1,776,000. There are a number of options available to you, including cash, surety bond, irrevocable letter of credit, advance payment or a combination of more than one of these options. We are available to meet with you to work out specifics, and our preference is to resolve the issue amicably and quickly.

Sincerely,

Alan D. Bragg
Manager – Customer Services
Appalachian Power Company
Charleston, WV
(304) 348-4156

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

EXHIBIT__(RAB-3)

OF

RICHARD A. BAUDINO

[REVISED]

ON BEHALF OF

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

J. KENNEDY AND ASSOCIATES, INC.

JUNE 28, 2016

Exhibit__(RAB-3)

Fourth Quarter and Full Year 2015 - Earnings Call

March 15, 2016

Constellium

Aerospace and Transportation Segment

Segment Outlook/Mix

- Total shipments of 231 kt down 3%, Aerospace shipments of 116 kt up 8%, Transportation shipments of 115 kt down 11%
- Solid demand in Aerospace market with majority of business under long-term contracts
- Recovery in Aerospace Adjusted EBITDA and Adjusted EBITDA per ton

Constellium Recent Developments

- Record Adjusted EBITDA at Ravenswood in 2015
- New pusher furnace capacity on schedule for start of production by the end of the year as previously announced
- Continued focus towards high added value products

Constellium-Ravenswood Exhibit VR-D REDACTED [REVISED]

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

REDACTED

DIRECT TESTIMONY

AND EXHIBIT

OF

VICTUS ROSE

[REVISED]

ON BEHALF OF
CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

JUNE 28, 2016

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

REDACTED DIRECT TESTIMONY OF VICTUS ROSE [REVISED]

Q. Please state your name and business address.

A. My name is Victus Rose. My business address is 859 Century Road, P.O. Box 68, Ravenswood, West Virginia, 26164-0068.

Q. By whom are you employed?

A. I am employed by Constellium Rolled Products Ravenswood, LLC ("Constellium-Ravenswood").

Q. What is your position with Constellium-Ravenswood?

A. I am the Reliability Engineering Director and Energy Manager for Constellium-Ravenswood. My primary role as it relates to this case is the management of all aspects of energy procurement, budgeting, use reconciliation and reporting, for electricity and natural gas.

Q. Please describe your educational and employment background.

A. I received a B.S. in Aerospace Engineering (1984), an M.S. in Mechanical Engineering (1990), and an M.S. in Engineering Management (2014). I am a Registered Professional Engineer (North Carolina since 1997), Project Management Professional (2012), and Certified Maintenance and Reliability Professional (2016).

I have held positions of increasing responsibility in all areas of operations, maintenance, project engineering, process engineering, and engineering management (including energy management) over the last 32 years.

Q. In what type of business is Constellium-Ravenswood involved?

A. Constellium-Ravenswood is one of the largest rolled aluminum products facilities in the world, producing plate, sheet, and coil aluminum products for a wide range of industrial uses, including aerospace, defense, transportation, and marine.

Q. Does Constellium-Ravenswood consume significant amounts of electricity in its operations?

A. Yes. Constellium-Ravenswood's annual electricity consumption is about **[Begin Confidential** [redacted] **End Confidential]** per year at a current annual cost of approximately **[Begin Confidential** [redacted] **End Confidential]**.

Q. Are energy costs important to Constellium-Ravenswood?

A. Yes. Aluminum manufacturing is an energy-intensive process, so Constellium-Ravenswood's production is very dependent upon energy supply. As such, energy expenses, particularly the cost of electricity, comprise a significant portion of Constellium-Ravenswood's annual operating costs. The Ravenswood plant also consumes approximately **[Begin Confidential** [redacted] **End Confidential]** of natural gas each year, at costs ranging from **[Begin Confidential** [redacted] **End Confidential]** depending on the commodity index price for natural gas. These main energy costs can be as much as **[Begin Confidential** [redacted] **End Confidential]** of total manufacturing costs, and electricity continues to rise in its proportion of the total cost. Constellium-Ravenswood continues to enjoy stable and mutually beneficial relationships with its natural gas suppliers. Although payment terms with the natural gas suppliers are similar to the special contract terms with Appalachian Power Company ("APCo"), there have been no demands for security deposits or the impositions on scarce personnel and financial resources to assert our understanding of our contractual obligations with those suppliers.

Q. Are you familiar with the rates that Constellium-Ravenswood pays to APCo for electric service?

A. Yes. As Energy Manager, I am responsible for the monthly reconciliation of energy costs to budgets and forecasts. This includes overseeing all of Constellium-Ravenswood's energy costs, including the payment of utility bills.

Q. Under what arrangement does Constellium-Ravenswood currently take electric service from APCo?

A. Constellium-Ravenswood takes service from APCo pursuant to the terms of a Special Contract that Constellium-Ravenswood entered into with APCo on August 1, 2011. This initial three-year Special Contract was renewed on August 1, 2014, and again on August 1, 2015.

Q. Are you aware of the issues that gave rise to the Complaint filed by Constellium-Ravenswood in this case?

A. Yes. I have been involved with this matter from the time that APCo initially contacted Constellium-Ravenswood to discuss their demand for a security deposit.

Q. At the time that APCo first communicated its request for additional security, was there any issue with Constellium-Ravenswood's ability to pay for electricity service?

A. No.

Q. Has Constellium-Ravenswood ever had difficulty making timely payments to APCo?

A. No. Based on my review of our records of bill payments, Constellium-Ravenswood has now paid its bills to APCo on time or early for four years and 10 months (since August 2011). Prior to Constellium-Ravenswood, the Ravenswood operation was owned by Alcan which also paid all bills on time or early since beginning to take service from APCo in January 2006.

Q. **Is there currently any issue with Constellium-Ravenswood's ability to pay for the electricity it receives from APCo?**

A. No. In fact, Constellium-Ravenswood continues to pay its electric bills on time. At no time since APCo first indicated that it wanted additional security from Constellium-Ravenswood in June 2015 have any of the concerns voiced by APCo materialized.

Q. **Is Constellium-Ravenswood currently at risk of defaulting on its payments to APCo?**

A. No. I would note, however, that any payment of a $1.8 million security deposit, particularly if Constellium-Ravenswood has no assurance that it will ever be returned, substantially decreases the cash flow available to our operations and presents a significant risk to Constellium-Ravenswood

Q. **Is Constellium-Ravenswood fully responsible for the cost of service that it receives from APCo?**

A. Yes. We have met and continue to meet all of our obligations to APCo and other customers on APCo's system.

Q. **Are you familiar with the terms of the Special Contract between Constellium-Ravenswood and APCo?**

A. Yes. Specifically, Article 1 unequivocally defines the contract parties: the Company (APCo) and Customer (Constellium Rolled Products Ravenswood, LLC). Article 11 completely enumerates the sources of billing categories. Article 14 incorporates the Commissioned-approved Terms and Conditions contained in the APCo tariff. Article 17 states that: "All terms and stipulations made or agreed to regarding the subject matter of this Special Contract are completely expressed and merged in this Special Contract[.]" None of the subject matter under contention is mentioned in the foregoing Special Contract provisions.

Q. Were you involved in the Special Contract negotiations with APCo?

A. Yes. I was the lead negotiator for Constellium-Ravenswood during the establishment of the Special Contract.

Q. What is your understanding of the purpose and effect of the Special Contract?

A. My understanding is that the terms of the Special Contract reflect the full obligations of both Constellium-Ravenswood and APCo in connection with the provision and receipt of electric service. As such, the Special Contract establishes the entirety of Constellium-Ravenswood's payment obligations to APCo under Rate Schedule IP. Article 14.2 of the Special Contract provides that APCo's Terms and Conditions of Service as reflected in its tariff are incorporated into the Special Contract if they are not modified by the Special Contract. Article 14.2 of the Special Contract also states, however, that if there is a conflict between APCo's Terms and Conditions of Service and the Special Contract then the "provisions of [the] Special Contract shall control." I have attached a copy of the Special Contract as Exhibit__(VR-1).

Q. Do the terms of the Special Contract include a requirement for Constellium-Ravenswood to pay a security deposit to APCo?

A. No. Had APCo required a security deposit at the time of the Special Contract, it would have been incorporated in the contract's terms.

Q. Do the provisions of the Special Contract require Constellium-Ravenswood to provide any assurances, at any time, of Constellium-Ravenswood's financial stability or to demonstrate "credit worthiness" as a condition of receiving electric service from APCo?

A. No.

Q. When the Special Contract was renewed in August 2014 and August 2015, did APCo request a modification of the terms of the Special Contract to require Constellium-Ravenswood to pay a security deposit?

A. No. Presumably, if APCo required a security deposit at that time, this modification would have been proposed. APCo did not make this request at any time in connection with renewal of the Special Contract.

Q. Are you familiar with APCo's Terms and Conditions of service contained in its tariff on file with the Public Service Commission of West Virginia ("PSC" or "Commission")?

A. Generally, yes, and I have reviewed the specific Terms and Conditions addressing security deposits in connection with Constellium-Ravenswood's Complaint and this proceeding.

Q. Do the Terms and Conditions of Service contained in APCo's tariff permit APCo to demand a security deposit based on APCo's assessment of a customer's "credit-worthiness?"

A. Based on my reading of the APCo tariff, there is nothing that expressly permits APCo to demand a security deposit based on an amorphous evaluation of a customer's credit-worthiness. The only provision in the APCo tariff that provides any insight into an evaluation of a customer's financial fitness is the requirement for APCo to return a security deposit to a customer after 12 months of timely bill payments. Constellium-Ravenswood has met this clearly defined standard many times over.

But even if APCo might have this authority under its tariff, the provisions of APCo's Special Contract with Constellium-Ravenswood should control whether, and on what basis, Constellium-Ravenswood should be required to pay a security deposit. As I previously stated, the Special Contract does not require Constellium-Ravenswood to make such payment, nor does it permit APCo to make such a demand on any basis, let alone on the basis of APCo's analysis of Constellium-Ravenswood's "credit worthiness."

Q. Do you think APCo's request violates the Special Contract that you negotiated?

A. Yes. The Special Contract and Commission-approved Terms and Conditions represent the entirety of the agreement between Constellium-Ravenswood and APCo. None of the subject matter under contention is addressed by either document, and the only reasonable basis for making the demand for a security deposit would be inability to make on-time payments as reflected in the Commissioned-approved Terms and Conditions.

Q. If the Commission determines that APCo can require a security deposit based on APCo's evaluation of Constellium-Ravenswood's credit-worthiness, under either the provisions of the Special Contract or tariff Terms and Conditions of Service, is it manageable for Constellium-Ravenswood?

A. No. As a captive customer of APCo, it will be difficult to accurately forecast spending for electricity when the Company's demands can change arbitrarily. It has already been established that electricity costs are a significant portion of our manufacturing costs, and a $1.8 million security deposit is a significant expense.

Q. In your opinion, is APCo's demand for a security deposit from Constellium-Ravenswood reasonable?

A. No. As stated earlier, Constellium-Ravenswood's annual natural gas purchases are equivalent in cost to its electricity purchases from APCo, but none of its suppliers have made demands for security or expressed any concern over Constellium-Ravenswood's ability to pay.

APCo created a premise regarding Constellium-Ravenswood's financial health based on APCo's analysis of the financial health of a remote corporate parent (Constellium N.V.) that is clearly not a party to the Special Contract, and has generated this entire contest over that false premise. In the 12 months since this confrontation was manufactured, Constellium-Ravenswood continues to deliver the highest levels of profitability, and definitely higher than when the Special Contract was consummated in August 2011. APCo apparently could continue this charade indefinitely, and, if allowed to collect the security deposit, hold onto it during years when Constellium-Ravenswood would continue to grow and profit.

It is also clear from testimony in a related case (Case No. 15-1673-E-T) that the real risk to APCo from bankruptcy defaults is merely 0.05% of its revenues from commercial and industrial customers, yet APCo endeavors to extract a disproportionately large deposit from its valued customers in order to cover that minimal risk.

As demonstrated in that proceeding, I believe that the bankruptcies which precipitated this security deposit initiative from Columbus, Ohio, are the direct result of the Environmental Protection Agency's ("EPA") policy impact on the West Virginia coal economy. As such, it is unreasonable for APCo to conflate that issue with the financial health of its customers, which have little or no relation to the coal economy. This is a heavy-handed approach that places an unreasonable burden on customers who need working capital to satisfy current and future business needs, rather than losing those resources to some dubious rainy-day fund for the regulated utility.

Q. What do you hope the Commission will do in this case?

A. Constellium-Ravenswood asks that the Commission require APCo to cease and desist from demanding a security deposit, or any other form of security, from Constellium-Ravenswood.

Additionally, Constellium-Ravenswood asks the Commission to set clear and reasonable rules and Terms and Conditions so the obligations on ratepayers and the utility are transparent. This dispute has consumed a significant amount of personnel and financial resources for Constellium-Ravenswood to assert its understanding of its obligations under the Special Contract with APCo and the Commission-approved Terms and Conditions.

Constellium-Ravenswood asks the Commission to ensure that the laws, tariffs, and Terms and Conditions are applied justly and without discrimination or bias (contrary to what APCo is attempting to do with its selective targeting of customers upon which to apply seemingly arbitrary financial obligations).

Finally, Constellium-Ravenswood asks the Commission to recognize that when a captive customer of the utility is told that the utility has the authority to demand changes to the contractual agreements whenever it chooses, and for whatever reasons it chooses, this creates an atmosphere of intimidation and hostility. It cannot be in the best interest of the ratepayers in West Virginia to be bullied by utilities driven by corporate interests in Columbus, Ohio, who would threaten to disrupt service to a customer with an on-time payment record for <u>over a decade</u> — especially when that customer is in the process of adding jobs and tax revenue to the West Virginia economy. Even if the Commission eventually resolves these types of disputes in the future, the financial and resource drain on APCo customers that is necessary to protect their rights clearly is not justified, nor is it in the best interest of the West Virginia economy.

Q. Does this conclude your Direct Testimony?

A. Yes.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

EXHIBIT__(VR-1)

OF

VICTUS ROSE

[REVISED]

ON BEHALF OF
CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

JUNE 28, 2016

SPECIAL CONTRACT
BETWEEN
APPALACHIAN POWER COMPANY
AND
CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

THIS SPECIAL CONTRACT is made and entered into on this date, September 6th, 2011, by and among **APPALACHIAN POWER COMPANY,** a Virginia corporation, qualified to do business in West Virginia, (hereinafter called "Appalachian" or the "Company") and CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC, a Delaware corporation, qualified to do business in West Virginia (hereinafter referred to as the "Customer").

WITNESSETH:

WHEREAS, the Company is a corporation organized and existing under the laws of the State of Virginia, with its principal place of business in the State of West Virginia located at 707 Virginia Street, East, Charleston, West Virginia, and owns and operates facilities for the generation, transmission and distribution of electric power and energy; and

WHEREAS, the Customer is a corporation registered and authorized to do business under the laws of the State of West Virginia, and operates a manufacturing facility in Ravenswood, West Virginia; and

WHEREAS, the service the Company is to provide the Customer pursuant to this Special Contract will provide benefits to the Customer, the Company, the Company's West Virginia ratepayers, and the State of West Virginia; and

WHEREAS, on and after the effective date of this new Special Contract, the Special Contract dated November 17, 2005, and all its addenda are hereby cancelled; and

WHEREAS, the Company agrees to furnish to the Customer, and the Customer agrees to take from the Company, 18,000 kW of firm capacity and up to 19,000 kW of Advanced Time-of-Day (ATOD) interruptible capacity in accordance with the provisions of this Special Contract; and

WHEREAS, the Company foresees that it can supply 18,000 kW of firm capacity and up to 19,000 kW of ATOD interruptible capacity, requested by the Customer throughout the initial term of this Special Contract without requiring the construction of new generation or local facilities except for the purchase of the Dresden Plant; and

WHEREAS, in recognition of the need for the efficient use of existing utility generation and transmission facilities, the Company and the Customer agree to an interruptible rate design with time-of-use characteristics.

NOW THEREFORE, in consideration of the mutual covenants and agreements herein contained, and subject to the terms and conditions contained herein, the Company and the Customer agree as follows:

ARTICLE 1

DEFINITIONS

1.1 Whenever used herein, the following terms shall have the respective meanings set forth, unless a different meaning is plainly required by the context:

A. "AEP System Interconnection Agreement" shall mean the contractual arrangement or any successor thereto, by which the members of the AEP System share the costs of capacity to serve the customers of the AEP System Companies, as approved by the Federal Energy Regulatory Commission or any successor regulatory body.

B. "Commission" shall mean the Public Service Commission of West Virginia, the regulatory agency having jurisdiction over the retail electric service of the Company in West Virginia, including the electric service covered by this Special Contract, or any successor thereto.

C. "Customer" shall mean CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC.

D. "Special Contract" shall mean this Special Contract for electric service between the Company and the Customer, as the same may, from time to time, be amended. Said Special Contract is set forth in its entirety herein.

E. "Parties" shall mean the Company and the Customer.

F. "Party" shall mean either the Company or the Customer.

G. "Schedule I.P." shall mean the Company's Industrial Power Service Schedule, or any successor thereto, approved by the Commission.

H. "Customer Communications System" shall mean the computerized system allowing the exchange of information between the Company and the Customer.

I. "Maximum Capacity Reservation" shall refer to the maximum monthly Metered Demand in kW the Customer expects to place on the facilities of the Company during the term of the Special Contract.

J. "Firm Contract Capacity" shall refer to the maximum capacity to be supplied by and taken from the Company by the Customer on a firm basis.

K. "Firm Billing Energy" shall refer to the energy associated with the Firm Contract Capacity reservation.

L. “Interruptible Contract Capacity” shall refer to the maximum capacity to be supplied by and taken from the Company by the Customer on an interruptible basis.

M. “Interruptible Billing Energy” shall refer to all metered energy in excess of the Firm Billing Energy.

N. The “Metered Demand” in kW shall be taken each month as the single highest 30-minute integrated combined peak in kW as recorded during the month by meters on the Customer’s 138 kV Delivery Point.

O. The “Reactive Metered Demand” shall refer to the single highest 30-minute leading or lagging integrated combined reactive peak in kVAR as registered during the billing month by the meters on the 138 kV Delivery Point.

P. “Billing Energy” shall refer to all monthly-metered energy.

Q. “Advanced Time-of-Day” (“ATOD”) interruptible service offering shall mean the pricing concept that determines retail energy charges for the next day based upon projections of AEP system load.

R. “Expanded Net Energy Cost” (“ENEC”) shall refer to the cost components of the Company’s power supply that are subject to periodic rate adjustment approved by the Commission.

S. “Member Load Ratio” (“MLR”) shall refer to the ratio of the Company’s highest internal peak demand occurring during the previous twelve-months to the sum of the highest internal peak demands of all the operating company members of the AEP Interconnection Agreement, occurring during the previous twelve months, so long as the AEP System Interconnection Agreement or any successor agreement thereto is relevant and applicable.

1.2 Unless the context plainly indicates otherwise, words importing the singular number shall be deemed to include the plural number (and vice versa); terms such as "hereof," "herein," "hereunder" and other similar compounds of the word "here" shall mean and refer to the entire Special Contract rather than any particular part of the same. Certain other definitions, as required, appear in subsequent parts of this Special Contract.

ARTICLE 2

DELIVERY POINTS

2.1 Subject to the terms and conditions specified herein, the Company agrees to furnish to the Customer, during the term of this Special Contract, and the Customer agrees to take and pay for, all of the electric capacity and energy that shall be purchased by the Customer solely for consumption in the premises located at Ravenswood, West Virginia.

2.2 The Delivery Point for electric power and energy delivered hereunder shall be the point at which the Company's devices are metering the Customer's load, which are located within the Customer's 138kV substation.

ARTICLE 3

DELIVERY

3.1 The electric energy delivered hereunder to the 138 kV Delivery Point shall be three-phrase alternating current having a frequency of approximately 60 cycles per second at approximately 138,000 volts. The said electric energy shall be delivered and maintained reasonably close to constant potential and frequency and it shall be measured by meters owned and installed by the Company and located at the Customer's substation.

ARTICLE 4

CAPACITY RESERVATIONS

4.1 The Maximum Capacity Reservation contracted for by the Customer is fixed at 37,000 kW. The Customer shall not exceed the Maximum Capacity Reservation except by mutual agreement of the Parties or pursuant to Article 4.3 hereof.

4.2 The Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement.

4.3 Notwithstanding the provisions of Articles 4.1 and 4.2, the Customer may change the Maximum Capacity Reservation contracted for by providing the Company with one-year's written notice.

ARTICLE 5

DESIGNATION OF FIRM SERVICE

5.1 The Customer designates 18,000 kW of the Maximum Capacity Reservation specified in Article 4.1 as the Firm Contract Capacity, not subject to interruption as provided in Article 6, which shall be billed in accordance with the rates provided for in Article 10.

5.2 Firm Billing Energy during the billing period shall be the Customer's metered Billing Energy in any hour up to a maximum of 18,000 kWh, and shall be billed in accordance with the applicable rate provided for in Table 1 of Article 10.1.

ARTICLE 6

INTERRUPTIBILITY OF SERVICE

6.1 The Customer designates that a portion of the Maximum Capacity Reservation in excess of the Firm Contract Capacity as the Interruptible Contract Capacity.

6.2 The Company reserves the right to interrupt service to the Customer's load, down to the level of the Firm Contract Capacity, at any time and for such period of time that, in the sole judgment of the Company, an emergency condition exists on the AEP System or, the Company anticipates that it will establish a new internal peak demand that changes its Member Load Ratio (MLR), as applicable, or, during other such hours as the Company may otherwise reasonably determine.

6.3 The Company will provide the Customer as much advance notice as possible of interruptions of service described in Article 6.2; however, if so requested, the Customer shall interrupt service within ten minutes.

6.4 If the Customer receives notification from the Company of an interruption and fails to interrupt load as requested by the Company, the maximum uninterrupted demand in excess of the Firm Contract Capacity shall be billed at a rate equal to three times the Schedule I.P. transmission service related Demand Charge for that billing month.

6.5 The Company shall own all metering and telemetering equipment required for interruptible service and shall be responsible for maintaining and upgrading such equipment. The Customer agrees to expeditiously take such steps as may be necessary in order to use the Customer Communications System, and the Customer shall own and maintain all computer hardware required to meet the specifications of the Customer Communications System. The Company shall provide all software associated with the Customer Communications System. The Customer agrees to execute any documents necessary to license the use of the software by the Customer.

6.6 No responsibility or liability of any kind shall attach to or be incurred by the Company for, or on account of, any loss, cost, expense or damage caused by or resulting from, either directly or indirectly, an interruption of service under this Article and/or Article 14.

ARTICLE 7

DETERMINATION OF MONTHLY INTERRUPTIBLE BILLING ENERGY

7.1 Monthly P1 Interruptible Billing Energy shall be measured as the total kWh registered during each P1 Billing Hour of the month by the Company's energy meters, less the Firm Billing Energy for that hour as specified in Article 5.2. P1 Billing Hours comprise those hours when the internal load of the AEP System is projected to be less than or equal to 80% of the AEP System's annual internal peak load occurring during the previous three calendar years.

7.2 Monthly P2 Interruptible Billing Energy shall be measured as the total kWh registered during each P2 Billing Hour of the month by the Company's energy meters, less the Firm Billing Energy for that hour as specified in Article 5.2. P2 Billing Hours comprise those hours when the internal load of the AEP System is projected to be greater than 80% but less than or equal to 90% of the AEP System's annual internal peak load occurring during the previous three calendar years.

7.3 Monthly P3 Interruptible Billing Energy shall be measured as the total kWh registered during each P3 Billing Hour of the month by the Company's energy meters, less the Firm Billing Energy for that hour as specified in Article 5.2. P3 Billing Hours comprise those hours when the internal load of the AEP System is projected to be greater than 90% but less than or equal to 95% of the AEP System's annual internal peak load occurring during the previous three calendar years.

7.4 Monthly P4 Interruptible Billing Energy shall be measured as the total kWh registered during each P4 Billing Hour of the month by the Company's energy meters, less the Firm Billing Energy for that hour as specified in Article 5.2. P4 Billing Hours comprise those hours when the internal load of the AEP System is projected to be greater than 95% of the AEP System's annual internal peak load occurring during the previous three calendar years.

7.5 All billing hours to the Customer under Article 7 shall be based on the projections of internal load pursuant to Article 7.6 hereof and shall be unaffected by actual internal load.

7.6 The Company shall make available to the Customer by no later than 12:00 noon local time of the preceding day, the Company's projection of whether each hour of a succeeding day for the purpose of Articles 7.1, 7.2, 7.3, 7.4 and 7.7 will be a P1, P2, P3, P4 or P2.5 billing hour. It is the intent of this Article that the Customer will know at least twelve hours before the commencement of each day what billing hour classification will be applicable for each hour of that day.

7.7 If the Company forecasts more than a total of six P3 and/or P4 hours for any day, the Company will select only six (6) hours to be priced at the P3 and/or P4 level. The remaining hours initially forecast as P3 and/or P4 will be reclassified as P2.5 billing hours and priced at the P2.5 rate set forth in Table 1 of Article 10.1 of this Special Contract (hereinafter P2.5 hours).

7.8 If the Company determines that a significant change has occurred in the availability of system capacity or in the AEP System's internal load, such that a reclassification of the hours initially forecast as either P3 or P4 would not be detrimental to the Company, the Company may reclassify the hours as P2.5 hours and the applicable price will be the P2.5 rate set forth in Table 1 of Article 10.1 of this Special Contract. In the event the Company elects to reassign such periods, the Customer will be provided as much notice as possible.

ARTICLE 8

DETERMINATION OF MONTHLY INTERRUPTIBLE BILLING DEMAND

8.1 The Monthly Interruptible Billing Demand shall be taken each month as the greater of: (1) the monthly Metered Demand less the Firm Contract Capacity during the current billing period, rounded up to the nearest 1000 kilowatts or (2) the highest Monthly Interruptible Billing Demand established during the past eleven (11) months.

ARTICLE 9

DETERMINATION OF MONTHLY REACTIVE BILLING DEMAND

9.1 The monthly Reactive Billing Demand shall be taken each month as the maximum leading or lagging Reactive Metered Demand in kVAR in excess of fifty percent of the maximum monthly Metered Demand in kW.

ARTICLE 10

RATES

10.1 All kW demands and the kWh associated with capacity delivered through the 138 kV Delivery Point, shall be rendered at the following rates and charges, which may change as provided in Articles 10.3, 10.4 and 14:

Table 1

Charges	ENEC Rate Component	Base Rate Component	Totals
Monthly Service Charge	--	$1200.00	$1200.00
Monthly Firm Capacity Charge (per kW of Firm Contract Capacity)	$3.347	$9.580	$12.927
Monthly Construction Surcharge (per kW of Metered Demand)	--	$0.374	$0.374
Monthly Firm Billing Energy Charge	$0.03130	$0.00223	$0.03353
Monthly Interruptible Capacity Charge (per kW of Monthly Interruptible Billing Demand)	$3.347	$1.195	$4.542
ATOD Energy Charges:			
All kWh consumed during P1 billing hours	$0.03130	$0.01428	$0.04558
All kWh consumed during P2 billing hours	$0.03130	$0.02714	$0.05844
All kWh consumed during P3 billing hours	$0.03130	$0.14196	$0.17326
All kWh consumed during P4 billing hours	$0.03130	$2.8337	$2.865
All kWh consumed during P2.5 billing hours	$0.03130	$0.03785	$0.06915
Monthly Reactive Demand Charge (per kVAR of Monthly Reactive Billing Demand)	--	$0.70	$0.70
Monthly EE/DR Surcharge, unless opting out	--	$0.000369	$0.000369

10.2 It is understood and agreed that the Company may, from time to time, either upon its own initiative or as directed by the Commission, file for changes in the ENEC rate components set forth in Table 1 of Article 10.1. Any changes in the ENEC rate components approved by the Commission shall replace the ENEC rate components, and the total rates shall be adjusted accordingly to reflect the change in the ENEC recovery components and shall be applied to all service rendered under this Special Contract on and after the effective date for the changes specified by the Commission.

10.3 It is understood and agreed that the Company may, from time to time, either upon its own initiative or as directed by the Commission, file for changes in the Monthly Construction Surcharge as set forth in Table 1 of Article 10.1. Any changes in the surcharge approved by the Commission shall replace the applicable surcharge rate, and the total rates shall be adjusted accordingly and shall be applied to all service rendered under this Special Contract on and after the effective date for the changes specified by the Commission.

10.4 It is understood and agreed that the Company may, from time to time, either upon its own initiative or as directed by the Commission, file for changes in the Base Rates as set forth in Table 1 of Article 10.1. Any changes in the Base Rates approved by the Commission shall replace the respective Base Rates, and the total rates shall be adjusted accordingly and shall be applied to all service rendered under this Special Contract on and after the effective date for the changes specified by the Commission.

10.5 If during the term of the Special Contract, the Commission approves any additional surcharges (positive or negative) applicable to service to the Customer, such surcharges shall become applicable to sales to the Customer on and after the effective date for the changes specified by the Commission.

ARTICLE 11

DETERMINATION OF MONTHLY BILL

11.1 The Monthly Bill shall be the sum of the following:

A. The Monthly Service Charge;

B. The product of the Firm Contract Capacity and the Monthly Firm Capacity Charge set forth in Table 1 of Article 10.1;

C. The product of the Metered Demand and the Monthly Construction Surcharge set forth in Table 1 of Article 10.1;

D. The product of the Firm Billing Energy and the Monthly Firm Billing Energy Charge set forth in Table 1 of Article 10.1;

E. The product of the Monthly Interruptible Billing Demand and the Monthly Interruptible Contract Capacity Charge set forth in Table 1 of Article 10.1;

F. The product of the Monthly P1 Billing Energy and the ATOD Energy Charge applicable to P1 billing hours as set forth in Table 1 of Article 10.1;

G. The product of the Monthly P2 Billing Energy and the ATOD Energy Charge applicable to P2 billing hours as set forth in Table 1 of Article 10.1;

H. The product of the Monthly P3 Billing Energy and the ATOD Energy Charge applicable to P3 billing hours as set forth in Table 1 of Article 10.1;

I. The product of the Monthly P4 Billing Energy and the ATOD Energy Charge applicable to P4 billing hours as set forth in Table 1 of Article 10.1;

J. The product of the Monthly P2.5 Billing Energy and the ATOD Energy Charge applicable to P2.5 billing hours as set forth in Table 1 of Article 10.1;

K. The product of the Monthly Reactive Billing Demand and the Monthly Reactive Demand Charge set forth in Table 1 of Article 10.1;

L. Any applicable EE/DR Surcharge, unless the Customer opts-out from paying such surcharge;

M. Any charges specified in Article 6.5 resulting from the failure of the Customer to interrupt load when requested by the Company;

N. Any surcharges (positive or negative) subsequently approved by the Commission and consistent with the provisions of Article 10.5; and

O. Any applicable taxes.

11.2 Service under this Special Contract is subject to a Monthly Minimum Charge equal to the sum of the Monthly Service Charge, the Monthly Firm Capacity Charge, the Monthly Firm Construction Surcharge, the Monthly Interruptible Capacity Charge, and the Monthly Interruptible Special Construction Charge, except as modified for certain contingencies as set forth in Article 19.

ARTICLE 12

BILLING, PAYMENT AND RECORDS

12.1 Bills computed under this Special Contract are due upon receipt. Any amount due and not received at the Company by the last pay date shown on the bill shall be subject to a Delayed Payment Charge of 1%. The last pay date shown on the bill shall be 20 days following the date of bill preparation.

12.2 If the Customer disputes the accuracy of a Bill, timely payment of the Bill, as rendered, shall be made, unless the Company expressly waives payment of the disputed portion of the bill pending resolution of the dispute. The parties shall use their best efforts to resolve the dispute and shall make such adjustment, if any, by credit or additional charge on the next Bill rendered. If it is determined that a credit is due to the Customer of the disputed amount timely paid by the Customer, and if that credit is not made on the next Bill rendered, then the Company shall include interest on the amount of the credit calculated at the rate of six percent (6%) per annum, accrued from the date of payment until the date the credit is included in the Customer's Bill. The existence of a dispute as to any Bill shall not relieve either Party of compliance with the terms of this Special Contract. Other than as required by law or regulatory action, Bill adjustments must be made within six months of the rendering of the initial Bill.

12.3 If the Customer fails or refuses to pay the Bill rendered by the Company in accordance with the provisions of the Special Contract, the Company may, after ten (10) days' written notice, suspend the delivery of capacity and energy to the Customer until all Bills, together with the Delayed Payment Charge as computed under the provisions of Article 12.1, shall have been paid. Any such suspension of delivery of capacity and energy to the Customer shall not relieve the Customer from liability to continue the payment of the Monthly Minimum Charge as specified in Article 11.2 and shall not terminate this Special Contract.

ARTICLE 13

EFFECTIVE DATE AND TERM OF SPECIAL CONTRACT

13.1 The effective date of this Special Contract shall be August 1, 2011.

13.2 The term of this Special Contract shall be for an initial period of 3 years, and shall remain in effect thereafter until either Party shall give at least one year's written notice to the other of the intention to terminate this Special Contract. The initial period shall commence on the effective date of the Special Contract as established under Article 13.1. Each Party may avail itself of its respective legal rights in effect at the time of the expiration of this Special Contract.

13.3 The Customer is also required to provide at least one-years' written notice prior to transferring to firm service under any of the Company's applicable tariffs as filed with the Commission. Concurrent with providing said notice to transfer to firm service, the Customer will enter into a firm service contract or agreement that will become effective at the end of the notice period.

ARTICLE 14

SERVICE CONDITIONS

14.1 Each Party shall exercise reasonable care to maintain and operate, or to cause to be maintained and operated, their respective facilities in accordance with good engineering practices.

14.2 To the extent not specifically modified by this Special Contract, the Company's Terms and Conditions of Service, on file with the Commission, are incorporated herein by reference and made a part hereof. The Customer acknowledges receipt of the currently approved Terms and Conditions of Service. In the event of a conflict between the provisions of this Special Contract and the provisions of the Company's Terms and Conditions of Service, the provisions of this Special Contract shall control.

14.3 In addition to the interruptibility provisions set forth in Article 6, any service being provided under this Special Contract may be interrupted or reduced (a) by operation of equipment installed for power system protection, (b) after adequate notice to and consultation with the Customer for routine installation, maintenance, inspection, repairs, or replacement of equipment or (c) when such action is necessary to preserve the integrity of, or to prevent or limit any instability or material disturbance on, or to avoid a burden on, its electric system or an interconnected system.

14.4 The Company reserves the right to disconnect from its system the Customer's conductors or apparatus without notice when, in the exercise of reasonable care, the Company determines that it is necessary in the interest of preserving or protecting life and/or property.

14.5 During the term hereof, the Customer's plant shall not be connected to any outside source of electric power other than the Delivery Points described in Articles 2.2, without written notice and mutual agreement between the Parties.

14.6 The Customer shall, as soon as possible after discovery of any impairment of or defect in the Company's service that significantly disrupts the Customer's operations, notify the Company, and the Customer shall confirm such notice in writing by the close of the next business day. The Company shall not be liable for any loss, injury or damage that could have been prevented by timely notice of a defect or impairment of service.

14.7 The Customer shall notify the Company in advance of any changes to be made to the Customer's plant that have the potential of materially affecting the Company's system.

ARTICLE 15

METERING

15.1 Electric power and energy delivered under this Special Contract shall be measured by metering equipment owned, installed, operated and maintained by the Company.

15.2 Any Party on whose property another Party's equipment is to be located under this Special Contract shall furnish suitable space without cost to the equipment owner. All such equipment shall retain its character as personal property of the owner regardless of its method of attachment to any other property, and authorized representatives of the owner shall have access thereto at all reasonable times. Upon termination of this Special Contract, all such equipment shall be removed by its owner from the premises on which it is located.

15.3 The Company shall at all times have the right to inspect and test meters and, if found defective, to repair or replace them at its option. Meters shall be tested periodically in accordance with the Commission's Regulations. The Company shall inspect and test such meters once each calendar year, at the expense of the Company. If the Customer shall request a test of such meters more frequently than provided in the Commission's Regulations, the Customer shall bear the expense of such additional test, except that if the meters are found to be inaccurate in excess of the standard prescribed by the Commission, the Company shall bear the expense of such test.

15.4 If any test of metering equipment discloses an inaccuracy exceeding two percent, the Customer's account shall be adjusted in accordance with the Regulations prescribed by the Commission.

15.5 The Company shall repair and re-test or replace a defective meter within a reasonable time.

15.6 Should any metering equipment fail to register, or register only minimally, the amounts of energy and capacity delivered shall be estimated based upon use of energy and/or demand for power in a similar period of like use or other data available to the Company.

ARTICLE 16

REGULATORY AUTHORITIES

16.1 The Parties hereto recognize that this Special Contract is subject to the jurisdiction of the Commission, and is also subject to such lawful action, as any regulatory authority having jurisdiction shall take hereafter with respect thereto. The performance of any obligation of either Party hereto shall be subject to the receipt from time to time as required of such authorizations, approvals or actions of regulatory authorities having jurisdiction as shall be required by law.

16.2 The Company and the Customer agree that this Special Contract reflects the steps required to insure adequate service to the Customer and that the Company will file this Special Contract with the Commission. This Special Contract is expressly conditioned upon the acceptance by the Commission without change or condition. In the event that the Commission does not accept this Special Contract, then this Special Contract shall not become effective, unless the Parties agree otherwise in writing, it being the intent of the Parties that such acceptance, without change or condition, is a prerequisite to the validity of this Special Contract.

16.3 The Parties expressly agree and understand that the Commission has jurisdiction over the rates and charges contained herein.

ARTICLE 17

GENERAL

17.1 Any waiver at any time of any rights as to any default or other matter arising hereunder shall not be deemed a waiver as to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right hereunder shall not be deemed a waiver of such right.

17.2 In the event that any of the provisions, or portions thereof, of this Special Contract is held to be unenforceable or invalid by any court of competent jurisdiction, the validity and enforceability of the remaining provisions, or portions thereof, shall not be affected thereby.

17.3 All terms and stipulations made or agreed to regarding the subject matter of this Special Contract are completely expressed and merged in this Special Contract, and no previous promises, representations or agreements made by, or on behalf of, the Company or the Customer shall be binding on either Party unless contained herein.

17.4 The Parties agree that the terms and conditions of this Special Contract, including, but not limited to, the rates set forth in Table 1 of Article 10.1, shall be treated as confidential and shall be protected from disclosure to the fullest extent possible under the law.

17.5 The rights and remedies granted under this Special Contract shall not be exclusive rights and remedies but shall be in addition to all other rights and remedies available at law or in equity.

17.6 The validity and meaning of this Special Contract shall be governed by the laws of the State of West Virginia.

ARTICLE 18

ASSIGNMENT

18.1 This Special Contract shall inure to the benefit of and be binding upon the successors and assigns of the Parties.

18.2 This Special Contract shall not be assigned by either Party without the written consent of the other Party. Such consent shall not be unreasonably withheld.

18.3 Any assignment by one Party to this Special Contract shall not relieve that Party of its financial obligation hereunder unless the other Party to this Special Contract so consents in writing. Such consent shall not be unreasonably withheld.

ARTICLE 19

LIABILITY AND FORCE MAJEURE

19.1 Neither the Company nor the Customer shall be liable to the other for damages caused by the interruption, suspension, reduction or curtailment of the delivery of electric energy hereunder due to, occasioned by or in consequence of, any of the following causes or contingencies, (hereinafter "events of Force Majeure") viz: acts of God, the elements, storms, hurricanes, tornadoes, cyclones, sleet, floods, backwaters caused by floods, lightning, earthquakes, landslides, washouts or other revulsions of nature, epidemics, accidents, fires, failures of facilities, collisions, explosions, strikes, lockouts, differences with workers and other labor disturbances, vandalism, sabotage, riots, inability to secure cars, coal, fuel, or other materials, supplies or equipment from usual sources, breakage or failure of machinery, generating equipment, electrical lines or equipment, wars, insurrections, blockades, acts of the public enemy, arrests and restraints of rulers and people, civil disturbances, acts or restraints of federal, state or other governmental authorities, and any other causes or contingencies not within the control of the Party whose performance is interfered with, whether of the kind herein enumerated or otherwise. It is expressly understood and agreed that economic conditions, such as a downturn in the market for the product or products produced at any of the Customer's facilities, do not constitute an event of Force Majeure. Settlement of strikes and lockouts shall be wholly within the discretion of the Party having the difficulty. An event or events of Force Majeure shall not relieve the Company or the Customer of liability in the event of its concurring negligence or in the event of failure of either to use reasonable means to remedy the situation and remove the cause in an adequate manner and with reasonable dispatch. An event or events of Force Majeure shall not relieve either the Company or the Customer from its obligation to pay amounts due hereunder, except as follows:

A. If the Company experiences an event or events of Force Majeure, then the Customer's obligation to pay the Monthly Service Charge, the Monthly Firm

Capacity Charge, the Monthly Special Construction Charge, and the Monthly Interruptible Capacity Charge provided for hereunder shall be suspended when both of the following criteria are met; 1.) The Company is unable to deliver electric energy to the Delivery Point designated hereunder as a result of such causes and contingencies; and 2.) The interruption in the delivery of electric energy exceeds fifteen (15) calendar days. The suspension period shall begin on the sixteenth day following such an interruption and extend until service is restored. The Monthly Service Charge, the Monthly Firm Capacity Charge, the Monthly Construction Surcharge, and the Monthly Interruptible Capacity Charge owed by the Customer to the Company in any month that does not fall entirely within this suspension period shall be prorated using the number of calendar days in that month.

B. Except as otherwise addressed in Article 19.1.C, should the Customer experience an event or events of Force Majeure, then the Customer shall issue a written declaration to the Company within fourteen (14) days of its occurrence. The Customer's obligation to pay the Monthly Service Charge, the Monthly Firm Capacity Charge, the Monthly Construction Surcharge, and the Monthly Interruptible Capacity Charge provided for hereunder shall continue for a period of six (6) months after such written declaration. The Customer shall notify the Company, in writing, within six (6) months of the date of its written declaration of its election of one (1) of the following two (2) options:

(1) Beginning six (6) months after the issuance of its written declaration, through the remaining term of the Special Contract, the Customer may reduce its Maximum Capacity Reservation to a level consistent with the effects of the event or events of Force Majeure, but in no event shall the Maximum Capacity Reservation be reduced below ten (10) MW. Such an election shall reduce the Company's obligation to provide such capacity. If the Customer elects this option, the Company shall prorate the Customer's Monthly Interruptible Capacity Charge and the Monthly Construction Surcharge during the applicable billing months to reflect the Customer's reduced Maximum Capacity Reservation, but all other charges shall be as stated in this Special Contract.

(2) Alternatively, the Customer may elect to suspend all or part of its Maximum Capacity Reservation, for up to a maximum of six (6) months, and establish a temporary Maximum Capacity Reservation at a level consistent with the effects of the event or events of Force Majeure. Such an election shall also suspend the Company's obligation to provide such capacity for the period selected by the Customer. If the Customer elects this option, the Company shall prorate the Customer's Monthly Interruptible Capacity Charge and the Monthly Construction Surcharge during the applicable billing months to reflect the suspension of all or part of the Maximum Capacity Reservation, but all other charges shall be as stated in this

Special Contract. Regardless of whether the Force Majeure situation has been corrected, the Customer's obligation to pay the full amount of the Monthly Interruptible Capacity Charge and the Monthly Construction Surcharge provided for hereunder shall re-commence as of the end of the suspension period chosen by the Customer.

Should the Customer fail to provide the Company of its written election of either of the above two (2) options within six (6) months of its written declaration of an event or events of Force Majeure, the Customer will be billed in accordance with the terms of this Special Contract during the remainder of its term.

C. (1) Notwithstanding any other Article or provision of this Special Contract, during the term of this Special Contract, the Customer shall issue a written declaration to the Company within two (2) days of the occurrence of a strike. Beginning thirty (30) days following the issuance of its written declaration, through the end of the strike or the remaining term on the Contract, the Customer may elect to reduce its contract capacity to a level consistent with the effects of the strike, but in no event shall the contract capacity be reduced below seven (7) MW. Such an election shall reduce the Company's obligation to provide such capacity. Moreover, for the purposes of determining any minimum billing demand obligation under this Special Contract after the effective date of a reduction in contract capacity, coincident with the effective date of such reduction the

Company shall adjust downward the prior eleven (11) months billing demands included in the Customer's highest previously established monthly billing demand during the past 11 months by an amount equivalent to the requested reduction in contract capacity, but not lower than seven (7) MW. All other charges shall be as stated in this Special Contract.

(2) Should the Customer reduce its contract capacity in accordance with the paragraph above, the Customer may elect to increase its contract capacity by issuing a written declaration to the Company at least thirty (30) days prior to the effective date of such increase. The written declaration shall specify the increased contract capacity in whole MWs, up to 37 MWs. The Customer shall not increase its usage prior to the date specified in the thirty (30) day notice unless authorized by the Company in writing.

19.2 The Company assumes no responsibility of any kind with respect to construction, maintenance or operation of the electric facilities or other property owned or used by the Customer and shall not be liable for any loss, injury (including death), damage to or destruction of property (including loss of use thereof) arising out of such installation, maintenance or operation or out of any use by the Customer or others, of said energy and/or capacity provided by the Company except to the extent such damage or injury shall be caused by the negligence or willful misconduct of the Company, its agents, or employees. The Customer assumes no responsibility of any kind with respect to construction, maintenance or operation of the electric facilities or other property owned or used by the Company and shall not be liable for any loss, injury (including death), damage to or destruction of property (including loss of use thereof) arising out of such installation, maintenance or operation except to the extent such damage or injury shall be caused by the negligence or willful misconduct of the Customer, its agents, or employees.

19.3 To the extent permitted by law, the Customer shall protect, defend, indemnify, and hold harmless the Company from and against any losses, liabilities, costs, expenses, suits, actions, claims, and all other obligations and proceedings whatsoever, including, without limitation, all judgments rendered against and all fines and penalties imposed upon the Company, arising out of injuries to persons, including death, or damage to third-party property, to the extent caused by, or occurring in connection with any willful or negligent act or omission of the Customer, its employees, agents or contractors, or which are due to or arise out of defective electrical equipment belonging to the Customer. Neither the Company nor the Customer shall be liable for any indirect, special, incidental or consequential damages, including loss of profits due to business interruptions or otherwise, in connection with this Special Contract. To the extent permitted by law, the Company shall protect, defend, indemnify, and hold harmless the Customer from and against any losses, liabilities, costs, expense, suits, actions, claims, and all other obligations whatsoever, including, without limitation, all judgments rendered against and all fines and penalties imposed upon the Customer, arising out of injuries to persons, including death, or damages to third-party property, to the extent caused by or occurring in connection with any willful or negligent act or omission of the Company, its employees, agents or contractors. The Company shall not be responsible or liable for any indirect, special, incidental or consequential damages, including loss of profits due to business interruptions in connection with this Special Contract.

19.4 Any indemnification of the Parties or any limitation of the Parties' liability which is made or granted under this Special Contract shall to the same extent apply to the Party's directors, officers, partners, employees and agents, and to the Party's affiliated companies, including any directors, officers, partners, employees and agents thereof.

IN WITNESS WHEREOF, the Parties hereto have caused this Special Contract to be duly executed the day and year first above written.

APPALACHIAN POWER COMPANY	CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC
By *Charles Patton*	By [illegible]
Title *President & COO*	Title *CEO RAVENSWOOD*
Date *9-6-11*	Date *11/17/2011*

State of *West Virginia*, City of *Charleston*. The foregoing instrument was acknowledged before me this *6th* of *September*, 2011 by Charles R. Patton President and COO of APPALACHIAN POWER COMPANY, a Virginia Corporation, on behalf of the Corporation.

Notary Public in and for said *Kanawha County* City. My Commission expires *October 2, 2019*.

OFFICIAL SEAL
STATE OF WEST VIRGINIA
NOTARY PUBLIC
DOROTHY E. PHILYAW
APPALACHIAN POWER
PO BOX 1986
CHARLESTON, WV 25327-1986
My commission expires October 2, 2019

State of *West Virginia*, City of *Ravenswood*. The foregoing instrument was acknowledged before me this *17* of *November*, 2011 by *Kyle Lorentzen*, *CEO* of CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC.

Notary Public in and for said *Jackson County* City. My Commission expires *February 11, 2021*.

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
HANNAH J. HERN
17 1st Avenue
Ravenswood, West Virginia 26164
My Commission Expires Feb. 11, 2021

Exhibit A

AMERICAN ELECTRIC POWER SYSTEM
INTERRUPTION SEQUENCE DURING CAPACITY DEFICIENCIES

Real Time Pricing IRP

Hourly Energy Sales

Surplus Energy Sales

Opportunity Sales IRP

Multi-Hour Energy Sales

Capacity Deficiency B IRP

Current Tariff IRP Customers

Capacity System Sales

Capacity Deficiency A IRP

ATOD Customers

Emergency Sales

Voluntary Firm Load Curtailments

Mandatory Firm Load Curtailments

Constellium-Ravenswood Exhibit DS-D REDACTED [REVISED]

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

REDACTED

DIRECT TESTIMONY

OF

DEREK SCANTLIN

[REVISED]

ON BEHALF OF

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

JUNE 28, 2016

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

REDACTED DIRECT TESTIMONY OF DEREK SCANTLIN [REVISED]

Q. Please state your name and business address.

A. My name is Derek Scantlin. My business address is 859 Century Road, P.O. Box 68, Ravenswood, West Virginia, 26164-0068.

Q. By whom are you employed?

A. I am employed by Constellium Rolled Products Ravenswood, LLC ("Constellium-Ravenswood").

Q. What is your position with Constellium-Ravenswood?

A. I am the Chief Financial Officer ("CFO") of Constellium-Ravenswood. As CFO, my primary role is to provide financial leadership and oversight over all financial and accounting activities at Ravenswood, including cash management, audit, compliance, reporting, and analysis.

Q. Please describe your educational and employment background.

A. I have an MBA as well as a BA and MS in mechanical engineering. I have over 27 years of business experience, having worked in the metals industry for the past 21 years in various financial leadership roles with aluminum rolling and recycling companies. I have been CFO of Constellium-Ravenswood since March 17, 2014. Prior to joining Constellium-Ravenswood, I was Vice President of Finance for another major U.S. aluminum rolling company.

Q. Please provide a brief history of Constellium-Ravenswood.

A. Constellium-Ravenswood began operations in Ravenswood, West Virginia, in 1957, and is currently one of the largest rolled aluminum products facilities in the world, producing plate, sheet, and coil aluminum products for a wide range of industrial uses, including aerospace, defense, transportation, and marine.

Q. Please discuss the Constellium-Ravenswood facility's impact on the state and local economy.

A. Constellium-Ravenswood currently employs over 1,100 people at the rolling mill with an annual payroll of approximately $78.4 million. Constellium-Ravenswood paid over $5 million in taxes and other fees last year to the local economy and spends approximately $31 million annually to vendors based inside of West Virginia. Constellium-Ravenswood employees participate in and donate funds to several local organizations. Constellium-Ravenswood also provides over **[Begin Confidential** [redacted] **End Confidential]** of medical benefits and pension payments to 5,600 former employees.

Q. Are you aware of the issues that gave rise the Complaint filed by Constellium-Ravenswood in this case?

A. Yes. I have been involved with this matter from the time that APCo contacted Constellium-Ravenswood early in 2015 and then subsequently informed us verbally of their demand for a security deposit in mid-2015. APCo followed that verbal demand, after subsequent discussions, with a written demand for security deposit payment on November 10, 2015.

Q. Did APCo contact you directly?

A. Yes. Mr. Alan Bragg, Manager – Customer Services at APCo, contacted us throughout this time to discuss APCo's demand for a security deposit, along with other APCo representatives.

Q. Based on the communications that occurred in 2015, what is your understanding of the basis for APCo's security deposit demand?

A. My understanding is that APCo determined that Constellium-Ravenswood's indirect parent company, Constellium N.V., posed a risk of bankruptcy, and therefore, according to APCo, Constellium-Ravenswood posed a risk of defaulting on its electricity payment obligations. My understanding is that this assessment was based on APCo's review of the reports of commercial credit agencies of the available credit of Constellium N.V., not Constellium-Ravenswood. This resulted in their demand for a security deposit payment from Constellium-Ravenswood of $1,766,000.

Q. Why did APCo not use available credit data for Constellium-Ravenswood?

A. Constellium-Ravenswood is not a publically traded company and as such does not have independent credit ratings. Constellium-Ravenswood is a wholly-owned subsidiary of Constellium US Holdings I, LLC, which is, in turn, a wholly-owned subsidiary of Constellium N.V. (In addition to this structure, there are two additional European holding companies between Constellium N.V. and Constellium US Holdings I, LLC, meaning that there are at least three tiers of corporate structure separating Constellium-Ravenswood from Constellium N.V.)

Q. Did APCo provide an explanation of the precise credit data that APCo used to make its assessment of Constellium N.V.'s (and indirectly, Constellium-Ravenswood's) financial condition?

A. No. Mr. Bragg only indicated that APCo used reports by ratings agencies "such as Moody's, Standard and Poor's and others," and stated "as an example" that APCo used "a tool developed to forecast the probability of bankruptcy occurring within the next 12 months." APCo did not specify what this "tool" was; however, APCo later indicated in its Answer to Constellium-Ravenswood's Complaint that this tool is "proprietary."

Q. Does Constellium-Ravenswood have access to this "proprietary tool?"

A. No.

Q. Did Constellium-Ravenswood agree to pay APCo the demanded security deposit?

A. No. We believed at the time that there was no basis in fact, or in the provisions of either the Special Contract or APCo's tariff, for APCo's demand; however, we continued to discuss this matter with APCo until we became aware of APCo's request to modify the Terms and Conditions of its tariff related to security deposits in the separate proceeding at Case No. 15-1673-E-T. Based on our analysis of APCo's filing in that proceeding, it became obvious to us that Constellium-Ravenswood was at risk of never having a security deposit returned if we agreed to APCo's demand and if APCo's proposal in that proceeding was approved. At that point, APCo threatened to bill Constellium-Ravenswood for the demanded security deposit and indicated that APCo might terminate service to Constellium-Ravenswood if we did not pay the security deposit. Constellium-Ravenswood then filed its Complaint in this case.

Q. Does the credit worthiness or financial viability of Constellium N.V. have any direct impact on Constellium-Ravenswood's financial viability?

A. No. Constellium-Ravenswood operates as a standalone business maintaining its own **[Begin Confidential** [redacted] **End Confidential]** revolving credit facility to provide additional liquidity as needed to manage the day-to-day cash requirements of the business.

Q. Was Constellium-Ravenswood at risk of filing for bankruptcy in May 2015 or at any time between May 2015 and when Constellium-Ravenswood filed its complaint in this case?

A. No. During this period Constellium-Ravenswood generated sufficient profitability and liquidity to satisfy all of its financial obligations on a timely basis.

Q. Is Constellium-Ravenswood currently at risk of filing for bankruptcy?

A. No. Constellium-Ravenswood continues to generate cash flow to fund operations and invest for the future. Constellium-Ravenswood is currently funding an expansion of over $30 million to increase its production of aluminum plate for aerospace and military applications. Constellium-Ravenswood is a key supplier of aluminum plate to all of the major airplane manufacturers and its plate production capabilities are unmatched by its competitors. Additionally, Constellium-Ravenswood has long-term supply agreements for aluminum sheet and plate in place with several customers.

Q. Has Constellium N.V. filed for bankruptcy since May 2015?

A. No. Constellium N.V. has not filed for bankruptcy in the 14 months since May 2015, despite APCo's predictions. Furthermore, Constellium N.V. just completed a senior secured note offering in March 2016 for $425 million, further improving the company's liquidity position. As such, APCo's "proprietary tool" for predicting that Constellium N.V. might file for bankruptcy was clearly inadequate and based on faulty data – data that was entirely outside of <u>Constellium-Ravenswood's</u> control. Moreover, during this entire period Constellium-Ravenswood has continued to timely pay all bills to APCo and has never been remotely close to defaulting on its electricity payment obligations.

Q. If Constellium-Ravenswood is required to remit payment of a security deposit to APCo, what impact might that have on Constellium-Ravenswood?

A. This would immediately reduce our liquidity and result in Constellium-Ravenswood borrowing from our revolving credit facility. We would incur additional interest expense and it would reduce our ability to fund operations and invest in growth projects.

Q. APCo has suggested that Constellium-Ravenswood could alternatively provide a Surety Bond or Irrevocable Letter of Credit instead of payment of a cash security deposit. Does this alleviate the impact on Constellium-Ravenswood?

A. No. These alternatives still reduce Constellium-Ravenswood's liquidity, are costly, and essentially have the same impact on Constellium-Ravenswood as a cash deposit payment.

Q. The Commission has suggested that pre-payment of electric bills might be a viable alternative to Constellium-Ravenswood providing a security deposit. Is this an acceptable solution?

A. Unfortunately, it is not.

First, it is simply unnecessary. As a matter of fact, Constellium-Ravenswood has continued its impeccable record of timely paying its bills from APCo since first learning of APCo's security deposit demand and throughout the duration of this dispute with APCo. As Constellium-Ravenswood witness Mr. Victus Rose notes, this record of on-time or early payments now exceeds 10 years.

Second, as I previously explained, Constellium-Ravenswood is not at risk of defaulting on its payment obligations to APCo, and the financial condition of Constellium N.V. does not impact Constellium-Ravenswood's ability to keep these obligations.

Third, pre-payment for electric service is neither workable nor reasonable for Constellium-Ravenswood. This alternative effectively reduces our liquidity and would result in additional interest expense.

Q. **Do you believe APCo's demand to Constellium-Ravenswood is reasonable when balanced against the potential harm to Constellium-Ravenswood?**

A. No. The request is not reasonable on its face given the experience that APCo has with our impeccable payment record, but it is even more egregious when balanced against the potential financial harm to our business, our employees, our suppliers and vendors, our customers, and the West Virginia economy.

Q. **You've discussed the <u>potential</u> costs to Constellium-Ravenswood if it is required to remit a security deposit or some other instrument to APCo. Has APCo's demand already had an impact on Constellium-Ravenswood?**

A. Yes. This issue is a distraction for management, taking critical time and resources away from running our business. Moreover, we have already incurred thousands of dollars in legal fees and will continue to incur them as APCo continues to pressure us with their unreasonable demand.

Q. What do you hope the Commission will do in this case?

A. Constellium-Ravenswood asks that the Commission require APCo to cease and desist from demanding a security deposit, or any other form of security, from Constellium-Ravenswood.

Q. Does this conclude your Direct Testimony?

A. Yes.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

REBUTTAL TESTIMONY AND EXHIBIT OF RICHARD A. BAUDINO

ON BEHALF OF

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

J. KENNEDY AND ASSOCIATES, INC.

JULY 12, 2016

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

REBUTTAL TESTIMONY OF RICHARD A. BAUDINO

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to J. Kennedy and Associates.

Q. Did you submit Direct Testimony in this proceeding?

A. Yes. I submitted Direct Testimony on behalf of Constellium Rolled Products Ravenswood, LLC ("Constellium-Ravenswood")

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to address certain points raised in the Direct Testimony filed by Appalachian Power Company ("APCo" or "Company"). Specifically, I will respond to certain portions of the Direct Testimony of Mr. Alan Bragg and Mr. Gregory Holland. APCo also submitted testimony by Mr. Russell Ray Johnson III, an attorney who provided his assessment of bankruptcy law. I am not an attorney and will not be addressing Mr. Johnson's testimony; however, I understand from discussions with counsel that Constellium-Ravenswood does not agree with Mr. Johnson's legal analysis and may address this at the hearing or in its briefs in this case.

Q. Before you discuss the specific points raised in APCo's Direct Testimony, what general comments do you have with respect to that testimony?

A. APCo's Direct Testimony failed to address the main points I raised in my Direct Testimony, which are as follows:

- APCo's proposed security deposit violates certain Commission Rules governing security deposits.
- APCo's proposed security deposit violates the currently effective contract with Constellium-Ravenswood.
- APCo's demand for a security deposit is arbitrary, capricious, and unreasonable.

I will now proceed to discuss certain points raised by APCo's witnesses in response to the Complaint.

Q. Please refer to page 3, lines 15 through 18 of Mr. Bragg's Direct Testimony. He testified that APCo has been "monitoring the credit-worthiness of certain existing large C&I customers that may be in a precarious financial condition in order to determine whether a security deposit or other form of security should be collected." Please respond to this portion of Mr. Bragg's testimony.

A. First and foremost, as I clearly pointed out in my Direct Testimony, Constellium-Ravenswood has provided at least 36 months of uninterrupted payments to APCo, far surpassing the current 12-month requirement for a security deposit contained in Commission Rule 4.2.a.1. In my view, timely payment is the only financial requirement that APCo may use under the Commission's rules to determine whether to demand a security deposit. Despite this, APCo continues to press its case for extracting a needless security deposit from Constellium-Ravenswood.

Second, as clearly stated by Mr. Bragg throughout his Direct Testimony, APCo only evaluated financial criteria related to Constellium-Ravenswood's parent company. This has no bearing whatsoever on Constellium-Ravenswood's financial position. Even if APCo's credit-worthiness analysis was permissible, Mr. Bragg and the other APCo witnesses have simply not shown that *Constellium-Ravenswood* failed any of the financial tests APCo used to determine credit-worthiness.

Third, there is no rule or tariff change approved by the Commission that authorizes the change in approach by APCo to Constellium-Ravenswood. Essentially, APCo is arbitrarily applying its credit tests to certain customers without approval by the

Commission, and without providing any notice to customers of this approach, or any opportunity for them, or the Commission, to review a substantial change in policy that obviously presents significant financial risk to those customers.

Fourth, I am aware that the Commission recently issued a Final Order in Case No. 15-1673-E-T ("T&C Final Order"), finding that APCo's proposed use of a credit-worthiness analysis to determine whether a security deposit might be returned was not reasonable. For the same reasons that this approach was not reasonable in that context, it remains unreasonable in this context. Specifically, the Commission noted in that case that the "information provided by the subscription service used by the Companies to assist in identifying credit risks would not be available to the customer or the Commission unless they too subscribed to the subscription service." T&C Final Order, p. 6. The brief testimony that APCo presented from Mr. Holland in this case provides no additional clarity or transparency to the process employed by the Company in evaluating Constellium-Ravenswood's credit-worthiness.

This question of access to APCo's credit evaluation tool has been an issue in this case. In response to Constellium-Ravenswood's request in discovery for a "full, complete, and operational copy or version of the 'proprietary tool' used by APCo" to supposedly evaluate Constellium-Ravenswood's credit worthiness and a detailed explanation of how APCo used this tool, APCo simply responded that Constellium-Ravenswood could inspect the proprietary tool "during regular business hours" at their Charleston headquarters "by arrangement." APCo Response to Request No. 1 of Constellium-

Ravenswood's First Request for Information (attached as Exhibit__(RAB-4)). Clearly, this is not reasonable access or transparency for any customer, including Constellium-Ravenswood, that is being asked to remit a security deposit at the risk of having electric service terminated.

Last, the upshot of the T&C Final Order is that if Constellium-Ravenswood was required to submit to a security deposit demand based on a credit-worthiness analysis in this case, then the refund of that security deposit would be based on the T&C Final Order requiring a refund after 24 months of non-delinquent payments. It is simply unreasonable to require a security deposit from a good-paying customer on the basis of one type of analysis (a credit-worthiness analysis[1]), and then refund that deposit based on a 24-month payment criteria approved by the Commission. If allowed, this could lead to an absurd (if unintended by the Commission) situation in which as soon as Constellium-Ravenswood once again meets the 24-month tariff payment requirement for a refund, APCo could then turn around and demand a new security deposit based on a different type of analysis of Constellium-Ravenswood's credit-worthiness (or its indirect parent's). Essentially, this would allow APCo to retain Constellium-Ravenswood's security deposit in perpetuity.

[1] But even here, it is the indirect parent that is being analyzed.

Q. On page 4, lines 3 through 16 Mr. Bragg provided his interpretation of Rule 4.2.1.a. in which he claimed that APCo has authority to charge a security deposit from customers. Please address Mr. Bragg's interpretation of this Commission Rule.

A. The fact is that Rule 4.2.1.a. only allows for a security deposit if experience with a customer supports it. It is clear that Constellium-Ravenswood's payment history – which according to Constellium-Ravenswood witness Mr. Rose now equals or exceeds four years and ten months of non-delinquent payments – does not support the imposition of a security deposit.

Q. On page 4, lines 20 through 22, Mr. Bragg cited the Commission's June 2, 2016, Order in this case as support for collection of a deposit "in certain circumstances." Please address Mr. Bragg's citation of the Commission's Order.

A. Mr. Bragg failed to point out the following language from page 4 of the Commission's Order:

> Neither the tariff nor the Electric Rules, though, address whether APCo may require an existing customer that has timely paid for electric service for twelve months without a delinquency to pay a new deposit. *Electric Rules 4.2.a.1 and 4.2.b.2 and the tariff must be read to require APCo to act reasonably when it imposes a new security deposit or guarantee requirement upon an existing customer.*

(Emphasis added.)

In this case, APCo is not acting reasonably in its attempt to levy a security deposit on Constellium-Ravenswood, particularly given the absence of any authorization to do so in the Special Contract, the Commission's rules, or the APCo tariff and given Constellium-Ravenswood's payment history.

Q. On page 14, lines 5 through 14 Mr. Bragg discussed APCo's "efforts to protect against discernible risks of large uncollectibles posed by particular C&I customers." Please respond to Mr. Bragg's testimony on this point.

A. Neither Mr. Bragg nor APCo has provided any evidence or support of any risk of uncollectible activity from Constellium-Ravenswood. Therefore, the Commission and APCo do not need to protect other ratepayers from Constellium-Ravenswood by allowing the collection of a security deposit.

In this respect, I agree with Commission Staff witness Randall Short. Mr. Short concluded on page 3, lines 9 through 17 of his Direct Testimony that "APCO has apparently ignored the payment history of Constellium-Ravenswood" as an indicator of financial risk.

Furthermore, I do not believe that there is meaningful risk to other customers from large industrial uncollectibles. In Case No. 15-1673-E-T, the West Virginia Energy Users Group ("WVEUG") and the PSC Staff ("Staff") presented evidence that the actual risk of uncollectibles from APCo's largest customers is *de minimis* (approximately 0.05% of all C&I revenues). See Case No. 15-1673-E-T, WVEUG Initial Brief, pp. 7-8, and Staff Initial Brief, p. 16. In fact, Mr. Bragg has testified in this case that APCo is currently recovering only $3.9 million of large customer charge-offs through base rates. Based on my review, however, it appears that the large customer class is responsible for paying approximately $392,000 of bad debt charge-offs on an annual basis, but is only actually responsible for $317,000 of that debt. See Case No. 15-1673-E-T, WVEUG Initial Brief, pp. 7-8. Moreover, APCo's approved rates in the last base rate case reflected that large customers are paying a $39 million annual subsidy to the benefit of other classes. See id. at 8 n.6 (citing Appalachian Power Co. and Wheeling Power Co., Case Nos. 14-1152-E-42T and 14-1151-E-D (Order entered May 26, 2015) ("Base Rate Case Order"), pp. 100-01); and Base Rate Case Order, Appendix C. On balance, other customer classes are simply not at risk by Constellium-Ravenswood not submitting to the Company's demand for a security deposit.

Certainly, in balancing the amount of the security deposit that APCo is attempting to extract from Constellium-Ravenswood and the potential impact on Constellium-Ravenswood as a result, the obvious conclusion is that APCo's demand is unreasonable and unsupported by any evidence of a supposed risk to other ratepayers.

Q. On page 6, lines 7 through 12 Mr. Bragg discussed why in his view "it is important for utilities to have security deposits for accounts that have non-investment grade credit ratings and/or are at a higher risk of experiencing financial difficulty, including an increased risk of filing for bankruptcy protection." Does Constellium-Ravenswood have a non-investment grade credit rating?

A. No, it does not. Please refer to the Direct Testimony of Constellium-Ravenswood witnesses Mr. Scantlin and Mr. Rose for a more complete discussion of the financial standing of this facility.

Q. **On page 7, lines 2 through 3 of his Direct Testimony Mr. Bragg testified that regular payment history by itself is "insufficient." Please address Mr. Bragg's view on this point.**

A. In fact, payment history is the only standard addressed by the Commission Rules with respect to security deposits, as I pointed out earlier in my Rebuttal Testimony and in my Direct Testimony. Apparently, APCo does not believe it is bound by this portion of the Commission's Rules but instead believes that it can make its own determination based on its own rules, which have not been approved by the Commission and are not a part of APCo's existing tariffs. The Commission's Final Order in Case No. 15-1673-E-T only reinforces this sole standard of examining payment history in the context of security deposits.

Q. **On pages 8 and 9 of his Direct Testimony, Mr. Bragg discusses the Company's experiences with coal company bankruptcies. Does this experience support APCo's attempt to levy a security deposit on Constellium-Ravenswood?**

A. No. The main conclusion to draw from Mr. Bragg's discussion (and coincidentally from Mr. Holland's testimony) is that the Company moved to address a coal company problem. There is no evidence that such a problem exists with Constellium-Ravenswood. The problems within one industry should not be used as a basis for placing an unjust and unreasonable financial burden on other APCo customers such as Constellium-Ravenswood.

Q. On page 10, lines 17 through 19 of his Direct Testimony, Mr. Bragg presented the credit ratings of Constellium N.V., Constellium-Ravenswood's parent company. Do these credit ratings have any bearing on Constellium-Ravenswood's ability to pay its electric bills to APCo?

A. No, they obviously have no effect whatsoever, given Constellium-Ravenswood's excellent payment history.

I note that in their Direct Testimonies both Mr. Holland (pages 2-3) and Mr. Johnson (page 3) also discuss the importance of examining the financial health of *customers*. As I have stated here and in my Direct Testimony, the fact remains that APCo only examined the credit of Constellium N.V., and Constellium N.V. is not an APCo customer.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

EXHIBIT

OF

RICHARD A. BAUDINO

ON BEHALF OF

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

J. KENNEDY AND ASSOCIATES, INC.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0073-E-C

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC,

Complainant,

v.

APPALACHIAN POWER COMPANY,
a public utility,

Defendant.

EXHIBIT__(RAB-4)

OF

RICHARD A. BAUDINO

ON BEHALF OF

CONSTELLIUM ROLLED PRODUCTS RAVENSWOOD, LLC

J. KENNEDY AND ASSOCIATES, INC.

CONSTELLIUM'S FIRST REQUEST FOR INFORMATION FROM
Appalachian Power Company
Case No. 16-0073-E-C
Constellium Rolled Products Ravenswood LLC. v. APCo

Request No. 1

Reference paragraph 22 of APCo's Answer to Constellium-Ravenswood's Verified Complaint, stating that "APCo used a proprietary tool to forecast the likelihood of a bankruptcy of Constellium NV."

(a) Please provide a full, complete, and operational copy or version of the "proprietary tool" used by APCo.

(b) Please provide a detailed explanation of how APCo used this "proprietary tool" to forecast the likelihood of a bankruptcy by indirect parent company, Constellium NV.

Response No. 1

(a) Because the response to this question involves materials which are confidential the materials will be made available for inspection during regular business hours at Appalachian Power Company in Charleston, WV, by arrangement.

(b) APCo does not use the proprietary tool to forecast the likelihood of bankruptcy. Rather, the FRISK score, which is the result of Credit Risk Monitor's (CRM) proprietary tool that it uses to predict a company's risk of bankruptcy, is looked at by APCo as part of its evaluation of a customer.

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September 1, 2016

VIA FEDERAL EXPRESS AND ELECTRONIC MAIL

David J. Collins
Executive Secretary
Public Service Commission
State of Maryland
6 St. Paul Street, 16th Floor
Baltimore, MD 21202

Re: *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, Case No. 9418

Dear Mr. Collins:

Enclosed please find an original and seventeen (17) copies of the Surrebuttal Testimony and Exhibits of Mr. Richard Baudino, on behalf of the Healthcare Council of the National Capital Area in the above-referenced docket. The paper copies will be either sent by fed-ex or hand delivered according to the Commission's rules regarding e-filing.

If you have any questions, please do not hesitate to contact me at (202) 662-2715 or by mail at kwiseman@andrewskurth.com.

Sincerely,

/s/ Kenneth L. Wiseman
Kenneth L. Wiseman

cc: Parties of Record
Case No. 9418

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
RETAIL RATES FOR THE DISTRIBUTION	**)**	
OF ELECTRIC ENERGY	**)**	

SURREBUTTAL TESTIMONY

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

HEALTHCARE COUNCIL OF THE NATIONAL CAPITAL AREA

September 2016

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR ADJUSTMENTS TO ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY	**)))))**	**CASE NO. 9418**

SURREBUTTAL TESTIMONY OF RICHARD A. BAUDINO

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Did you submit Direct and Rebuttal Testimony and Exhibits in this proceeding?

A. Yes. I submitted Direct and Rebuttal Testimony and Exhibits on behalf of the Healthcare Council of the National Capital Area ("HCNCA").

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to update the revenue requirement effects of the ratemaking adjustments ("RMA") that I presented in my Direct Testimony. This is in response to the revised revenue requirement presented in Potomac Electric Power Company's ("Pepco" or "Company") Rebuttal Testimony.

I also provide updates to my return on equity analyses from my Direct Testimony. Mr. Hevert updated his ROE analyses in his Rebuttal Testimony and so I provide updated market data for my ROE recommendation as well.

Q. Please describe the updated RMA analysis you are providing.

A. Exhibit No. ____(RAB-17) summarizes the update to my recommended revisions to Potomac Electric Power Company's ("Pepco" or "Company") RMAs from my Direct Testimony. This update is based on the revenue requirement updates that Pepco witness W. Michael VonSteuben presented in his Rebuttal Testimony. My exhibit was developed from Mr. VonSteuben's Schedule (WMV-R)-1, page 4 of 40.

Exhibit No. ____(RAB-17) shows the revenue requirement effect of my recommended adjustments to RMAs 6, 23, 24, and 25. The Company agreed to a 10-year amortization period for RMA 6 consistent with my recommendation. My adjustments to RMAs 23, 24, and 25 still utilize my recommended 10-year amortization period. Regarding RMA 7, Mr. VonSteuben removed the return portion on the unamortized balance of legacy meters consistent with my recommendation in my Direct Testimony.

Q. Please summarize the update to your ROE analyses that you presented in your Direct Testimony.

A. Surrebuttal Table 1 below summarizes my updated ROE analyses.

SURREBUTTAL TABLE 1
SUMMARY OF ROE ESTIMATES

Baudino DCF Methodology:	
Average Growth Rates	
- High	9.32%
- Low	8.05%
- Average	8.54%
Median Growth Rates:	
- High	9.36%
- Low	8.34%
- Average	8.75%
CAPM:	
- 5-Year Treasury Bond	7.60%
- 20-Year Treasury Bond	7.84%
- Historical Returns	5.81% - 7.28%

The update to my ROE analyses still supports my recommended ROE for Pepco of 9.0%, although the results from the DCF and CAPM are slightly lower. The detailed results of the update are contained in my Exhibit No. ___(RAB-18) through Exhibit No. ___(RAB-21).

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

HCNCA

Revised Analysis of Revenue Requirement by Ratemaking Adjustment
Twelve Months Ended December 31, 2015 (12+0)

		------------------Pepco------------------			HCNCA Adjusted	HCNCA Adjusted	HCNCA Adjusted
	(Thousands of Dollars)	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement
	Unadjusted Results	$ 1,596,664	$ 97,241		$ 1,596,664	$ 97,241	
	Revenue Requirement Based on Unadjusted Results			$ 52,554			$ 52,551
	Ratemaking Adjustments						
1	Annualization of Test Year Reliability Plant Closings	$ 22,478	$ (2,047)	$ 6,597	$ 22,478	$ (2,047)	$ 6,597
2	Post Test Year Reliability Closings (Jan thru Aug 2016)	40,491	(3,597)	11,728	$ 40,491	$ (3,597)	$ 11,728
3	Post Test Year Reliability Closings (Sep thru Oct 2016)	16,813	(211)	2,671	$ 16,813	$ (211)	$ 2,671
4	Post Test Year Reliability Closings (Nov thru Dec 2016)	29,573	(389)	4,728	$ 29,573	$ (389)	$ 4,728
5	Case 9385 Depreciation Rates	(5,785)	(11,545)	19,000	$ (5,785)	$ (11,545)	$ 19,000
6	AMI Regulatory Asset Amortization	33,866	(6,395)	15,616	$ -	$ (8,145)	$ 13,966
7	Legacy Meter Regulatory Asset Amortization	-	(5,049)	8,657	$ -	$ (5,049)	$ 8,657
8	Reflection of 2014 NOL Accrual	(1,851)	-	(254)	$ (1,851)	$ -	$ (254)
9	Tax Compensation Carrying Costs	-	1,050	(1,800)	$ -	$ 1,050	$ (1,800)
10	Reversal of Tax Compensation Carrying Costs	-	(1,050)	1,800	$ -	$ -	$ -
11	Reflection of Uncollectible Write-Offs	-	141	(242)	$ -	$ 141	$ (242)
12	Annualization of Wage Increases	-	(1,554)	2,664	$ -	$ (1,554)	$ 2,664
13	Reflection of Employee Health & Welfare Cost Increases	-	(478)	820	$ -	$ (478)	$ 820
14	Reflection of 3-Year Average AIP Costs	-	279	(478)	$ -	$ 279	$ (478)
15	Exclusion of Executive Incentive Costs	-	1,789	(3,067)	$ -	$ 1,789	$ (3,067)
16	Reflection of 50% SERP Liability and Expense	(4,913)	1,077	(2,521)	$ (4,913)	$ 1,077	$ (2,521)
17	Current Rate Case Costs	-	(11)	18	$ -	$ (11)	$ 18
18	Reflection of 3-Year Avg Auto & General Claim Payments	-	3	(5)	$ -	$ 3	$ (5)
19	Exclusion of Institutional & Promotional Ad Expense	-	598	(1,025)	$ -	$ 598	$ (1,025)
20	Exclusion of 50% Employee Activity Costs	-	47	(81)	$ -	$ 47	$ (81)
21	Test Period Reg Asset Removal	(23)	435	(749)	$ (23)	$ 435	$ (749)
22	Electric Vehicle Pilot Costs	-	(90)	154	$ -	$ (90)	$ 154
23	Winter Storm PAX	366	(81)	189	$ -	$ (61)	$ 104
24	Winter Storm Jonas	926	(206)	480	$ -	$ (153)	$ 263
25	Reflection of Synergies and CTA	8,704	1,290	(1,017)	$ -	$ 1,782	$ (3,055)
26	Inclusion of Commission Authorized Interest Expense	-	(208)	357	$ -	$ (208)	$ 357
27	AFUDC Synchronization	-	260	(446)	$ -	$ 260	$ (446)
28	Adjustments to Cash Working Capital Allowance	(5,580)	-	(766)	$ (5,580)	$ -	$ (766)
29	Tax Effect of Proforma Interest Expense	-	1,552	(2,661)	$ -	$ 1,552	$ (2,661)
30	Removal of Benning Environmental Remediation Cost	-	1,449	(2,484)	$ -	$ 1,449	$ (2,484)
31	Annualization of Late Payment Revenues	-	321	(550)	$ -	$ 321	$ (550)
32	Billing System Transition Costs	3,906	3,472	(5,416)	$ 3,906	$ 3,472	$ (5,416)
33	Legacy Billing Costs	382	340	(530)	$ 382	$ 340	$ (530)
	Total ratemaking adjustments	139,353	(18,808)	$ 51,384	95,491	(18,943)	$ 45,590
	Total revenue requirement at 8.01% rate of return based on adjusted results	$ 1,736,017	$ 78,433	$ 103,938	$ 1,692,155	$ 78,298	$ 98,147

COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jul-16	Jun-16	May-16	Apr-16	Mar-16	Feb-16
ALLETE	High Price ($)	65.410	64.690	58.490	56.800	58.340	54.960
	Low Price ($)	62.500	57.320	54.030	53.470	51.290	50.830
	Avg. Price ($)	63.955	61.005	56.260	55.135	54.815	52.895
	Dividend ($)	0.520	0.520	0.520	0.520	0.520	0.520
	Mo. Avg. Div.	3.25%	3.41%	3.70%	3.77%	3.79%	3.93%
	6 mos. Avg.	3.64%					
Alliant Energy	High Price ($)	40.990	40.240	37.210	75.180	74.350	70.250
	Low Price ($)	39.070	36.920	35.080	68.150	66.520	64.760
	Avg. Price ($)	40.030	38.580	36.145	71.665	70.435	67.505
	Dividend ($)	0.294	0.294	0.294	0.588	0.588	0.588
	Mo. Avg. Div.	2.94%	3.05%	3.25%	3.28%	3.34%	3.48%
	6 mos. Avg.	3.22%					
Avista Corp.	High Price ($)	45.220	44.810	42.170	41.370	41.310	39.300
	Low Price ($)	42.870	40.000	38.830	38.480	36.890	36.720
	Avg. Price ($)	44.045	42.405	40.500	39.925	39.100	38.010
	Dividend ($)	0.343	0.343	0.343	0.343	0.343	0.343
	Mo. Avg. Div.	3.11%	3.24%	3.39%	3.44%	3.51%	3.61%
	6 mos. Avg.	3.38%					
Consolidated Edison	High Price ($)	81.880	80.440	76.760	77.230	77.020	73.900
	Low Price ($)	78.310	72.940	70.310	70.730	68.440	69.080
	Avg. Price ($)	80.095	76.690	73.535	73.980	72.730	71.490
	Dividend ($)	0.670	0.670	0.670	0.670	0.670	0.670
	Mo. Avg. Div.	3.35%	3.49%	3.64%	3.62%	3.68%	3.75%
	6 mos. Avg.	3.59%					
Edison International	High Price ($)	78.720	77.710	73.250	72.410	72.340	69.240
	Low Price ($)	74.450	70.720	68.470	67.710	65.600	61.490
	Avg. Price ($)	76.585	74.215	70.860	70.060	68.970	65.365
	Dividend ($)	0.480	0.480	0.480	0.480	0.480	0.480
	Mo. Avg. Div.	2.51%	2.59%	2.71%	2.74%	2.78%	2.94%
	6 mos. Avg.	2.71%					
Eversource Energy	High Price ($)	60.440	59.950	58.260	59.090	58.810	56.920
	Low Price ($)	57.240	54.860	53.900	54.510	52.620	52.930
	Avg. Price ($)	58.840	57.405	56.080	56.800	55.715	54.925
	Dividend ($)	0.445	0.445	0.445	0.445	0.445	0.445
	Mo. Avg. Div.	3.03%	3.10%	3.17%	3.13%	3.19%	3.24%
	6 mos. Avg.	3.14%					
IDACORP	High Price ($)	83.400	81.360	74.470	74.990	74.960	73.820
	Low Price ($)	79.210	72.910	69.830	70.400	69.030	68.300
	Avg. Price ($)	81.305	77.135	72.150	72.695	71.995	71.060
	Dividend ($)	0.510	0.510	0.510	0.510	0.510	0.510
	Mo. Avg. Div.	2.51%	2.64%	2.83%	2.81%	2.83%	2.87%
	6 mos. Avg.	2.75%					

COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jul-16	Jun-16	May-16	Apr-16	Mar-16	Feb-16
Northwestern Corp.	High Price ($)	63.750	63.300	59.440	62.510	62.220	60.760
	Low Price ($)	60.050	57.520	55.340	55.910	57.460	55.490
	Avg. Price ($)	61.900	60.410	57.390	59.210	59.840	58.125
	Dividend ($)	0.500	0.500	0.500	0.500	0.500	0.480
	Mo. Avg. Div.	3.23%	3.31%	3.48%	3.38%	3.34%	3.30%
	6 mos. Avg.	3.34%					
OGE Energy	High Price ($)	32.960	32.750	31.070	29.620	28.740	27.810
	Low Price ($)	31.300	30.090	28.970	27.270	24.830	24.390
	Avg. Price ($)	32.130	31.420	30.020	28.445	26.785	26.100
	Dividend ($)	0.275	0.275	0.275	0.275	0.275	0.275
	Mo. Avg. Div.	3.42%	3.50%	3.66%	3.87%	4.11%	4.21%
	6 mos. Avg.	3.80%					
Portland General Electric	High Price ($)	45.210	44.120	41.940	40.030	39.900	40.480
	Low Price ($)	43.280	40.960	39.470	37.770	37.040	37.400
	Avg. Price ($)	44.245	42.540	40.705	38.900	38.470	38.940
	Dividend ($)	0.300	0.300	0.300	0.300	0.300	0.300
	Mo. Avg. Div.	2.71%	2.82%	2.95%	3.08%	3.12%	3.08%
	6 mos. Avg.	2.96%					
WEC Energy	High Price ($)	66.100	65.300	60.510	60.320	60.160	58.150
	Low Price ($)	63.370	59.620	57.250	55.460	54.850	54.730
	Avg. Price ($)	64.735	62.460	58.880	57.890	57.505	56.440
	Dividend ($)	0.495	0.495	0.495	0.495	0.495	0.495
	Mo. Avg. Div.	3.06%	3.17%	3.36%	3.42%	3.44%	3.51%
	6 mos. Avg.	3.33%					
Xcel Energy	High Price ($)	45.420	44.780	41.980	42.040	41.850	40.420
	Low Price ($)	43.100	40.990	39.690	38.430	38.260	36.250
	Avg. Price ($)	44.260	42.885	40.835	40.235	40.055	38.335
	Dividend ($)	0.340	0.340	0.340	0.340	0.340	0.320
	Mo. Avg. Div.	3.07%	3.17%	3.33%	3.38%	3.40%	3.34%
	6 mos. Avg.	3.28%					
Average Dividend Yield		3.26%					

Source: Yahoo! Finance

COMPARISON GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) IBES
ALLETE, Inc.	3.50%	4.00%	3.00%	5.50%	5.00%
Alliant Energy Corporation	4.50%	6.00%	5.50%	6.10%	6.60%
Avista Corporation	4.00%	5.00%	3.00%	5.00%	5.00%
Consolidated Edison, Inc.	3.00%	2.50%	3.00%	2.70%	1.98%
Edison International	9.00%	3.50%	5.50%	5.30%	2.07%
Eversource Energy	6.00%	6.00%	4.00%	6.30%	5.66%
IDACORP, Inc.	7.50%	3.00%	3.50%	4.00%	4.00%
NorthWestern Corp.	5.50%	6.50%	4.00%	5.00%	5.00%
OGE Energy	9.50%	3.00%	3.50%	5.20%	4.30%
Portland General Electric Company	6.00%	5.50%	4.00%	6.20%	6.30%
WEC Energy	7.00%	6.00%	3.50%	6.20%	6.72%
Xcel Energy Inc.	6.00%	5.50%	4.00%	5.40%	5.42%
Averages	5.96%	4.71%	3.88%	5.24%	4.84%
Median Values	6.00%	5.25%	3.75%	5.35%	5.00%

Sources: Value Line Investment Survey, June 17, July 29, and August 19, 2016
Yahoo! Finance for IBES growth rates retrieved August 31, 2016
Zacks growth rates retrieved August 31, 2016

COMPARISON GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.26%	3.26%	3.26%	3.26%	3.26%
Average Growth Rate	5.96%	4.71%	5.24%	4.84%	5.19%
Expected Div. Yield	3.36%	3.34%	3.35%	3.34%	3.35%
DCF Return on Equity	***9.32%***	***8.05%***	***8.59%***	***8.18%***	***8.54%***
Method 2:					
Dividend Yield	3.26%	3.26%	3.26%	3.26%	3.26%
Median Growth Rate	6.00%	5.25%	5.35%	5.00%	5.40%
Expected Div. Yield	3.36%	3.35%	3.35%	3.34%	3.35%
DCF Return on Equity	***9.36%***	***8.60%***	***8.70%***	***8.34%***	***8.75%***

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Comparison Group

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.92%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.13%
4	Risk Premium	
5	(Line 1 minus Line 3)	7.79%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	5.71%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.84%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.92%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.23%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.68%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.37%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.60%

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Comparison Group

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
February-16	2.20%
March-16	2.28%
April-16	2.21%
May-16	2.22%
June-16	2.02%
July-16	1.82%
6 month average	2.13%

5 Year Treasury Bond Data

	Avg. Yield
February-16	1.22%
March-16	1.38%
April-16	1.26%
May-16	1.30%
June-16	1.17%
July-16	1.07%
6 month average	1.23%

Source: www.federalreserve.gov, Selected Interest Rates (Dalily) - H.15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.80%
Estimated Market Return	9.84%
Value Line Projected 3-5 Yr. Median Annual Total Return	10.00%
Average of Projected Mkt. Returns	9.92%

Source: Value Line Investment Survey for Windows retreived August 16, 2016

Comparison Group Betas:	Value Line
ALLETE, Inc.	0.75
Alliant Energy Corporation	0.75
Avista Corporation	0.75
Consolidated Edison, Inc.	0.55
Edison International	0.70
Eversource Energy	0.75
IDACORP, Inc.	0.80
NorthWestern Corp.	0.70
OGE Energy	0.95
Portland General Electric Company	0.80
WEC Energy	0.65
Xcel Energy Inc.	0.65
Average	0.73

Source: Value Line Investment Survey

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.07%	5.07%	
Historical Market Risk Premium	5.03%	7.03%	6.19%
Comparison Group Beta, Value Line	0.73	0.73	0.73
Beta * Market Premium	3.69%	5.16%	4.54%
Current 20-Year Treasury Bond Yield	2.13%	2.13%	2.13%
CAPM Cost of Equity, Value Line Beta	**5.81%**	**7.28%**	**6.66%**

Source: *Ibbotson SBBI 2015 Classic Yearbook,* Morningstar, pp. 39 - 40, 152, 157 - 158

CERTIFICATE OF SERVICE
CASE NO. 9418

I HEREBY CERTIFY that a copy of the foregoing **HEALTHCARE COUNCIL OF THE NATIONAL CAPITAL AREA'S RESPONSE TO POTOMAC ELECTRIC POWER COMPANY'S DATA REQUEST NO. 3** has been furnished by electronic mail, U.S. Mail or Federal Express, this 1st day of September, 2016 to the following:

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VIA OVERNIGHT MAIL

August 17, 2016

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17105-3265

Re: Pennsylvania Public Utility Commission v. West Penn Power Company; Docket No. R-2016-2537359, et. al.

Dear Secretary Chiavetta:

Please find enclosed the REBUTTAL TESTIMONY OF RICHARD A. BAUDINO on behalf of AK STEEL CORPORATION for filing in the above-captioned proceeding.

By copy of this letter, all parties listed on the Certificate of Service have been served.

Respectfully submitted,

David F. Boehm, Esq. (PA Attorney I.D. # 72752)
BOEHM, KURTZ & LOWRY

COUNSEL FOR AK STEEL CORPORATION

DFBkew
Enclosure
cc: Certificate of Service
ALJ Mary D. Long (via email and overnight mail)
malong@pa.gov
Pa. Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537349, *et al.*
v.	:	
Metropolitan Edison Company	:	
Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537352, *et al.*
v.	:	
Pennsylvania Electric Company	:	
Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537355, *et al.*
v.	:	
Pennsylvania Power Company	:	
Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537359, *et al.*
v.	:	
West Penn Power Company	:	

REBUTTAL TESTIMONY

OF

RICHARD A. BAUDINO

ON BEHALF OF

AK STEEL CORPORATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

AUGUST 17, 2016

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, *et al.* v. Metropolitan Edison Company	: : :	R-2016-2537349, *et al.*
Pennsylvania Public Utility Commission, *et al.* v. Pennsylvania Electric Company	: : :	R-2016-2537352, *et al.*
Pennsylvania Public Utility Commission, *et al.* v. Pennsylvania Power Company	: : :	R-2016-2537355, *et al.*
Pennsylvania Public Utility Commission, *et al.* v. West Penn Power Company	: : :	R-2016-2537359, *et al.*

REBUTTAL TESTIMONY OF RICHARD A. BAUDINO
ON BEHALF OF AK STEEL

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Did you submit Direct Testimony in this proceeding?

A. Yes. I submitted Direct Testimony on behalf of AK Steel Corporation.

Q. What is the purpose of your Rebuttal Testimony?

A. I will respond to the CCOSS and revenue allocation testimony filed by Mr. Clarence L. Johnson, witness for the Pennsylvania Office of Consumer Advocate ("OCA") and Mr. Jeremy Hubert, witness for the Bureau of Investigation and Enforcement ("BIE").

<u>Response to OCC witness Johnson</u>

Q. On page 10, line 9 through 10 of his Direct Testimony, Mr. Johnson testified that the minimum distribution plant concept is "inherently flawed and fails to reflect cost causation." Does West Penn Power's ("WPP" or "Company") minimum system approach reflect cost causation?

A. Yes, it does. Mr. Johnson's assertion regarding the minimum system approach should be rejected.

Q. Please explain how distribution costs are incurred.

A. Distribution costs are incurred to meet customer demands on the distribution system, as well as the minimum requirements to simply provide an interconnection to a customer (minimum system costs). The *Electric Utility Cost Allocation Manual*

("Manual"), January 1992, published by the National Association of Regulatory Utility Commissioners ("NARUC") discusses methodologies adopted by the industry and regulators to allocate and recover the cost of distribution facilities. These methodologies recognize that the cost incurred to provide distribution service is a fixed cost and should be allocated on the basis of one or more demands (for example, customer maximum demands, class diversified demand) and on the basis of the number of customers taking distribution service on the rate schedule.

Q. Would you explain the concept underlying the minimum size approach that the Company used to classify distribution plant and expenses between customer and demand components?

A. Yes. As described in the NARUC Manual, the underlying argument in support of the minimum system approach, which includes a customer component, is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (lines, poles, transformers) that is independent of the level of demand of the customer. To the extent that this component of distribution cost is a function of the requirement to interconnect the customer, regardless of the customer's size, it is appropriate to assign the cost of these facilities to rate schedules on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC Manual:

> "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs."

Q. Is the Company's use of a minimum grid methodology consistent with the accepted methods discussed in the NARUC manual?

A. Yes. There are two recognized methodologies to estimate the customer component of distribution costs. These methods, which are described in the NARUC manual, are the "minimum intercept" method and the "minimum size" method, which is similar to the approach used by WPP. Each of the two methods is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer.

A minimum size distribution cost of service analysis is designed to reflect the costs associated with changes in both the number of distribution customers and the loads of these customers. The conceptual basis for the minimum size method is that it reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, irrespective of the kW load of the customer. From a cost causation standpoint, the argument supporting this approach is that all of these minimal facilities would be required simply due to the requirement to interconnect the customer.

Q. On page 11 of his Direct Testimony, Mr. Johnson recommended that Accounts 364 - 368 be classified as 100% demand related. Please respond to this recommendation.

A. Based on the foregoing discussion, Mr. Johnson's recommended classification of Accounts 364 - 368 should be rejected. Classifying these accounts solely on the basis of demand would result in an unwarranted shift in cost responsibility from residential customers to the larger customer classes, such as Rate PP46. I recommend that the Commission adopt and approve WPP's recommended classification of these accounts.

Q. On page 30 of his Direct Testimony, Mr. Johnson recommended allocating Account 910, Customer Service Expenses, 50% on the basis of revenues and 50% on a customer basis. Please address Mr. Johnson's recommendation.

A. The Commission should reject Mr. Johnson's recommended allocation of Account 910 expenses. These expenses are totally customer related and should be allocated on that basis. The Company's weighted customer allocation should be adopted since it is based on a weighted percentage of call center calls attributable to particular customer classes. Using class revenues as an allocator would unfairly shift these costs toward non-residential customer classes. Mr. Johnson provided no analyses whatsoever that supported any allocation of Account 910 on the basis of revenues.

The NARUC Manual also stated the following with respect to customer service and informational expenses (Accounts 906 through 910) on page 103:

> "These accounts include the costs of encouraging safe and efficient use of the utility's service. Except for conservation and load management, these costs are classified as customer-related. Emphasis is placed upon the costs of responding to customer inquiries and preparing billing inserts."

Q. Mr. Johnson recommended that the Commission accept his revised CCOSS as summarized in his Schedule CJ-4. What is your recommendation with respect to Mr. Johnson's recommended CCOSS?

A. The Commission should reject Mr. Johnson's proposed CCOSS. It inappropriately shifts substantial cost responsibility from the Residential class to other rate classes. This is due primarily to his rejection of the Company's minimum grid study and the classification of costs in Accounts 364 - 368 as 100% demand related. Mr. Johnson's shifting of customer-related costs in Account 910 is also unjustified and served to inappropriately shift costs to customers who are not responsible for those costs. Finally, Mr. Johnson's CCOSS is based on the inappropriate classification and allocation of substations, which I identified and explained in my Direct Testimony.

Q. Should the Commission place any weight on the relative rates of return ("RROR") shown on page 32 of Mr. Johnson's Direct Testimony for West Penn?

A. No. These RRORs are based on Mr. Johnson's flawed CCOSS. They do not present an accurate representation of West Penn's customer class rates of return.

Q. On page 37 of his Direct Testimony, Mr. Johnson presented his recommended class revenue allocation for West Penn. Please respond to Mr. Johnson's proposed class revenue allocation.

A. The Commission must reject Mr. Johnson's class revenue allocation. Mr. Johnson's revenue allocation is based on his deeply flawed CCOSS, which unfairly and inappropriately shifted cost responsibility from the RS class to other customers and failed to correct West Penn's allocation of substation costs. As a result, customer classes such as PP46 are burdened with an unjustified revenue increase that does not reflect cost responsibility.

<u>Response to BIE witness Hubert</u>

Q. Could you please comment on Mr. Hubert's revenue allocation recommendation?

A. Yes. Mr. Hubert presented his recommended revenue reallocation beginning on page 33 of his Direct Testimony. Mr. Hubert testified that his recommended revenue reallocation was designed to (1) move each rate class closer to the system average rate of return, and limit the distribution revenue increase to any particular class to no more that 1.5 times the overall system average increase.

Mr. Hubert's recommended revenue allocation is based on WPP's CCOSS, which incorrectly allocates the cost of substations, thus overstating cost responsibility of Primary service customers for substation costs, as I explained in my Direct Testimony. Mr. Hubert's revenue allocation cannot be used in its present form to properly allocate WPP's proposed revenue increase to customer classes due to the flaw in the Company's CCOSS. Thus, I do not agree with Mr. Hubert's revenue reallocation recommendation.

Q. Does that complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Sworn to and subscribed before me on this 16th day of August 2016.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
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PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of August, 2016 I served a true copy of the REBUTTAL TESTIMONY OF RICHARD A. BAUDINO on behalf of AK STEEL CORPORATION on the following persons listed on the attached Certificate of Service in the matter specified in accordance with the requirements of 52 Pa. Code §1.54.

David F. Boehm

David F. Boehm, Esq. (PA Attorney I.D. # 72752)
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VIA OVERNIGHT MAIL

July 22, 2016

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17105-3265

Re: Pennsylvania Public Utility Commission v. West Penn Power Company; Docket No. R-2016-2537359, et . al.

Dear Secretary Chiavetta:

Please find enclosed the DIRECT TESTIMONY AND EXHIBITS OF RICHARD A. BAUDINO on behalf of AK STEEL CORPORATION for filing in the above-captioned proceeding.

By copy of this letter, all parties listed on the Certificate of Service have been served.

Respectfully submitted,

David F. Boehm, Esq. (PA Attorney I.D. # 72752)
BOEHM, KURTZ & LOWRY

COUNSEL FOR AK STEEL CORPORATION

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Enclosure
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537349, *et al.*
v.	:	
Metropolitan Edison Company	:	
Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537352, *et al.*
v.	:	
Pennsylvania Electric Company	:	
Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537355, *et al.*
v.	:	
Pennsylvania Power Company	:	
Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537359, *et al.*
v.	:	
West Penn Power Company	:	

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

AK STEEL CORPORATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JULY 22, 2016

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, *et al.* v. Metropolitan Edison Company	: : :	R-2016-2537349, *et al.*
Pennsylvania Public Utility Commission, *et al.* v. Pennsylvania Electric Company	: : :	R-2016-2537352, *et al.*
Pennsylvania Public Utility Commission, *et al.* v. Pennsylvania Power Company	: : :	R-2016-2537355, *et al.*
Pennsylvania Public Utility Commission, *et al.* v. West Penn Power Company	: : :	R-2016-2537359, *et al.*

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

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Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537352, *et al.*
v.	:	
Pennsylvania Electric Company	:	
Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537355, *et al.*
v.	:	
Pennsylvania Power Company	:	
Pennsylvania Public Utility Commission, *et al.*	:	R-2016-2537359, *et al.*
v.	:	
West Penn Power Company	:	

DIRECT TESTIMONY OF RICHARD A. BAUDINO ON BEHALF OF AK STEEL

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ____(RAB-1) summarizes my expert testimony experience.

Q. Have you previously testified in proceedings before the Pennsylvania Public Utility Commission ("PPUC" or "Commission")?

A. Yes.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of AK Steel Corporation, a large industrial customer taking service on Rate PP46.

Q. What is the purpose of your testimony?

A. The purpose of my testimony in this proceeding is to address issues relating to class cost of service and the allocation of the overall approved revenue increase to rate classes. In addressing these issues, I will also respond to the Direct Testimony of West Penn Power Company ("WPP" or "Company") witnesses Thomas Dolezal and Kevin Siedt.

Q. Please summarize your conclusions and recommendations.

A. My conclusions are as follows:

1. WPP's CCOSS inappropriately allocates costs in Account 362 - Station Equipment, also known as substations. WPP's allocation method causes an excessive allocation of substation costs to rate classes that only take service at 23 kilovolts ("kV") and above.
2. I prepared a CCOSS that includes a correction to the Company's allocation of Account 362 - Station Equipment. The AK Steel CCOSS shows that the current rate of return for Rate PP46 customers is 7.87%, compared to WPP's overall current rate of return of 1.85%.
3. The AK Steel CCOSS shows that PP46 customers should receive virtually no increase in this case. WPP's proposed revenue increase to Rate PP46 of

$1.041 million, or 36.2%, is totally unjustified and should be rejected by the Commission.

4. I recommend that the Commission adopt my recommended AK Steel CCOSS, which properly allocates the costs of substations to customers taking service at 23 kV and above.

5. With respect to revenue allocation, I recommend that the Commission move customer classes to their respective cost of service, but limit the percentage increase to the GSS class to no more that 1.5 times the system average increase. No customer class should receive a revenue decrease in this proceeding. My approach would limit the increase to the Residential class (RS10) to 1.38 times the system average increase and GSS customers to 1.5 times the system average increase.

6. When Rider charges are included, Residential customers' total revenue increase would be 11.22%, slightly higher than WPP's proposed increase of 10.47%.

II. CLASS COST OF SERVICE

Q. Have you reviewed the Company's filed distribution class cost of service study in this case?

A. Yes.

Q. Please briefly summarize the important aspects of a class cost of service study.

A. A class cost of service study allocates and assigns the total joint cost of providing utility service to the classes of customers receiving that service. In certain instances, the subject utility can identify and directly assign costs to customers. But for the vast majority of costs, a cost of service study is required so that the remaining costs may be allocated to customers.

The development of a class cost of service study consists of three steps: functionalization, classification, and allocation. Step 1, functionalization, involves separating the utility's investment and expenses into major functional categories. For integrated electric utilities, these categories include production, transmission, and distribution. The FERC Uniform System of Accounts provides the method by which costs are identified and segregated into these various functional categories.

Step 2 is classification. Once functionalization is complete, the utility's costs are classified into demand, energy, and customer components. Demand-related costs are fixed in the short run and are sized based on the yearly demands of the utility's customers. Fixed production and transmission costs and a significant portion of the distribution system investment in poles, wires, etc. is considered demand-related. Energy-related costs vary with kWh consumption and include fuel and variable purchased power costs. Customer-related costs are associated with the number of customers and include items such as meters and services. It is also appropriate to classify a portion of distribution investment in FERC Accounts 364 through 370 as customer-related.

Step 3 is allocation. After costs are classified, they are allocated to customer classes based on each class' contribution to the respective cost classifications. Generally speaking, demand costs are allocated based on class contributions to system peak and/or non-coincident peaks. Energy costs are allocated based on class kWh consumption. Customer costs are allocated based on the number of customers or on weighted customer allocation factors.

Q. Why is a properly constructed CCOSS important in the ratemaking process?

A. A properly performed class cost of service study assigns and allocates the utility's total cost of service to the customer classes that cause the utility to incur the cost, and that receive that service. Based on current class revenues, the regulatory commission may then determine whether each customer class is paying its fair share of costs and can then allocate any revenue increase (or decrease) accordingly. For example, a customer class that is not paying its fair share of costs should receive a percentage revenue increase greater than the overall system increase. Likewise, a customer class that is paying more than its fair share of costs should receive a lower than average percentage increase. In certain cases, it may be appropriate for such a class of customers to receive no increase or even a decrease in rates if that class is paying rates greatly in excess of its allocated cost of service.

Accurate cost allocation also promotes economic efficiency. If electricity prices are based on an accurate assessment of the underlying cost to serve customers, then customers can make correctly informed decisions about their usage of electricity. For example, many industrial firms use significant amounts of electricity in their production processes. If the price these companies pay for electricity is based on costs, then they will be able to produce their goods and services at the lowest and most efficient cost for society. If electricity prices are set above the actual underlying cost, then these goods and services will be overpriced, under produced, or both.

Q. Generally describe the approach used by Mr. Dolezal with respect to cost allocation.

A. WPP witness Dolezal began a discussion of the Company's CCOSS methodology on page 7 of his Direct Testimony. Non-coincident peak ("NCP") demands were used to allocate costs that are classified as demand-related. WPP's method allocates demand-related costs for large distribution plant accounts based on NCP demands of three groups of customers. The first group, designated as "PRI" in the Company's CCOSS, consists of customers that receive service at primary voltage and use only the Primary Distribution system. The second group, "SEC", are customers that take service at secondary voltage and that use both the Primary and Secondary distribution system. The third group, "PRI_SEC", are all customers using the distribution system and consists of Primary and Secondary customers. The Company's CCOSS further functionalizes plant Accounts 361 - 368 between Primary and Secondary voltage levels and is shown on pages 10 and 11 of Mr. Dolezal's Direct Testimony.

WPP's CCOSS then classified its system cost of service into demand and customer classifications. Mr. Dolezal explained beginning on page 13 that plant Accounts 364 - 369 were classified based on a minimum grid study, which was provided in Supporting Study No. 7. This study determined the minimum size of poles, conductors, transformers, and service drops required to serve a customer. The cost of this "minimum size system" determined the customer component of the above accounts and the remainder is classified as the demand component. NCP is then used to allocate the demand-related portion of these accounts and the customer component is allocated based on the number of customer accounts. The rest of WPP's distribution system is allocated to customer classes according to their respective demand and customer allocators.

Q. Please summarize the results of WPP's CCOSS as filed by Mr. Dolezal.

A. Table 1 below shows the existing class rates of return and unitized rates of return from WPP's filed CCOSS. Unitized rate of return is a measure of how close a customer class rate of return is to the system average rate of return. For example, suppose that a utility company's overall rate of return on rate base is 10%. Then suppose that Customer Class A has a return on rate base of 11%. The unitized rate of return for Customer Class A, then, is 1.10 (11% divided by 10%), which means that Customer Class A's rate of return is 10 percent higher than system average.

TABLE 1
West Penn COSS
Current Class Rates of Return

	Pct. Return	Relative ROR
WP_RS	3.0%	0.72
WP_GS10	19.9%	4.82
WP_GSS	-1.9%	(0.47)
WP_GSM	12.4%	3.00
WP_GSL	9.7%	2.34
WP_PP40	2.1%	0.51
WP_POL	16.1%	3.90
WP_PSU	7.3%	1.76
WP_PP44	256.5%	61.98
WP_PP46	1.9%	0.45
WP_STLT	3.1%	0.75
Total Retail	4.1%	

WPP's filed CCOSS shows that Rate PP46 is earning a low rate of return of only 1.9%. WPP witness Siedt used these results, in part, to recommend an increase to PP46 customers of 36.2%. However, as I will discuss next, the Company's study incorrectly allocated the costs related to FERC Account 362 - Station Equipment. I will discuss this in the next section of my testimony, as well as how the Commission can correct this allocation.

<u>Correction to Account 362 - Station Equipment</u>

Q. Please describe how WPP's CCOSS allocates the cost of substations.

A. Account 362 - Station Equipment (also known as substations) is allocated on the basis of customer class NCP regardless of the voltage level at which WPP's customers take service. In other words, the Company's allocation of distribution substations assumes that all substations serve all distribution loads whether customers take service at primary or secondary voltage levels.

Q. Did you address this problem in WPP's last rate case in Docket No. R-2014-2428742?

A. Yes, I did.

Q. Is the Company's allocation of substations correct?

A. No. WPP's CCOSS ignores the fact that some substations only serve loads that take service below 23 kV. Other substations serve only Primary voltages greater than 23 kV and may be used by both Primary customers above and below 23 kV and by Secondary customers. Because of this improper functionalization of substations, customers taking service at voltages greater than 23 kV are paying for substation costs for which they are not responsible.

The Company's CCOSS properly analyzes the uses of Primary lines and related facilities to separate those serving Primary customers and those dedicated to serving only Secondary customers. This is very important from the standpoint of cost allocation because the lines used to serve customers who take service at Secondary voltage levels do not serve customers who take service at Primary voltage levels. If the costs associated with Secondary voltage facilities were allocated to Primary voltage customers, then Primary customers would be assigned costs for which they are not responsible and would be subsidizing Secondary customers in the process.

Unfortunately, this is the result with respect to the way WPP allocated the cost of substations in its CCOSS.

Q. How should substations be functionalized and allocated in the Company's CCOSS?

A. Since some rate schedules serving large primary customers are restricted to serving customers at 23 kV and above, this is a logical dividing point to prevent higher voltage customers from being allocated the cost of facilities that are dedicated to serving lower voltage customers. I performed a study using WPP's FERC Form 1 data to calculate the percentage of substation capacity that has a secondary voltage of less than 23 kV. This calculation is shown in Exhibit ___(RAB-2).

Q. How did you incorporate the separation of substations serving loads at 23 kV and above and those only serving loads at voltages less than 23 kV?

A. I created a weighted NCP Allocator (DMD_NCP_SUBT) that properly reflects the division of substations at 23 kV. Weights from the FERC Form 1 analysis presented in Exhibit ___(RAB-2) are in Row 1 of Columns AR and AU in the 'Allocator Inputs' worksheet in my AK Steel CCOSS. Columns AS and AV of that worksheet represent an allocation of the portion of the cost of Account 362 - Station Equipment associated with greater than 23 kV and less than 23 kV service, respectively. Using this split for substation costs more accurately classifies and allocates these costs to customer classes taking service at Primary and Secondary voltage levels.

Q. Have you prepared a CCOSS that correctly functionalizes and allocates substations?

A. Yes. Please refer to Exhibit ___(RAB-3), which presents a summary of my AK Steel recommended CCOSS at present rates. I developed this CCOSS using WPP's CCOSS that was provided in discovery in this proceeding. This CCOSS incorporates my recommended functionalization and reallocation of Account 362 substation costs. Table 2 below presents customer class rates of return and unitized rates of return.

TABLE 2
AK Steel COSS
Current Class Rates of Return

	Pct. Return	Relative ROR
WP_RS	2.9%	0.69
WP_GS10	19.2%	4.64
WP_GSS	-2.0%	(0.47)
WP_GSM	11.8%	2.85
WP_GSL	9.2%	2.23
WP_PP40	6.4%	1.54
WP_POL	16.0%	3.87
WP_PSU	6.2%	1.49
WP_PP44	256.5%	61.98
WP_PP46	7.9%	1.90
WP_STLT	3.1%	0.74
Total Retail	4.1%	

Q. How do the results of AK Steel CCOSS compare to WPP's CCOSS?

A. My recommended AK Steel CCOSS shows that with the proper allocation of substations included in the analysis, Rate PP46 is paying a significantly higher rate of return currently than WPP's CCOSS shows. Under the AK Steel CCOSS, the current return for PP46 increases from only 1.9% in the Company's study to 7.9%.

Given the change in the PP46 rate of return under the AK Steel CCOSS, West Penn should not impose a 36.2% increase on PP46 customers. This increase is unjustified and unreasonable.

Q. Should the Commission use your recommended AK Steel CCOSS for purposes of revenue allocation in this proceeding?

A. Yes. The AK Steel CCOSS properly allocates the cost of substations in Account 362 - Station Equipment. In Section III of my testimony, I will present my recommended class revenue allocation based on the AK Steel CCOSS.

III. REVENUE ALLOCATION

Q. How do you recommend that the Commission allocate WPP's revenue increase in this proceeding?

A. For purposes of this proceeding, I recommend that the Commission move to reduce subsidies by allocating the Company's revenue increase such that each class moves toward a relative rate of return of 1.0 based on my recommended AK Steel CCOSS. In order to avoid a large increase for the GSS class, I also recommend that its full cost of service increase be limited to 1.5 times the system average increase, or 39.5%.

The specific application of my recommended revenue allocation method would work as follows:

1. Calculate each rate class' revenue increase or decrease needed to achieve the system average rate of return.
2. Calculate each class' total percentage increase or decrease as a multiple of the system average increase. For example, the GSS class would require an increase of $15.7 million, or 129%, in order to move this class to its true cost to serve.
3. Zero out any class revenue decreases that would occur by moving to the system rate of return. In this case Rates GS10, GSM, GSL, POL, and PP44 would receive no decrease and would have their current revenues held

constant. The total revenue reduction for these classes would have been $14.64 million.

4. Limit the GSS increase to 1.5 times the system average increase, or 39.5%. This would lower the dollar increase to GSS to $4.8 million from $15.7 million, a difference of $10.9 million.
5. Add the $10.9 million from lowering the GSS increase to the total class revenue reductions of $14.64 million. This results in a remaining revenue decrease of $3.76 million.
6. Use the $3.76 remaining revenue reduction to lower the increase to the Residential class (RS). This lowers the RS increase from $88.25 million to $84.49 million, or 36.4%.

This procedure relies upon both class cost responsibility from the AK Steel CCOSS and gradualism so that the RS and GSS revenue increases are mitigated. Exhibit ____(RAB-4) presents the detailed calculations of how this process was accomplished using the AK Steel CCOSS.

Q. Please show how your proposed revenue allocation method would work using your recommended AK Steel CCOSS.

A. Table 3 below summarized the class revenue increases in both dollar and percentage terms from my revenue allocation proposal.

TABLE 3

AK Steel
Proposed Class increases
(000s)

RS	$	84,494	36.4%
GS10	$	-	0.0%
GSS	$	4,805	39.5%
GSM	$	-	0.0%
PP40	$	805	8.9%
GSL	$	-	0.0%
POL	$	-	0.0%
PSU	$	120	11.5%
PP44	$	-	0.0%
PP46	$	5	0.2%
STLT	$	2,874	44.2%
Total	$	93,104	26.4%

Q. How would your revenue allocation work if the Commission reduces WPP's requested revenue increase in this case?

A. I recommend a uniform percentage scale-back of the increases shown in my Table 3 in the likely event that the Commission adopts a lower revenue increase than WPP requested.

Q. Please summarize your conclusions with respect to cost and revenue allocation.

A. First, I recommend that the Commission adopt my recommended AK Steel CCOSS in this proceeding. My revision to WPP's CCOSS is both reasonable and necessary to properly allocate Account 362 Station Equipment. The AK Steel CCOSS demonstrates that the Company's CCOSS allocates far too much Station Equipment costs to PP46 customers and greatly overstates the cost responsibility for this class.

Second, when the allocation of Station Equipment costs is corrected, PP46 customers should receive virtually no increase in this proceeding.

Third, my revenue allocation proposal reasonably mitigates a full cost of service rate increase to RS and GSS customers and provides that no class receive a rate decrease in this case.

Q. Does that complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Sworn to and subscribed before me on this
21st day of July 2016.

Notary Public

RANDY A FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 26, 2016
COBB COUNTY, GEORGIA

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission, *et al.* v. Metropolitan Edison Company	: : :	R-2016-2537349, *et al.*
Pennsylvania Public Utility Commission, *et al.* v. Pennsylvania Electric Company	: : :	R-2016-2537352, *et al.*
Pennsylvania Public Utility Commission, *et al.* v. Pennsylvania Power Company	: : :	R-2016-2537355, *et al.*
Pennsylvania Public Utility Commission, *et al.* v. West Penn Power Company	: : :	R-2016-2537359, *et al.*

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

AK STEEL

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JULY 22, 2016

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area
Vermont Department of Public Service

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Evaluation of cost allocation, rate design, rate plan, and carrying charge proposals.
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR- 09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E- GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009- 2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010- 2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010- 2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010- 2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010- 2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010- 2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010- 2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011- 2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

**Expert Testimony Appearances
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As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

Expert Testimony Appearances
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As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

Expert Testimony Appearances
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Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
07/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital
07/16	R-2016-2537359	PA	AK Steel Corp.	West Penn Power Co.	Cost and revenue allocation

West Penn Power
Summary of Pennsylvania Substations
2015 FERC Form 1

Character	VOLTAGE Primary	Secondary	Count	Substation Capacity in Mva
Distribution - U	0	0	22	(capacitors)
Distribution - U	25	4	1	3
Distribution - U	25	4.16	1	10
Distribution - U	25	12.5	52	580
Distribution - U	26	12.5	1	7
Distribution - U	34.5	4.16	1	21
Distribution - U	34.5	12.5	11	182
Distribution - U	46	4	2	19
Distribution - U	46	12.5	29	855
Distribution - U	69	12.5	2	44
Distribution - U	138	4.16	1	13
Distribution - U	138	12.5	59	2,590
Distribution - U	138	25	31	2,103
Distribution - U	138	34.5	3	170
Distribution - U	138	46	2	171
Distribution - U	138	69	2	142
Distribution - U	230	12.5	1	11
Distribution - U	230	46	3	444
Distribution - U	230	138	1	224
Distubution - U	46	12.5	1	24
Network	34.5	12.5	1	21
Network	46	12.5	1	45
Network	138	12.5	9	532
Network	138	25	8	725
Network	138	34.5	1	67
Network	138	46	1	80
Network	138	69	2	180
Network - U	138	12.5	1	102
Network - U	138	25	1	187
Transmission	138	12.5	2	102
Transmission	230	46	1	140
Transmission - U	25	12.5	2	17
Transmission - U	46	12.5	1	11
Transmission - U	69	25	1	39
Transmission - U	115	46	1	60
Transmission - U	138	4.16	1	14
Transmission - U	138	12.5	4	169
Transmission - U	138	25	10	756
Transmission - U	138	138	1	224
Transmission - U	230	46	1	280
Transmission - U	230	138	1	224
Transmission - U	500	138	2	3,136
Transmission- U	138	12.5	1	34
Total Distribution			204	7,613
Distribution with Secondary < 23 mV			162	4,359
			79.4%	57.3%

AK STEEL CLASS COST OF SERVICE STUDY
FULLY FUTURE TEST YEAR
PRESENT RATES, $1,000s

	TOTAL RETAIL	RS	GS10	GSS	GSM	PP40	GSL	POL	PSU	PP44	PP46	STLT
RATE BASE												
Plant in Service	2,422,305	1,667,397	2,507	144,160	299,834	65,590	133,990	22,003	8,250	5	20,761	57,808
Depreciation Reserve	878,013	581,935	955	47,112	115,868	32,233	55,565	9,647	3,804	1	10,755	20,138
Net Plant	1,544,292	1,085,462	1,553	97,048	183,967	33,357	78,425	12,356	4,446	4	10,006	37,670
Rate Base Additions	196,600	134,005	214	12,717	26,202	5,275	11,270	1,351	566	3	1,451	3,546
Rate Base Deductions	376,676	254,311	405	22,095	52,056	9,901	21,608	3,497	1,214	1	3,047	8,541
Rate Base Other Total	(180,076)	(120,306)	(191)	(9,379)	(25,854)	(4,626)	(10,338)	(2,146)	(648)	2	(1,596)	(4,995)
Rate Base Total	1,364,216	965,156	1,362	87,670	158,113	28,731	68,087	10,210	3,798	6	8,410	32,675
INCOME STATEMENT												
Revenue												
Tariff Revenue Total	353,143	231,994	703	12,150	61,463	9,077	22,847	4,458	1,041	31	2,880	6,498
Other Revenue Total	17,165	13,365	14	1,151	1,404	276	489	93	31	0	88	256
Retail Total	370,309	245,359	717	13,301	62,867	9,353	23,336	4,551	1,071	31	2,968	6,754
Expenses												
Total Operation & Maintenance Expense	139,733	105,054	114	8,172	13,430	3,074	5,532	698	347	0	973	2,339
Depreciation Expense	78,455	55,690	74	4,726	8,834	1,782	3,736	752	209	0	544	2,107
Other Expenses Amortization Expense Total	19,222	12,905	23	1,447	2,917	507	1,168	37	33	1	94	91
Taxes Other than Income Taxes Excl GRT	3,889	2,751	4	236	444	101	191	26	12	0	32	91
Gross Receipts Tax	20,835	13,688	41	717	3,626	536	1,348	263	61	2	170	383
Total Operating Expense	262,135	190,088	256	15,298	29,251	5,999	11,975	1,776	663	3	1,813	5,012
Income Before Taxes	108,174	55,271	461	(1,997)	33,616	3,353	11,361	2,774	408	28	1,155	1,743
Income taxes												
Current State Income Tax	11,156	5,695	47	(161)	3,467	361	1,173	268	40	3	118	145
Current Federal Income Tax	19,766	7,391	131	(1,428)	9,007	716	2,837	704	74	9	240	85
Provision for Deferred Income Taxes	21,592	15,140	22	1,360	2,589	467	1,104	175	62	0	140	533
Investent Tax Credit Adjustments	(795)	(557)	(1)	(50)	(95)	(17)	(41)	(6)	(2)	(0)	(5)	(20)
Total Income Tax	51,719	27,669	199	(279)	14,967	1,526	5,074	1,141	175	12	493	743
Net Income After Tax	56,454	27,602	262	(1,718)	18,648	1,827	6,287	1,634	234	16	662	1,000
Rate of Return	4.14%	2.86%	19.21%	-1.96%	11.79%	6.36%	9.23%	16.00%	6.16%	256.49%	7.87%	3.06%

AK STEEL CLASS COST OF SERVICE STUDY
FULLY FUTURE TEST YEAR
PRESENT RATES, $1,000s
RECOMMENDED REVENUE ALLOCATION

	TOTAL RETAIL	RS	GS10	GSS	GSM	PP40	GSL	POL	PSU	PP44	PP46	STLT
RATE BASE												
Plant in Service	2,422,305	1,667,397	2,507	144,160	299,834	65,590	133,990	22,003	8,250	5	20,761	57,808
Depreciation Reserve	878,013	581,935	955	47,112	115,868	32,233	55,565	9,647	3,804	1	10,755	20,138
Net Plant	1,544,292	1,085,462	1,553	97,048	183,967	33,357	78,425	12,356	4,446	4	10,006	37,670
Rate Base Additions	196,600	134,005	214	12,717	26,202	5,275	11,270	1,351	566	3	1,451	3,546
Rate Base Deductions	376,676	254,311	405	22,095	52,056	9,901	21,608	3,497	1,214	1	3,047	8,541
Rate Base Other Total	(180,076)	(120,306)	(191)	(9,379)	(25,854)	(4,626)	(10,338)	(2,146)	(648)	2	(1,596)	(4,995)
Rate Base Total	1,364,216	965,156	1,362	87,670	158,113	28,731	68,087	10,210	3,798	6	8,410	32,675
INCOME STATEMENT												
Revenue												
Tariff Revenue Total	446,247	320,248	424	27,840	50,277	9,882	21,200	2,955	1,161	3	2,885	9,372
Other Revenue Total	17,332	13,508	14	1,164	1,412	276	490	94	31	0	88	256
Retail Total	463,579	333,756	437	29,004	51,689	10,158	21,689	3,049	1,191	3	2,973	9,629
Expenses												
Total Operation & Maintenance Expense	139,733	105,054	114	8,172	13,430	3,074	5,532	698	347	0	973	2,339
Depreciation Expense	78,455	55,690	74	4,726	8,834	1,782	3,736	752	209	0	544	2,107
Other Expenses Amortization Expense Total	19,222	12,905	23	1,447	2,917	507	1,168	37	33	1	94	91
Taxes Other than Income Taxes Excl GRT	3,889	2,751	4	236	444	101	191	26	12	0	32	91
Gross Receipts Tax	26,329	18,895	25	1,643	2,966	583	1,251	174	68	0	170	553
Total Operating Expense	267,628	195,295	240	16,223	28,591	6,047	11,878	1,688	670	2	1,813	5,181
Income Before Taxes	195,951	138,461	197	12,781	23,098	4,111	9,811	1,361	522	1	1,160	4,447
Income taxes												
Current State Income Tax	19,925	14,006	20	1,315	2,416	436	1,018	127	52	0	119	415
Current Federal Income Tax	47,419	33,598	48	3,227	5,694	955	2,349	259	110	1	242	937
Provision for Deferred Income Taxes	21,592	15,140	22	1,360	2,589	467	1,104	175	62	0	140	533
Investent Tax Credit Adjustments	(795)	(557)	(1)	(50)	(95)	(17)	(41)	(6)	(2)	(0)	(5)	(20)
Total Income Tax	88,141	62,187	90	5,853	10,603	1,841	4,431	554	221	1	495	1,865
Net Income After Tax	107,809	76,274	108	6,928	12,495	2,270	5,380	807	300	0	665	2,582
Rate of Return	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%
Current Tariff Revenues	353,143	231,994	703	12,150	61,463	9,077	22,847	4,458	1,041	31	2,880	6,498
Increase to System ROR	93,104	88,254	(280)	15,689	(11,186)	805	(1,647)	(1,503)	120	(28)	5	2,874
Percentage Increase	26.4%	38.0%	-39.8%	129.1%	-18.2%	8.9%	-7.2%	-33.7%	11.5%	-90.2%	0.2%	44.2%
Multiple of System Average Increase		1.44	-1.51	4.90	-0.69	0.34	-0.27	-1.28	0.44	-3.42	0.01	1.68
Sum of Class Rate Reductions	(14,644)		(280)		(11,186)		(1,647)	(1,503)		(28)		
Limit GSS Increase to 1.5 Times System Average				4,805								
Class Rate Reductions Less GSS Difference	(3,760)	(3,760)										
Revised Class increases	93,104	84,494	-	4,805	-	805	-	-	120	-	5	2,874
Percentage Increase		36.4%	0.0%	39.5%	0.0%	8.9%	0.0%	0.0%	11.5%	0.0%	0.2%	44.2%
Multiple of System Average Increase		1.38	-	1.50	-	0.34	-	-	0.44	-	0.01	1.68

CERTIFICATE OF SERVICE

I hereby certify that on this 22nd day of July, 2016 I served a true copy of the DIRECT TESTIMONY AND EXHIBITS OF RICHARD A. BAUDINO on behalf of AK STEEL CORPORATION on the following persons listed on the attached Certificate of Service in the matter specified in accordance with the requirements of 52 Pa. Code §1.54.

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BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
RETAIL RATES FOR THE DISTRIBUTION	**)**	
OF ELECTRIC ENERGY	**)**	

REBUTTAL TESTIMONY

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

HEALTHCARE COUNCIL OF THE NATIONAL CAPITAL AREA

August 2016

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
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REBUTTAL TESTIMONY OF RICHARD A. BAUDINO

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Did you submit Direct Testimony and Exhibits in this proceeding?

A. Yes. I submitted Direct Testimony and Exhibits on behalf of the Healthcare Council of the National Capital Area ("HCNCA").

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to issues relating to cost allocation, revenue allocation, and rate design that were raised in the Direct Testimony filed by the Staff of the Maryland Public Service Commission ("Staff"), the Office of Public Counsel ("OPC"), and the Apartment and Office Building Association ("AOBA").

Commission Staff Direct Testimony - Cost and Revenue Allocation

Q. Please summarize the position of Staff witness Norman on the classification and allocation of Advanced Metering Infrastructure ("AMI") meters.

A. Ms. Norman recognized that the Commission declined to allocate the cost of AMI meters in Order No. 85724 based on benefits. Ms. Norman noted that although the Commission allocated the "incremental burden" of AMI meter costs on the basis of revenues, Ms. Norman characterized the Commission as finding that an allocation of AMI meters' cost based on benefits was not an obvious or immediate solution.

Ms. Norman's Table 13 presented CCOSS results with 25% of AMI costs allocated based on the CUST3701 allocator and the remainder allocated evenly between demand and energy. It is my understanding from her testimony that the CCOSS results in her Table 13 represent her preferred CCOSS. Mr. Blaise used these results in his revenue allocation proposal, which I will discuss later.

Ms. Norman also discussed and presented the results of additional class cost of service studies ("CCOSS") beginning on page 21 of her Direct Testimony, based on different ways of allocating AMI costs. Ms. Norman's Tables 11 through 13 contained the CCOSS results that allocated AMI meters based on Pepco's Supplemental filing, a demand allocation, and an energy allocation.

Q. Please summarize the relative rate of return for the classes that are not earning the system average rate of return from Ms. Norman's CCOSS presentation.

A. The relative rates of return for the under earning classes are shown below in my Rebuttal Table 1. They were taken from Tables 11 and 13 in Ms. Norman's Direct Testimony.

Rebuttal Table 1
Case No. 9418 CCOSS Results, Relative Rates of Return

	Residential	RTM	GS-LV
Company filed CCOSS	0.59	0.69	0.70
Staff Demand Based	0.64	0.69	0.79
Staff Energy Based	0.65	0.70	0.79
Staff Recommended	0.63	0.70	0.77

Sources: Norman Direct, pp. 22 - 23

Q. What are your initial conclusions with respect to the alternative CCOSS results presented by Ms. Norman?

A. No matter which alternative method is used to allocate AMI meter costs, the subsidized rate schedules are contributing at a level still *far* below their cost to serve. In fact, the alternative demand-based, energy-based and recommended CCOSS RRORs presented by Ms. Norman are not significantly different from one another.

The alternative CCOSS results presented by Ms. Norman still point to the need for an above average increase for classes that are far from paying their fair share of costs. Later in my Rebuttal Testimony, I will demonstrate to the Commission that the revenue allocation methodology I presented in my Direct Testimony will work effectively even with the class RRORs in Staff's preferred CCOSS.

Q. Do you agree with allocating AMI meter costs using demand and energy allocation factors?

A. No, I do not.

AMI metering costs, like the costs of other meters, should be classified as customer-related and allocated to the customer classes that receive the AMI meters. This approach follows the principle of cost causation, meaning that cost responsibility should be assigned to the customers that cause costs to be incurred. In the case of AMI meters, the residential and small commercial customers that have the meters installed on their premises are directly responsible for those costs. I do not agree with allocating costs based on benefits to the non-AMI metered customer classes that have not been quantified and either allocated or assigned to those customer classes.

The rate classes that received the AMI meters will benefit from those meters over time. Pepco's CCOSS followed this principle and assigned costs to those classes that incurred the AMI metering costs. In an <u>unbundled</u> environment, default customers clearly benefit from energy management tools available with AMI meters, but customers large enough to shop for energy supplies are not necessarily getting the most of these benefits. These customers may already be paying in their commodity and energy rates costs for load management information and services.

Q. In your opinion, does Ms. Norman's preferred CCOSS allocate AMI meter costs commensurate with the benefits to customer classes?

A. No. Ms. Norman's preferred CCOSS allocates AMI meter costs based on a 25% weighting of the CUST3701 allocator. The other 75% was based on an equal weighting of demand and energy allocators. This allocation assumes, without foundation, that 75% of the costs are allocable to all customer classes based on their respective shares of existing demand and energy consumption. It also implicitly assumes that the customer classes without AMI metering received benefits based in large part on their relative shares of demand and energy consumption. Ms. Norman presented no analysis or support for this allocator, which apparently was based on her judgment. She presented no evidence or analysis that this allocator apportions AMI meter costs commensurate with customer class benefits. In fact, nowhere in the witness' testimony is there any quantification of the benefits of the AMI metering system by customer class and certainly no quantification of benefits for classes with AMI metering.

Moreover, as a matter of fundamental logic, if AMI metering allows the customers behind the AMI equipment to shape their demands and to reduce and/or modify the timing of their energy consumption, those customers will be the direct beneficiaries.

Q. If the residential and small commercial customers take full advantage of AMI metering capabilities, what would happen with respect to the allocation of costs on Pepco's system?

A. If AMI metered customers are able to reduce their demand and energy consumption through load shaping activities, then they would likely reduce their shares of demand and energy costs on Pepco's system relative to other customer classes. For example, residential customers could reduce their allocated share of Pepco's demand-related distribution costs and thereby reduce their bills from Pepco. Of course, if AMI metered classes reduce their relative shares of cost responsibility on Pepco's system, then the remaining customers would be responsible for those costs. That could hardly be described as a benefit with regard to the costs saved by AMI metered customers that instead must be re-assigned to the remaining customers.

Q. Did Pepco provide any analysis suggesting that AMI metered customers could reduce their demands and/or consumption on its system?

A. Yes. Pepco witness Lefkowitz discussed the AMI-enabled demand side management initiatives established by the Company beginning on page 47 of her Direct Testimony. Ms. Lefkowitz also described the Company's Dynamic Pricing Program on pages 48 and 49, which provides a residential customer bill credit of $1.25 per kWh reduced during Peak Energy Savings Credit ("PESC") event periods. Obviously, these benefits are not available to customers that do not have AMI metering.

Q. Please summarize your understanding of the Commission's view with respect to the allocation of AMI metering costs to customer classes.

A. On page 18 of her Direct Testimony, Ms. Norman noted the Commission's position with respect to Smart Grid Initiative costs in its Order 87591 in Docket No. 9406. In that Order the Commission rejected BGE's assignment of Smart Grid Initiative costs because it did not allocate those costs "commensurate with the allocation of Smart Grid benefits to those classes."

Q. Given the Commission's Order 87591, how do you recommend the Commission use the alternative CCOSS presented by Ms. Norman?

A. Ms. Norman's preferred CCOSS appears to be a step toward the Commission's Order 87591, but places too little emphasis on the CUST3701 allocator. If the Commission chooses to carry its finding on the allocation of Smart Grid Initiative costs for BGE into this proceeding, then I recommend the Commission look at the range of outcomes between Pepco's filed CCOSS and Ms. Norman's preferred CCOSS. For Schedule R, for example, the range of RRORs is 0.59 to 0.63. As I have previously pointed out, this range of results shows that Schedule R is being subsidized, and thus not paying its fair share of costs. Recognition of that subsidy would suggest that a larger than system average increase in this case should be allocated to Rate Schedule R to address what has been an ongoing subsidization problem across the last several rate cases. Even under the Staff's preferred CCOSS, Schedule R has a lower RROR than it did in the Company's last rate proceeding.

Q. Turning now to revenue allocation, how did Mr. Blaise propose to allocate Staff's recommended electric service revenue increase to Pepco's rate classes?

A. Mr. Blaise described his recommended revenue allocation procedure beginning on page 9 of his Direct Testimony. Mr. Blaise recommended a two-step revenue increase process. In the first step, 18% of the increase is allocated to classes that are not earning the system average rate of return based on their proportional revenues, namely Schedules R, RTM, and GS-LV. In the second step, the remaining 82% is allocated to all rate classes, excluding Schedules GT-3B and TN, based on their proportionate share of base revenues. On page 17, lines 16 through 18, Mr. Blaise testified that his proposals "aim at addressing any potential issues of inter- and intra-class imbalances while avoiding rate shocks."

According to Mr. Blaise's Exhibit LB-2, his revenue allocation proposal resulted in a RROR of 0.75 for Schedule R. Apparently, Mr. Blaise used Ms. Norman's preferred CCOSS to allocate class revenues and calculate the resulting class RRORs from his revenue allocation proposal.

Q. Is Mr. Blaise's electric revenue allocation proposal reasonable?

A. No. Mr. Blaise's revenue allocation proposal fails to address the persistently low class rates of return for under earning classes that I presented in my Direct Testimony.

In my Direct Testimony, I noted that allocating 25% of the increase in the Step One portion of revenue allocation in the past had not adequately moved Pepco's customer classes toward the system average rate of return over time. Referring to Table 4 on page 55 of my Direct Testimony, Schedule R's RROR in Case No. 9336 was 0.75 and in this case it is 0.60. Moreover, Table 4 provided RRORs from Case No. 9286 through the current proceeding. The Commission issued its Order in Case No. 9286 on July 20, 2012. This means that for four years of rate cases, classes that have not been earning the system rate of return have not moved toward their cost of service.

Schedules R and RTM have even taken a step back since Case No. 9336. Obviously, these persistent inter-class subsidies existed before Case No. 9286 given the extremely low returns that were generated by Schedules R and RTM in that proceeding.

Mr. Blaise's revenue allocation would merely bring the Schedule R class back to the RROR that was targeted in Case No. 9336. Therefore, Mr. Blaise's recommended revenue allocation makes no progress toward alleviating the history of actual cross class subsidies in Pepco's class revenues.

Q. On page 17, lines 19 through 23, Mr. Blaise noted that the Commission upheld his two-step approach in several cases, including Case No. 9230. Would you recommend that the Commission follow Mr. Blaise's approach in this proceeding?

A. No. Mr. Blaise's approach does not go far enough in bringing class rates of return toward parity. The approach that the Commission adopted in Case No. 9230 does not apply to the persistent, long-term, and very significant subsidization that has been present in Pepco's customer class revenues. The approach I recommended in my Direct Testimony would make a very reasonable move toward (but not attain) full cost of service based rates for the under earning classes and would alleviate the long-term subsidies being paid by other rate classes.

Q. Referring to Order 87591, what was the resulting RROR for Rate Schedule R using Mr. Blaise's recommended revenue allocation?

A. On pages 197 and 198 of Order 87591, the Commission noted the following regarding Mr. Blaise's two-step revenue allocation method:

> "Staff recommends the Commission-approved two-step methodology for allocating revenues. In step-one, Mr. Blaise allocates 17 percent of the Company's new revenues toward Schedules R and RL (which he notes are BGE's under-earning rate classes). Then, in step-two, he proposes distributing the remaining revenue among all classes except Schedules SL, PL and T. He urges that his proposed allocation approach moves all classes closer to the system's RROR in a gradual way. He selected 17 percent for step-one as the "optimal allocation" of the new revenue requirement to avoid rate shock and for fairness to ratepayers. This selection, Mr. Blaise notes also helps increase the RROR of the under-earning classes and reduces cross-subsidization without causing rate shock. Staff also notes that the upward movement of the Schedule R RROR from 0.69 to 0.90 represents a greater than 50 percent increase in the Schedule R RROR."

Q. Did Staff's proposal move under-earning rate classes to a 0.90 RROR in this case?

A. No, it did not. Staff's proposal would move Schedule R to a RROR of .75.

Q. Did Staff move the RRORs of under-earning classes upward by 50% in this case?

A. No, it did not.

Q. Has the Commission allocated more than 17% - 18% in Step One of its revenue allocation in past cases?

A. Yes. In Order No. 85028 in Case No. 9286 the Commission allocated *50%* of the total revenue increase in Step One to Schedules R, RTM, and GS-LV. On page 125 of the Order, the Commission stated the following:

> "Pepco is directed first to apply 50% of the authorized revenue increase in this order to the three under-earning classes, R, RTM and

> GS-LV in proportion to the class distribution revenues compared to the overall revenues of these three classes. Next, the remainder of the revenue increase shall be distributed among all rate classes, (except the GT-3B, TN, and MGT-3A classes, because they have URORs significantly above average), based upon the class distribution revenues compared to the overall revenues, excluding the three over-earning classes mentioned above. Additionally, we direct the Company in its next rate proceeding to file its inter-class rate design proposal consistent with the two-step Commission methodology, although we do not direct the use of any specific percentage split herein. Finally, we direct the Company to provide a rate class rate of return and UROR comparison in its next rate case that conforms to AOBA's recommendations regarding the allocation of rate base and operating income adjustments consistent with COSS apportionments."

The Commission moved decisively in Case No. 9286 to reduce inter-class subsidies and move under-earning classes toward their allocated cost to serve. I note that the 50% Step One increase that the Commission employed in both Order No. 87591 and Order No. 85028 is greater than I recommend in this proceeding.

Q. Does Staff's proposed revenue allocation achieve goals Staff identified in its Direct Testimony?

A. No. Staff acknowledged that ratemaking seeks to achieve fairness to customers, which includes minimizing interclass subsidies. Mr. Blaise testified that "[a]ny proportion different than unity implies that the rate class is being subsidized (RROR<1.00) or the rate class is subsidizing other classes (RROR>1.00). In this situation there is a lack of equity in sharing the cost burden among the customers." Blaise Direct Testimony at page 5, lines 15 through 18.

I agree. Unfortunately, Staff's proposed revenue allocation perpetuates the "lack of equity" in the cost burden that rate classes must share through continued subsidization of the under earning classes.

Q. Staff included the GT-LV class in the allocation of his Step Two increase. Should the GT-LV class be included in Step Two?

A. No. Even under Staff's preferred CCOSS, the GT-LV class has a RROR of nearly 2.0. Under Mr. Blaise's revenue allocation method, the GT-LV class ends up with a RROR of 1.67. This is an unacceptably high RROR and indicates that the GT-LV class continues to provide significant subsidies to the under earning classes. Similar to the GT-3B and TN classes, the GT-LV class should receive no increase in this proceeding.

Q. Have you performed a calculation of class RRORs using the results of Staff's preferred CCOSS and your recommended revenue allocation procedure?

A. Yes, I have. Please refer to Rebuttal Exhibit ____(RAB-13). This exhibit was created using Mr. Blaise's work papers that Staff provided in response to HCNCA's discovery request. It shows the resulting customer class RRORs using Staff's recommended revenue requirement in this case and my revenue allocation recommendation that allocates 40% of the revenue requirement increase to Step One. The remaining 60% of the increase is allocated to the other rate classes, excluding GT-LV, GT-3B, and TN. Rebuttal Table 2 below presents a comparison of customer class RRORs between Mr. Blaise's revenue allocation and my revenue allocation.

Rebuttal Table 2

Customers Class RROR Comparison
At Staff Recommended Revenue Increase

Customer Class	Staff Proposed	HCNCA Proposed
R	0.75	0.80
RTM	0.77	0.81
GS-LV	0.91	0.96
MGT-LV	1.31	1.27
MGT-3A	1.14	1.10
GT-LV	1.67	1.47
GT-3B	5.73	5.73
GT-3A	1.05	1.02
TM-RT	1.27	1.23
SL	1.15	1.11
SSL	1.02	0.97
TN	3.42	3.42

Q. What is the important conclusion to draw from the RROR comparison in your Rebuttal Table 2?

A. My recommended Step One increase, which allocates 40% of the increase to under earning classes, moves those classes closer to their cost of service than Mr. Blaise's proposal does. In fact, the Step One allocation should be even greater than 40% in order to move R and RTM to a 0.90 RROR. In that sense, my recommended revenue increase is conservative with respect to the rate impact on the rate schedules receiving the greatest subsidies from other customers.

In addition, my proposed revenue allocation moves R and RTM to a higher RROR than those classes generated in Pepco's last rate case. This is consistent with one of the Commission's goals of moving classes toward cost of service over time. Staff's recommended revenue allocation is not consistent with that goal.

Q. What is the difference in the rate impact between your proposal and Staff's proposal on an average residential customer's monthly bill?

A. In order to answer this question, I developed a residential rate design using Mr. Blaise's work papers and the Schedule R revenue increase from my recommended revenue allocation. Please refer to Rebuttal Exhibit ____(RAB-14), which shows the resulting Schedule R rates. I accepted Staff's proposed customer charge and collected the remaining additional revenues in the energy charges.

Rebuttal Exhibit ____(RAB-15) shows the residential bill impact using the spreadsheet provided by the Staff in response to HCNCA's data request. This analysis corresponds to the information provided by Staff in Exhibit LB-4(1). However, my review of Staff's work papers indicated several calculation errors in Exhibit LB-4(1). I corrected these errors and the results are contained in my Rebuttal Exhibit ____(RAB-16). Based on my analysis, here are the following important points of comparison between my revenue allocation proposal and Staff's proposal with respect to the bill impact on a Schedule R customer who uses 924 kWh per month:

- The total percentage increase for summer rates is 5.13% for my proposal and 4.72% for Staff's proposal (*i.e.*, a difference of .41 percentage points).

- The monthly summer bill increase under my proposal is $7.74. Under Staff's proposal, the monthly increase is $7.11 per month. *The difference between my proposal and Staff's proposal is 63 cents per month.*

Q. What were the calculation errors you found in Exhibit LB-4(1)?

A. I found the following errors:

- Gross receipts taxes were not properly included in Total Fixed Charges under Staff Proposed Rates for the summer period.
- Total Fixed Charges for Staff's proposed winter rates was incorrect.
- The current winter volumetric rate was incorrect.
- The Total Volumetric Rate for proposed winter rates was calculated incorrectly.
- Winter Distribution Bill at Proposed Rates was calculated incorrectly.

Rebuttal Exhibit ____(RAB-16) corrected these errors.

Q. Please summarize your conclusions with respect to your revenue allocation proposal compared to Staff's proposal.

A. HCNCA's revenue allocation proposal, which allocates 40% of the total revenue increase to Step One, actually moves the subsidized classes toward the system rate of return. Staff's proposal does not; it perpetuates the subsidies rather than makes material but gradual progress in reducing the subsidies. My proposal does not result in rate shock and, in fact, does not represent a much higher bill increase for Schedule R customers than Staff's proposal based upon Staff's recommended revenue increase. The HCNCA proposal doesn't just stay within the Commission's past parameters; it actually is more restrained in terms of the proportion of any increase assigned exclusively to the most subsidized customers.

Finally, even if the Commission uses Ms. Norman's preferred CCOSS, I have demonstrated that my revenue allocation is still sound and moves subsidized classes toward the system rate of return.

<u>OPC Cost and Revenue Allocation</u>

Q. On page 20 of his Direct Testimony, Mr. Pavlovic recommended rejection of Pepco's proposed revenue allocation. Instead, Mr. Pavlovic recommended that the Commission's authorized revenue increase be allocated to all rate classes in proportion to each class' test year adjusted revenues. What is your conclusion with respect to Mr. Pavlovic 's revenue allocation proposal?

A. The Commission should reject Mr. Pavlovic's proposed revenue allocation.

On page 12 of his Direct Testimony, Mr. Pavlovic claimed to have found three errors in Pepco's filed CCOSS. However, Mr. Pavlovic failed to provide a CCOSS that "corrected" these "errors". As a result, the Commission, Staff, and other parties have no way of knowing whether an alternative CCOSS using the allocations advocated by Mr. Pavlovic would make any difference at all in terms of class RRORs. Furthermore, since Mr. Pavlovic provided no alternative CCOSS, he has absolutely no foundation for the reasonableness of his proposed revenue allocation, which amounts to an across-the-board increase for all customer classes, including the ones that are paying greatly in excess of their cost to serve, based on <u>any</u> of the multiple CCOSS that have been sponsored in this case.

AOBA and I have accepted Pepco's CCOSS for purposes of this case. Staff accepted Pepco's CCOSS with the modification of the allocation of AMI meters. Both Pepco's and Staff's preferred CCOSS show that the subsidized rate schedules are not paying nearly their fair share of costs and should be have an increase greater than the system average increase. It is important to note that no valid CCOSS presented in this case justifies a system average increase for the subsidized classes.

Finally, I note that the Commission has employed a two-step process for revenue allocation in several Pepco rate cases. Mr. Pavlovic's proposed across-the-board increase is certainly not consistent with the past orders involving Pepco.

Q. On page 18, lines 4 through 6 Mr. Pavlovic makes the claim that it is "well established that there is no justification in economic theory for such a requirement to allocate the return to the individual service provided by either a regulated utility or a market competitive firm." Please respond to this claim.

A. It is an established ratemaking principle that rates should be based on the cost to serve. It is a principle that is recognized by Staff’s Mr. Blaise, AOBA’s Mr. Oliver, Pepco’s Mr. Janocha, and by me. Class rates of return are the bell weather by which the rate analyst and the Commission can ascertain whether the rates being paid by customers are based on the cost to serve them. If one were to follow Mr. Pavlovic's view of the world, then rates could be based on practically anything.

Q. On page 19, line 5 Mr. Pavlovic testified that there is "no discernible temporal pattern" in the unitized rates of return for Pepco's rate classes. Is Mr. Pavlovic correct?

A. Mr. Pavlovic is completely incorrect. In fact, there is a strong and clearly discernible pattern showing that the subsidized rate schedules' RROR is significantly and persistently below 1.0. I recommend that the Commission move to correct this trend in this case by allocation of 40% of the allowed increase in Step One of the revenue allocation process. In this manner, the subsidized rate schedules would show a movement toward a RROR of 1.0.

Rate Design - Staff, OPC, and AOBA

Q. On page 21 of his Direct Testimony, Mr. Blaise presented his rate design recommendations for the non-residential rate schedules. Please summarize these recommendations.

A. Staff's explanation of how it designed rates for the non-residential rate schedules was rather short on specifics. Staff testified it increased the customer charge "with the goal that any increase in the customer charge should not distort the current relationship between customer, demand, and volumetric billing components to the extent that intra-class subsidies would result." Blaise Direct Testimony at page 21, lines 22 through 25.

I reviewed the rate classes under which HCNCA members take the bulk of their electric service: GT-LV and MGT-3A. For GT-LV, Staff's recommended equal percentage revenue increases for the volumetric and demand charges of 18.5%. Staff recommended and 8.5% increase in customer charge revenues. For GT-3A, Staff recommended an equal 13.5% increase in demand and volumetric charge revenues and a 7.02% increase in customer charge revenues.

Q. Are Staff's rate design recommendations for the non-residential rate schedules appropriate?

A. No. Staff proposed to collect far too much of Pepco's fixed costs in the volumetric rates for non-residential customers. Pepco's transmission and distribution system are fixed and do no vary with energy consumption. There is no ratemaking basis that poles, primary and secondary lines, transformers, and so on are sized to meet energy needs. They are not. They are sized and installed to meet the demands of customers as well as the number of customers on the system.

Further, in both Pepco's and Staff's preferred CCOSS, these distribution accounts are allocated to customers based on demand or customers, not on energy usage. This follows the National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual*, which states the following on page 90:

> "Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or

> customer-related. *Because there is no energy component of distribution-related costs, we need consider only the demand and customer components*." [Emphasis added.]

Rates should be designed to send proper price signals to customers. Staff's proposed rate design would send confusing and inaccurate pricing signals to demand metered customers. This is because the volumetric charge is higher than it should be and the demand charge is lower than it should be. An overpriced volumetric charge tells customers that the cost of using energy is higher than it really is. Likewise, the underpriced demand charge sends the signal that the cost of Pepco's distribution capacity, or fixed cost, is much lower than it really is. This provides a perverse incentive for customers to lower their energy usage relative to their demand usage, resulting in lower load factors for customers.

Furthermore, Staff's proposed rate design would detrimentally impact high load factor demand metered customers, whose energy usage is efficient relative to their peak demands compared to lower load factor customers. The more that demand-related fixed costs are collected through the variable energy charge, lower load factor customers who use less energy relative to their peak demands pay less of those costs than they should. This results in intra-class inequities for non-residential classes with demand charges.

Q. Do intra-class subsidies result from Staff's proposed rate design?

A. They most certainly do. Staff's proposed rate design results in higher load factor customers subsidizing lower load factor customers. Staff's proposed rate design favors maintaining the current relationship between customer, demand, and energy charges. Unfortunately, this relationship is not based on costs to serve or on sending accurate pricing signals to customers.

Q. On page 16 lines 12 through 13 AOBA witness Oliver testified that it is "hard to rationalize how a demand charge increase of over 80% would impact all customers equitably." Please respond to his position.

A. I disagree with Mr. Oliver. In fact, Mr. Oliver's rate design proposal, in which all rate components are given an equal percentage increase, fails to treat MGT and GT customers equitably because it maintains an improper and uneconomic rate structure that unfairly favors low load factor customers over high load factor customers.

In my view, Pepco's proposed rate design moves to reduce a substantial amount of inequity in its current rate design for MGT and GT customers by moving demand charges more toward their cost based level, which reduces intra-class subsidies. This is an equitable result and I recommend that the Commission should adopt Pepco's proposed rate design for MGT and GT customers.

Q. Should the Commission reject Mr. Pavlovic's proposed rate design for MGT and GT customers?

A. Yes. On page 23 of his Direct Testimony, Mr. Pavlovic recommended that the distribution of the revenue requirement to customer, demand, and volumetric charges be maintained under the Company's current rate structure. This recommendation is similar to those of Staff witness Blaise, and AOBA witness Oliver and should be rejected on the grounds I explained previously.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

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IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
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EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

HEALTHCARE COUNCIL OF THE NATIONAL CAPITAL AREA

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

August, 2016

Case No. 9418
Exhibit No. ___ (RAB-13)
Page 1 of 1

HCNCA PROPOSED CLASS REVENUE ALLOCATION - STAFF RECOMMENDED REVENUE REQUIREMENT

Required Revenue	$53,400,000.00
Proportion of Required Revenue	100%
Staff Recommended Increase	**$37,000,000**
First Step Allocation	40.00%

	Total	R	RTM	GS-LV	MGT-LV	MGT-3A	GT-LV	GT-3B	GT-3A	TM-RT	SL	SSL	TN
		Residential	**RTM**										
Distribution Rate Base	$1,788,760,182	$831,672,647	$159,067,116	$66,512,798	$472,767,985	$5,654,451	$98,281,378	$4,136,397	$97,922,058	$14,869,309	$7,116,122	$29,877,525.42	$882,395.28
Operating Income	$69,424,057	$20,430,803.75	$4,291,367.96	$1,983,256.34	$26,995,423.95	$276,553.46	$7,329,403.61	$1,204,891.03	$4,376,843.72	$829,744.50	$357,564.71	$1,194,485.00	$153,718.71
ROR	3.88%	2.46%	2.70%	2.98%	5.71%	4.89%	7.46%	29.13%	4.47%	5.58%	5.02%	4.00%	17.42%
Unitized ROR	**1.00**	**0.63**	**0.70**	**0.77**	**1.47**	**1.26**	**1.92**	**7.51**	**1.15**	**1.44**	**1.29**	**1.03**	**4.49**
An. Current Distribution Revenue	$435,480,550	$205,733,415	$34,898,074	$19,681,516	$110,371,680	$1,237,707	**$25,532,946**	**$2,899,394**	$21,400,983	$3,276,030	$1,447,175	$8,599,573	**$402,058**
		79.03%	13.41%	7.56%									
Step 1 Total Increase	$14,800,000	$11,696,897.51	$1,984,117.15	$1,118,985.34									
Total Margin After Step 1	$450,280,550	$217,430,312	$36,882,191	$20,800,501	$110,371,680	$1,237,707	$25,532,946	$2,899,394	$21,400,983	$3,276,030	$1,447,175	$8,599,573	$402,058
Revenue Share		50.59%	8.58%	4.84%	27.14%	0.30%			5.26%	0.81%	0.36%	2.11%	
Step 2 Allocation	$22,200,000	$11,231,587	$1,905,188	$1,074,471	$6,025,512	$67,570	$0		$1,168,342	$178,848	$79,005	$469,476	
Total Reqired Revenue	**$37,000,000**	**$22,928,485**	**$3,889,305**	**$2,193,457**	**$6,025,512**	**$67,570**	**$0**	**$0**	**$1,168,342**	**$178,848**	**$79,005**	**$469,476**	**$0.00**
Revenue Conversion Factor	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144
Incremental Income	$21,581,895	$13,374,058	$2,268,610	$1,279,431	$3,514,648	$39,413	$0	$0	$681,487	$104,321	$46,083	$273,843	$0
Adjusted Operating Income	$91,005,951	$33,804,862	$6,559,978	$3,262,687	$30,510,072	$315,967	$7,329,404	$1,204,891	$5,058,331	$934,066	$403,648	$1,468,328	$153,719
New Revenue Requirement	***$472,480,550***	***$228,661,899***	***$38,787,379***	***$21,874,973***	***$116,397,192***	***$1,305,277***	***$25,532,946***	***$2,899,394***	***$22,569,325***	***$3,454,878***	***$1,526,180***	***$9,069,049***	**$402,058**
Percentage Increase	**8.50%**	**11.14%**	**11.14%**	**11.14%**	**5.46%**	**5.46%**	**0.00%**	**0.00%**	**5.46%**	**5.46%**	**5.46%**	**5.46%**	**0.00%**
Class Increase Multiple of System Average		1.31	1.31	1.31	0.64	0.64	-	-	0.64	0.64	0.64	0.64	-
ROR	5.09%	4.06%	4.12%	4.91%	6.45%	5.59%	7.46%	29.13%	5.17%	6.28%	5.67%	4.91%	17.42%
RROR	1.00	0.80	0.81	0.96	1.27	1.10	1.47	5.73	1.02	1.23	1.11	0.97	3.42

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HCNCA
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2015
Schedule Residential ("R")

	TEST YEAR BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (a) (2)	EFFECTIVE RIDER 25 ADJ. (b) (3)	CURRENT EFFECTIVE RATES (4) = (2) + (3)	REVENUE AT CURRENT RATES (5) = (1) x (4)	WEATHER ADJUSTED BILLING DETERMINANTS (6)	PROPOSED CHANGE IN REVENUE: PROPOSED Rate (7)	PROPOSED Increase	REVENUE AT PROPOSED RATES (8) = (6) x (7)	CHANGE IN BASE REVENUE: REVENUE (9) = (8) - (5)	CHANGE IN BASE REVENUE: PERCENT (10) = (9) / (5)	Change in Rates
1. Customer Charge	BILLS					BILLS						
	5,447,616	$ 7.39		$ 7.39	$40,257,882.24	5,447,616	$ 7.85	$ 0.46	$ 42,774,000	**$ 2,516,118**	6.25%	6.25%
					19.61%				**18.71%**			
2. Distribution	kWh	$/kWh	$/kWh	$/kWh		kWh	$/kWh					
Summer	2,146,247,594	0.04492		0.04492	$96,409,442.00	1,994,103,290	0.05263	0.00771	$ 104,942,841	**$ 8,533,399**	8.85%	17.16%
Winter	2,883,035,730	0.02381		0.02381	$68,645,081.00	2,874,285,704	0.02816	0.00435	$ 80,945,059	**$ 12,299,978**	17.92%	18.28%
					$165,054,523.00				$ 185,887,900	**$ 20,833,377**		
					80.39%				**81.29%**			
3. Current Revenue					$205,312,405.24							
4. BSA					$421,010					**$ (421,010)**		
5. Total Revenue					$205,733,414.80				$ 228,661,900	$ 22,928,485	11.1%	
						6. Total Revenue (old + New)			**$ 228,661,900**	$ -		
			-			7. New Revenue			New Revenue Allocation	$ 22,928,485		
						8. Difference From New Revenue			Revenue Difference	$ -		

Residential Bill Impact Under HCNCA Proposal

Summer

	Current Rates	HCNCA Proposed
Fixed Charge	$ 7.39	$ 7.85
EUSP	$ 0.36	$ 0.36
County Tax	$ 0.01130831	$ 0.01131
Generation	$ 0.08017000	$ 0.08017
Admin Tax	$ (0.00029120)	$ (0.00029)
Total Fixed Charges	$ 7.91	$ 8.38
Delivery Charge ($/kWh)	$ 0.04492	$ 0.05263
Transmission	$ 0.007510	$ 0.00751
PSC Tax	$ 0.000620	$ 0.00062
MD Environmental Surcharge Tax ($/kWh)	$ 0.000147	$ 0.00015
MD Resource Surcharge Tax (kWh)	$ 0.000070	$ 0.00007
EmPower MD	$ 0.008763	$ 0.00876
GRC	$ 0.000140	$ 0.00014
TOTAL VOLUMETRIC RATE	**$ 0.15463**	**$ 0.16249**

Current Monthly Use (kWh)	Distribution Bill at Current Rates	Proposed Monthly Use (kWh)	Distribution Bill at Proposed Rates	Distribution Bill Increase %
100	$ 23.37	100	$ 24.63	5.37%
150	$ 31.10	150	$ 32.75	5.30%
200	$ 38.83	200	$ 40.88	5.26%
250	$ 46.56	250	$ 49.00	5.23%
300	$ 54.30	300	$ 57.12	5.21%
350	$ 62.03	350	$ 65.25	5.19%
400	$ 69.76	400	$ 73.37	5.18%
450	$ 77.49	450	$ 81.50	5.17%
500	$ 85.22	500	$ 89.62	5.16%
550	$ 92.95	550	$ 97.75	5.16%
600	$ 100.68	600	$ 105.87	5.15%
650	$ 108.41	650	$ 114.00	5.15%
700	$ 116.15	700	$ 122.12	5.14%
800	$ 131.61	800	$ 138.37	5.14%
924	$ 150.78	**924**	$ 158.52	**5.13%**
1,000	$ 162.53	1,000	$ 170.87	5.13%
1,200	$ 193.46	1,200	$ 203.37	5.12%
1,500	$ 239.85	1,500	$ 252.11	5.11%
1,800	$ 286.23	1,800	$ 300.86	5.11%
2,100	$ 332.62	2,100	$ 349.61	5.11%
2,500	$ 394.47	2,500	$ 414.60	5.10%
3,500	$ 549.10	3,500	$ 577.09	5.10%
5,000	$ 781.04	5,000	$ 820.83	5.09%

Winter

	Current Rates	HCNCA Proposed	GRT
Fixed Charge	$ 7.39	$ 7.85	0.020408
EUSP	$ 0.36	$ 0.36	
County Tax	$ 0.01130831	$ 0.01131	
Generation	$ 0.08017000	$ 0.08017	
Admin Tax	$ (0.00029120)	$ (0.00029)	
Total Fixed Charges	$ 7.91	$ 8.38	
Volumetric Charge ($/kWh)	$ 0.02381000	$ 0.02816	
Franchise Tax ($/kWh)	$ 0.00751000	$ 0.00751	
County Surcharge Tax ($/kWh)	$ 0.00062000	$ 0.00062	
MD Environmental Surcharge Tax ($/kWh)	$ 0.00014700	$ 0.00015	
MD Resource Surcharge Tax (kWh)	$ 0.00007000	$ 0.00007	
MD Admin. Credit (kWh)	$ 0.00876300	$ 0.00876	
GRC Tracker ($/kWh)	$ 0.00014000	$ 0.00014	
TOTAL VOLUMETRIC RATE	**$ 0.13309**	**$ 0.13753**	

Current Monthly Use (kWh)	Distribution Bill at Current Rates	Proposed Monthly Use (kWh)	Distribution Bill at Proposed Rates	Distribution Bill Increase %
100	$ 21.22	100	$ 22.13	4.31%
150	$ 27.87	150	$ 29.01	4.07%
200	$ 34.53	200	$ 35.88	3.93%
250	$ 41.18	250	$ 42.76	3.84%
300	$ 47.83	300	$ 49.64	3.77%
350	$ 54.49	350	$ 56.51	3.71%
400	$ 61.14	400	$ 63.39	3.67%
450	$ 67.80	450	$ 70.26	3.64%
500	$ 74.45	500	$ 77.14	3.61%
550	$ 81.10	550	$ 84.02	3.59%
600	$ 87.76	600	$ 90.89	3.57%
650	$ 94.41	650	$ 97.77	3.55%
700	$ 101.07	700	$ 104.65	3.54%
800	$ 114.38	800	$ 118.40	3.52%
924	$ 130.88	**924**	$ 135.45	**3.49%**
1,000	$ 140.99	1,000	$ 145.90	3.48%
1,200	$ 167.61	1,200	$ 173.41	3.46%
1,500	$ 207.54	1,500	$ 214.67	3.44%
1,800	$ 247.46	1,800	$ 255.92	3.42%
2,100	$ 287.39	2,100	$ 297.18	3.41%
2,500	$ 340.62	2,500	$ 352.19	3.40%
3,500	$ 473.71	3,500	$ 489.72	3.38%
5,000	$ 673.33	5,000	$ 696.01	3.37%

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Residential Bill Impact Under Staff's Proposal - Corrected

Summer

	Current Rates	Staff Proposed Rates
Fixed Charge	$ 7.39	$ 7.85
EUSP	$ 0.36	$ 0.36
County Tax	$ 0.01130831	$ 0.01131
Generation	$ 0.08017000	$ 0.08017
Admin Tax	$ (0.00029120)	$ (0.00029)
Total Fixed Charges	$ 7.91	$ 8.38
Delivery Charge ($/kWh)	$ 0.04492	$ 0.05196
Transmission	$ 0.007510	$ 0.00751
PSC Tax	$ 0.000620	$ 0.00062
MD Environmental Surcharge Tax ($/kWh)	$ 0.000147	$ 0.00015
MD Resource Surcharge Tax (kWh)	$ 0.000070	$ 0.00007
EmPower MD	$ 0.008763	$ 0.00876
GRC	$ 0.000140	$ 0.00014
TOTAL VOLUMETRIC RATE	$ 0.15463	$ 0.16181

Current Monthly Use (kWh)	Distribution Bill at Current Rates	Proposed Monthly Use (kWh)	Distribution Bill at Proposed Rates	Distribution Bill Increase %
100	$ 23.37	100	$ 24.56	5.08%
150	$ 31.10	150	$ 32.65	4.98%
200	$ 38.83	200	$ 40.74	4.91%
250	$ 46.56	250	$ 48.83	4.87%
300	$ 54.30	300	$ 56.92	4.84%
350	$ 62.03	350	$ 65.01	4.81%
400	$ 69.76	400	$ 73.10	4.79%
450	$ 77.49	450	$ 81.19	4.78%
500	$ 85.22	500	$ 89.28	4.77%
550	$ 92.95	550	$ 97.38	4.76%
600	$ 100.68	600	$ 105.47	4.75%
650	$ 108.41	650	$ 113.56	4.74%
700	$ 116.15	700	$ 121.65	4.74%
800	$ 131.61	800	$ 137.83	4.73%
924	$ 150.78	**924**	$ 157.89	**4.72%**
1,000	$ 162.53	1,000	$ 170.19	4.71%
1,200	$ 193.46	1,200	$ 202.55	4.70%
1,500	$ 239.85	1,500	$ 251.10	4.69%
1,800	$ 286.23	1,800	$ 299.64	4.68%
2,100	$ 332.62	2,100	$ 348.19	4.68%
2,500	$ 394.47	2,500	$ 412.91	4.67%
3,500	$ 549.10	3,500	$ 574.73	4.67%
5,000	$ 781.04	5,000	$ 817.45	4.66%

Winter

	Current Rates	Staff Proposed Rates	GRT
Fixed Charge	$ 7.39	$ 7.85	0.020408
EUSP	$ 0.36	$ 0.36	
County Tax	$ 0.01130831	$ 0.01131	
Generation	$ 0.08017000	$ 0.08017	
Admin Tax	$ (0.00029120)	$ (0.00029)	
Total Fixed Charges	$ 7.91	$ 8.38	
Columetric Charge ($/kWh)	$ 0.02381000	$ 0.02750	
Franchise Tax ($/kWh)	$ 0.00751000	$ 0.00751	
County Surcharge Tax ($/kWh)	$ 0.00062000	$ 0.00062	
MD Environmental Surcharge Tax ($/kWh)	$ 0.00014700	$ 0.00015	
MD Resource Surcharge Tax (kWh)	$ 0.00007000	$ 0.00007	
MD Admin. Credit (kWh)	$ 0.00876300	$ 0.00876	
GRC Tracker ($/kWh)	$ 0.00014000	$ 0.00014	
TOTAL VOLUMETRIC RATE	$ 0.13308506	$ 0.13685	

Current Monthly Use (kWh)	Distribution Bill at Current Rates	Proposed Monthly Use (kWh)	Distribution Bill at Proposed Rates	Distribution Bill Increase %
100	$ 21.22	100	$ 22.06	3.99%
150	$ 27.87	150	$ 28.91	3.71%
200	$ 34.53	200	$ 35.75	3.54%
250	$ 41.18	250	$ 42.59	3.43%
300	$ 47.83	300	$ 49.43	3.34%
350	$ 54.49	350	$ 56.28	3.28%
400	$ 61.14	400	$ 63.12	3.23%
450	$ 67.80	450	$ 69.96	3.19%
500	$ 74.45	500	$ 76.80	3.16%
550	$ 81.10	550	$ 83.65	3.13%
600	$ 87.76	600	$ 90.49	3.11%
650	$ 94.41	650	$ 97.33	3.09%
700	$ 101.07	700	$ 104.17	3.07%
800	$ 114.38	800	$ 117.86	3.04%
924	$ 130.88	**924**	$ 134.83	**3.02%**
1,000	$ 140.99	1,000	$ 145.23	3.00%
1,200	$ 167.61	1,200	$ 172.60	2.98%
1,500	$ 207.54	1,500	$ 213.65	2.95%
1,800	$ 247.46	1,800	$ 254.71	2.93%
2,100	$ 287.39	2,100	$ 295.76	2.91%
2,500	$ 340.62	2,500	$ 350.50	2.90%
3,500	$ 473.71	3,500	$ 487.35	2.88%
5,000	$ 673.33	5,000	$ 692.63	2.87%

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Redline of Rebuttal Testimony

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
RETAIL RATES FOR THE DISTRIBUTION	**)**	
OF ELECTRIC ENERGY	**)**	

REBUTTAL TESTIMONY

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

HEALTHCARE COUNCIL OF THE NATIONAL CAPITAL AREA

August 2016

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
RETAIL RATES FOR THE DISTRIBUTION	**)**	
OF ELECTRIC ENERGY	**)**	

REBUTTAL TESTIMONY OF RICHARD A. BAUDINO

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Did you submit Direct Testimony and Exhibits in this proceeding?

A. Yes. I submitted Direct Testimony and Exhibits on behalf of the Healthcare Council of the National Capital Area ("HCNCA").

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to issues relating to cost allocation, revenue allocation, and rate design that were raised in the Direct Testimony filed by the Staff of the Maryland Public Service Commission ("Staff"), the Office of Public Counsel ("OPC"), and the Apartment and Office Building Association ("AOBA").

Commission Staff Direct Testimony - Cost and Revenue Allocation

Q. Please summarize the position of Staff witness Norman on the classification and allocation of Advanced Metering Infrastructure ("AMI") meters.

A. Ms. Norman recognized that the Commission declined to allocate the cost of AMI meters in Order No. 85724 based on benefits. Ms. Norman noted that although the Commission allocated the "incremental burden" of AMI meter costs on the basis of revenues, Ms. Norman characterized the Commission as finding that an allocation of AMI meters' cost based on benefits was not an obvious or immediate solution.

Ms. Norman's Table 13 presented CCOSS results with 25% of AMI costs allocated based on the CUST3701 allocator and the remainder allocated evenly between demand and energy. It is my understanding from her testimony that the CCOSS results in her Table 13 represent her preferred CCOSS. Mr. Blaise used these results in his revenue allocation proposal, which I will discuss later.

Ms. Norman also discussed and presented the results of additional class cost of service studies ("CCOSS") beginning on page 21 of her Direct Testimony, based on different ways of allocating AMI costs. Ms. Norman's Tables 11 through 13 contained the CCOSS results that allocated AMI meters based on Pepco's Supplemental filing, a demand allocation, and an energy allocation.

Q. Please summarize the relative rate of return for the classes that are not earning the system average rate of return from Ms. Norman's CCOSS presentation.

A. The relative rates of return for the under earning classes are shown below in my Rebuttal Table 1. They were taken from Tables 11 and 13 in Ms. Norman's Direct Testimony.

Rebuttal Table 1
Case No. 9418 CCOSS Results, Relative Rates of Return

	Residential	RTM	GS-LV
Company filed CCOSS	0.59	0.69	0.70
Staff Demand Based	0.64	0.69	0.79
Staff Energy Based	0.65	0.70	0.79
Staff Recommended	0.63	0.70	0.77

Sources: Norman Direct, pp. 22 - 23

Q. What are your initial conclusions with respect to the alternative CCOSS results presented by Ms. Norman?

A. No matter which alternative method is used to allocate AMI meter costs, the subsidized rate schedules are contributing at a level still *far* below their cost to serve. In fact, the alternative demand-based, energy-based and recommended CCOSS RRORs presented by Ms. Norman are not significantly different from one another.

The alternative CCOSS results presented by Ms. Norman still point to the need for an above average increase for classes that are far from paying their fair share of costs. Later in my Rebuttal Testimony, I will demonstrate to the Commission that the revenue allocation methodology I presented in my Direct Testimony will work effectively even with the class RRORs in Staff's preferred CCOSS.

Q. Do you agree with allocating AMI meter costs using demand and energy allocation factors?

A. No, I do not.

AMI metering costs, like the costs of other meters, should be classified as customer-related and allocated to the customer classes that receive the AMI meters. This approach follows the principle of cost causation, meaning that cost responsibility should be assigned to the customers that cause costs to be incurred. In the case of AMI meters, the residential and small commercial customers that have the meters installed on their premises are directly responsible for those costs. I do not agree with allocating costs based on benefits to the non-AMI metered customer classes that have not been quantified and either allocated or assigned to those customer classes.

The rate classes that received the AMI meters will benefit from those meters over time. Pepco's CCOSS followed this principle and assigned costs to those classes that incurred the AMI metering costs. In an unbundled environment, default customers clearly benefit from energy management tools available with AMI meters, but customers large enough to shop for energy supplies are not necessarily getting the most of these benefits. These customers may already be paying in their commodity and energy rates costs for load management information and services.

Q. In your opinion, does Ms. Norman's preferred CCOSS allocate AMI meter costs commensurate with the benefits to customer classes?

A. No. Ms. Norman's preferred CCOSS allocates AMI meter costs based on a 25% weighting of the CUST3701 allocator. The other 75% was based on an equal weighting of demand and energy allocators. This allocation assumes, without foundation, that 75% of the costs are allocable to all customer classes based on their respective shares of existing demand and energy consumption. It also implicitly assumes that the customer classes without AMI metering received benefits based in large part on their relative shares of demand and energy consumption. Ms. Norman presented no analysis or support for this allocator, which apparently was based on her judgment. She presented no evidence or analysis that this allocator apportions AMI meter costs commensurate with customer class benefits. In fact, nowhere in the witness' testimony is there any quantification of the benefits of the AMI metering system by customer class and certainly no quantification of benefits for classes with AMI metering.

Moreover, as a matter of fundamental logic, if AMI metering allows the customers behind the AMI equipment to shape their demands and to reduce and/or modify the timing of their energy consumption, those customers will be the direct beneficiaries.

Q. If the residential and small commercial customers take full advantage of AMI metering capabilities, what would happen with respect to the allocation of costs on Pepco's system?

A. If AMI metered customers are able to reduce their demand and energy consumption through load shaping activities, then they would likely reduce their shares of demand and energy costs on Pepco's system relative to other customer classes. For example, residential customers could reduce their allocated share of Pepco's demand-related distribution costs and thereby reduce their bills from Pepco. Of course, if AMI metered classes reduce their relative shares of cost responsibility on Pepco's system, then the remaining customers would be responsible for those costs. That could hardly be described as a benefit with regard to the costs saved by AMI metered customers that instead must be re-assigned to the remaining customers.

Q. Did Pepco provide any analysis suggesting that AMI metered customers could reduce their demands and/or consumption on its system?

A. Yes. Pepco witness Lefkowitz discussed the AMI-enabled demand side management initiatives established by the Company beginning on page 47 of her Direct Testimony. Ms. Lefkowitz also described the Company's Dynamic Pricing Program on pages 48 and 49, which provides a residential customer bill credit of $1.25 per kWh reduced during Peak Energy Savings Credit ("PESC") event periods. Obviously, these benefits are not available to customers that do not have AMI metering.

Q. Please summarize your understanding of the Commission's view with respect to the allocation of AMI metering costs to customer classes.

A. On page 18 of her Direct Testimony, Ms. Norman noted the Commission's position with respect to Smart Grid Initiative costs in its Order 87591 in Docket No. 9406. In that Order the Commission rejected BGE's assignment of Smart Grid Initiative costs because it did not allocate those costs "commensurate with the allocation of Smart Grid benefits to those classes."

Q. Given the Commission's Order 87591, how do you recommend the Commission use the alternative CCOSS presented by Ms. Norman?

A. Ms. Norman's preferred CCOSS appears to be a step toward the Commission's Order 87591, but places too little emphasis on the CUST3701 allocator. If the Commission chooses to carry its finding on the allocation of Smart Grid Initiative costs for BGE into this proceeding, then I recommend the Commission look at the range of outcomes between Pepco's filed CCOSS and Ms. Norman's preferred CCOSS. For Schedule R, for example, the range of RRORs is 0.59 to 0.63. As I have previously pointed out, this range of results shows that Schedule R is being subsidized, and thus not paying its fair share of costs. Recognition of that subsidy would suggest that a larger than system average increase in this case should be allocated to Rate Schedule R to address what has been an ongoing subsidization problem across the last se~~r~~veral rate cases. Even under the Staff's preferred CCOSS, Schedule R has a lower RROR than it did in the Company's last rate proceeding.

Q. Turning now to revenue allocation, how did Mr. Blaise propose to allocate Staff's recommended electric service revenue increase to Pepco's rate classes?

A. Mr. Blaise described his recommended revenue allocation procedure beginning on page 9 of his Direct Testimony. Mr. Blaise recommended a two-step revenue increase process. In the first step, 18% of the increase is allocated to classes that are not earning the system average rate of return based on their proportional revenues, namely Schedules R, RTM, and GS-LV. In the second step, the remaining 82% is allocated to all rate classes, excluding Schedules GT-3B and TN, based on their proportionate share of base revenues. On page 17, lines 16 through 18, Mr. Blaise testified that his proposals "aim at addressing any potential issues of inter- and intra-class imbalances while avoiding rate shocks."

According to Mr. Blaise's Exhibit LB-2, his revenue allocation proposal resulted in a RROR of 0.75 for Schedule R. Apparently, Mr. Blaise used Ms. Norman's preferred CCOSS to allocate class revenues and calculate the resulting class RRORs from his revenue allocation proposal.

Q. Is Mr. Blaise's electric revenue allocation proposal reasonable?

A. No. Mr. Blaise's revenue allocation proposal fails to address the persistently low class rates of return for under earning classes that I presented in my Direct Testimony.

In my Direct Testimony, I noted that allocating 25% of the increase in the Step One portion of revenue allocation in the past had not adequately moved Pepco's customer classes toward the system average rate of return over time. Referring to Table 4 on page 55 of my Direct Testimony, Schedule R's RROR in Case No. 9336 was 0.75 and in this case it is 0.60. Moreover, Table 4 provided RRORs from Case No. 9286 through the current proceeding. The Commission issued its Order in Case No. 9286 on July 20, 2012. This means that for four years of rate cases, classes that have not been earning the system rate of return have not moved toward their cost of service.

Schedules R and RTM have even taken a step back since Case No. 9336. Obviously, these persistent inter-class subsidies existed before Case No. 9286 given the extremely low returns that were generated by Schedules R and RTM in that proceeding.

Mr. Blaise's revenue allocation would merely bring the Schedule R class back to the RROR that was targeted in Case No. 9336. Therefore, Mr. Blaise's recommended revenue allocation makes no progress toward alleviating the history of actual cross class subsidies in Pepco's class revenues.

Q. **On page 17, lines 19 through 23, Mr. Blaise noted that the Commission upheld his two-step approach in several cases, including Case No. 9230. Would you recommend that the Commission follow Mr. Blaise's approach in this proceeding?**

A. No. Mr. Blaise's approach does not go far enough in bringing class rates of return toward parity. The approach that the Commission adopted in Case No. 9230 does not apply to the persistent, long-term, and very significant subsidization that has been present in Pepco's customer class revenues. The approach I recommended in my Direct Testimony would make a very reasonable move toward (but not attain) full cost of service based rates for the under earning classes and would alleviate the long-term subsidies being paid by other rate classes.

Q. **Referring to Order 87591, what was the resulting RROR for Rate Schedule R using Mr. Blaise's recommended revenue allocation?**

A. On pages 197 and 198 of Order 87591, the Commission noted the following regarding Mr. Blaise's two-step revenue allocation method:

> "Staff recommends the Commission-approved two-step methodology for allocating revenues. In step-one, Mr. Blaise allocates 17 percent of the Company's new revenues toward Schedules R and RL (which he notes are BGE's under-earning rate classes). Then, in step-two, he proposes distributing the remaining revenue among all classes except Schedules SL, PL and T. He urges that his proposed allocation approach moves all classes closer to the system's RROR in a gradual way. He selected 17 percent for step-one as the "optimal allocation" of the new revenue requirement to avoid rate shock and for fairness to ratepayers. This selection, Mr. Blaise notes also helps increase the RROR of the under-earning classes and reduces cross-subsidization without causing rate shock. Staff also notes that the upward movement of the Schedule R RROR from 0.69 to 0.90 represents a greater than 50 percent increase in the Schedule R RROR."

Q. Did Staff's proposal move under-earning rate classes to a 0.90 RROR in this case?

A. No, it did not. Staff's proposal would move Schedule R to a RROR of .75.

Q. Did Staff move the RRORs of under-earning classes upward by 50% in this case?

A. No, it did not.

Q. Has the Commission allocated more than 17% - 18% in Step One of its revenue allocation in past cases?

A. Yes. In Order No. 85028 in Case No. 9286 the Commission allocated *50%* of the total revenue increase in Step One to Schedules R, RTM, and GS-LV. On page 125 of the Order, the Commission stated the following:

> "Pepco is directed first to apply 50% of the authorized revenue increase in this order to the three under-earning classes, R, RTM and

> GS-LV in proportion to the class distribution revenues compared to the overall revenues of these three classes. Next, the remainder of the revenue increase shall be distributed among all rate classes, (except the GT-3B, TN, and MGT-3A classes, because they have URORs significantly above average), based upon the class distribution revenues compared to the overall revenues, excluding the three over-earning classes mentioned above. Additionally, we direct the Company in its next rate proceeding to file its inter-class rate design proposal consistent with the two-step Commission methodology, although we do not direct the use of any specific percentage split herein. Finally, we direct the Company to provide a rate class rate of return and UROR comparison in its next rate case that conforms to AOBA's recommendations regarding the allocation of rate base and operating income adjustments consistent with COSS apportionments."

The Commission moved decisively in Case No. 9286 to reduce inter-class subsidies and move under-earning classes toward their allocated cost to serve. I note that the 50% Step One increase that the Commission employed in both Order No. 87591 and Order No. 85028 is greater than I recommend in this proceeding.

Q. Does Staff's proposed revenue allocation achieve goals Staff identified in its Direct Testimony?

A. No. Staff acknowledged that ratemaking seeks to achieve fairness to customers, which includes minimizing interclass subsidies. Mr. Blaise testified that "[a]ny proportion different than unity implies that the rate class is being subsidized (RROR<1.00) or the rate class is subsidizing other classes (RROR>1.00). In this situation there is a lack of equity in sharing the cost burden among the customers." Blaise Direct Testimony at page 5, lines 15 through 18.

I agree. Unfortunately, Staff's proposed revenue allocation perpetuates the "lack of equity" in the cost burden that rate classes must share through continued subsidization of the under earning classes.

Q. Staff included the GT-LV class in the allocation of his Step Two increase. Should the GT-LV class be included in Step Two?

A. No. Even under Staff's preferred CCOSS, the GT-LV class has a RROR of nearly 2.0. Under Mr. Blaise's revenue allocation method, the GT-LV class ends up with a RROR of 1.67. This is an unacceptably high RROR and indicates that the GT-LV class continues to provide significant subsidies to the under earning classes. Similar to the GT-3B and TN classes, the GT-LV class should receive no increase in this proceeding.

Q. Have you performed a calculation of class RRORs using the results of Staff's preferred CCOSS and your recommended revenue allocation procedure?

A. Yes, I have. Please refer to Rebuttal Exhibit ____(RAB-~~1~~13). This exhibit was created using Mr. Blaise's work papers that Staff provided in response to HCNCA's discovery request. It shows the resulting customer class RRORs using Staff's recommended revenue requirement in this case and my revenue allocation recommendation that allocates 40% of the revenue requirement increase to Step One. The remaining 60% of the increase is allocated to the other rate classes, excluding GT-LV, GT-3B, and TN. Rebuttal Table 2 below presents a comparison of customer class RRORs between Mr. Blaise's revenue allocation and my revenue allocation.

Rebuttal Table 2

Customers Class RROR Comparison
At Staff Recommended Revenue Increase

Customer Class	Staff Proposed	HCNCA Proposed
R	0.75	0.80
RTM	0.77	0.81
GS-LV	0.91	0.96
MGT-LV	1.31	1.27
MGT-3A	1.14	1.10
GT-LV	1.67	1.47
GT-3B	5.73	5.73
GT-3A	1.05	1.02
TM-RT	1.27	1.23
SL	1.15	1.11
SSL	1.02	0.97
TN	3.42	3.42

Q. What is the important conclusion to draw from the RROR comparison in your Rebuttal Table 2?

A. My recommended Step One increase, which allocates 40% of the increase to under earning classes, moves those classes closer to their cost of service than Mr. Blaise's proposal does. In fact, the Step One allocation should be even greater than 40% in order to move R and RTM to a 0.90 RROR. In that sense, my recommended revenue increase is conservative with respect to the rate impact on the rate schedules receiving the greatest subsidies from other customers.

In addition, my proposed revenue allocation moves R and RTM to a higher RROR than those classes generated in Pepco's last rate case. This is consistent with one of the Commission's goals of moving classes toward cost of service over time. Staff's recommended revenue allocation is not consistent with that goal.

Q. What is the difference in the rate impact between your proposal and Staff's proposal on an average residential customer's monthly bill?

A. In order to answer this question, I developed a residential rate design using Mr. Blaise's work papers and the Schedule R revenue increase from my recommended revenue allocation. Please refer to Rebuttal Exhibit ____(RAB-~~2~~14), which shows the resulting Schedule R rates. I accepted Staff's proposed customer charge and collected the remaining additional revenues in the energy charges.

Rebuttal Exhibit ____(RAB-~~3~~15) shows the residential bill impact using the spreadsheet provided by the Staff in response to HCNCA's data request. This analysis corresponds to the information provided by Staff in Exhibit LB-4(1). However, my review of Staff's work papers indicated several calculation errors in Exhibit LB-4(1). I corrected these errors and the results are contained in my Rebuttal Exhibit ____(RAB-~~4~~16). Based on my analysis, here are the following important points of comparison between my revenue allocation proposal and Staff's proposal with respect to the bill impact on a Schedule R customer who uses 924 kWh per month:

- The total percentage increase for summer rates is 5.13% for my proposal and 4.72% for Staff's proposal (*i.e.*, a difference of .41 percentage points).

- The monthly summer bill increase under my proposal is $7.74. Under Staff's proposal, the monthly increase is $7.11 per month. *The difference between my proposal and Staff's proposal is 63 cents per month.*

Q. What were the calculation errors you found in Exhibit LB-4(1)?

A. I found the following errors:

- Gross receipts taxes were not properly included in Total Fixed Charges under Staff Proposed Rates for the summer period.
- Total Fixed Charges for Staff's proposed winter rates was incorrect.
- The current winter volumetric rate was incorrect.
- The Total Volumetric Rate for proposed winter rates was calculated incorrectly.
- Winter Distribution Bill at Proposed Rates was calculated incorrectly.

Rebuttal Exhibit ____(RAB-~~4~~16) corrected these errors.

Q. Please summarize your conclusions with respect to your revenue allocation proposal compared to Staff's proposal.

A. HCNCA's revenue allocation proposal, which allocates 40% of the total revenue increase to Step One, actually moves the subsidized classes toward the system rate of return. Staff's proposal does not; it perpetuates the subsidies rather than makes material but gradual progress in reducing the subsidies. My proposal does not result in rate shock and, in fact, does not represent a much higher bill increase for Schedule R customers than Staff's proposal based upon Staff's recommended revenue increase. The HCNCA proposal doesn't just stay within the Commission's past parameters; it actually is more restrained in terms of the proportion of any increase assigned exclusively to the most subsidized customers.

Finally, even if the Commission uses Ms. Norman's preferred CCOSS, I have demonstrated that my revenue allocation is still sound and moves subsidized classes toward the system rate of return.

OPC Cost and Revenue Allocation

Q. On page 20 of his Direct Testimony, Mr. Pavlovic recommended rejection of Pepco's proposed revenue allocation. Instead, Mr. ~~Wallach~~Pavlovic recommended that the Commission's authorized revenue increase be allocated to all rate classes in proportion to each class' test year adjusted revenues. What is your conclusion with respect to Mr. ~~Wallach's~~Pavlovic 's revenue allocation proposal?

A. The Commission should reject Mr. Pavlovic's proposed revenue allocation.

On page 12 of his Direct Testimony, Mr. Pavlovic claimed to have found three errors in Pepco's filed CCOSS. However, Mr. Pavlovic failed to provide a CCOSS that "corrected" these "errors". As a result, the Commission, Staff, and other parties have no way of knowing whether an alternative CCOSS using the allocations advocated by Mr. Pavlovic would make any difference at all in terms of class RRORs. Furthermore, since Mr. Pavlovic provided no alternative CCOSS, he has absolutely no foundation for the reasonableness of his proposed revenue allocation, which amounts to an across-the-board increase for all customer classes, including the ones that are paying greatly in excess of their cost to serve, based on any of the multiple CCOSS that have been sponsored in this case.

AOBA and I have accepted Pepco's CCOSS for purposes of this case. Staff accepted Pepco's CCOSS with the modification of the allocation of AMI meters. Both Pepco's and Staff's preferred CCOSS show that the subsidized rate schedules are not paying nearly their fair share of costs and should be have an increase greater than the system average increase. It is important to note that no valid CCOSS presented in this case justifies a system average increase for the subsidized classes.

Finally, I note that the Commission has employed a two-step process for revenue allocation in several Pepco rate cases. Mr. Pavlovic's proposed across-the-board increase is certainly not consistent with the past orders involving Pepco.

Q. On page 18, lines 4 through 6 Mr. Pavlovic makes the claim that it is "well established that there is no justification in economic theory for such a requirement to allocate the return to the individual service provided by either a regulated utility or a market competitive firm." Please respond to this claim.

A. It is an established ratemaking principle that rates should be based on the cost to serve. It is a principle that is recognized by Staff's Mr. Blaise, AOBA's Mr. Oliver, Pepco's Mr. Janocha, and by me. Class rates of return are the bell weather by which the rate analyst and the Commission can ascertain whether the rates being paid by customers are based on the cost to serve them. If one were to follow Mr. Pavlovic's view of the world, then rates could be based on practically anything.

Q. On page 19, line 5 Mr. Pavlovic testified that there is "no discernible temporal pattern" in the unitized rates of return for Pepco's rate classes. Is Mr. Pavlovic correct?

A. Mr. Pavlovic is completely incorrect. In fact, there is a strong and clearly discernible pattern showing that the subsidized rate schedules' RROR is significantly and persistently below 1.0. I recommend that the Commission move to correct this trend in this case by allocation of 40% of the allowed increase in Step One of the revenue allocation process. In this manner, the subsidized rate schedules would show a movement toward a RROR of 1.0.

Rate Design - Staff, OPC, and AOBA

Q. On page 21 of his Direct Testimony, Mr. Blaise presented his rate design recommendations for the non-residential rate schedules. Please summarize these recommendations.

A. Staff's explanation of how it designed rates for the non-residential rate schedules was rather short on specifics. Staff testified it increased the customer charge "with the goal that any increase in the customer charge should not distort the current relationship between customer, demand, and volumetric billing components to the extent that intra-class subsidies would result." Blaise Direct Testimony at page 21, lines 22 through 25.

I reviewed the rate classes under which HCNCA members take the bulk of their electric service: GT-LV and MGT-3A. For GT-LV, Staff's recommended equal percentage revenue increases for the volumetric and demand charges of 18.5%. Staff recommended and 8.5% increase in customer charge revenues. For GT-3A, Staff recommended an equal 13.5% increase in demand and volumetric charge revenues and a 7.02% increase in customer charge revenues.

Q. Are Staff's rate design recommendations for the non-residential rate schedules appropriate?

A. No. Staff proposed to collect far too much of Pepco's fixed costs in the volumetric rates for non-residential customers. Pepco's transmission and distribution system are fixed and do no vary with energy consumption. There is no ratemaking basis that poles, primary and secondary lines, transformers, and so on are sized to meet energy needs. They are not. They are sized and installed to meet the demands of customers as well as the number of customers on the system.

Further, in both Pepco's and Staff's preferred CCOSS, these distribution accounts are allocated to customers based on demand or customers, not on energy usage. This follows the National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual*, which states the following on page 90:

> "Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or

> customer-related. *Because there is no energy component of distribution-related costs, we need consider only the demand and customer components*." [Emphasis added.]

Rates should be designed to send proper price signals to customers. Staff's proposed rate design would send confusing and inaccurate pricing signals to demand metered customers. This is because the volumetric charge is higher than it should be and the demand charge is lower than it should be. An overpriced volumetric charge tells customers that the cost of using energy is higher than it really is. Likewise, the underpriced demand charge sends the signal that the cost of Pepco's distribution capacity, or fixed cost, is much lower than it really is. This provides a perverse incentive for customers to lower their energy usage relative to their demand usage, resulting in lower load factors for customers.

Furthermore, Staff's proposed rate design would detrimentally impact high load factor demand metered customers, whose energy usage is efficient relative to their peak demands compared to lower load factor customers. The more that demand-related fixed costs are collected through the variable energy charge, lower load factor customers who use less energy relative to their peak demands pay less of those costs than they should. This results in intra-class inequities for non-residential classes with demand charges.

Q. Do intra-class subsidies result from Staff's proposed rate design?

A. They most certainly do. Staff's proposed rate design results in higher load factor customers subsidizing lower load factor customers. Staff's proposed rate design favors maintaining the current relationship between customer, demand, and energy charges. Unfortunately, this relationship is not based on costs to serve or on sending accurate pricing signals to customers.

Q. On page 16 lines 12 through 13 AOBA witness Oliver testified that it is "hard to rationalize how a demand charge increase of over 80% would impact all customers equitably." Please respond to his position.

A. I disagree with Mr. Oliver. In fact, Mr. Oliver's rate design proposal, in which all rate components are given an equal percentage increase, fails to treat MGT and GT customers equitably because it maintains an improper and uneconomic rate structure that unfairly favors low load factor customers over high load factor customers.

In my view, Pepco's proposed rate design moves to reduce a substantial amount of inequity in its current rate design for MGT and GT customers by moving demand charges more toward their cost based level, which reduces intra-class subsidies. This is an equitable result and I recommend that the Commission should adopt Pepco's proposed rate design for MGT and GT customers.

Q. Should the Commission reject Mr. Pavlovic's proposed rate design for MGT and GT customers?

A. Yes. On page 23 of his Direct Testimony, Mr. Pavlovic recommended that the distribution of the revenue requirement to customer, demand, and volumetric charges be maintained under the Company's current rate structure. This recommendation is similar to those of Staff witness Blaise, and AOBA witness Oliver and should be rejected on the grounds I explained previously.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY**	**)**	
	CORPORATION FOR AN	**)**	**DOCKET NO. 2015-00343**
	ADJUSTMENT OF RATES AND	**)**	
	TARIFF MODIFICATIONS	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

APRIL 2016

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE: APPLICATION OF ATMOS ENERGY	)	
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BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	**APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES AND TARIFF MODIFICATIONS**	**)**	**DOCKET NO. 2015-00343**

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ___(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the allowed return on equity for regulated electric operations for Atmos Energy ("Atmos" or "Company"). I will also address certain capital structure issues as well as the cost of short-term debt. Finally, I will respond to the Direct Testimony of Dr. James Vander Weide, witness for the Company.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows.

First, I recommend that the Kentucky Public Service Commission ("KPSC" or "Commission") adopt a fair rate of return on equity of 9.0% for Atmos Energy. My recommended return on equity ("ROE") is based on a Discounted Cash Flow analysis using two comparison groups of regulated utilities, one consisting of gas distribution companies and the other based on regulated water companies. These are the same two groups of companies used by Dr. Vander Weide in his Direct Testimony on behalf of Atmos, adjusted for recent merger-related activity. My recommended 9.0% ROE is fully supported by current stock market data and expected growth rates and is consistent with the low interest rate environment that is present today.

Second, I recommend that the commitment and banking fees expenses that Atmos included in its cost of short-term debt be removed and placed into operations and maintenance expenses. I also recommend that the Commission adopt the Company's proposed cost of short-term debt, excluding the commitment and banking fees.

Third, I recommend that the Commission reject Atmos' proposed 55.32% equity ratio for the test year. This equity ratio is inflated and inconsistent with the Company's historical equity ratios. Instead, I recommend that the Commission authorize a 52.99% equity ratio consistent with the Company's base period capital structure. The difference between Atmos' requested equity ratio and my recommended 52.99% equity ratio should be made up by increasing the Company's short-term debt. Given the current low interest rate environment, Atmos should employ additional short-term debt to fund its capital expenditures and lower its cost of capital. In connection with this recommendation, if the Commission adopts Atmos' requested common equity ratio of 55.32%, then I recommend that the allowed ROE should be reduced to 8.60%.

Fourth, my recommended adjusted weighted cost of capital for Atmos is 7.05%.

Fifth, I recommend that the Commission reject Dr. Vander Weide's recommended 10.5% cost of equity. For reasons that I shall explain in Section IV of my testimony, a cost of equity of 10.5% is overstated, inconsistent with current market required returns, and would result in an excessive revenue requirement for Atmos.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Generally speaking, interest rates have declined over the last few years. Exhibit ___(RAB-2) presents a graphic depiction of the trend in interest rates from January 2008 through March 2016. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. In January 2008, the average public utility bond yield was 6.08% and the 20-year Treasury Bond yield was 4.35%. As of March 2016 the average public utility bond yield was 4.40%, representing a decline of 168 basis points, or 1.68% from January 2008. Likewise, the 20-year Treasury bond declined to 2.28% in March 2016, a decline of 2.07% (207 basis points) from January 2008.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in Exhibit ___(RAB-2)?

A. Yes. In response to the 2007 financial crisis and severe recession that followed in December 2007, the Federal Reserve ("Fed") undertook a series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets."[1]

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[1] http://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm

QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases.

QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury securities by the second quarter of 2011.[2]

Beginning in September 2011, the Federal Reserve initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist" was designed by the Federal Reserve to lower long-term interest rates and support the economic recovery.

QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities. On June 19, 2013, the Federal Open Market Committee ("FOMC") issued a press release indicating that it intended to extend "Operation Twist." In its press release, the Federal Reserve stated:

> To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its

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[2] http://www.federalreserve.gov/newsevents/press/monetary/20101103a.htm

> dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.

More recently, the Federal Reserve began to pare back its purchases of securities. For example, on January 29, 2014 the Federal Reserve stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Federal Reserve continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October.[3]

Q. Since the Federal Reserve's announcements of scaling back and finally ending its purchases of long-term Treasury securities, what has the trend been in long-term Treasury yields from 2014 through 2016?

A. The yield on the 20-year Treasury bond has actually declined since the beginning of 2014. The January 2014 yield on the 20-year Treasury bond was 3.52%. The closing yield for March 2016 was 2.28%, a decline of 124 basis points since January 2014.

[3] http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm

Q. Has the Federal Reserve recently indicated any important changes to its monetary policy?

A. Yes. Recently the Federal Reserve raised its target range for the federal funds rate to 1/4% to 1/2% from 0% to 1/4%. The Federal Reserve also issued a press release on March 16, 2016 stating that it would continue to maintain this target range at present.[4] This press release also stated:

"The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will continue to strengthen. However, global economic and financial developments continue to pose risks. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to monitor inflation developments closely.

Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation."

Q. Why is it important to understand the Fed's actions with respect to monetary policy since 2007?

A. The Fed's monetary policy actions since 2007 were deliberately undertaken to lower interest rates and support economic recovery. The Fed's actions have been quite successful in lowering interest rates given that the 20-year Treasury Bond yield in June 2007 was 5.29% and the public utility bond yield was 6.34%. The U.S. economy is currently in a low interest rate environment that, in my opinion, will likely continue at least through this year. As I will demonstrate later in my

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[4] http://www.federalreserve.gov/newsevents/press/monetary/20160316a.htm

testimony, low interest rates have also significantly lowered investors' required return on equity for the stocks of regulated utilities.

Q. Are current interest rates indicative of investor expectations regarding future policy actions by the Federal Reserve?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> "A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information."[5]

I acknowledge that the U.S. economy is operating in a low interest rate environment. It is likely at some point in the near future that the Federal Reserve will raise short-term interest rates further. However, the timing and the level of any such move are not known at this time. It is important to realize that investor expectations of higher interest rates, if any, are already embodied in current securities prices, which include debt securities and stock prices.

The current low interest rate environment favors lower risk regulated utilities. As I shall demonstrate in Section III, all the market evidence I examined suggests that investors require lower rates of return on equity on regulated utility stocks. It would not be advisable for utility regulators to raise ROEs in anticipation of higher interest rates that may or may not occur.

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5 Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.

Q. How does the investment community regard the regulated gas distribution industry as a whole?

A. The Value Line Investment Survey's March 4, 2016 summary report on the Natural Gas Utility industry noted the following:

> Stocks in Value Line's Natural Gas Utility Industry have performed nicely thus far in 2016. (Some were even trading at record-high price levels at the time of this writing.) We believe one factor is expectations of generally decent earnings in 2016. Too, during this period of greater financial market uncertainty (caused by concerns over such matters as persistently low oil prices and China's decelerating economy) the equities in our category appear more enticing than those of other sectors. That's largely because they offer well-covered, generous amounts of dividend income, which provide a measure of much-needed stability. What's more, there are some selections here that are favorably ranked for Timeliness, not a common occurrence since their historical price movements have tended to be steady.

Q. What do you conclude from the aforementioned quote from Value Line?

A. Utilities in general and gas utilities in particular continue to be safe, solid stock choices for investors. Even with uncertainty regarding the Federal Reserve's future moves on interest rates, utilities' prices have made solid gains since the beginning of 2016. For example, the Dow Jones utility average opened January 2016 at 574.51 and closed at 660.11 on April 8, 2016. This represents a gain of 14.9% since the beginning of this year.

It appears that the Fed will continue a relatively accommodating stance with respect to monetary policy in 2016 and has signaled that it does not intend to raise short-term interest rates at this time. The volatile economic conditions that were present in the 2008 - 2009 period are over and the U.S. economy continues to slowly recover from the recession that began in 2007.

Q. What are the current credit ratings and bond ratings for Atmos Energy?

A. Atmos Energy's current unsecured bond rating from Standard and Poor's is A- and A2 from Moody's. These ratings are both solidly investment grade ratings. Atmos also carries a positive ratings outlook from Standard and Poor's, indicating that the Company's rating could be raised "as a result of consistent and timely recovery of invested capital."[6]

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[6] https://www.standardandpoors.com/en_US/web/guest/article/-/view/type/HTML/id/1472798

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for Atmos.

A. I employed a Discounted Cash Flow ("DCF") analysis using two groups of regulated utilities. One group is comprised of gas distribution companies and the other of water utilities. With two adjustments to the gas distribution group, these are the same groups used by Dr. Vander Weide in his Direct Testimony. In my opinion, they form a reasonable basis for estimating the investor required return on equity for Atmos.

My DCF analysis is my standard constant growth form of the model that employs four different growth rate forecasts from the Value Line Investment Survey, IBES, and Zacks. I also employed Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data. Although I did not rely on the CAPM for my recommended 9.0% ROE for Atmos, the results from the CAPM tend to support this recommendation.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) and Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many electric utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the risk of a particular investment. The end result of their analyses is a bond and/or credit rating that reflect these risks.

<u>Discounted Cash Flow ("DCF") Model</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I typically employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}\!/_{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Embodied in this formula, it is assumed that "k" reflects the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for Atmos?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to Atmos. In estimating the cost of equity for a gas distribution company such as Atmos, I would begin with the group of gas distribution utilities followed by the Value Line Investment Survey. This is the same basic approach that Dr. Vander Weide followed in his Direct Testimony. He also added a group of water utilities as a supplement to the gas distribution group. This general approach is quite reasonable for estimating the cost of equity for Atmos in this case and I shall adopt it for purposes of my analysis as well.

Q. Did you make any adjustments to the two groups used by Dr. Vander Weide?

A. Yes. Dr. Vander Weide excluded companies from his group that were involved in merger activity, a selection criterion that I also use. In October 2015, Piedmont Natural Gas agreed to be acquired by Duke Energy. Therefore, it is now appropriate to exclude Piedmont Natural Gas from the gas distribution group for purposes of estimating the cost of equity. In addition, I added Southwest Gas to the gas distribution group. This company has growth rate forecasts from Value Line and IBES and is not subject to merger activity. Therefore, Southwest Gas should be included in the gas distribution group.

Q. What was your first step in determining the DCF return on equity for the comparison groups of regulated utilities?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from October 2015 through March 2016. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the gas distribution group is 3.11%. These calculations are shown in Exhibit ___(RAB-3).

The average dividend yield for the water utility group is 2.54%, the calculation for which may be found in Exhibit ____(RAB-5).

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the comparison groups?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and IBES. This is the method I typically use for estimating growth for my DCF calculations.

Q. Please briefly describe Value Line, Zacks, and IBES.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Plus Edition. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, IBES also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. Please explain how you used analysts' dividend and earnings growth forecasts in your constant growth DCF analysis.

Q. Columns (1) through (5) of Exhibit ____(RAB-4) shows the forecasted dividend, earnings, and retention growth rates from Value Line and the earnings growth forecasts from IBES and Zacks for the companies in the gas distribution group. In my analysis I used four of these growth rates: dividend and earnings growth from Value Line and earnings growth from Zacks and IBES. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows. Value Line is the only sources of which I am aware that forecasts dividend growth and my approach gives this forecast equal weight with each of the three earnings growth forecasts.

Exhibit ____(RAB-6) presents the dividend and earnings growth forecasts for the water utility group.

Q. How did you proceed to determine the DCF return of equity for the two comparison groups?

A. To estimate the expected dividend yield (D_1), the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

Exhibit ___(RAB-4) presents my standard method of calculating dividend yields, growth rates, and return on equity for the gas distribution group of companies. The DCF Return on Equity Calculation section shows the application of each of four growth rates I used in my analysis to the current group dividend yield of 3.11% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. In evaluating investor expected growth rates, I use both the average and the median values for the comparison group under consideration.

Exhibit ____(RAB-6) presents the same information for the water utility group. Please note that Zack's did not have earnings growth forecasts for Middlesex Water Company, SJW Corp., and York Water Company so I simply substituted the IBES growth rates for those companies.

Q. What are the results of your constant growth DCF model?

A. Referring to the gas distribution group in Exhibit ____(RAB-4), for the average growth rates the results range from 7.56% to 9.16%, with the average of these results being 8.61%. Using the median growth rates, the results range from 6.92% to 9.46%, with the average of these results being 8.56%.

Referring to the water utility group in Exhibit____(RAB-6), DCF results using the average growth rates range from 7.91% to 9.25%, with the average of these results being 8.65%. Using the median growth rates, the results range from 7.60% to 9.12%, with the average of these results being 8.24%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: *K* = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[7] There is evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total

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[7] For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206 - 211, 2007 edition.

market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for April 4, 2016. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit ____(RAB-7). I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 9.93% to 12.0%. The average of these three market returns is 10.97%.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2015 Classic Yearbook*. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit ____(RAB-8) presents the calculation of the market returns using the historical data.

Q. Please explain how this historical risk premium is calculated.

A. Exhibit ___(RAB-8) shows both the geometric and arithmetic average of yearly historical stock market returns over the historical period from 1926 - 2014. The average annual income return for 20-year Treasury bond is subtracted from these historical stocks returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The historical market risk premium range is 5.01% - 7.01%.

Q. Did you add an additional measure of the historical risk premium in this case?

A. Yes. Morningstar reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001.[8] Morningstar recommended adjusting this growth in the P/E ratio for stocks out of the historical risk premium because "it is not believed that P/E will continue to increase

8 *2014 Ibbotson SBBI Classic Yearbook,* Morningstar, pp. 156 - 158.

in the future." Morningstar's adjusted historical arithmetic market risk premium is 6.19%, which I have also included in Exhibit ___(RAB-8).

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from October 2015 through March 2016. The 20-year Treasury bond may be used as a proxy for the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM return on equity may be estimated.

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the gas distribution group from most recent Value Line reports. The average of the Value Line betas for the comparison group is 0.79.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 9.01% - 9.21%. Using historical risk premiums, the CAPM results are 6.44% - 8.03%.

ROE Conclusions and Recommendations

Q. Please summarize the cost of equity results for your DCF and CAPM analyses.

A. Table 1 below summarizes my return on equity results using the DCF and CAPM for my comparison group of companies.

TABLE 1

ATMOS ENERGY
ROE RESULTS SUMMARY

DCF Results:	
Average Growth Rates, Gas Group	
- High	9.16%
- Low	7.56%
- Average	8.61%
Median Growth Rates, Gas Group	
- High	9.46%
- Low	6.92%
- Average	8.56%
Average Growth Rates, Water Group	
- High	9.25%
- Low	7.91%
- Average	8.65%
Median Growth Rates, Water Group	
- High	9.12%
- Low	7.60%
- Average	8.24%
CAPM:	
- 5-Year Treasury Bond	9.01%
- 20-Year Treasury Bond	9.21%
- Historical Returns	6.44% - 8.03%

Q. What is your recommended return on equity for Atmos?

A. I recommend that the Commission adopt a 9.0% return on equity for Atmos. My recommendation is consistent with the midpoint of the range of DCF results that employed earnings growth forecasts for the gas distribution group. Based on current market evidence, a 9.0% return on equity is fair and reasonable for A/A-rated gas utility company like Atmos.

Q. Mr. Baudino, are you concerned that your recommended cost of equity is too low?

A. No, not at all. All of the market evidence I examined fully supports my ROE recommendation for Atmos in this proceeding. As I described in Section II of my testimony, the U. S. economy is in a low interest rate environment, one that has been supported in a deliberate and considered fashion by Federal Reserve monetary policy. Both my DCF and CAPM ROE estimates show that the investor required ROE for Atmos, as well as other regulated gas and water utilities, reflects this low interest rate environment. A 9.0% ROE recommendation for Atmos is by no means too low in the current economic and financial environment.

In fact, the average DCF results for both the gas and water groups suggest that an allowed ROE in the range of 8.40% - 8.70% would be reasonable for the Company. However, I am adjusting my recommended ROE upward due to the change in Federal Reserve policy I described in Section II of my testimony. The Federal Reserve recently increased its target range for the federal funds rate and I believe it is likely that the Fed could raise interest rates slightly later this year. Given this change in policy, an upward adjustment to my ROE recommendation appears reasonable at this particular point in time.

Cost of Short-Term Debt

Q. Please explain how you adjusted the Company's cost of short-term debt.

A. According to Schedule J-2 Atmos included commitment fees of $2.273 million in its requested cost of short-term debt. These fixed fees should not be included in the cost of short-term debt. Including these largely fixed fees in short-term debt costs requires the Commission to recalculate the percentage cost of short-term debt whenever it changes the rate base or modifies the amount of short-term debt.

Instead, I recommend that these fees be collected in O&M expenses. In this manner, the Commission ensures that the Company fully recovers these fixed expenses. At the same time, only the short-term debt interest rate itself is reflected in the weighted cost of capital regardless of the adjustments to rate base or the modifications to the capital structure.

Excluding commitment fees, Atmos' cost of short-term debt is 0.396%. This is the cost rate I recommend the Commission adopt for the Company's cost of capital in this case.

Capital Structure and Weighted Cost of Capital

Q. What is your recommended weighted cost of capital?

A. My weighted cost of capital recommendation is 7.05%. It is based on an adjusted equity ratio of 52.99%, an adjusted short-term debt ratio of 8.80%, an adjusted short-term debt cost of 0.40%, and my recommended ROE of 9.0%.

TABLE 2

ATMOS ENERGY
WEIGHTED COST OF CAPITAL

	Percentage	Cost	Wtd. Cost
Short-term Debt	8.80%	0.40%	0.03%
Long-term Debt	38.21%	5.90%	2.25%
Common Equity	52.99%	9.00%	4.77%
Total	100.00%		7.05%

Q. Please explain why you adjusted the Company's common equity ratio.

A. The Company's requested common equity ratio of 55.32% in the forecasted period is unreasonable and should be rejected by the Commission.

Atmos' Schedule J-1 shows that the percentage of common equity in the base period capital structure is 52.99%. In the forecasted period, Schedule J-1 shows an increase in common equity of $318.1 million, which is nearly equal to the increase in total capital from the base period to the forecasted period. Atmos has thus assumed, without foundation or analysis, that it is reasonable to finance nearly the entire amount of increased capital in the forecasted period with common equity. It is this assumption that caused the common equity ratio to rise from 52.99% to 55.32%.

Common equity is the most expensive form of financing available to the Company. In today's low interest rate environment Atmos should be taking full advantage of additional debt financing in order to lower its total cost of capital to ratepayers.

Q. Is the Company's forecasted common equity ratio consistent with its common equity ratios over the last ten years?

A. It certainly is not. Table 3 below shows Atmos' common equity ratios including short-term debt from 2006 through the base period. The percentages are based on using the daily average of short-term debt over the year. This information came from the Company's response to Staff 1-03.

TABLE 3

Atmos Historical Common Equity Ratios

2006	44.10%
2007	48.10%
2008	47.70%
2009	50.20%
2010	50.40%
2011	49.10%
2012	51.30%
2013	48.80%
2014	53.30%
Base Year	52.99%
Forecast Yr.	***55.32%***

Table 3 clearly shows how excessive the Company's requested common equity ratio is compared to the last 10 years. With the exception of 2014, even the base year common equity ratio is greater than the historical ratios.

Q. How do you recommend that the Commission adjust the Company's capital structure to maintain the base period common equity ratio of 52.99%?

A. I recommend that the Commission set the Company's common equity ratio in the forecasted year to 52.99%, which results in a total common equity amount of $3.405 billion. I also recommend that the amount of short-term debt be increased to $0.565 billion, or 8.80%. The Company's requested amount of long-term debt should be accepted.

Q. How does the Company's capital structure compare with the capital structure of your comparison group?

A. Table 4 below presents the 2015 common equity ratios for the companies in the gas utility group. These numbers were taken from the most recent Value Line Investment Survey reports for each company.

TABLE 4

GAS UTILITY GROUP
2015 COMMON EQUITY RATIOS

Atmos Energy	56.5%
LaClede Group	47.0%
New Jersey Resources	56.8%
Northwest Natural Gas	57.6%
South Jersey Industries	51.5%
Southwest Gas	50.7%
UGI Corp.	44.0%
WGL Holdings	56.1%
Average	52.5%

Source: Value Line Investment Survey

The base period common equity ratio of 52.99% for Atmos is consistent with the average common equity ratio for the gas utility group.

Q. If the Commission accepts the Company's requested 55.32% common equity ratio, should it also reduce your recommended ROE of 9.0%?

A. Yes. If the Commission accepts the Company's requested common equity ratio for the forecasted period, then my recommended ROE should be reduced in order to compensate for the lower financial risk that would result. I recommend that the Commission adopt a ROE in the range of 8.56% to 8.61%, which is the range of my

DCF results for the gas utility group. A ROE of 8.60% would be reasonable given the higher common equity ratio of 55.32%.

IV. RESPONSE TO ATMOS ENERGY TESTIMONY

Q. Have you reviewed the Direct Testimony of Dr. Vander Weide?

A. Yes.

Q. Please summarize your conclusions with respect to their testimony and return on equity recommendation.

A. My conclusions regarding Dr. Vander Weide's testimony and return on equity recommendations are as follows.

First, Dr. Vander Weide's recommended ROE of 10.5% is overstated and does not reflect the return requirement of investors in today' marketplace. A DCF model that is properly specified and applied shows a much lower range of results.

Second, Dr. Vander Weide's DCF results are overstated. This overstatement is due to the use of stale stock prices, the use of quarterly compounding in the calculation of the dividend yield component of the DCF model, and the addition of flotation costs.

Third, Dr. Vander Weide’s risk premium results are overstated and should be rejected. In particular, Dr. Vander Weide's use of a forecasted A-rated utility bond yield greatly inflated his risk premium results. For reasons I will explain later, the use of forecasted bond yields in the risk premium and CAPM estimates of ROE should be rejected.

Fourth, Dr. Vander Weide included a size adjustment that inflated his CAPM results. He also testified that the CAPM results are likely understated for companies such as regulated utilities that have betas less than 1.0. I disagree with this conclusion.

Q. Please summarize Dr. Vander Weide's approach to the DCF model and its results.

A. Dr. Vander Weide employed two comparison groups of companies to estimate the cost of equity for Atmos. One group consisted of publicly traded gas utilities and the other was comprised of water companies. Dr. Vander Weide confined his growth rate analysis to earnings forecasts from IBES for the gas utility group. For the water utility group he used an average of IBES and Value Line earnings growth forecasts. He also utilized quarterly compounding in his DCF calculations. Dr. Vander Weide did not consider forecasted dividend growth for either group of companies.

Q. What period did Dr. Vander Weide use to obtain stock prices for his DCF model?

A. Dr. Vander Weide used the 3-month period from June through August 2015.

Q. Are these prices out of date?

A. Yes. Since Dr. Vander Weide filed his testimony stock prices for the companies in the gas and water utility groups have increased. As stock prices increase, dividend yields will fall give a constant level of dividends. Using Dr. Vander Weide's work papers, I calculate that the current dividend yield for his gas group using his 3-month period for stock prices is 3.40%. The dividend yield using my 6-month period for stock prices, October 2015 through March 2016, is 3.16% for this group, which excludes Southwest Gas. Thus, current dividend yields are on average 24 basis points lower now than they were when Dr. Vander Weide filed his testimony.

Q. Should Dr. Vander Weide have included dividend growth forecasts in his DCF analyses?

A. Yes. Dr. Vander Weide erred in failing to include available dividend growth forecasts from Value Line in his DCF analyses. With respect to regulated utility companies, dividend growth provides the primary source of cash flow to the investor. It is certainly the case that earnings growth fuels dividend growth and should be considered in estimating the ROE using the DCF model; however, Value Line's dividend growth forecasts are widely available to investors and can reasonably be assumed to influence their expectations with respect to growth. I agree that earnings growth is the primary factor considered by investors, but it should not be considered the only factor, particularly if near-term dividend growth is expected to be less than longer-term earnings growth.

Exhibit ____(RAB-4) shows that Value Line's forecasted dividend growth for the gas distribution company group is lower than the earnings growth forecasts. Using dividend growth would have lowered Dr. Vander Weide's DCF results for the gas group. I also note that Exhibit ____(RAB-6) shows that dividend growth forecasts for the water utility group are on average higher than the earnings growth forecasts.

Q. On page 18, Dr. Vander Weide rejects the annual DCF model and recommends that the Commission accept a quarterly DCF calculation. Is a quarterly version of the DCF model appropriate for determining the allowed ROE for regulated utility companies?

A. No. The quarterly DCF model proposed by Dr. Vander Weide is unnecessary, overcompensates investors, and results in excessive costs for ratepayers.

I agree that dividends are paid quarterly and that investors have the ability to reinvest those dividends. This means that through quarterly compounding, if a utility company is allowed a 10% return on equity then investors will realize slightly more than a 10% return due to the reinvestment effect. However, this effect does not need to be added to the annual model that uses the 1 + 0.5 times growth adjustment that I used in my DCF calculations. Including quarterly compounding in the DCF calculation would basically compensate investors twice for the reinvestment effect.

Further, quarterly compounding is likely already accounted for in a company's stock price since investors know that dividends are paid quarterly and that they may reinvest those cash flows. Adding an incremental return for quarterly compounding merely serves to inappropriately and unnecessarily enhance the expected return on equity.

Q. Beginning on page 23 of his Direct Testimony, Dr. Vander Weide discussed his inclusion of a flotation cost adjustment in his DCF analyses. Do you agree with a flotation cost adjustment?

A. No, I do not. I recommend that the Commission reject a flotation cost adjustment in setting the cost of equity for Atmos.

In my opinion it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A

DCF model using current stock prices should already account for investor expectations, if any, regarding the collection of flotation costs. Multiplying the dividend yield by a 3% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. I do not believe that this is an appropriate assumption. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

Q. What is the overstatement of Dr. Vander Weide's DCF results due to the inclusion of quarterly compounding and flotation costs?

A. I calculated that quarterly compounding added 30 basis points to Dr. Vander Weide's DCF results. Flotation costs added another 20 basis points to his DCF results for a total of 50 basis points, or 0.50%.

<u>Risk Premium Model</u>

Q. Please present your conclusions regarding the results of Dr. Vander Weide's ex-ante risk premium analyses.

A. Dr. Vander Weide's ex-ante risk premium results are overstated and cannot be relied upon for setting Atmos' allowed ROE in this case. His results are overstated due to:

1. Use of a "forecasted" A-rated bond yield.
2. Sole use of forecasted earnings growth to calculate the DCF return for the gas group.
3. Inclusion of flotation costs.
4. Use of quarterly compounding in his DCF calculation.

I have already discussed items 2 through 4 previously in my testimony and they apply to the manner in which Dr. Vander Weide calculated the DCF return for his comparable group of gas distribution utilities. Dr. Vander Weide did not consider lower dividend growth in calculating the DCF return for his comparable gas company group. This omission likely overstates the expected DCF return for the group. And the inclusion of flotation costs and quarterly compounding further inflates his group DCF results. Taken together, all three of these problems overstate the risk premium he used in his analysis.

Q. How does the use of a forecasted A-rated bond yield overstate the risk premium return on equity?

A. Dr. Vander Weide's use of a forecasted A-rated utility bond yield should be rejected.

Current, observable bond yields should be used for any risk premium analysis. Current bond yields reflect all relevant current market information, including expectations about future interest rates. If investors really expected A-rated utility bonds to be significantly higher than they are now, they likely would have already adjusted the current bond yield to avoid or minimize capital losses in the future.

Q. How does the forecasted A-rated utility bond yield used by Dr. Vander Weide compare to current A-rated utility bond yields?

A. The March 2016 yield on A-rated utility bonds from the Mergent Bond Record was 4.16%. Dr. Vander Weide's forecasted A-rated utility bond yield is 6.20%, *which is over 200 basis points higher than the current yield*. On its face, Dr. Vander Weide's forecasted bond yield is so far removed from current interest rates that the Commission should simply reject his risk premium analysis and results out of hand.

Q. On page 32, lines 18 through 21, Dr. Vander Weide opined that current interest rates are a poor indicator of future interest rates due to the Federal Reserve's "extraordinary" efforts to keep interest rates low. Please comment on this testimony.

A. Current interest rates are indeed the best indicators of investor sentiment regarding the future course of interest rates. Current rates embody expectations regarding the Federal Reserve's possible future moves on interest rates, which are by no means certain. In my opinion, it is likely that interest rates will rise in the future but no one really knows by how much or when such future movements will occur. Until then, current interest rates should be used in the risk premium and CAPM estimates of the investor required return on equity.

Q. What are your conclusions with respect to Dr. Vander Weide's ex-post risk premium approach?

A. First, it is risky to assume that investors require an unchanging risk premium based on long-term historical returns of stocks over bonds. Changing economic conditions will likely affect investors' risk premium requirement. What investors require today may be quite different from a long-term historical risk premium.

Second, Dr. Vander Weide calculated an historical risk premium using the S&P 500 stock portfolio. Investor expected risk premiums for gas distribution utility stocks over bonds are likely much lower than the expected risk premium for unregulated companies in the S&P 500. Using the S&P 500 risk premium overstated the risk premium ROE for a lower-risk gas company such as Atmos.

Third, Dr. Vander Weide's ex-post risk premium results are significantly overstated due to his inappropriate use of a forecasted A-rated bond. *Using the March 2016 A-rated utility bond yield of 4.16% and adding this to his risk premium range of 3.9% - 4.5% results in an ex-post risk premium return on equity range of 8.06% - 8.66%.*

CAPM Analysis

Q. On page 42 of his Direct Testimony, Dr. Vander Weide cited a number of studies in support of his proposition that the CAPM underestimates required returns for securities with betas less than 1.0. On page 44, he concludes that the financial literature supports the proposition that the CAPM understates the cost of equity for companies such as public utilities with betas less than 1.0. Please address Dr. Vander Weide's testimony in this area.

A. Although Dr. Vander Weide cited a number of studies on page 42, the problem is that there is no evidence that the CAPM bias he alleges has any applicability to regulated utility companies. Regulated gas utilities have betas lower than 1.0 because they are lower in risk than the market as a whole. Thus, the average gas utility group beta from my group, 0.79, reflects the lower risk of regulated gas distribution operations vis-à-vis the unregulated market. Dr. Vander Weide failed to show any downward CAPM bias related to gas utility betas.

Q. On page 40 of his Direct Testimony, Dr. Vander Weide suggested the addition of a size premium to his CAPM results to account for the small market capitalization of natural gas distribution companies. Do you agree with the inclusion of a size premium?

A. No. It is true that the Ibbotson Yearbooks discuss size premiums, but they do not evaluate whether any such size premium is applicable to regulated utilities generally, or to regulated gas companies specifically. Thus, the size premiums shown on Table 1, page 40 of Dr. Vander Weide's Direct Testimony have no relevance whatsoever for lower-risk regulated gas distribution utilities such as Atmos.

Q. On page 46 of his Direct Testimony, Dr. Vander Weide stated that his recommended ROE of 10.5% was conservative because the market value capital structure of his proxy companies contains a higher equity percentage than Atmos' book value capital structure. Please comment on Dr. Vander Weide's testimony on this point.

A. I disagree with Dr. Vander Weide on this point. First, ratemaking does not use the market value equity ratio for Atmos or any of the other companies in the two groups that Dr. Vander Weide and I used to estimate the cost of equity. Utility regulators use book value equity ratios to calculate the regulated cost of capital. In this sense, Atmos is no different from the utilities in the gas and water company groups. In terms of assessing relative financial risk, one should instead look at the book equity ratios of Atmos and the companies in the two groups. I demonstrated earlier in my testimony that Atmos' base period equity percentage is consistent with the group of gas utilities I used to estimate the cost of equity. No additional adjustment for financial risk is required. Furthermore, a 10.5% ROE is excessive is the current economic environment, rather than conservative.

Q. Does this complete your Direct Testimony?

A. Yes.

BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

COMMONWEALTH OF KENTUCKY

IN RE:	APPLICATION OF ATMOS ENERGY	)	
	CORPORATION FOR AN	)	DOCKET NO. 2015-00343
	ADJUSTMENT OF RATES AND	)	
	TARIFF MODIFICATIONS	)	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

APRIL 2016

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor

Expert Testimony Appearances
of
Richard A. Baudino
As of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
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As of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

**Expert Testimony Appearances
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Richard A. Baudino
As of April 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042-000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

**Expert Testimony Appearances
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Richard A. Baudino
As of April 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

**Expert Testimony Appearances
of
Richard A. Baudino
As of April 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

Expert Testimony Appearances
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Richard A. Baudino
As of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

Expert Testimony Appearances
of
Richard A. Baudino
As of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

Expert Testimony Appearances
of
Richard A. Baudino
As of April 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR- 09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E- GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009- 2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010- 2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010- 2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010- 2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010- 2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010- 2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010- 2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011- 2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

**Expert Testimony Appearances
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As of April 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

**Expert Testimony Appearances
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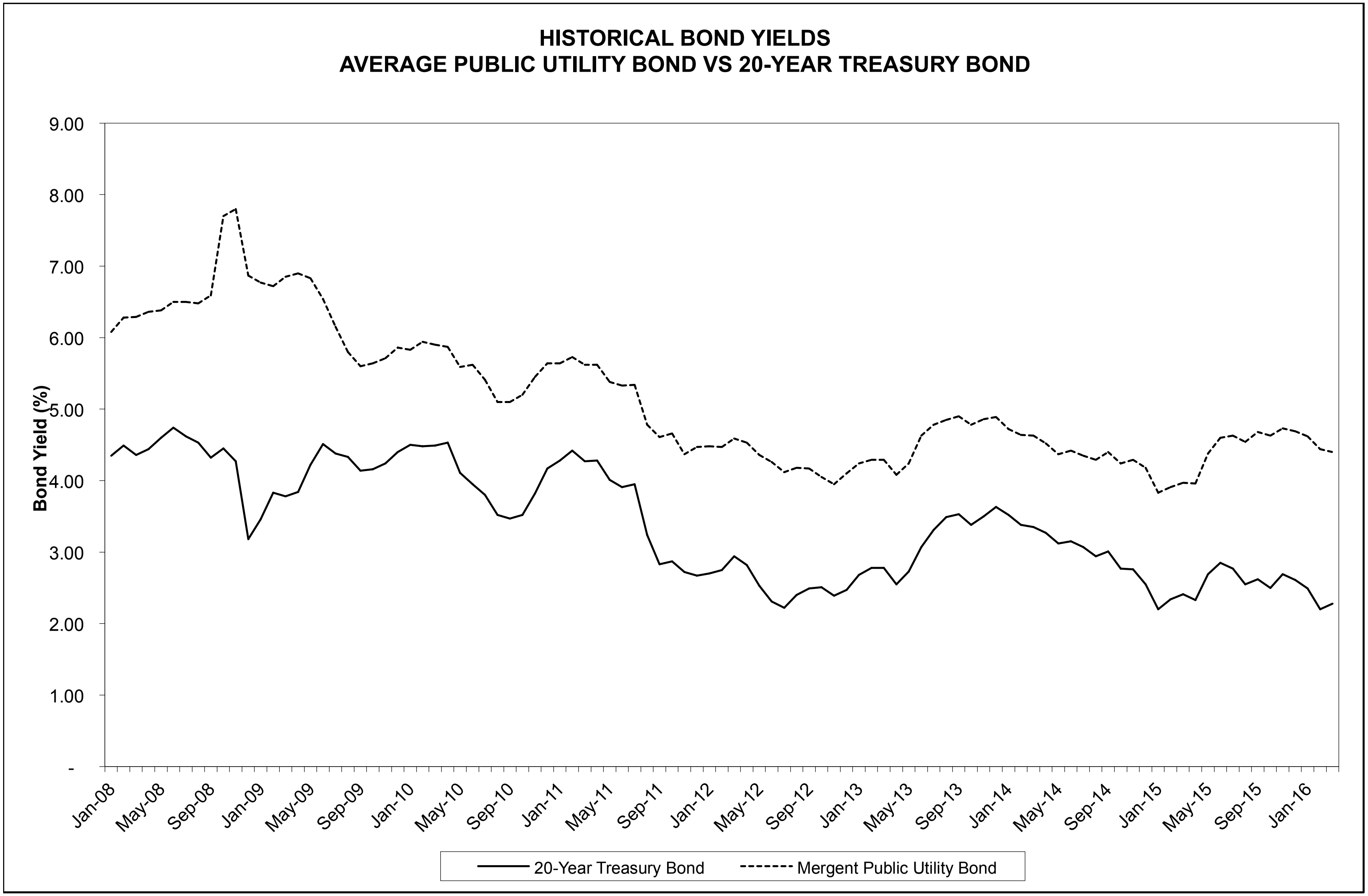
As of April 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/116	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure

Exhibit ___(RAB-2)



ATMOS ENERGY
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-16	Feb-16	Jan-16	Dec-15	Nov-15	Oct-15
Atmos Energy	High Price ($)	74.600	71.900	69.220	64.790	63.770	63.460
	Low Price ($)	68.600	67.940	60.000	60.420	59.220	57.370
	Avg. Price ($)	71.600	69.920	64.610	62.605	61.495	60.415
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.390
	Mo. Avg. Div.	2.35%	2.40%	2.60%	2.68%	2.73%	2.58%
	6 mos. Avg.	2.56%					
LaClede Group	High Price ($)	68.790	66.430	63.940	61.040	59.100	59.380
	Low Price ($)	64.390	63.310	57.100	55.240	54.330	53.860
	Avg. Price ($)	66.590	64.870	60.520	58.140	56.715	56.620
	Dividend ($)	0.490	0.490	0.490	0.490	0.460	0.460
	Mo. Avg. Div.	2.94%	3.02%	3.24%	3.37%	3.24%	3.25%
	6 mos. Avg.	3.18%					
New Jersey Resources	High Price ($)	36.850	36.570	35.570	34.070	31.970	31.850
	Low Price ($)	33.320	33.370	32.320	28.020	29.420	29.670
	Avg. Price ($)	35.085	34.970	33.945	31.045	30.695	30.760
	Dividend ($)	0.240	0.240	0.240	0.240	0.240	0.240
	Mo. Avg. Div.	2.74%	2.75%	2.83%	3.09%	3.13%	3.12%
	6 mos. Avg.	2.94%					
Northwest Natural Gas	High Price ($)	54.510	53.880	52.010	51.850	48.910	48.610
	Low Price ($)	48.900	49.410	49.300	47.780	45.380	45.030
	Avg. Price ($)	51.705	51.645	50.655	49.815	47.145	46.820
	Dividend ($)	0.468	0.468	0.468	0.468	0.468	0.468
	Mo. Avg. Div.	3.62%	3.62%	3.70%	3.76%	3.97%	4.00%
	6 mos. Avg.	3.78%					
South Jersey Industries	High Price ($)	29.140	26.940	24.860	24.400	27.020	27.340
	Low Price ($)	25.270	24.540	22.060	21.240	22.830	24.650
	Avg. Price ($)	27.205	25.740	23.460	22.820	24.925	25.995
	Dividend ($)	0.264	0.264	0.264	0.264	0.251	0.251
	Mo. Avg. Div.	3.88%	4.10%	4.50%	4.63%	4.03%	3.86%
	6 mos. Avg.	4.17%					
Southwest Gas	High Price ($)	67.290	62.430	58.920	56.710	62.330	62.890
	Low Price ($)	59.490	58.070	53.510	50.530	54.430	56.430
	Avg. Price ($)	63.390	60.250	56.215	53.620	58.380	59.660
	Dividend ($)	0.405	0.405	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	2.56%	2.69%	2.88%	3.02%	2.77%	2.72%
	6 mos. Avg.	2.77%					

ATMOS ENERGY
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-16	Feb-16	Jan-16	Dec-15	Nov-15	Oct-15
UGI Corp.	High Price ($)	40.850	37.210	34.370	34.980	37.510	36.940
	Low Price ($)	36.890	33.330	31.590	31.510	33.680	34.160
	Avg. Price ($)	38.870	35.270	32.980	33.245	35.595	35.550
	Dividend ($)	0.228	0.228	0.228	0.228	0.228	0.228
	Mo. Avg. Div.	2.35%	2.59%	2.77%	2.74%	2.56%	2.57%
	6 mos. Avg.	2.59%					
WGL Holdings	High Price ($)	74.100	69.200	66.810	65.550	62.590	63.200
	Low Price ($)	67.230	62.930	59.990	58.620	57.040	56.900
	Avg. Price ($)	70.665	66.065	63.400	62.085	59.815	60.050
	Dividend ($)	0.463	0.463	0.463	0.463	0.463	0.463
	Mo. Avg. Div.	2.62%	2.80%	2.92%	2.98%	3.10%	3.08%
	6 mos. Avg.	2.92%					
Average Dividend Yield	3.11%						

Source: Yahoo! Finance

ATMOS ENERGY
GAS DISTRIBUTION COMPANY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson/ IBES
Atmos Energy	6.50%	6.00%	5.00%	6.60%	6.40%
LaClede Group	3.50%	9.00%	4.50%	4.80%	4.70%
New Jersey Resources	3.00%	1.50%	5.00%	6.50%	6.50%
Northwest Natural Gas	1.50%	5.00%	3.00%	4.00%	4.00%
South Jersey Industries	6.50%	5.50%	4.00%	6.00%	6.00%
Southwest Gas	7.50%	7.00%	6.50%	5.00%	4.00%
UGI Corp.	4.00%	4.50%	8.00%	6.70%	8.00%
WGL Holdings	2.50%	5.00%	4.50%	7.30%	8.00%
Average Growth Rates	4.38%	5.44%	5.06%	5.86%	5.95%
Median Growth Rates	3.75%	5.25%	4.75%	6.25%	6.20%

Sources: Zack's and Thomson Earnings Reports, retrieved April 4, 2016
Value Line Investment Survey, March 4, 2016

ATMOS ENERGY
GAS DISTRIBUTION COMPANY GROUP
DCF RETURN ON EQUITY CALCULATION

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.11%	3.11%	3.11%	3.11%	3.11%
Average Growth Rate	4.38%	5.44%	5.86%	5.95%	5.41%
Expected Div. Yield	3.18%	3.20%	3.20%	3.21%	3.20%
DCF Return on Equity	***7.56%***	***8.64%***	***9.06%***	***9.16%***	***8.61%***
Method 2:					
Dividend Yield	3.11%	3.11%	3.11%	3.11%	3.11%
Median Growth Rate	3.75%	5.25%	6.25%	6.20%	5.36%
Expected Div. Yield	3.17%	3.20%	3.21%	3.21%	3.20%
DCF Return on Equity	***6.92%***	***8.45%***	***9.46%***	***9.41%***	***8.56%***

ATMOS ENERGY
WATER UTILITY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-16	Feb-16	Jan-16	Dec-15	Nov-15	Oct-15
American States Water	High Price ($)	43.080	47.240	45.470	44.140	42.400	42.400
	Low Price ($)	38.250	41.830	39.160	39.690	39.670	40.310
	Avg. Price ($)	40.665	44.535	42.315	41.915	41.035	41.355
	Dividend ($)	0.224	0.224	0.224	0.224	0.224	0.224
	Mo. Avg. Div.	2.20%	2.01%	2.12%	2.14%	2.18%	2.17%
	6 mos. Avg.	2.14%					
American Water Works	High Price ($)	70.100	68.490	65.040	61.200	58.400	59.200
	Low Price ($)	64.930	63.160	58.900	56.400	55.130	54.620
	Avg. Price ($)	67.515	65.825	61.970	58.800	56.765	56.910
	Dividend ($)	0.340	0.340	0.340	0.340	0.340	0.340
	Mo. Avg. Div.	2.01%	2.07%	2.19%	2.31%	2.40%	2.39%
	6 mos. Avg.	2.23%					
Aqua America	High Price ($)	32.440	32.340	31.530	31.090	29.700	28.790
	Low Price ($)	30.450	30.560	28.350	28.830	28.050	26.200
	Avg. Price ($)	31.445	31.450	29.940	29.960	28.875	27.495
	Dividend ($)	0.178	0.178	0.178	0.178	0.178	0.178
	Mo. Avg. Div.	2.26%	2.26%	2.38%	2.38%	2.47%	2.59%
	6 mos. Avg.	2.39%					
California Water	High Price ($)	27.330	25.860	25.140	24.200	22.830	24.350
	Low Price ($)	24.720	23.200	22.480	22.090	21.010	21.640
	Avg. Price ($)	26.025	24.530	23.810	23.145	21.920	22.995
	Dividend ($)	0.173	0.173	0.168	0.168	0.168	0.168
	Mo. Avg. Div.	2.66%	2.82%	2.82%	2.90%	3.07%	2.92%
	6 mos. Avg.	2.87%					
Connecticut Water	High Price ($)	45.660	43.940	43.120	39.930	37.360	38.490
	Low Price ($)	41.240	40.360	37.480	34.770	34.150	35.970
	Avg. Price ($)	43.450	42.150	40.300	37.350	35.755	37.230
	Dividend ($)	0.268	0.268	0.268	0.268	0.268	0.268
	Mo. Avg. Div.	2.47%	2.54%	2.66%	2.87%	3.00%	2.88%
	6 mos. Avg.	2.74%					
Middlesex Water	High Price ($)	32.100	29.770	29.010	28.020	25.970	26.650
	Low Price ($)	26.460	27.300	25.000	24.250	24.010	23.400
	Avg. Price ($)	29.280	28.535	27.005	26.135	24.990	25.025
	Dividend ($)	0.199	0.199	0.199	0.199	0.199	0.199
	Mo. Avg. Div.	2.72%	2.79%	2.95%	3.05%	3.19%	3.18%
	6 mos. Avg.	2.98%					
SJW Corp.	High Price ($)	37.860	37.230	32.630	30.890	31.760	33.840
	Low Price ($)	34.850	31.390	28.580	27.600	28.030	30.460
	Avg. Price ($)	36.355	34.310	30.605	29.245	29.895	32.150
	Dividend ($)	0.203	0.203	0.195	0.195	0.195	0.195
	Mo. Avg. Div.	2.23%	2.37%	2.55%	2.67%	2.61%	2.43%
	6 mos. Avg.	2.48%					

ATMOS ENERGY
WATER UTILITY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Mar-16	Feb-16	Jan-16	Dec-15	Nov-15	Oct-15
York Water Company	High Price ($)	30.990	28.770	26.670	26.670	24.000	23.860
	Low Price ($)	26.580	26.270	23.790	22.810	22.180	20.930
	Avg. Price ($)	28.785	27.520	25.230	24.740	23.090	22.395
	Dividend ($)	0.156	0.156	0.156	0.156	0.156	0.156
	Mo. Avg. Div.	2.17%	2.27%	2.47%	2.52%	2.70%	2.79%
	6 mos. Avg.	2.49%					
Average Dividend Yield		2.54%					

Source: Yahoo! Finance

Exhibit ____ (RAB-6)

ATMOS ENERGY
WATER UTILITY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson/ IBES
American States Water	7.00%	6.00%	6.00%	3.80%	3.85%
American Water Works	10.50%	8.00%	5.00%	7.40%	7.60%
Aqua America	9.00%	7.00%	4.50%	6.20%	5.85%
California Water Service Group	6.50%	6.00%	4.00%	5.00%	5.00%
Connecticut Water Services	4.50%	4.50%	4.50%	5.00%	5.00%
Middlesex Water Company	3.00%	3.50%	3.00%	2.70%	2.70%
SJW Corp.	6.00%	1.50%	4.00%	14.00%	14.00%
York Water Company	6.50%	6.00%	4.00%	4.90%	4.90%
Averages	6.63%	5.31%	4.38%	6.13%	6.11%
Median Values	6.50%	6.00%	4.25%	5.00%	5.00%

Sources: Zack's and Thomson Earnings Reports, retrieved April 4, 2016
Value Line Investment Survey, April 15, 2016

ATMOS ENERGY
RETURN ON EQUITY CALCULATION
WATER UTILITY GROUP

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) First Call Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	2.54%	2.54%	2.54%	2.54%	2.54%
Growth Rate	6.63%	5.31%	6.13%	6.11%	6.04%
Expected Div. Yield	2.62%	2.60%	2.61%	2.61%	2.61%
DCF Return on Equity	***9.25%***	***7.91%***	***8.74%***	***8.72%***	***8.65%***
Method 2:					
Dividend Yield	2.54%	2.54%	2.54%	2.54%	2.54%
Median Growth Rate	6.50%	6.00%	5.00%	5.00%	5.63%
Expected Div. Yield	2.62%	2.61%	2.60%	2.60%	2.61%
DCF Return on Equity	***9.12%***	***8.61%***	***7.60%***	***7.60%***	***8.24%***

GAS DISTRIBUTION COMPANY GROUP
Capital Asset Pricing Model Analysis

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.97%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.46%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.50%
6	Comparison Group Beta	0.79
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.75%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.21%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.97%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.48%
4	Risk Premium	
5	(Line 1 minus Line 3)	9.49%
6	Comparison Group Beta	0.79
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	7.53%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.01%

GAS DISTRIBUTION COMPANY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
Oct-15	2.50%
Nov-15	2.69%
Dec-15	2.61%
Jan-16	2.49%
Feb-16	2.20%
Mar-16	2.28%
6 month average	2.46%

5 Year Treasury Bond Data

	Avg. Yield
Oct-15	1.39%
Nov-15	1.67%
Dec-15	1.70%
Jan-16	1.52%
Feb-16	1.22%
Mar-16	1.38%
6 month average	1.48%

Source: www.federalreserve.gov, Selected Interest Rates (Daily) - H.15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.89%
Estimated Market Return	9.93%
Value Line Projected 3-5 Yr. Median Annual Total Return	12.00%
Average of Projected Mkt. Returns	10.97%

Source: Value Line Investment Survey for Windows retreived April 4, 2016

Comparison Group Betas:

Atmos Energy	0.80
LaClede Group	0.70
New Jersey Resources	0.80
Northwest Natural Gas	0.65
South Jersey Industries	0.85
Southwest Gas	0.80
UGI Corp.	0.95
WGL Holdings	0.80
Average	0.79

Source: Value Line Investment Survey, March 4, 2016

CAPITAL ASSET PRICING MODEL ANALYSIS
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.09%	5.09%	
Historical Market Risk Premium	5.01%	7.01%	6.19%
Gas Distribution Group Beta, Value Line	0.79	0.79	0.79
Beta * Market Premium	3.98%	5.56%	4.91%
Current 20-Year Treasury Bond Yield	2.46%	2.46%	2.46%
CAPM Cost of Equity, Value Line Beta	**6.44%**	**8.03%**	**7.37%**

Source: *Ibbotson SBBI 2015 Classic Yearbook,* Morningstar, pp. 40, 152, 157 - 158

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Sworn to and subscribed before me on this
15th day of April 2016.

Notary Public

RANDY A FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 26, 2018
COBB COUNTY, GEORGIA

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July 7, 2016

VIA E-FILING

Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399

Re:

- *Docket No. 160021-EI, In re: Petition for Rate Increase by Florida Power & Light Company;* and
- *Docket No. 160062-EI, In re: 2016 Depreciation and dismantlement study by Florida Power & Light Company (consolidated)*

Dear Ms. Stauffer:

Please find enclosed for electronic filing in the above-referenced dockets the Direct Testimony and exhibits of witnesses Richard Baudino (Exhibits RAB-1 through RAB-13), Lane Kollen (Exhibits LK-6 through LK-36), and Stephen Baron (Exhibits SJB-1 through SJB-17), filed on behalf of intervenor South Florida Hospital & Healthcare Association.

If you have any questions, please do not hesitate to contact me at (202) 662-2715 or by e-mail at kwiseman@andrewskurth.com.

Very truly yours,

/s/ Kenneth L. Wiseman
Kenneth L. Wiseman

cc: All parties of record

CERTIFICATE OF SERVICE
DOCKET NO. 160021-EI

I HEREBY CERTIFY that a copy of the foregoing has been furnished by electronic mail and U.S. Mail to the following parties on this 7th day of July, 2016:

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/s/ Kevin C. Siqveland
Kevin C. Siqveland

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY**	**)**	
	FLORIDA POWER AND LIGHT	**)**	**DOCKET NO. 160021-EI**
	COMPANY AND SUBSIDIARIES	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE
SOUTH FLORIDA HOSPITAL AND HEALTH CARE ASSOCIATION

July 2016

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY AND SUBSIDIARIES	)))	**DOCKET NO. 160021-EI**

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service,

rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit No. ___ (RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the South Florida Hospital and Healthcare Association ("SFHHA").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my direct testimony is to address the allowed return on equity, cost of debt, and capital structure for ratemaking purposes for Florida Power and Light Company ("FPL" or "Company").

Q. Please summarize your Direct Testimony regarding the cost of equity.

A. I recommend that the Florida Public Service Commission ("Commission") approve a rate of return on equity ("ROE") for FPL of 9.00%. This recommendation is based on the results from my Discounted Cash Flow ("DCF") analyses for a comparison group of electric companies that has similar bond ratings to FPL. I also employed the Capital Asset Pricing Model ("CAPM"). Those results are set forth below. In my opinion, a return on equity of 9.00% is a reasonable estimate of the required return on equity for a low-risk, financially robust electric company such as FPL. As I will demonstrate in the following sections of my testimony, the market evidence I examined supports my ROE recommendation.

The Commission should reject the return on equity recommendation of 11.0% of FPL witness Robert Hevert. I will demonstrate in detail in Section IV of my Direct Testimony that Mr. Hevert's ROE analyses significantly inflated the investor required return for FPL. Mr. Hevert's recommended return on equity of 11.0% is unsupported by an objective evaluation of current financial markets. Moreover, a 11.0% ROE would burden Florida ratepayers with excessive rate levels.

In addition to FPL's excessive ROE request of 11.0%, several FPL witnesses also supported the addition of 0.50% to Mr. Hevert's recommended ROE, raising the Company's requested ROE to 11.50%. I will explain later in my testimony that the addition of a ROE adder for allegedly "excellent performance" is unwarranted, unreasonable and should be rejected by the Commission.

Q. Please summarize your testimony regarding the cost of debt.

A. FPL included two forecasted rates of long-term issuances with assumed coupon rates that are excessive and failed to reflect the reality of current debt costs. FPL assumed a 6.16% cost rate for these forecasted debt issuances in its 2017 rate year and a 6.50% rate for an additional issuance in its 2018 rate year. In order to reflect current and far more realistic debt costs, I recommend that these three issuances be assigned coupon rates of 4.10%.

Q. Please summarize your conclusions and recommendations regarding capital structure.

A. FPL witness Dewhurst recommended a capital structure that consists of approximately 60% common equity. This proposed equity ratio is clearly excessive and completely unnecessary for FPL to maintain an A credit rating. Under either my recommended ROE or that of FPL, *the carrying cost of each dollar of equity is three times as expensive as a dollar of debt.* Yet during the past four years, FPL failed to conduct analyses relevant to ensuring that ratepayers are not burdened with an excessive, unjust, and unreasonable amount of common equity in its capital structure. FPL did not benchmark its target capitalization against other utilities. In fact, FPL's proposed cost of equity and capital structure in this case will cost ratepayers approximately $723 million at a 9% equity return for the 2017 test year, according to Mr. Kollen's calculations. *See* SFHHA Witness Kollen Direct Testimony at page 5. I shall show later in my testimony that a 60% common equity ratio is significantly greater than prevalent in *any* of the electric utility comparison groups used to estimate the return on equity for FPL. In this proceeding, I recommend that the Commission set FPL's equity ratio at 55%. A 55% equity ratio is still higher than the average of the electric utility comparison groups used by Mr. Hevert and myself and is consistent with and A/A credit rating.

In a period of record low or near record low interest rates, it is wholly inconsistent with protecting the interests of FPL's ratepayers' to simply presume the capital structure of FPL should be set at 60%, above the level used by any of the comparison group members advanced by FPL or in my testimony. As recently as 2014, FPL's equity component of capital structure, as shown in MFRs, was 55%. FPL suffered no diminution in its credit and bond ratings from this lower common equity percentage.

I recognize that the Commission declined to adopt my recommendation in Docket No. 080677-EI to lower FPL's common equity ratio. In that proceeding, FPL's requested common equity ratio from investor-supplied capital was 59.6%. In that case, the Company imputed off-balance sheet purchased power agreements ("PPAs") of $950 million, which lowered its "adjusted" common equity ratio to 55.8%. Since FPL's last rate case, its PPA liabilities have declined substantially. To the extent that the Commission felt in 2012 it was necessary for FPL to increase its common equity ratio to offset its purchased power contract obligations, the reduction in FPL's PPA liabilities substantially reduces that concern.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Generally speaking, interest rates have declined over the last few years. Exhibit No. ___ (RAB-2) presents a graphic depiction of the trend in interest rates from January 2008 through May 2016. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. In January 2008, the average public utility bond yield was 6.08% and the 20-year Treasury Bond yield was 4.35%. As of May 2016 the average public utility bond yield was 4.06%, representing a decline of 202 basis points, or 2.02 percentage points, from January 2008. Likewise, the 20-year Treasury bond declined to 2.22% in May 2016, a decline of 2.13 percentage points (213 basis points) from January 2008.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in Exhibit No. ___(RAB-2)?

A. Yes. In response to the 2007 financial crisis and severe recession that followed in December 2007, the Federal Reserve ("Fed") undertook a series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets." Exhibit No. ___ (RAB-3) at pp. 1-2 (also available at: http://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm).

QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases.

QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury securities by the second quarter of 2011. Exhibit No. ___ (RAB-3) at pp. 3-4 (also available at: http://www.federalreserve.gov/newsevents/press/monetary/20101103a.htm).

Beginning in September 2011, the Fed initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as “Operation Twist,” was designed by the Fed to lower long-term interest rates and support the economic recovery.

QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities. On June 19, 2013, the Federal Open Market Committee (“FOMC”) issued a press release indicating that it intended to extend "Operation Twist." In its press release, the Federal Reserve stated:

> To support a stronger economic recovery and to help ensure

> that inflation, over time, is at the rate most consistent with its dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.
>
> [Exhibit No. ___ (RAB-3) at pp. 5-6 (also available at: https://www.federalreserve.gov/newsevents/press/monetary/20130619a.htm).]

More recently, the Fed began to pare back its purchases of securities. For example, on January 29, 2014 the Fed stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Fed continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October. Exhibit No. ___ (RAB-3) at pp. 7-8 (also available at: http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm).

Q. Since the Fed's announcements of scaling back and finally ending its purchases of long-term Treasury securities, what has the trend been in long-term Treasury yields from 2014 through 2016?

A. The yield on the 20-year Treasury bond has actually declined since the beginning of 2014. The January 2014 yield on the 20-year Treasury bond was 3.52%. Exhibit No. ___ (RAB-2). The closing yield for May 2016 was 2.22%, a decline of 130 basis points since January 2014. Exhibit No. ___ (RAB-2).

Q. Has the Fed recently indicated any important changes to its monetary policy?

A. Yes. Recently the Fed raised its target range for the federal funds rate to 1/4% to 1/2% from 0% to 1/4%. The Federal Reserve also issued a press release on March 16, 2016 stating that it would continue to maintain this target range at present. Exhibit No. ___ (RAB-3) at pp. 9-10 (also available at: http://www.federalreserve.gov/newsevents/press/monetary/20160316a.htm). This press release also stated:

> The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will continue to strengthen. However, global economic and financial developments continue to pose risks. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to monitor inflation developments closely.
>
> Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.

Q. Why is it important to understand the Fed's actions with respect to monetary policy since 2007?

A. The Fed's monetary policy actions since 2007 were deliberately undertaken to lower interest rates and support economic recovery. The Fed's actions have been quite successful in lowering interest rates given that the 20-year Treasury Bond yield in June 2007 was 5.29% and the public utility bond yield was 6.34%. The U.S. economy is currently in a low interest rate environment that, in my opinion, will likely continue at least through this year. As I will demonstrate later in my testimony, low interest rates have also significantly lowered investors' required return on equity for the stocks of regulated utilities.

Q. Have recent developments reinforced the prevailing low interest rate environment?

A. Yes. Several central banks have implemented *negative* interest rates. Exhibit No. __ (RAB-3) at pp. 11-12 (noting that the Swiss National Bank set its benchmark interest rate at minus 0.75% and that nearly the entirety of Switzerland's yield curve was negative; yield curves for Japan and Germany are also provided showing negative interest rates for bonds with a duration of up to 10 years). Indeed, Federal Reserve Chairman Yellen has discussed the possibility of negative interest rates (available at: http://www.bloomberg.com/news/articles/2016-05-12/yellen-doesn-t-rule-out-negative-rates-in-letter-to-congressman (last visited July 2, 2016) (in written responses Thursday to questions from Representative Brad Sherman, Yellen said that "while I would not completely rule out the use of negative interest rates in some future very adverse scenario, policy makers would need to consider a wide range of issues before employing this tool in the United States, including the potential for unintended consequences.").

Q. Is NextEra Energy obtaining significant financing from outside of the U.S.?

A. Yes. *See* Exhibit No. ___ (RAB-4) at p. 5.

Q. Are current interest rates indicative of investor expectations regarding future policy actions by the Federal Reserve?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information.

I acknowledge that the U.S. economy is operating in a low interest rate environment. It is likely at some point in the near future that the Fed will raise short-term interest rates further. However, the timing and the level of any such move are not known at this time. It is important to realize that investor expectations of higher interest rates, if any, are already embodied in current securities prices, which include debt securities and stock prices.

The current low interest rate environment favors lower risk regulated utilities. As I shall demonstrate in Section III, market evidence indicates that investors require lower rates of return on equity on regulated utility stocks than many other types of enterprises. It would not be advisable for utility regulators to raise ROEs in anticipation of higher interest rates that may or may not occur.

Q. Please compare current financial market conditions with the conditions that were present during FPL's last rate case, Docket No. 1200015-EI.

A. When I submitted my Direct Testimony in July 2012, Treasury bond yields were 2.22%, virtually unchanged from their present levels. I noted in my testimony that the June 13, 2012 Moody's average public utility bond yield was 4.28%. As of June

13, 2016, Moody's average public utility bond yield was 3.90%, 38 basis points lower than 2012. Moreover, public utility bond yields have declined this year from the 4.62% yield in January.

Q. How does the investment community regard the electric utility industry as a whole?

A. The Value Line Investment Survey noted the following in its May 20, 2016 report on the Electric Utility (East) Industry:

> So far, 2016 has been an excellent year for electric utility stocks. Every issue we cover is up, year to date, and most have risen at a low double-digit pace. With interest rates as low as they are, some investors are reaching for yield. This is reflected in the high valuation of many electric company equities. Most are trading at a market premium, and have recent quotations within our 2019-2021 Target Price Range. The average dividend yield of this group is just 3.4%, which is low by historical standards. The average 3- to 5-year total return potential is just 3%, which is low by any standard.

Value Line also noted the following in its June 17, 2016 report on the Electric Utility (Central) Industry:

> Merger and acquisition activity (or speculation of deals) is just one factor in the strong performance of electric utility equities so far in 2016. The price of every issue under our coverage is up, year to date, and in most cases, the rise has been significant: between 10% and 20%. Another factor is the ongoing low-interest rate environment, and the belief that the Federal Reserve will be slow to raise rates. With minuscule returns available on savings accounts, CDs, and money-market funds, many income-oriented investors have reached for yield by putting money into utility stocks.
>
> As long as the interest-rate environment remains benign, this would be good for electric utility stocks. If interest rates are higher over the 3- to 5-year period, as we expect, that would probably be unfavorable for the equities in the group.

Q. Briefly describe FPL.

A. FPL is a wholly owned subsidiary of NextEra Energy, Inc. ("NextEra Energy"). NextEra Energy's other principal subsidiary is NextEra Energy Resources, which engages in the competitive energy business and produces its energy primarily from clean and renewable fuels. FPL's 2015 SEC Form 10-K noted that NextEra Energy is one of the largest electric power companies in North America, servicing over 5.3 million customers and having over 46,000 megawatts ("mW") of generating capacity in 27 states and 4 provinces in Canada. Exhibit No.__ (RAB-4) at p. 13. As of December 31, 2015, FPL's resources for serving load consisted of 26,073 mWs.

Q. How has FPL described its generation fleet?

A. On page 8 of its 2015 10-K report, FPL noted: "FPL relies upon a mix of fuel sources for its generation facilities, along with purchased power, in order to maintain the flexibility to achieve a more economical fuel mix by responding to market and industry developments." Exhibit No. ___ (RAB-4) at p. 14.

Q. How does FPL's generation fleet position it with regard to possible implementation of the Clean Power Plan or similar environmental regulation?

A. FPL derived approximately 69% of its 2015 Mwh produced from natural gas fired generating plants. Exhibit No. ___ (RAB-4) at p. 14. Compared to electric utilities that rely on coal-fired capacity, FPL's risk from carbon-based environmental rules and legislation is lower.

Q. How does FPL recover its fuel costs?

A. FPL collects fuel costs through a recovery mechanism approved by the Commission that enables the company to true-up differences between actual and projected costs.

Q. Is that the only tracker FPL enjoys?

A. No. In addition, FPL receives substantial benefits from a number of other cost recovery clauses that have been approved by the Commission over the years. The Company stated the following on page 12 of its 2015 10-K report:

> Cost recovery clauses, which are designed to permit full recovery of certain costs and provide a return on certain assets allowed to be recovered through the various clauses, *include substantially all fuel, purchased power and interchange expense, certain construction-related costs and conservation and certain environmental-related costs*. Cost recovery clause costs are recovered through levelized monthly charges per kWh or kW, depending on the customer's rate class. These cost recovery clause charges are calculated at least annually based on estimated costs and estimated customer usage for the following year, plus or minus true-up adjustments to reflect the estimated over or under recovery of costs for the current and prior periods. An adjustment to the levelized charges may be approved during the course of a year to reflect revised estimates. [Exhibit No. ___ (RAB-4) at p. 16 (emphasis added)].

Regarding the cost of compliance with environmental laws and regulations, FPL noted on page 13 of its 2015 10-K that the Company "expects to seek recovery through the environmental clause for compliance costs associated with any new environmental laws and regulations." *Id.* at p. 17.

With respect to capitalization, FPL's regulated utility operations are far less leveraged, and far less risky, than NextEra Energy's unregulated operations. As of December 31, 2015, FPL's utility operations were capitalized with 60.4% common equity compared to NextEra Energy's unregulated operations, which were supported by only 27.8% common equity. This information came from FPL's Schedule D-2.

Q. What else have ratings agencies stated about FPL's regulatory approach?

A. Following its discussion of the Commission's order on FPL's 2012 rate case, Fitch noted that "[w]hile the order spans a four-year term (till December 2016), *FPL could potentially delay filing a rate case for a longer period by proactively managing its costs*." Exhibit No. ____(RAB-5) at p. 2 (SFHHA 007530) (emphasis added).

Q. What has happened with respect to the credit rating of FPL since FPL's last base rate case?

A. In January 2014, Moody's upgraded the ratings of FPL, including its long term issue rating, to A1 from A2 with an outlook of stable. According to a Moody's Senior Vice President, "FPL is one of the strongest regulated electric utilities in the U.S. . . ." *See* FPL Response to OPC POD No. 12 (OPC 009813). "Because a high percentage of FPL's revenues are recovered through cost recovery clauses and its leverage is low, FPL's credit metrics are among the strongest in the utility sector . . . ." *Id.*

Q. What else has happened since FPL's last base rate case that signals increased confidence in FPL's ability to maintain or grow its earnings?

A. In August 2015, NextEra Energy announced its intention to increase its proportion of dividend payouts, from 55% in 2014 to 65% in 2018. Exhibit No. ____(RAB-5) at p. 27 (OPC 009881).

Q. Does FPL's messaging to investors about its service territory support an increased payout ratio?

A. According to an investor presentation provided in June 2016, NextEra states that FPL "is one of the best utility franchises in the U.S." Exhibit No. ___ (RAB-4) at p. 9.

Q. Do the rating agencies have a comparable outlook regarding FPL's service territory?

A. Fitch's November 2015 credit report states:

> Florida's economy is recovering well after the recent prolonged recession, with most key indicators such as housing starts, employment statistics and consumer sentiment on an upward trend. Adjusted for weather, FPL's retail kilowatt hour sales grew 1.3% in 2014, driven by 1.2% customer growth and 0.1% usage increase. Fitch's financial forecasts for FPL are based on a 1% cumulative annual growth rate in retail sales over 2015-2018; any upside in sales growth would be positive for FPL's credit metrics.

See Exhibit No. ___ (RAB-5) at p. 4 (OPC 009887).

Q. How is FPL's capital structure described by the credit rating agencies?

A. According to Moody's, FPL's "debt-to-capitalization of 30.4% at 31 December 2015 is among the lowest in its peer group . . . ." FPL Response to OPC POD No. 12 at OPC 009810.

Q. What are the current senior secured bond ratings for FPL?

A. FPL's senior secured ratings are A by Standard & Poor's ("S&P") and Aa2 by Moody's. These are basically the same bond ratings that the Company had during its last base rate case before this Commission, although Moody's rating actually improved from Aa3 in 2012.

Q. What commentary accompanies these ratings of extremely high credit quality?

A. In its March 31, 2016 report on FPL, Moody's noted that FPL is "one of the strongest regulated utilities in the US" with "good cost recovery mechanisms that produce consistently above-average financial performance." FPL Response to OPC POD No. 12 at OPC 009807.

According to Moody's, "FPL has some of the strongest cash flow metrics in the US utilities sector, because a high degree of its revenues is recovered through cost recovery clauses and it is well capitalized . . . These metrics are strongly positioned for the company's current rating category." FPL Response to OPC POD No. 12 at OPC 009809.

S&P found FPL's business risk is "excellent" in its June 15, 2015 report on the Company. This is the category for enterprises with the lowest level of business risk according to S&P. Standard and Poor's noted that it attributed "significantly higher business risk" to NextEra Energy 's non-utility operations compared to its regulated utility operations (Exhibit No. ___ (RAB-5) at p. 10 (OPC 009834)), meaning that NextEra Energy has higher business risk overall than FPL.

Q. How does FPL's capital structure compare to that of its owner, NextEra Energy?

A. With respect to capitalization, FPL's regulated utility operations are far less leveraged, and thus involve much less financial risk, than NextEra Energy's unregulated operations. As of December 31, 2015, FPL's utility operations were capitalized with 60.4% common equity compared to NextEra Energy's unregulated operations, supported by only 27.8% common equity. These numbers are based on FPL's Schedule D-2. Yet, FPL's utility operations also have far less business risk than NextEra Energy's other operations as well.

Q. What does S&P's outlook say?

A. S&P states that:

> Our rating outlook on NextEra and its subsidiaries is stable and reflects a business risk profile that is equally affected by higher-risk merchant energy activities and a utility that still presents a better credit profile than its peers. [Exhibit No. ___ (RAB-5) at p. 41 [SFHHA 007583]; *id.* at p. 49 [SFHHA 007592]].

Q. Are those the only statements highlighting the difference in risks between FPL and other NextEra Energy investments?

A. No. S&P notes that while the "[r]egulated utility operations have low business risk and support the overall credit profile," "[n]on-utility operations are primarily engaged in unregulated power generation and materially increase business risk." Exhibit No. ___ (RAB-5) at p. 8 (OPC 009832).

Q. Is there additional credit rating agency analysis of the difference between the risk of FPL and its NextEra Energy affiliates?

A. Yes.

> NextEra's regulated utility operations have low business risk and provide about 60% of consolidated operating income, lending support to the company's overall business risk profile within the “strong” category. The regulated business is conducted through Florida Power & Light (FPL) and benefits from operations under a constructive regulatory framework that provides for timely investment and fuel cost recovery. FPL has historically managed its regulatory risk effectively and this has resulted in earned returns that are consistently close to or at the authorized levels. The customer base is large with no meaningful industrial exposure and demonstrates above-average growth. The company has material exposure to natural-gas-fired generation, which, in combination with low natural gas prices and the company’s efficient operations, contributes to overall competitive customer rates.
>
> The company’s non-utility operations are conducted under NextEra Energy Capital Holdings Inc. (NEECH). We ascribe significantly higher business risk to these non-utility operations compared to the regulated utility operations because they focus largely on unregulated generation, both merchant and contracted, with an emphasis on renewable energy projects and to a lesser extent on fossil-fired and nuclear generation. Integral to our view of NextEra’s business risk profile as “strong” is that all merchant generation projects that are financed in a nonrecourse manner provide NextEra with only residual cash flows, an arrangement that we view as inherently weaker compared to NextEra having full access to all project cash flows. NextEra’s non-utility operations also engage in proprietary trading and marketing as well as retail supply and wholesale full requirements contracts, businesses which can have significant liquidity needs and are generally characterized by small margins on a per unit basis, relying on large volumes to generate a meaningful contribution. Moreover, these operations require excellent risk management and disciplined hedging practices to limit a company’s exposure to the fluctuation in commodity prices. [Exhibit No. ___ (RAB-5) at p. 10 (OPC 009834)].

Q. Does Fitch’s link FPL’s credit ratings to that of NextEra Energy?

A. Yes. Fitch's observed that with regard to potential "Positive Rating Action," "Given strong rating linkage with its parent company, NextEra Energy Inc. . . . future positive rating actions appear unlikely." Exhibit No. ___ (RAB-5) at p. 5 (OPC 009888).

Fitch's also noted that NextEra Energy's "continued shift away from merchant businesses toward regulated investments and contracted non-regulated renewable assets is also supportive of its credit profile." Exhibit No. ___ (RAB-5) at p. 2 (SFHHA 007530).

Finally, Fitch's states that if "parent [NextEra Energy] increases its debt leverage or changes its corporate strategy such that its risk profile materially worsens, it could adversely affect *FPL's ratings* . . . ." Exhibit No. ___ (RAB-5) at p. 3 (SFHHA 007531) (emphasis added).

Q. What does S&P say about the impact of FPL's affiliates upon their affiliates' ratings.

A. S&P states that:

> Standard & Poor's Ratings Services' ratings on all NextEra entities reflect *the strength of the regulated cash flows from integrated electric utility FP&L*, and the diverse and substantial cash-generation capabilities of its unregulated operations at subsidiary NextEra Energy Resources (NER). FP&L represents about half of the consolidated credit profile and has better business fundamentals than most of its integrated electric peers, with a better-than-average service territory, sound operations, and a credit-supportive regulatory environment in which the company has been able to manage its regulatory risk very well. A willingness to expand through acquisitions, fluctuating cash flows from NER's rapidly expanding portfolio of merchant generation assets and growing marketing and trading activities, and significant exposure at the utility to natural gas detract from credit

> quality, in our view.
>
> We characterize FP&L's business risk profile as "excellent," NextEra's business risk profile as "strong," and the consolidated financial risk profile as "intermediate" under our criteria.
>
> * * * *
>
> NER, the main subsidiary under unregulated NextEra Energy Capital Holdings Inc., engages in electric generation, marketing, and trading throughout the U.S. NER's focus is on geographic and fuel diversity and on developing environmentally advantageous facilities that benefit from public policy trends. The merchant generator's capacity of almost 16,600 MW consists of more than half wind turbines, one-quarter natural-gas-fired stations, and the rest mainly nuclear facilities. More than three-quarters of the wind projects and almost 60% of the total portfolio operate under largely fixed-price, long-term contracts. The rest of the portfolio, including one nuclear plant, is merchant capacity that can be exposed to market prices for its output. While a policy of actively hedging the commodity price risk of plant inputs and outputs helps to reduce the risks associated with merchant energy activities, NER faces an inherent level of commodity price risk. In addition, NER's extensive project financing (approximately 46% of installed capacity) of its assets diminishes its cash flow quality, but this is offset by lower financial risk. NER's risks permanently hinder NextEra's credit quality, especially in light of the influence that marketing and high-risk proprietary trading results have on NER's earnings and cash flows. [Exhibit No. ___ (RAB-5) at pp. 33-34 (SFHHA 007574-75) (emphasis added)].

Q. Does NextEra Energy's group credit profile affect FPL?

A. Yes. S&P states:

> FPL is subject to our group rating methodology criteria. We assess FPL as a "core" subsidiary of NextEra because it . . . . is closely linked to the parent's reputation. As a result, the issuer credit rating on FPL is 'A-', in line with the 'a-' group credit profile of NextEra. [Exhibit No. ___ (RAB-5) at p. 58 (OPC 008063)].

Q. Is there another reason why FPL's credit rating and NextEra Energy's credit rating are linked?

A. Yes. S&P explains that:

> We assess the status of NextEra's subsidiaries, Florida Power & Light Co. and NextEra Energy Capital Holdings, Inc., as core subsidiaries . . . . Because there are no structural or regulatory insulation provisions in place that could restrict NextEra's access to the assets and cash flow of its subsidiaries, the issuer credit rating on each subsidiary is 'A-', based on the group credit profile of NextEra. [Exhibit No. ___ (RAB-5) at pp. 64-65 (OPC 008151-52)].

Q. Mr. Baudino, what is your conclusion regarding the financial health and overall risk of FPL?

A. FPL remains a low cost and low risk electric utility with strong A/A ratings.

FPL benefits from several Commission-approved cost recovery clauses that significantly reduce its business and financial risk profiles and help stabilize its earnings. Its excellent bond ratings currently enjoy a stable credit outlook from Moody's and S&P. Overall FPL remains a low risk electric utility with rock solid financial health and overall better credit metrics than its electric utility peers.

Further, as I mentioned earlier, current interest rates are at or near historic lows. Although the Fed may increase interest rates later this year, I expect the Fed to support the current low interest rate environment in order to foster economic growth. This interest rate environment supports lower expected returns from investors and my ROE analysis in the next section of my testimony will demonstrate that this is the case.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for FPL.

A. I employed a Discounted Cash Flow ("DCF") analysis for a group of comparison electric companies to estimate the cost of equity for the Company's regulated electric operations. I also employed several Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) and *Bluefield W.W. & Improv. Co. v. Public Service Comm'n,* 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to at least what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by at least what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of comparable investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is comparable to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. The stocks of numerous enterprises owning electric utilities are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the risk of a particular investment. The end result of their analyses is a bond and/or credit rating that reflects these risks.

<u>Discounted Cash Flow ("DCF") Model</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 *= the next period dividend*
P_0 *= current stock price*
g *= expected growth rate*
k *= investor-required return*

Under the formula, it is apparent that "k" must reflect the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for FPL?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to FPL.

Q. Please describe your approach for selecting a comparison group of electric companies.

A. I used several criteria to select a comparison group. First, using the June 2016 issue of AUS Utility Reports, I selected electric companies whose bonds were rated at least A by Moody's and/or Standard and Poor's. FPL currently carries senior secured bond ratings of A from S&P and Aa2 from Moody's, so using the either/or criterion for an A rating assures that the companies in the comparison group carry bond ratings that are similar to FPL.

From that group, I selected companies that had at least 50% of their revenues from electric operations and that had long-term earnings growth forecasts from Value Line and either Zacks Investment Research ("Zacks") or Thomson Financial. I will describe Zacks and Thomson Financial later in my testimony. From this group, I then eliminated companies that had recently cut or eliminated dividends, or were recently or currently involved in significant merger activities.

The resulting comparison group of 12 electric companies that I used in my analysis is shown in the table below.

TABLE 1
COMPARISON GROUP

	Company	S&P Bond Rating	Moody's Bond Rating
1	ALLETE, Inc. (NYSE-ALE)	A-	A3
2	Alliant Energy Corporation (NYSE-LNT)	A-	A2/A3
3	Avista Corporation (NYSE-AVA)	A-	Baa1
4	Consolidated Edison, Inc. (NYSE-ED)	A-/BBB+	A3
5	Edison International (NYSE-EIX)	BBB+	A2/A3
6	Eversource Energy (NYSE-ES)	A-	A3/Baa1
7	IDACORP, Inc. (NYSE-IDA)	A-	A3
8	NorthWestern Corporation (NYSE-NWE)	NR	A3
9	OGE Energy Corp. (NYSE-OGE)	BBB+	A3
10	Portland General Electric Company (NYSE-POR)	A-	A3
11	Wisconsin Energy Corporation (NYSE-WEC)	A-/BBB+	A1/A2
12	Xcel Energy Inc. (NYSE-XEL)	A-	A3

Source: AUS Monthly Utility Report, June 2016

Q. What was your first step in determining the DCF return on equity for the comparison group?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from December 2015 through May 2016. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the group is 3.44%. These calculations are shown in Exhibit No. ___ (RAB-6).

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the electric comparison group?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

In this analysis, I relied on three major sources of analysts' forecasts for growth. These sources are Value Line, Zacks, and Thomson Financial.

Q. Please briefly describe Value Line, Zacks, and Thomson Financial.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand companies in its Plus Edition. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

According to Zacks' website, Zacks "was formed in 1978 to compile, analyze, and distribute investment research to both institutional and individual investors." Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth.

Like Zacks, Thomson Financial also provides detailed investment research on numerous companies. Thomson also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. How did you utilize your data sources to estimate growth rates for the comparison group?

A. Exhibit No. ___ (RAB-7) presents the Value Line, Zacks, and Thomson Financial forecasted growth estimates. These earnings and dividend growth estimates for the comparison group are summarized on Columns (1) through (5) of Exhibit No. ___ (RAB-7).

I also utilized the sustainable growth formula in estimating the expected growth rate. The sustainable growth method, also known as the retention ratio method, recognizes that the firm retains a portion of its earnings to fuel growth in dividends. These retained earnings, which are plowed back into the firm's asset base, are expected to earn a rate of return. This, in turn, generates growth in the firm's book value, market value, and dividends.

The sustainable growth method is calculated using the following formula:

$$G = B * R$$

Where: G = *expected retention growth rate*
B = *the firm's expected retention ratio*
R = *the expected return*

In its proper form, this calculation is forward-looking. That is, the investors' expected retention ratio and return must be used in order to measure what investors anticipate will happen in the future. Data on expected retention ratios and returns may be obtained from Value Line.

The expected sustainable growth estimates for the comparison group are presented in Column (3) on page 1 of Exhibit No. ___ (RAB-7). The data came from the Value Line forecasts for the comparison group.

Q. How did you approach the calculation of earnings growth forecasts in this case?

A. For purposes of this case, I looked at two different methods for calculating the expected growth rates for my comparison group. For Method 1, I calculated the average of all the growth rates for the companies in my comparison group using Value Line, Zacks, and Thomson. For Method 2, I calculated the median growth rates for my comparison group. The median value represents the middle value in a data range and is not influenced by excessively high or low numbers in the data set. The median growth rate for each forecast provides additional valuable information regarding expected growth rates for the group.

The expected growth rates produced from these two methods fall in a range from 3.75% to 6.00%.

Q. How did you proceed to determine the DCF return of equity for the electric comparison group?

A. To estimate the expected dividend yield (D_1) for the group, the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

I then added the expected growth rates to the expected dividend yield. The calculations of the resulting DCF returns on equity for both methods are presented on Exhibit No. ____ (RAB-7), page 2.

Q. Please explain how you calculated your DCF cost of equity estimates.

A. Exhibit No. ___ (RAB-7) presents the DCF results utilizing the two different methods I described earlier. I used the Value Line earnings and dividend growth forecasts and the consensus analysts' forecasts. Using the average group growth rate in Method 1, the DCF results range from 8.15% to 9.50%, with an average ROE for the group of 8.64%. For Method 2, which employs median growth rates, the DCF results range from 8.52% to 9.54%, with an average ROE of 8.87%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: *K* = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Conceptually, any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[1] There is evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated

1 For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206 - 211, 2007 edition.

beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst’s application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for June 12, 2016. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit No. ___ (RAB-8). I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 9.88% to 11.0%. The average of these two market returns is 10.44%.

Q. Why did you use median growth rate estimates rather than the average growth rate estimates for the Value Line companies?

A. Using median growth rates is likely a more accurate method of estimating the central tendency of Value Line's large data set compared to the average growth rates. Average earnings and book value growth rates may be unduly influenced by very high or very low 3 - 5 year growth rates that are unsustainable in the long run. For example, Value Line's Statistical Summary shows both the highest and lowest value for earnings and book value growth forecasts. For earnings growth, Value Line showed the highest earnings growth forecast to be 98% and the lowest growth rate to be -30.7%. The highest book value growth rate was 73.5% and the lowest was -40.0%. None of these levels of growth is compatible with long-run growth prospects for the market as a whole. The median growth rate is not influenced by such extremes because it represents the middle value of a very wide range of earnings growth rates.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2015 Classic Yearbook*. Some analysts employ historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit No. ___ (RAB-9) presents the calculation of the market returns using the historical data.

Q. Please explain how this historical risk premium is calculated.

A. Exhibit No. ____ (RAB-9) shows both the geometric and arithmetic average of yearly historical stock market returns over the historical period from 1926 - 2014. The average annual income return for 20-year Treasury bond is subtracted from these historical stocks returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The historical market risk premium range is 5.03% - 7.03%.

Q. Did you add an additional measure of the historical risk premium in this case?

A. Yes. Morningstar reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001.[2] Morningstar recommended adjusting this growth in the P/E ratio for stocks out of the

2 *2015 Ibbotson SBBI Classic Yearbook,* Morningstar, pp. 156 - 158.

historical risk premium because "it is not believed that P/E will continue to increase in the future." Morningstar's adjusted historical arithmetic market risk premium is 6.19%, which I have also included in Exhibit No. ___ (RAB-9).

Q. Mr. Baudino, you testified that you used the SBBI 2015 Yearbook. Does Morningstar still publish the SBBI Yearbook?

A. No. Morningstar discontinued publication of the SBBI Yearbook this year. However, I present the analyses in Exhibit No. ___ (RAB-9) as additional information and perspective with respect to historical risk premiums of common stocks over long-term Treasury bonds.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from December 2015 through May 2016. The 20-year Treasury bond may be used as a proxy for the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM return on equity may be estimated.

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the electric distribution group from the most recent Value Line reports. The average of the Value Line betas for the comparison group is 0.73.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 8.03% - 8.28%. Using historical risk premiums, the CAPM results are 6.02% - 7.49%.

<u>Conclusions and Recommendations Regarding Authorized ROE</u>

Q. Please summarize the cost of equity you recommend the Commission adopt for FPL.

A. I recommend that the Commission adopt the DCF model I developed and the cost of equity estimates for the comparison group of electric utility companies that I compiled. Table 2 below summarizes the results of my ROE analyses.

TABLE 2
SUMMARY OF ROE ESTIMATES

Baudino DCF Methodology:	
Average Growth Rates	
- High	9.50%
- Low	8.15%
- Average	8.64%
Median Growth Rates:	
- High	9.54%
- Low	8.52%
- Average	8.87%
CAPM:	
- 5-Year Treasury Bond	8.03%
- 20-Year Treasury Bond	8.28%
- Historical Returns	6.02% - 7.49%

The results for the electric company comparison group averages using the constant-growth DCF model and the expected growth rate forecasts ranged from 8.64% to 8.87%. Based on this range of results, I recommend that the Commission adopt a 9.00% return on equity for FPL in this proceeding. Based on a comparison of current bond ratings, FPL is a lower risk utility company relative to my comparison group. Nonetheless, for purposes of the ROE ranges I recommend, I am placing FPL at the top of the range and rounding upward to 9.0%. I offer this recommendation to the Commission as a just and reasonable estimate of investor return on equity requirements for a lower risk electric utility such as FPL.

Finally, it should be noted that the CAPM results are significantly lower than the DCF results in this proceeding. This is the case with both the forward-looking and the historical versions of the CAPM. I do not rely on the CAPM for my ROE recommendation, but these results suggest that my recommended ROE of 9.00% is reasonable, even generous, based on current capital market conditions.

Capital Structure

Q. Please explain what a capital structure is and how it affects a utility's rates.

A. A utility's capital structure consists of the percentages of debt, equity or other financial components that are used to finance a utility's investments. Equity and debt are two primary components for a capital structure and affect a utility's costs and rates in different ways.

Utilities are permitted an allowed return on common equity by regulatory commissions. Those returns are not tax deductible and an income tax gross-up is added to the calculated equity return. Therefore, equity financing is more expensive than debt financing when income taxes are considered. In this proceeding, for example, FPL's debt cost rate is 4.62% and its requested cost of equity, including the proposed performance adder, is 11.50%. Using the Company's gross-up factor of 1.63, the gross-up cost of equity is 18.75%. FPL's grossed-up requested cost of equity, then, is 400% greater than its cost of debt.

In addition, from the investors' perspective, equity investment is more risky than debt investment. Thus, equity investors require a higher return than debt investors to compensate them for the additional risks that they incur.

Selecting a utility's capital structure for ratemaking purposes involves balancing different considerations. Two extreme examples may help illustrate those considerations. If a utility were completely financed by equity, the utility would not have any leverage and would therefore be less risky. However, its overall rate of return, and therefore costs to consumers, would be higher because its capital structure would consist completely of higher cost equity. In this example, the manner in which the utility financed its rate base results in unreasonable and burdensome costs for ratepayers.

On the other hand, if a utility was completely financed by debt, the utility would experience a high amount of financial risk and the utility's cost of debt would substantially increase. In both of these examples, ratepayers would not be well served by the utility's management of its capital structure.

Setting a utility's target capital structure involves balancing the risk of using lower cost debt against the cost of equity financing, including both the actual cost of equity and the tax implications. A utility and its regulator must consider the risks and costs of various capitalization ratios to ensure that ratepayers are provided with a prudent capitalization ratio at the least overall cost.

Q. Do the incentives of regulated and unregulated enterprises differ when it comes to capital structures?

A. FPL has acknowledged that there is a distinction between rate regulated entities and unregulated entities. Exhibit No. ___ (RAB-10) at p. 8 (Tr. at 459). FPL has acknowledged that if an unregulated enterprise substitutes more debt in lieu of a thicker equity component, earnings per share would increase because of spreading such earnings over a smaller equity base. Exhibit No. ___ (RAB-10) at p. 5 (Tr. at 456:14-21).

However, if within FPL's capital structure existing equity was replaced with debt, earnings per share of FPL would not automatically increase, in contrast to unregulated entities. Exhibit No. ___ (RAB-10) at p. 8 (Tr. at 459:6-10).

Q. Did you review FPL's requested capital structure?

A. Yes. The Company's requested capital structure and weighted cost of capital is presented in Schedule D-1A and is supported by the Direct Testimony of FPL witnesses Hevert and Dewhurst. On page 23 of his Direct Testimony, Mr. Dewhurst recommended an equity ratio of 59.6% based on investor sources of capital. Mr. Dewhurst states that FPL has maintained its equity ratio at around 59% - 60% for "well over a decade". On lines 14 through 16, Mr. Dewhurst testified that "the current equity ratio will continue to support FPL's strong financial position and the benefits its provides to customers."

Q. When asked during discovery in this case to produce written documentation from NextEra Energy or FPL over the last 4 years discussing capital structures, how many documents were produced?

A. None. Exhibit No. ___ (RAB-5) at p. 68 (Response to OPC POD No. 35).

Q. What is FPL's position concerning capitalization structure?

A. FPL claims that FPL's current financial policies, including its capitalization, resulted in customers enjoying "a low total cost of capital" (Dewhurst Direct at 9:1). Yet FPL has no documents regarding how "increasing, decreasing or maintaining FPL's equity ratio would affect its 'total cost of capital.' " Exhibit No. ___ (RAB-5) at p. 69 (Response to SFHHA POD No. 62).

FPL Witness Dewhurst also claims that FPL's financial policies, including its capitalization, "resulted in an excellent credit rating." Dewhurst Direct at 16:7-9. Yet, when asked in discovery to provide "all documents prepared by or for FPL in the past four years but prior to March 15, 2016 that discuss or analyze how FPL's equity ratio affected its credit ratings," FPL could not provide any responsive documents. Exhibit No. ___ (RAB-5) at p. 70 (Response to SFHHA POD No. 65).

Q. As you described earlier, there is a tradeoff between cost and risk that must be considered when selecting a utility's capital structure. How has FPL documented its analysis of that trade off?

A. In discovery, FPL admitted that it had no "documents prepared by or for FPL in the past four years but prior to March 15, 2016 that discuss the costs and benefits of FPL maintaining its current credit rating" or "improving FPL's financial strength." Exhibit No. ___ (RAB-5) at pp. 72-73 (Responses to SFHHA POD Nos. 66 and 67).

Q. Did FPL provide any documents, created prior to filing this rate case, that described FPL's target capital structure?

A. No. Exhibit No. ___ (RAB-5) at p. 74 (Response to SFHHA POD No. 60).

Q. Did FPL provide any analysis, performed prior to filing the instant rate case, of the costs and benefits of maintaining FPL's credit ratings?

A. No. Exhibit No. ___ (RAB-5) at p. 73 (Response to SFHHA POD No. 67).

Q. Did FPL provide any analysis, performed prior to filing this rate case, concerning whether changing or retaining FPL's equity ratio would affect its total cost of capital?

A. No. Exhibit No. ___ (RAB-5) at p. 75 (Response to SFHHA POD No. 62).

Q. Did FPL provide any documents, prepared before filing this case, that analyzed how FPL's equity ratio affected its "financial strength" or access to capital?

A. No. Exhibit No. ___ (RAB-5) at p. 76 (Response to SFHHA POD No. 64).

Q. Did FPL document any analysis of how FPL's equity ratio affected its credit ratings?

A. No. Exhibit No. ___ (RAB-5) at p. 70 (Response to SFHHA POD No. 65).

Q. How many other vertically-integrated utilities did FPL identify as having an approved equity ratio equivalent to that of FPL based on investor-sourced funds?

A. None. Exhibit No. ___ (RAB-5) at pp. 77-78 (Responses to FIPUG Int. No. 3 and FIPUG POD No. 2).

Q. Did FPL adequately consider how other utilities finance their operations?

A. No. FPL Witness Dewhurst claimed that FPL "employed a balanced capital structure consistent with other financially strong utilities." However, when asked in discovery to "provide FPL's study of the capital structures employed by 'other financially strong utilities' ", FPL could not provide any analyses. Exhibit No. ___ (RAB-5) at p. 79 (Response to SFHHA POD No. 61).

FPL also failed to conduct any studies "that compare the financial strength of FPL to that of other U.S. electric utilities." Exhibit No. ___ (RAB-5) at p. 80 (Response to SFHHA POD No. 63).

Q. Mr. Baudino, is FPL's proposed proportion of investor-sourced capitalization composed of equity comparable to that of the companies in your comparison group?

A. No. The Company's proposed proportionate share composed of equity is significantly higher than that used by the companies in my comparison group. Table 3 below presents the common equity ratios for my comparison group. I obtained the data from the most recent Value Line Investment Survey reports and from AUS Utility Reports, June 2016.

TABLE 3
Comparison Group Capital Structure

	Value Line 2015 Common Equity	AUS Common Equity
ALLETE, Inc.	53.7%	54.1%
Alliant Energy Corp.	51.4%	48.3%
Avista Corporation	50.0%	50.3%
Consolidated Edison, Inc.	52.1%	48.2%
Edison International	46.7%	44.8%
Eversource Energy	53.6%	50.4%
IDACORP, Inc.	54.4%	52.4%
NorthWestern Corp.	46.9%	45.2%
OGE Energy	55.7%	53.9%
Portland General Electric	52.2%	51.0%
WEC Energy	48.6%	46.9%
Xcel Energy Inc.	45.9%	43.3%
Averages	50.9%	49.1%

Sources: Value Line Investment Survey, AUS Utility Monthly Reports

It is abundantly clear from Table 3 that FPL's equity ratio greatly exceeds the comparison group equity ratio. In fact, none of the companies has an equity ratio near 60%, the highest being OGE Energy at 55.7%.

Q. Does FPL need to maintain an unadjusted equity ratio of 60% to maintain its bond and credit ratings?

A. In my opinion, it does not. The utilities in my comparison have similar bond ratings to FPL and have much lower common equity ratios. In my view, this suggests that FPL could materially reduce its equity ratio and very likely be able to maintain an A/A bond rating.

Furthermore, FPL Witness Dewhurst’s comparison group of regulated utilities in Southeast States have authorized equity ratios that range from approximately 43% to just 54%. Exhibit No. ___ (RAB-5) at pp. 81-82 (Response to Staff ROG No. 146, Attachment No. 1).

Likewise, the average capital structure for Mr. Hevert's proxy group of utilities is 53%, slightly higher than my comparison group but very far below FPL's requested common equity ratio of nearly 60%.

Q. Do you have any other concern regarding FPL's equity rich capital structure?

A. Yes. One concern is that the excessive FPL common equity ratio means that ratepayers are subsidizing NextEra Energy’s unregulated affiliate activities. It is unlikely that NextEra Energy would be able to support and maintain a single ‘A’ credit rating on a corporate-wide basis without the support of an excessive FPL common equity ratio because NextEra Energy Resources is extremely highly leveraged. And, as I noted in Section II of my Direct Testimony, NextEra Energy 's unregulated operations are financed with only 27% common equity. The materials quoted in Section II above indicate that FPL’s credit rating is linked to that of NextEra Energy. NextEra Energy’s credit rating is a function of the higher-risk, higher-leverage non-retail electric service operations, and of FPL’s lower risk, modestly leveraged, retail electric service operations.

Second, debt financing for investment-grade enterprises with FPL's characteristics are at, or near, historic lows. FPL should have more fully analyzed the potential for capital cost savings to ratepayers. As shown above FPL has not done that in any form that regulators or customers can review and conclude that the Company made a series of sound choices to provide service at the lowest reasonable cost.

Third, it is an economically inefficient outcome for ratepayers to support a higher than necessary equity ratio for FPL. There is a transfer of income in the form of economic rents being paid by FPL's customers to FPL, a monopoly provider of electric service. Regulation should prevent this kind of income transfer, which benefits shareholders to the detriment of ratepayers.

A fourth reason relates to the efficient use of society's scarce capital resources. A 60% common equity ratio imposes higher than necessary capital costs, when the same productivity and output could be achieved with a less costly set of inputs. This approach is economically inefficient from the perspective of producing the same output at a lower total overall cost to society.

Q. What is your recommendation in this proceeding for FPL's capital structure and weighted cost of capital?

A. In this proceeding, I recommend that the Commission adopt a common equity ratio for FPL of 55%. The highest single common equity ratio in my comparison group is 55%. FPL had a 55% equity component in 2014 as described above. The Hevert comparison group has an overall average capital structure of 53% equity, and my comparison group has an average equity component of approximately 50% of average capital structure. My recommended common equity ratio of 55% is quite liberal and certainly reasonable compared to FPL's 60% common equity ratio.

Q. Didn't you accept FPL's common equity ratio in Docket No. 1200015-EI?

A. Yes, I did. However, I also testified in that docket that it would have been reasonable to reduce the Company's excessive common equity ratio in that case and that the Commission declined to accept my recommendation to reduce the Company's common equity ratio in the last base rate case Order in 2009.

In this docket, I recommend that the Commission focus on reducing FPL's common equity ratio. Equity financing is by far the most expensive form of financing for the Company. At a 9.0% return on equity, the pretax return equates to a pretax cost of 14.7% using a tax gross-up factor of 1.63. This is the return ratepayers must pay to finance the Company's rate base. The Company's current cost of long-term debt is 1,000 basis points lower, at 4.62%, obviously a far lower cost of financing than 14.7%. This disparity in cost between equity and debt is even greater -- approximately 1400 basis points -- if FPL’s recommended ROE were to be implemented. Thus equity under either ROE is at least 3 to 4 times as expensive as debt. Of course, FPL cannot finance its entire rate base with debt and must use common equity in order to reduce its financial risk and generate cash coverages to maintain its A/A bond rating. However, it is clear that FPL does not need a 60% common equity ratio to generate an A bond rating. Setting the Company's equity ratio at **55%** represents a fair balance between FPL's ratepayers and its financial integrity.

Q. In FPL's last rate case, did Company witnesses cite PPAs as support for having a higher common equity ratio?

A. Yes. Mr. Dewhurst noted on page 28, line 20 through page 29, line 17 of his Rebuttal Testimony in Docket No. 120015-EI that rating agencies make adjustments to a utility's capital structure in evaluating financial risk. Mr. Dewhurst testified that S&P imputed $922 million of the Company's PPAs as debt when evaluating FPL's financial strength.

Q. Did either Mr. Dewhurst or Mr. Hevert cite FPL's PPAs as a reason for maintaining the Company's common equity ratio at nearly 60% in this proceeding?

A. No.

Q. Has there been a reduction in FPL's PPA obligation since the last rate case?

A. Yes. FPL's 2012 Form 10-K noted on page 113 that the Company was obligated under take-or-pay purchased power contracts with the Jacksonville Electric Authority ("JEA") and with subsidiaries of the Southern Company to pay for approximately 1,330 mWs annually through 2015 and 375 mWs thereafter through 2021. For the year ending December 31, 2011, FPL stated that annual capacity charges its PPA contracts were $511 million.

For the year ending December 31, 2015, NextEra Energy 's 2015 10-K report noted on page 118 that its PPA obligations were for only 375 mWs through 2021, or about

28% of the level in 2011. This reflects the expiration of a substantial portion of FPL's PPAs since 2012. FPL reported that capacity charges under the PPAs were $434 million in 2015. However, the Company forecasted a substantial reduction in these charges, with $185 million in 2016 declining to $110 million in 2020.

Q. Given the substantial decline in FPL's PPA obligations, should the Commission continue to allow FPL a 60% common equity ratio?

A. No, given the change in circumstances since 2012.

Q. If the Commission decides to authorize a ROE greater than your recommended 9.0%, should your 55% equity ratio be adjusted?

A. Yes. If the Commission authorizes a ROE greater than 9.0%, I recommend that FPL's equity ratio be lowered. The Commission could lower the Company's equity ratio to 53%, which is the average common equity ratio of Mr. Hevert's proxy group of companies. This is certainly a reasonable, even generous, equity percentage considering that the average equity ratio for my comparison group of companies is 50%.

Cost of Debt

Q. Did you examine FPL's requested cost of long-term debt?

A. Yes, I did. On page 24 of his Direct Testimony, lines 10 through 13, Mr. Dewhurst testified that the Company projected its long-term debt cost by relying on the Blue Chip Financial Forecast. Cost projections were presented in MFR D-8. For the 2017 test year, the Company included two new issues of First Mortgage Bonds with assumed coupon rates of 6.16%. For the year 2018 the Company included two additional new issues of First Mortgage Bonds with assumed coupon rates of 6.50%.

Q. Are these assumed coupon rates for 2017 and 2018 reasonable?

A. No, they are not. Given current long-term debt rates for A-rated utilities, coupon rates from 6.16% to 6.50% are grossly inflated and should be rejected by the Commission.

Q. What have the recent yields been for A-rated utility bonds in 2016?

A. According to the Mergent Bond Record, A-rated utility bond yields ranged from 3.93% in May to 4.27% in January. Moody's reported that as of June 10, 2016 A-rated utility bond yields were 3.75%.

Although the Blue Chip Financial Forecasts may be forecasting higher future interest rates in 2017 and 2018, there is absolutely no reason to adopt forecasts that are excessively higher than today's current utility bond yields. Forecasts of future interest rates may never come to pass and in that eventuality, ratepayers would be forced to support inflated debt costs.

Q. What is your recommended cost of long-term debt for FPL's forecasted debt issues in 2017 and 2018?

A. I recommend that the Commission authorize a cost of debt of 4.1% for FPL's forecasted debt issues.

My recommendation is based on the highest yield for A-rated debt this year. As I stated previously, the yield on A-rated utility debt in June is 3.75%. Thus, my recommended yield of 4.10% allows for a 35 basis point increase in the current A-rated bond yield.

Q. How would financing debt in 2017 at FPL's projected interest rates compare to financing debt at current rates?

A. Presuming the need for $950 million in debt in 2018, it is obvious that financing it now rather than running the risk of incurring interest rates of 6.16% - 6.50% would benefit ratepayers.

Assume, for example, that FPL obtains an interest rate of 6.40% on future debt issuances. Borrowing $950 million at 6.40% per year on a non-amortizing basis would involve annual interest payments of **$60.8** million (*e.g.*, $950 million times 6.40%). Assume instead that the debt was financed in 2016 at 4.10% (the midpoint of the January-May yields identified above, and well above the 3.75% yield for the most current A-rated yield). The resulting annual interest cost would be **$39** million. The annual savings in that situation would be about $22 million, or about **$440** million over the life of a 20-year bond. The savings would be greater for bonds of longer duration.

While this simplified scenario can be modified for different maturities and types of debt (*e.g.*, amortizing versus non-amortizing), the point is the same. FPL can save ratepayers substantial money by financing its expected long-term debt at lower current interest rates.

Q. Did you review FPL's requested cost of short-term debt?

A. Yes. The Company's cost of short-term debt is included in its Schedule D-3.

Q. Is FPL's requested cost of short-term debt reasonable?

A. No. I recommend that FPL's cost of short-term debt be adjusted.

Q. Please explain how you adjusted the Company's cost of short-term debt.

A. According to Schedule D-3, FPL included commitment fees of $4.569 million in its requested cost of short-term debt. These fixed fees should not be included in the cost of short-term debt. Including these largely fixed fees in short-term debt costs requires the Commission to recalculate the percentage cost of short-term debt whenever it changes the rate base or modifies the amount of short-term debt.

Instead, I recommend that these fees be collected in O&M expenses. In this manner, the Commission ensures that the Company fully recovers these fixed expenses. At the same time, only the short-term debt interest rate itself is reflected in the weighted cost of capital regardless of the adjustments to rate base or the modifications to the capital structure.

Q. What is your recommended cost of short-term debt in this proceeding?

A. I recommend that the Commission adopt a cost of short-term debt of 0.56%. This is the percentage cost shown in Schedule D-3 for the prior year ended December 31, 2016. In my opinion, FPL inflated its cost of short-term debt based on forecasts that may or may not come to pass, just as it did for its forecasted long-term debt issuances. My recommended 0.56% cost of short-term debt allows for a reasonable increase over FPL's December 31, 2015 cost of short-term debt of 0.28%, which is also shown in Schedule D-3. The Commission should not allow FPL to pass through inflated costs of short-term debt to its Florida ratepayers.

Q. In your view, is it likely that interest rates will rise this year?

A. Yes, I believe it is likely that interest rates will rise. The Federal Reserve considered raising interest rates this year, only to defer any such increases due to economic concerns relating to job creation, domestic economic growth, and the effect on exchange rates that would increase the value of the dollar abroad and potentially harm U. S. exports. Many financial observers forecasted that the Federal Reserve would increase rates in June 2016; of course, that ultimately did not occur. In any case, how much interest rates will increase this year, if at all, in anyone's guess.

Q. Did FPL provide interest rate forecasts in its filing in Docket No. 120015-EI?

A. Yes. Dr. William Avera presented forecasts of interest rates in his Exhibit WEA-2, page 1 of 1. I have attached this exhibit as my Exhibit No. ___ (RAB-11). This exhibit shows that in 2012, Dr. Avera presented forecasted interest rates for 2016 for the 30-year Treasury Bond and the AA Utility bond. Those forecasts showed a 2016 30-Year Treasury yield of 5.3% - 5.5% and a AA Utility yield of 6.8% - 6.9%. Current experience shows that these forecasts were obviously very far off the mark. According to the Mergent Bond Record, the Aa Utility bond yield for May 2016 was 3.65%, 315 basis points lower than the forecasts presented by Dr. Avera. Likewise the 30-Year Treasury bond yield in May 2016 was 2.63%, 209 basis points less than the upper end of the forecasted yields presented by Dr. Avera.

This exhibit shows the dangers of relying on forecasted bond yields to set rates for Florida customers.

Q. What is the effect of your recommended common equity ratio, cost of equity and forecasted cost of debt on FPL weighted cost of capital?

A. Mr. Kollen quantified the effect of my recommendations in his Direct Testimony.

IV. RESPONSE TO FPL TESTIMONY

Q. Have you reviewed the Direct Testimony of Mr. Robert Hevert?

A. Yes.

Q. Please summarize Mr. Hevert's testimony and approach to return on equity.

A. Mr. Hevert employed four methods to estimate the investor required rate of return for FPL: (1) the CAPM, (2) the bond yield plus risk premium model, (3) the constant growth DCF model, and (4) a multi-stage DCF model.

With respect to the CAPM, Mr. Hevert's results ranged from 9.08% to 13.21%, including a proposed adjustment for imputed flotation costs. Hevert Direct at 22:19-20.

Mr. Hevert's formulation of the bond yield plus risk premium approach resulted in a ROE estimate range of 10.04% - 10.53%. Hevert Direct at 26, Table 3.

With respect to the DCF model, Mr. Hevert used 30-day, 90-day, and 180-day average stock prices ending January 15, 2016 to estimate the dividend yield for the companies in his proxy group.

For his constant growth DCF approach, he used Value Line, First Call, and Zacks for the investor expected growth rate. Mr. Hevert's mean growth rate ROE results for his proxy group of companies ranged from 9.31% to 9.42%, which include an adjustment for imputed flotation costs. Hevert Direct at 31, Table 4.

Regarding his multi-stage DCF analysis, Mr. Hevert used the same proxy group. This model consisted of three distinct stages with assumptions regarding growth rates and payout ratio changes. Mr. Hevert used a forecast of growth in nominal Gross Domestic Product ("GDP") for his long-term growth rate. The results for this method using the mean growth rate for his proxy group ranged from 9.84% to 9.96% including imputed flotation costs. Hevert Direct at 36, Table 7.

Based on the results of his analyses and judgment, Mr. Hevert recommended a ROE range for FPL of 10.50% to 11.50%, concluding that the cost of equity is 11.00%. Hevert Direct at 69:1-4.

Q. Before you proceed to the particulars of your review with respect to Mr. Hevert's testimony, what is your overall conclusion with respect to Mr. Hevert's recommended ROE range?

A. In my opinion, the results of Mr. Hevert's ROE analyses do not support his recommended ROE range of 10.5% to 11.5%. His mean DCF results for both the constant growth and multi-stage models are far below this recommended range. I would also note that his results for the constant growth DCF are consistent with the results I quantified. Mr. Hevert's bond yield plus risk premium approach yielded a midpoint ROE of 10.29%. Only his CAPM results showed an ROE greater than 10.5%, which is the lower bound of his recommended range. Indeed, Mr. Hevert appears to have omitted the entirety of his average, or mean, DCF results, all of which are significantly below the lower end of his recommended range. The Commission should reject Mr. Hevert's recommended ROE range as unsupported by his own analyses.

Q. You and Mr. Hevert used different proxy groups to estimate FPL's ROE in this proceeding. Do you have any comments with respect to Mr. Hevert's proxy group of companies?

A. Yes. Mr. Hevert's group includes Dominion Resources, Great Plains Energy, and Westar Energy. These three companies are involved in significant merger activity and should not be included in a proxy group for purposes of estimating the return on equity for FPL.

<u>CAPM</u>

Q. Briefly summarize the main elements of Mr. Hevert’s CAPM approach.

A. On page 20 of his Direct Testimony, Mr. Hevert testified that he used several different measures of the risk-free interest rate: the current 30-day average yield on the 30-year Treasury bond (2.96%) and near term and long term projected yields on 30-year Treasury bond yields (4.00% - 4.80%). Mr. Hevert did not consider any shorter maturity bonds, such as the 5-year Treasury note.

Mr. Hevert then calculated ex-ante measures of total market returns using data from Bloomberg and Value Line. Total market returns from these two sources were a 13.63% market return using Bloomberg data (Exhibit No. ___ (RBH-6) at p. 1) and a 12.82% return using Value Line data (Exhibit No. ___ (RBH-6) at p. 7).

Mr. Hevert used two different estimates for beta from Bloomberg and Value Line.

Q. Is it appropriate to use forecasted or projected bond yields in the CAPM?

A. Definitely not. Current interest rates and bond yields embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted bond yield used by Mr. Hevert is speculative at best and may never come to pass. Current interest rates provide tangible and verifiable market evidence of investor return requirements today, and these are the interest rates and bond yields that should be used in both the CAPM and in the bond yield plus risk premium analyses. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

As described *supra*, the interest rates FPL projected in 2012 to occur in 2016 never came to pass and were substantially higher than today's interest rates. This clearly demonstrates the risk of reliance on forecasted interest rates in setting the cost of equity and cost of debt for FPL. Once again, I strongly recommend that the Commission reject this approach.

Q. Should Mr. Hevert have considered shorter-term Treasury yields in his CAPM analyses?

A. Yes. In theory, the risk-free rate should have no interest rate risk. 30-year Treasury Bonds do face this risk, which is the risk that interest rates could rise in the future and lead to a capital loss for the bondholder. Typically, the longer the duration of the bond, the greater the interest rate risk. The 5-year Treasury note has much less interest rate risk than 20-year or 30-year Treasury Bonds and may be considered one reasonable proxy for a risk-free security. My CAPM analysis shows that the ROE using a 5-year Treasury note would be only 8.00% using the expected market return. This is much lower than any of the CAPM estimates provided by Mr. Hevert.

Q. Please comment on Mr. Hevert's use of Bloomberg and Value Line earnings growth estimates for the S&P 500.

A. Mr. Hevert used earnings growth estimates from these two sources to estimate the expected market return for his CAPM. Using the data contained in Exhibit No. ___ (RBH-6), I calculated that the average Value Line growth rate is 10.18% and the average Bloomberg growth rate is 10.06% (average the growth rates contained in column 7).

These are by no means long-run sustainable growth rates. They are about double the long-term GDP growth forecast of 5.35% presented by Mr. Hevert. If forecasted GDP growth is used, then both Mr. Hevert's and my own market return estimates would fall significantly. Obviously, using 5.35% as a proxy for long-term growth for the S&P 500 companies would reduce Mr. Hevert's market return of 12.82% and 13.63% quite substantially. This would also apply to my forward-looking CAPM analyses as well.

Q. Is the S&P 500 a good proxy for the market when estimating a CAPM return on equity?

A. No. That is because the S&P 500 is limited to the stocks of the 500 largest companies in the United States. The market return portion of the CAPM should represent the most comprehensive estimate of the total return for all investment alternatives, not just a small subset of publicly traded stocks. In practice, of course, finding such an estimate is difficult and is one of the more thorny problems in estimating an accurate ROE when using the CAPM. If one limits the market return to stocks, then there are more comprehensive measures of the stock market available, such as the Value Line Investment Survey that I used in my CAPM analysis. Value Line's projected earnings growth used a sample of 2,209 stocks and its book value growth estimate used 1,527 stocks. Value Line's projected annual percentage return included 1,680 stocks. These are much broader samples than Mr. Hevert's limited sample of the S&P 500.

Q. Do the market returns you used in your CAPM suggest that Mr. Hevert's estimated market returns are excessive?

A. Yes. The market returns I estimated from Value Line ranged from 9.88% to 11.00%, far lower than Mr. Hevert's estimated returns on the S&P 500.

<u>Bond Yield Plus Risk Premium Analysis</u>

Q. Please summarize Mr. Hevert's risk premium approach.

A. Mr. Hevert developed a historical risk premium using Commission-allowed returns for regulated electric and gas utility companies and 30-year Treasury bond yields from January 1980 through January 15, 2016. He used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. Applying the regression coefficients to the average risk premium and using both current and projected 30-year Treasury yields I discussed earlier, Mr. Hevert's risk premium ROE estimate ranges from 10.04% to 10.53%. Hevert Direct at 26, Table 3.

Q. Please respond to Mr. Hevert's risk premium analysis.

A. First, the bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time. As such, this approach is a "blunt instrument" for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on a historical risk premium analysis over a certain period of time.

Second, I recommend that the Commission reject the use of the forecasted Treasury bond yields for the same reasons I described in my response to Mr. Hevert's CAPM approach. The Blue Chip Consensus 30-Year Treasury yield forecasts resulted in ROEs of 10.24% - 10.53%, the highest of the three results obtained from Mr. Hevert's analysis. Changing Mr. Hevert's analysis only to use the current 30-Year Treasury yield, without addressing other potential shortcomings of that analysis, would result in a ROE of 10.04%. *See* Exhibit No. ___ (RBH-3) at p. 1, col. 5.

Constant Growth DCF Analyses

Q. What are Mr. Hevert's DCF results without the inclusion of flotation costs?

A. Table 4 below summarizes Mr. Hevert's constant growth DCF results excluding flotation costs and using average growth rates.

TABLE 4

Hevert Constant Growth DCF Results Without Flotation Costs

	Group Mean DCF	Group Median DCF
30-Day Average Stock Price	9.19%	9.00%
90-Day Average Stock Price	9.23%	8.99%
180-Day Average Stock Price	9.30%	9.12%

Once flotation costs are excluded, it becomes clear that Mr. Hevert's DCF results are quite similar to mine. Averaging Witness Hevert’s median growth rates produces a DCF result of 9.04%.

Q. Are the stock prices Mr. Hevert used in his DCF analyses out of date?

A. Yes, they are quite dated. Mr. Hevert used stock prices ending January 15, 2016, making them nearly six months out of date. The Commission should not rely on ROE analyses that use such stale data.

Q. Beginning on page 47 of his Direct Testimony, Mr. Hevert urges the imputation of flotation costs in the allowed ROE. Should the Commission add a flotation cost adjustment to the cost of equity for FPL?

A. No. In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. I do not believe that this is an appropriate assumption. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

Multi-stage DCF Model

Q. Please summarize the components of Mr. Hevert's multi-stage DCF model.

A. Mr. Hevert described the structure and the inputs for his multi-stage DCF model on pages 31 through 36 of his Direct Testimony. The main elements of Mr. Hevert's multi-stage DCF analyses are as follows:

- 30, 90, and 180 average stock prices.
- First stage of growth based on the average earnings growth rates from Value Line, Zacks, and First Call.
- A transition period from near-term to long-term growth.
- Long-term growth estimated using GDP growth based on historical real GDP growth from 1929 through 2014 and a forecasted inflation rate (5.35%).
- Expected dividend in the final year divided by solved cost of equity less long-term growth rate.
- Payout ratio assumptions based on Value Line for the first stage, a transition period, and a long-term expected payout ratio.

Q. As a practical matter, is it likely that investors would use the multi-stage model presented by Mr. Hevert?

A. No. In my opinion, it is highly unlikely that investors would employ the complicated structure and set of assumptions used by Mr. Hevert. Mr. Hevert presented no evidence whatsoever that investors use such a model in forming their required return for an electric utility such as FPL. He presented no evidence that investors use GDP growth in their evaluation of expected growth in dividends and earnings for electric utility companies. Nor did he show that investors utilize his assumptions regarding the transition period or payout ratio forecasts.

Q. In your opinion, did Mr. Hevert overstate expected GDP growth?

A. Yes. There are two publicly available forecasts of GDP growth that are relied upon by the Federal Energy Regulatory Commission ("FERC") in the determination of the second stage of the two-stage growth rate in its DCF return on equity formula. These forecasts come from the Energy Information Administration ("EIA"), and the Social Security Administration ("SSA") Trustees Report.[3] The latest EIA GDP forecast shows expected growth in nominal GDP of 4.19%. The SSA Report forecasts nominal growth in GDP of 4.41%. The average of these two long-term GDP forecasts is 4.30%. I include the calculations of these two GDP growth rates on Exhibit No. ___ (RAB-12). My calculations are based on my understanding of how the FERC Staff uses the data contained in the EIA and SSA documents to calculate long-term GDP growth for the second stage of its two-stage DCF model.

3 Please see the Energy Information Administration, *Annual Energy Outlook 2015* (April 2015) and Social Security Administration, 2016 OASDI Trustees Report, Table VI.G6 - Selected Economic Variables, Calendar Years 2015-90.

These independent sources are forecasting nominal GDP growth to be substantially lower than the forecast used by Mr. Hevert (4.30% vs. Mr. Hevert's forecast of 5.35%). In my opinion, Mr. Hevert's GDP forecast contributes to a significant overstatement of his multi-stage DCF results.

Q. Did you recalculate Mr. Hevert's multi-stage DCF using the 4.30% forecasted GDP from the two sources you just cited?

A. Yes. Please refer to my Exhibit No. ___ (RAB-13), which provide a recalculation of Mr. Hevert's multi-stage DCF using a 4.30% forecasted GDP growth and a 180-day average stock price from Exhibit No. ___ (RBH-5). I did not change any other assumption used by Mr. Hevert in this analysis.

The resulting mean DCF ROE result is 9.03%. This provides an idea of how much Mr. Hevert overstated his multi-stage DCF results using his own 5.35% GDP forecast.

Business Risks and Other Considerations

Q. Please summarize the business risk discussion contained in Section VI of Mr. Hevert’s Direct Testimony.

A. Beginning on page 37 of his Direct Testimony, Mr. Hevert presented the risks and other considerations that he believes should be taken into account in setting the allowed cost of equity for FPL. These considerations include:

- Geographic risk

- Capital access
- Nuclear generation regulatory requirements
- Four-year rate proposal

Q. Did Mr. Hevert perform a study comparing these risk considerations involving FPL to those of the companies he includes in his proxy group?

A. No. Mr. Hevert did not conduct any such studies regarding geographic risks (Exhibit No. ___ (RAB-5) at pp. 83-86 (FPL's Response to SFHHA ROG No. 85 and Staff ROG No. 239(b)), capital access (Exhibit No. ___ (RAB-5) at p. 87 (FPL's Response to SFHHA POD No. 76)), and nuclear generation regulatory requirements (Exhibit No. ___ (RAB-5) at p. 88 (FPL's Response to SFHHA POD No. 77)).

In response to discovery Mr. Hevert explained that he "did not believe it was necessary to perform any additional comparative risk analysis" other than his "selection criteria used to identify a proxy group of comparable publically traded electric utility companies." Exhibit No. ___ (RAB-5) at pp. 89-90 (FPL's Responses to SFHHA POD No. 79 and Staff ROG No. 236)).

Q. Mr. Baudino, what is your response to Mr. Hevert's discussion of these risk factors and their effect on the Commission's determination of a fair rate of return for FPL in this case?

A. It is important to consider that bond rating agencies consider the risks that Mr. Hevert mentioned, as well as other factors, in determining their bond and credit ratings for regulated electric companies. As I testified previously, these bond and credit ratings provide a summary assessment of the overall risk of a utility company such as FPL. Thus, comparing FPL's bond and credit ratings to the companies in our respective proxy groups will provide the Commission an objective assessment of how FPL's overall risk compares to our groups.

Referring to Table 1 of my Direct Testimony, six of the twelve companies in my comparison group have A/A ratings. They do not have a split bond rating in which one agency gave the subject company a BBB/Baa rating while the other agency gave the company an A/A rating. The remaining six companies in the comparison group have a split bond rating. FPL's senior securities carry an A/Aa2 bond rating. Comparing FPL's bond ratings to the bond ratings of my comparison group shows that FPL is a lower risk company than the group on the basis of bond ratings.

Q. Did Mr. Hevert conduct a comparison of FPL's bond and credit ratings to the companies in his electric proxy group?

A. No, he did not. However, I shall present such a comparison of FPL's bond ratings to the bond ratings contained in the June 2016 issue of AUS Utility Reports. Please refer to my Table 5 below for this information.

TABLE 5
Hevert Proxy Group Bond Ratings

Company	S&P	Moody's
ALLETE, Inc.	A-	A3
Alliant Energy Corporation	A-	A2/A3
Ameren Corporation	BBB+/BBB	Baa1
American Electric Power Company, Inc.	BBB/BBB-	Baa1
Avista Corporation	A-	Baa1
CMS Energy Corporation	BBB+/BBB	A3/Baa1
Dominion Resources, Inc.	A-	A3/Baa1
DTE Energy Company	A-/BBB+	A2/A3
Great Plains Energy Inc.	BBB	Baa2
IDACORP, Inc.	A-	A3
NorthWestern Corporation	NR	A3
OGE Energy Corp.	BBB+	A3
Otter Tail Corporation	BBB-	Baa2
Pinnacle West Capital Corporation	BBB	A3/Baa1
PNM Resources, Inc.	BBB	Baa2
Portland General Electric Company	A-	A3
SCANA Corporation	BBB+	Baa1/Baa2
Westar Energy, Inc.	A-	A3/Baa1
Xcel Energy Inc.	A-	A3

Table 7 shows the following:

- Six of the eighteen proxy companies have BBB/Baa bond ratings.
- Seven of the eighteen proxy companies have split ratings (A/BBB/Baa).
- Five of the eighteen proxy companies have A/A bond ratings.

The information in Table 7 clearly shows that the Mr. Hevert's proxy group is more risky than FPL when bond ratings are considered. *Thus, if the Commission is to make any adjustment to FPL's ROE based on the results of Mr. Hevert's ROE analyses, it should be to lower FPL's ROE compared to his proxy group*.

Q. Did Mr. Hevert omit any important considerations with respect to total company risk?

A. Yes. Mr. Hevert overlooked the fact that FPL's financial risk is lower than his proxy group due to FPL's inflated common equity ratio. Mr. Hevert's Exhibit No. ___ (RBH-10) shows that the average common equity ratio for his proxy group is 52.7%. The average common equity percentage for the operating companies is 53.2%. Adjusting the Company's requested 60% common equity to 55% would still leave FPL with a higher common equity ratio that his proxy group average, and correspondingly lower financial risk.

Q. Beginning on page 50 of his Direct Testimony, Mr. Hevert discussed additional risks from FPL's proposed Four Year Rate Proposal. Do you agree with Mr. Hevert's discussion on this point?

A. No. It would make no sense from FPL's perspective to propose a multi-year rate plan if such a plan did not have substantial benefits for its shareholders. The Company's Four Year Rate Proposal would lend revenue stability and certainty of cost recovery over the next four years if approved. Regarding the risk of higher interest rates over that time, FPL included substantially higher assumed interest rates for its projected new debt issues in 2017 and 2018. This would completely mitigate interest rate risk for the Company and, by the same token, expose Florida customers to paying a higher cost of debt if those assumed interest rates fail to materialize. In fact, if FPL expects interest rates to be higher in 2017 and 2018, it would be prudent for the Company to lock in lower interest rates now and issue its forecasted debt this year.

Finally, Mr. Hevert's proposed ROE of 11.0% is so far above recently approved ROEs that interest rates could rise substantially and FPL could still earn an above market ROE. Mr. Hevert's data on Exhibit No. ___ (RBH-3) shows Commission-allowed returns from January 1980 through January 2016. According to my calculations, the average Commission-allowed return from January 2015 through January 2016 was 9.59%, which is 141 basis points lower than Mr. Hevert's recommended 11.0% ROE. If the 50 basis point performance adder is included the 11.5% ROE becomes even further removed from recent Commission-allowed returns.

In conclusion, FPL's excessive ROE and interest rate projections have eliminated any cost of capital risk from its proposed four-year rate plan.

Q. Should the Commission raise FPL's ROE based on Mr. Hevert's discussion of the four risk factors you summarized earlier?

A. No. These risks are already embedded in FPL's bond and credit ratings. FPL carries a strong A/A credit rating from Moody's and Standard and Poor's. With respect to overall business risk, the S&P credit report I cited earlier in my testimony assigned FPL an "excellent" business risk rating, which is the very top of S&P's business risk scale.

<u>Capital Market Environment</u>

Q. Beginning on page 52 of his Direct Testimony, Mr. Hevert discussed current capital market conditions. Could you please respond to Mr. Hevert's discussion of these conditions?

A. Yes. As I described in Section II of my testimony, the United States continues to be a low interest rate environment that suggests lower ROEs for regulated utilities. Even though the Federal Reserve has considered raising interest rates this year, it has delayed any such move for the time being. In a press release dated June 15, 2016 the Federal Open Market Committee stated the following:

> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will strengthen. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of past declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to closely monitor inflation indicators and global economic and financial developments.
>
> Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation. [Exhibit No. ___ (RAB-3) at p.13].

Note that the stance of the Federal Reserve is one of accommodation and that it decided to maintain short-term interest rates at their present levels. This continues to favor lower expected returns on the part of investors for lower risk and higher yielding regulated utility stocks.

Q. Beginning on page 56, Mr. Hevert discusses equity market volatility. Please respond to his discussion on this point.

A. On page 61 of his Direct Testimony, Mr. Hevert testified: "in light of the fact that volatility now is considerably above its prior levels, it is difficult to conclude that fundamental risk aversion and investor return requirements have fallen."

I would agree with Mr. Hevert that the indices of overall market volatility he presented suggest that market volatility has increased so far in 2016. I would further suggest that market volatility will most likely increase further with Great Britain voting to leave the European Union on June 23, 2016. However, I would note that with respect to the stocks of regulated utilities, investors appear to be seeking safe havens for their money by purchasing utility stocks. For example, the Dow Jones Utilities Average ("DJU") began the year, January 4, 2016 at 574.51. The DJU closed on Friday, June 24 at 685.71, an increase of 19.4%. On June 24, 2016, the day after the "Brexit" vote, the DJU closed up from the prior day by 1.0%. Contrast this with the overall market. The S&P 500 lost 3.6% and the Dow Jones Industrial average lost 3.4%.

Investors appear to continue to view regulated utilities as safe, stable investments compared with the market as a whole. Recent stock market movements underscore my recommendation of 9.0% as reasonable, indeed generous, for a financially strong and low risk utility investment like FPL.

ROE Adder for Excellent Management

Q. Several FPL witnesses, including Mr. Hevert, recommended that the Commission recognize and encourage exemplary management in setting the

return on equity for FPL by adding 0.50% to the return on equity in this proceeding. Do you agree?

A. Definitely not. The Commission should base its allowed return on equity on market-based data and analysis that I have provided in my testimony. Using appropriate cost of equity models to estimate the investor required return for FPL will, if applied properly, fairly compensate investors for their equity investment. Arbitrarily increasing the investor required return to recognize factors such as alleged "excellent management" would overcompensate investors and result in excessive rates to ratepayers. The regulatory balance would be tipped in favor of shareholders and against customers.

Moreover, providing an inflated return on equity to recognize claimed "exemplary management" performance undercuts the benefits of such performance, which should be greater efficiency, lower costs, and lower rates to customers. Ratepayers should *expect* exemplary management from the Company without having to support inflated returns to shareholders beyond their actual requirements. It is important to realize that FPL's ratepayers have paid FPL dollar for dollar for the O&M expenses and capital investments the Company has made over time that have resulted in the rates currently being paid by customers. And FPL's management and employees have accomplished this without any special ROE adder that would flow to shareholders.

Also, with respect to the level of FPL's rates, there are other factors that have benefitted the Company beyond what could be considered "excellent management". One major factor is that gas prices are currently quite low. Since FPL derives approximately 69% of its generation from gas-fired units, low gas prices are a major contributing factor to lower rates. FPL's management is not the cause of low gas prices and its need to build new generation capacity over the past 3 decades to meet population growth has afforded it an opportunity to add gas-fired units when other utilities, not benefitting from such population growth, have not had the same opportunity.

Another major factor contributing to FPL's low rates is the fact that the Company is a very large utility with a contiguous Florida service territory that has economies of scale. This means that fixed costs per customer will be lower for FPL than other, smaller utilities that have higher fixed costs per customer. Again, economies of scale have no bearing on FPL's claimed "excellent management".

FPL's current nuclear fleet has also been significantly depreciated. Turkey Point has been operating since 1973 and St. Lucie has been in operation since 1983. These depreciated nuclear units, combined with very low running costs, are significant contributors to FPL's level of rates. Once again, this was not due to exemplary management and does not merit any bonus on the Company's ROE.

Q. Does this complete your prepared Direct Testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

RICHARD A. BAUDINO, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Richard A. Baudino

Richard A. Baudino

Sworn to and subscribed before me on this 6th day of July 2016.

Jessica K. In

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE:	**PETITION FOR RATE INCREASE BY**	**)**	
	FLORIDA POWER AND LIGHT	**)**	**DOCKET NO. 160021-EI**
	COMPANY AND SUBSIDIARIES	**)**	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTH CARE ASSOCIATION

July 2016

EXHIBIT NO. ___ (RAB-1)

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant -** Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist -** Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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03/06	05-1278- E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006- 0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008- 2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008- 2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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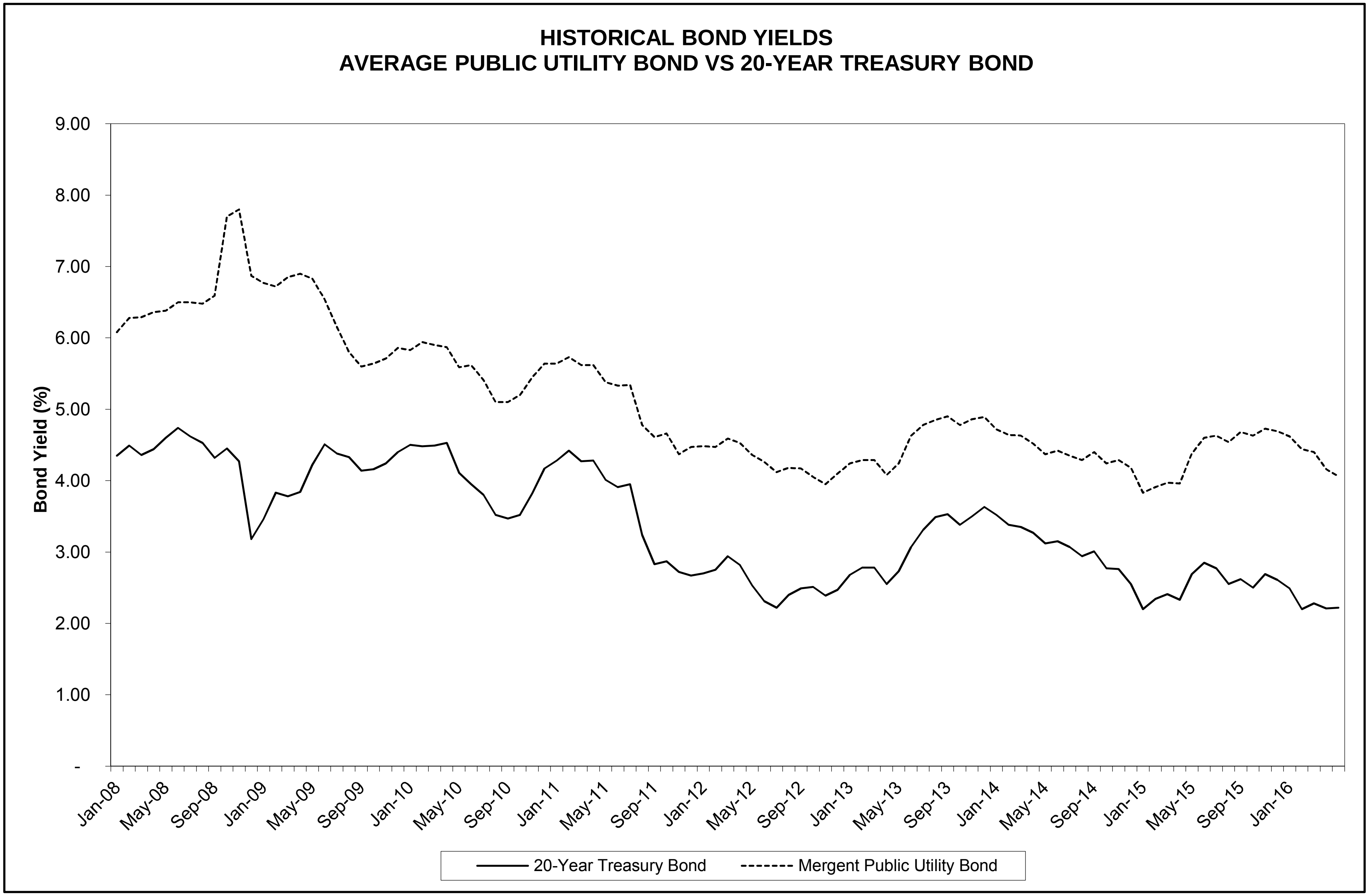
Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues

EXHIBIT NO. ___ (RAB-2)



Docket No. 160021-EI
Historical Bond Yields
Exhibit No. ___ (RAB-2), Page 1 of 1

EXHIBIT NO. ___ (RAB-3)

Board of Governors of the Federal Reserve System

Credit and Liquidity Programs and the Balance Sheet

- Overview
- Crisis response
- Monetary policy normalization
- Fed's balance sheet

- Federal Reserve liabilities
- Recent balance sheet trends
- Open market operations
- Central bank liquidity swaps

- Lending to depository institutions
- Fed financial reports
- Other reports and disclosures
- Information on closed programs

The Federal Reserve's response to the financial crisis and actions to foster maximum employment and price stability

The Federal Reserve responded aggressively to the financial crisis that emerged in the summer of 2007, including the implementation of a number of programs designed to support the liquidity of financial institutions and foster improved conditions in financial markets. These programs led to significant changes to the Federal Reserve's balance sheet.

While these crisis-related special programs have expired or been closed, the Federal Reserve continues to take actions to fulfill its statutory objectives for monetary policy: maximum employment and price stability. Over recent years, many of these actions have involved substantial purchases of longer-term securities aimed at putting downward pressure on longer-term interest rates and easing overall financial conditions.

Related

The Crisis and Policy Response
Speech by Chairman Ben S. Bernanke, Jan. 13, 2009

The Federal Reserve's Policy Actions during the Financial Crisis and Lessons for the Future
Speech by Vice Chairman Donald L. Kohn, May 13, 2010

The tools described in this section can be divided into three groups. The first set of tools, which are closely tied to the central bank's traditional role as the lender of last resort, involve the provision of short-term liquidity to banks and other depository institutions and other financial institutions. The traditional discount window falls into this category, as did the crisis-related Term Auction Facility (TAF), Primary Dealer Credit Facility (PDCF), and Term Securities Lending Facility (TSLF). Because bank funding markets are global in scope, the Federal Reserve also approved bilateral currency swap agreements with several foreign central banks. The swap arrangements assist these central banks in their provision of dollar liquidity to banks in their jurisdictions.

A second set of tools involved the provision of liquidity directly to borrowers and investors in key credit markets.

The crisis-related Commercial Paper Funding Facility (CPFF), Asset-Backed Commercial Paper Money Market Mutual Fund Liquidity Facility (AMLF), Money Market Investor Funding Facility (MMIFF), and the Term Asset-Backed Securities Loan Facility (TALF) fall into this category.

As a third set of instruments, the Federal Reserve expanded its traditional tool of open market operations to support the functioning of credit markets, put downward pressure on longer-term interest rates, and help to make broader financial conditions more accommodative through the purchase of longer-term securities for the Federal Reserve's portfolio. For example, starting in September 2012, the FOMC decided to increase policy accommodation by purchasing agency-guaranteed mortgage-backed securities (MBS) at a pace of $40 billion per month in order to support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate. In addition, starting in January 2013, the Federal Reserve began purchasing longer-term Treasury securities at a pace of $45 billion per month. Starting in January 2014, the FOMC reduced the pace of asset purchases in measured steps, and concluded the purchases in October 2014.

Additional information on closed facilities

As noted above, the Federal Reserve's crisis-related special credit and liquidity programs have expired or been closed. Information on these programs is available on the Information on closed programs page.

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Press Release

FEDERAL RESERVE press release

Release Date: November 3, 2010

For immediate release

Information received since the Federal Open Market Committee met in September confirms that the pace of recovery in output and employment continues to be slow. Household spending is increasing gradually, but remains constrained by high unemployment, modest income growth, lower housing wealth, and tight credit. Business spending on equipment and software is rising, though less rapidly than earlier in the year, while investment in nonresidential structures continues to be weak. Employers remain reluctant to add to payrolls. Housing starts continue to be depressed. Longer-term inflation expectations have remained stable, but measures of underlying inflation have trended lower in recent quarters.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. Currently, the unemployment rate is elevated, and measures of underlying inflation are somewhat low, relative to levels that the Committee judges to be consistent, over the longer run, with its dual mandate. Although the Committee anticipates a gradual return to higher levels of resource utilization in a context of price stability, progress toward its objectives has been disappointingly slow.

To promote a stronger pace of economic recovery and to help ensure that inflation, over time, is at levels consistent with its mandate, the Committee decided today to expand its holdings of securities. The Committee will maintain its existing policy of reinvesting principal payments from its securities holdings. In addition, the Committee intends to purchase a further $600 billion of longer-term Treasury securities by the end of the second quarter of 2011, a pace of about $75 billion per month. The Committee will regularly review the pace of its securities purchases and the overall size of the asset-purchase program in light of incoming information and will adjust the program as needed to best foster maximum employment and price stability.

The Committee will maintain the target range for the federal funds rate at 0 to 1/4 percent and continues to anticipate that economic conditions, including low rates of resource utilization, subdued inflation trends, and stable inflation expectations, are likely to warrant exceptionally low levels for the federal funds rate for an extended period.

The Committee will continue to monitor the economic outlook and financial developments and will employ its policy tools as necessary to support the economic recovery and to help ensure that inflation, over time, is at levels consistent with its mandate.

Voting for the FOMC monetary policy action were: Ben S. Bernanke, Chairman; William C. Dudley, Vice Chairman; James Bullard; Elizabeth A. Duke; Sandra Pianalto; Sarah Bloom Raskin; Eric S. Rosengren; Daniel K. Tarullo; Kevin M. Warsh; and Janet L. Yellen.

Voting against the policy was Thomas M. Hoenig. Mr. Hoenig believed the risks of additional securities purchases outweighed the benefits. Mr. Hoenig also was concerned that this continued high level of monetary accommodation increased the risks of future financial imbalances and, over time, would cause an increase in long-term inflation expectations that could destabilize the economy.

Statement from Federal Reserve Bank of New York

Press Release

FEDERAL RESERVE press release

Release Date: June 19, 2013

For immediate release

Information received since the Federal Open Market Committee met in May suggests that economic activity has been expanding at a moderate pace. Labor market conditions have shown further improvement in recent months, on balance, but the unemployment rate remains elevated. Household spending and business fixed investment advanced, and the housing sector has strengthened further, but fiscal policy is restraining economic growth. Partly reflecting transitory influences, inflation has been running below the Committee's longer-run objective, but longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with appropriate policy accommodation, economic growth will proceed at a moderate pace and the unemployment rate will gradually decline toward levels the Committee judges consistent with its dual mandate. The Committee sees the downside risks to the outlook for the economy and the labor market as having diminished since the fall. The Committee also anticipates that inflation over the medium term likely will run at or below its 2 percent objective.

To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.

The Committee will closely monitor incoming information on economic and financial developments in coming months. The Committee will continue its purchases of Treasury and agency mortgage-backed securities, and employ its other policy tools as appropriate, until the outlook for the labor market has improved substantially in a context of price stability. The Committee is prepared to increase or reduce the pace of its purchases to maintain appropriate policy accommodation as the outlook for the labor market or inflation changes. In determining the size, pace, and composition of its asset purchases, the Committee will continue to take appropriate account of the likely efficacy and costs of such purchases as well as the extent of progress toward its economic objectives.

To support continued progress toward maximum employment and price stability, the Committee expects that a highly accommodative stance of monetary policy will remain appropriate for a considerable time after the asset purchase program ends and the economic recovery strengthens. In particular, the Committee decided to keep the target range for the federal funds rate at 0 to 1/4 percent and currently anticipates that this exceptionally low range for the federal funds rate will be appropriate at least as long as the unemployment rate remains above 6-1/2 percent, inflation between one and two years ahead is projected to be no more than a half percentage point above the Committee's 2 percent longer-run goal, and longer-term inflation expectations continue to be well anchored. In determining how long to maintain a highly accommodative stance of monetary policy, the Committee will also consider other information, including additional measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial developments. When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent.

Voting for the FOMC monetary policy action were: Ben S. Bernanke, Chairman; William C. Dudley, Vice Chairman; Elizabeth A. Duke; Charles L. Evans; Jerome H. Powell; Sarah Bloom Raskin; Eric S. Rosengren; Jeremy C. Stein; Daniel K. Tarullo; and Janet L. Yellen. Voting against the action was James Bullard, who believed that the Committee should signal more strongly its willingness to defend its inflation goal in light of recent low inflation readings, and Esther L. George, who was concerned that the continued high level of monetary accommodation increased the risks of future economic and financial imbalances and, over time, could cause an increase in long-term inflation expectations.

Press Release

FEDERAL RESERVE press release

Release Date: October 29, 2014

For immediate release

Information received since the Federal Open Market Committee met in September suggests that economic activity is expanding at a moderate pace. Labor market conditions improved somewhat further, with solid job gains and a lower unemployment rate. On balance, a range of labor market indicators suggests that underutilization of labor resources is gradually diminishing. Household spending is rising moderately and business fixed investment is advancing, while the recovery in the housing sector remains slow. Inflation has continued to run below the Committee's longer-run objective. Market-based measures of inflation compensation have declined somewhat; survey-based measures of longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with appropriate policy accommodation, economic activity will expand at a moderate pace, with labor market indicators and inflation moving toward levels the Committee judges consistent with its dual mandate. The Committee sees the risks to the outlook for economic activity and the labor market as nearly balanced. Although inflation in the near term will likely be held down by lower energy prices and other factors, the Committee judges that the likelihood of inflation running persistently below 2 percent has diminished somewhat since early this year.

The Committee judges that there has been a substantial improvement in the outlook for the labor market since the inception of its current asset purchase program. Moreover, the Committee continues to see sufficient underlying strength in the broader economy to support ongoing progress toward maximum employment in a context of price stability. Accordingly, the Committee decided to conclude its asset purchase program this month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that the current 0 to 1/4 percent target range for the federal funds rate remains appropriate. In determining how long to maintain this target range, the Committee will assess progress--both realized and expected--toward its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial developments. The Committee anticipates, based on its current assessment, that it likely will be appropriate to maintain the 0 to 1/4 percent target range for the federal funds rate for a considerable time following the end of its asset purchase program this month, especially if projected inflation continues to run below the Committee's 2 percent longer-run goal, and provided that longer-term inflation expectations remain well anchored. However, if incoming information indicates faster progress toward the Committee's employment and inflation objectives than the Committee now expects, then increases in the target range for the federal funds rate are likely to occur sooner than currently anticipated. Conversely, if progress proves slower than expected, then increases in the target range are likely to occur later than currently anticipated.

When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent. The Committee currently anticipates that, even after employment and inflation are near mandate-consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels the Committee views as normal in the longer run.

Voting for the FOMC monetary policy action were: Janet L. Yellen, Chair; William C. Dudley, Vice Chairman; Lael Brainard; Stanley Fischer; Richard W. Fisher; Loretta J. Mester; Charles I. Plosser; Jerome H. Powell; and Daniel K. Tarullo. Voting against the action was Narayana Kocherlakota, who believed that, in light of continued sluggishness in the inflation outlook and the recent slide in market-based measures of longer-term inflation expectations, the Committee should commit to keeping the current target range for the federal funds rate at least until the one-to-two-year ahead inflation outlook has returned to 2 percent and should continue the asset purchase program at its current level.

Statement Regarding Purchases of Treasury Securities and Agency Mortgage-Backed Securities

Press Release

FEDERAL RESERVE press release

Release Date: March 16, 2016

For release at 2:00 p.m. EDT

Information received since the Federal Open Market Committee met in January suggests that economic activity has been expanding at a moderate pace despite the global economic and financial developments of recent months. Household spending has been increasing at a moderate rate, and the housing sector has improved further; however, business fixed investment and net exports have been soft. A range of recent indicators, including strong job gains, points to additional strengthening of the labor market. Inflation picked up in recent months; however, it continued to run below the Committee's 2 percent longer-run objective, partly reflecting declines in energy prices and in prices of non-energy imports. Market-based measures of inflation compensation remain low; survey-based measures of longer-term inflation expectations are little changed, on balance, in recent months.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will continue to strengthen. However, global economic and financial developments continue to pose risks. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to monitor inflation developments closely.

Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.

In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.

The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction, and it anticipates doing so until normalization of the level of the federal funds rate is well under way. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

Voting for the FOMC monetary policy action were: Janet L. Yellen, Chair; William C. Dudley, Vice Chairman; Lael Brainard; James Bullard; Stanley Fischer; Loretta J. Mester; Jerome H. Powell; Eric Rosengren; and Daniel K. Tarullo. Voting against the action was Esther L. George, who preferred at this meeting to raise the target range for the federal funds rate to 1/2 to 3/4 percent.

Implementation Note issued March 16, 2016

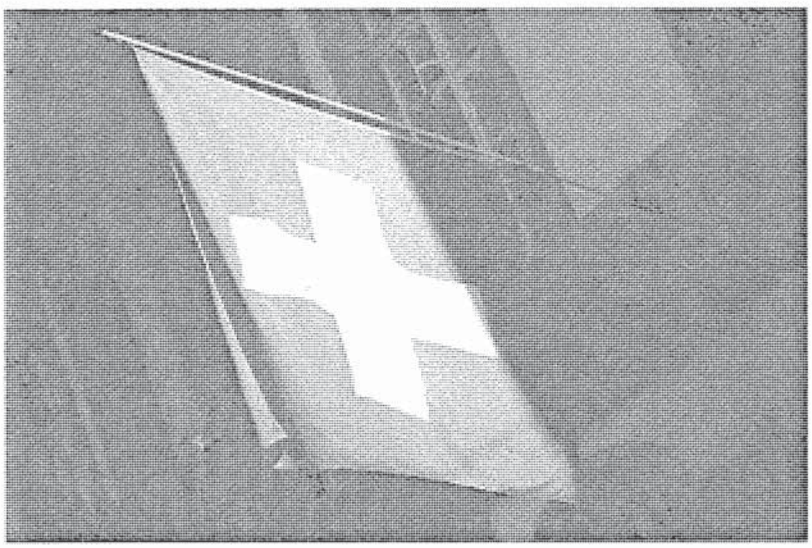
THE WALL STREET JOURNAL.

http://blogs.wsj.com/moneybeat/2016/06/16/from-1-month-to-33-years-almost-the-entire-yield-curve-for-swiss-bonds-is-negative/

MONEYBEAT

From 1 Month to 33 Years, Almost the Entire Yield Curve for Swiss Bonds is Negative

Switzerland has outdone Germany: the country's bonds have negative yields all the way out to 2049



The Swiss national flag is illuminated by evening sunlight as it hangs from a building in Bern, Switzerland, on Sunday, June 28, 2015. *PHOTO: BLOOMBERG NEWS*

By **MIKE BIRD**
Jun 16, 2016 11:19 am ET

Switzerland's government bonds have outdone Germany's this week: Though the 10-year German bund yields dipped into negative territory on Tuesday, Swiss sovereign bonds now have subzero yields all the way out to 33 years.

The benchmark 30 year bond dipped below zero to minus 0.004%, from a close of 0.04% at the end of trading on Wednesday.

Though Switzerland does have some longer-dated bonds with very narrowly positive yields, the country's yield curve is the lowest in the world, outdoing Japan.

Shorter dated Swiss bond yields are even lower, with a 10-year yield at minus 0.53%

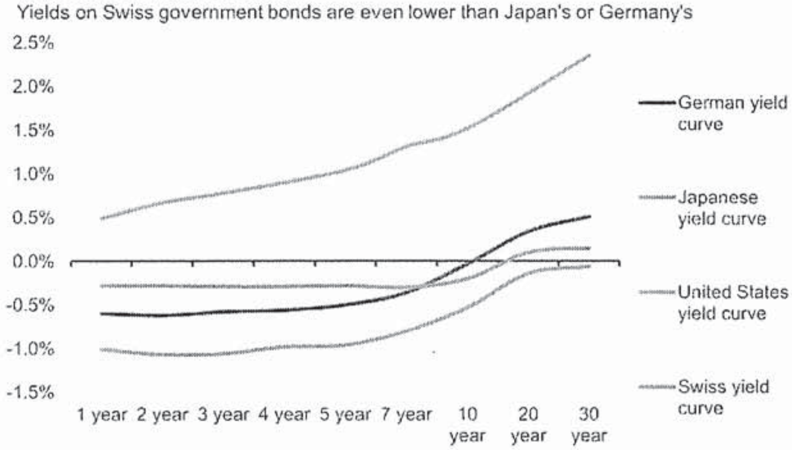
Bond yields move inversely to prices, so more demand for the bonds drives returns lower. The Swiss National Bank has set its benchmark interest rate at minus 0.75%, one of the most steeply negative in the world, in an effort to stave off its persistent deflation.

The flight to safety hitting global markets this week is particularly acute in Europe, with polls suggesting growing levels of support for Brexit, ahead of the U.K's June 23 referendum on its European Union membership.

Swiss assets are widely regarded as safe havens from financial turmoil, and the Swiss franc also climbed to its strongest level in nearly six months against the euro during Thursday trading.

Sub Zero Switzerland

Yields on Swiss government bonds are even lower than Japan's or Germany's



Press Release

FEDERAL RESERVE press release

Release Date: June 15, 2016

For release at 2:00 p.m. EDT

Information received since the Federal Open Market Committee met in April indicates that the pace of improvement in the labor market has slowed while growth in economic activity appears to have picked up. Although the unemployment rate has declined, job gains have diminished. Growth in household spending has strengthened. Since the beginning of the year, the housing sector has continued to improve and the drag from net exports appears to have lessened, but business fixed investment has been soft. Inflation has continued to run below the Committee's 2 percent longer-run objective, partly reflecting earlier declines in energy prices and in prices of non-energy imports. Market-based measures of inflation compensation declined; most survey-based measures of longer-term inflation expectations are little changed, on balance, in recent months.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will strengthen. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of past declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to closely monitor inflation indicators and global economic and financial developments.

Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.

In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.

The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction, and it anticipates doing so until normalization of the level of the federal funds rate is well under way. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

Voting for the FOMC monetary policy action were: Janet L. Yellen, Chair; William C. Dudley, Vice Chairman; Lael Brainard; James Bullard; Stanley Fischer; Esther L. George; Loretta J. Mester; Jerome H. Powell; Eric Rosengren; and Daniel K. Tarullo.

Implementation Note issued June 15, 2016

EXHIBIT NO. ___ (RAB-4)

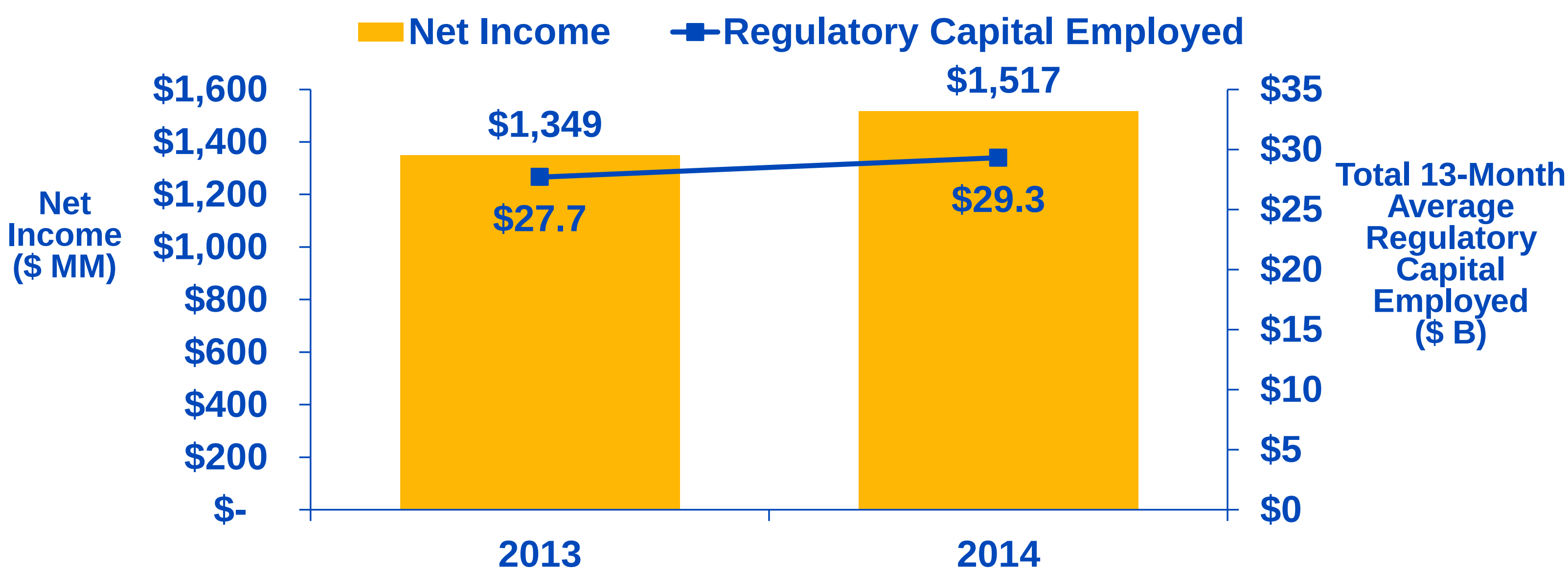
Japan Investor Presentation

February 2016

FPL®

FPL's net income is largely a function of capital employed, capital structure (equity ratio) and ROE earned

Net Income, Regulatory Capital Employed and ROE



	2013	2014
Retail Base Regulatory ROE	11.0%	11.5%

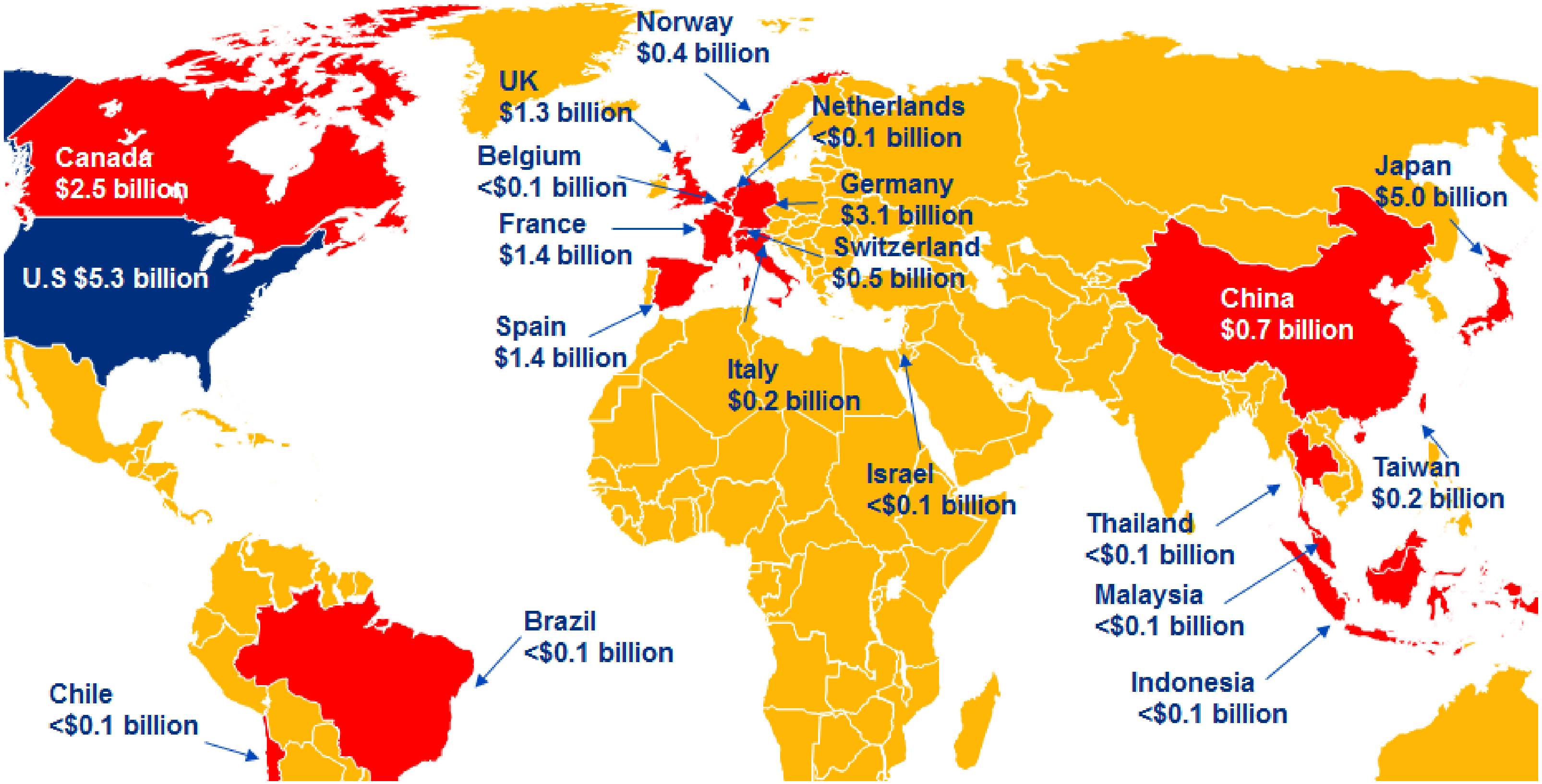
This relationship is largely true whether FPL is operating under a settlement agreement or traditional rate setting

NEXTera ENERGY

FINANCIAL REVIEW

Our diverse banking relationships have enabled us to secure ~$22 billion[(1)] in credit from over 100 banks that span 20 countries and 4 continents

Country Breakdown by Funding



Our lending group is large, balanced and well-diversified

(1) Reflects corporate credit facilities, commitments and term loans outstanding as of January 31, 2016 and original balances of project debt funded or committed by banks since 2003

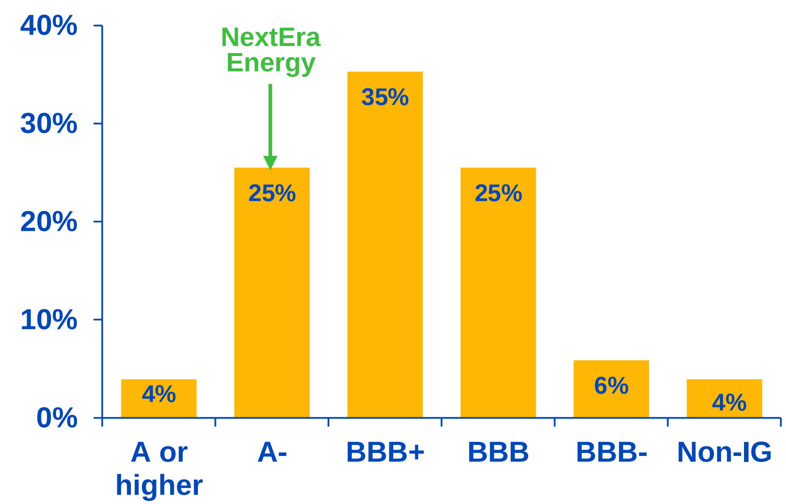
NEXTera ENERGY

NextEra Energy is one of the strongest investment-grade rated electric utilities in the U.S.

NextEra Energy Ratings[(1)]

	S&P	Moody's	Fitch
NextEra Energy			
Issuer Credit Rating	A-	Baa1	A-
Outlook	Stable	Stable	Stable
Florida Power & Light			
First Mortgage Bonds	A	Aa2	AA-
Commercial Paper	A-2	P-1	F-1
Outlook	Stable	Stable	Stable
Capital Holdings			
Sr. Unsecured Debentures	BBB+	Baa1	A-
Commercial Paper	A-2	P-2	F-1
Outlook	Stable	Stable	Stable

Utility Credit Ratings[(2)]



NextEra remains committed to preserving it's strong credit position and manages its balance sheet to maintain this key competitive advantage

(1) Reflects latest ratings as published by S&P on June 16, 2015, Moody's on October 27, 2015 and Fitch on December 3, 2015.
(2) Source: Edison Electric Institute: S&P Utility Credit Ratings Distribution – Financial Update Q4 2015.

June 2016 Investor Presentation

NEXTera ENERGY®

NEXTera energy™ PARTNERS

Over a sustained period of time, our growth strategy has led to real change in relative position

Top 20 Global Utility Equity Market Capitalization[1]

As of 6/1/2001 ($ MM)

Rank	Market Cap	
1	$38,574	
2	$38,185	
3	$34,476	
4	$34,111	
5	$30,955	
6	$23,906	
7	$21,537	
8	$20,093	
9	$17,297	
10	$16,873	
11	$16,279	
12	$15,884	
13	$15,785	
14	$14,601	
15	$14,461	
16	$14,223	
17	$13,773	
18	$13,550	
19	$13,136	
20	$12,934	
30	$10,206	NextEra Energy

As of 5/31/2016 ($ MM)

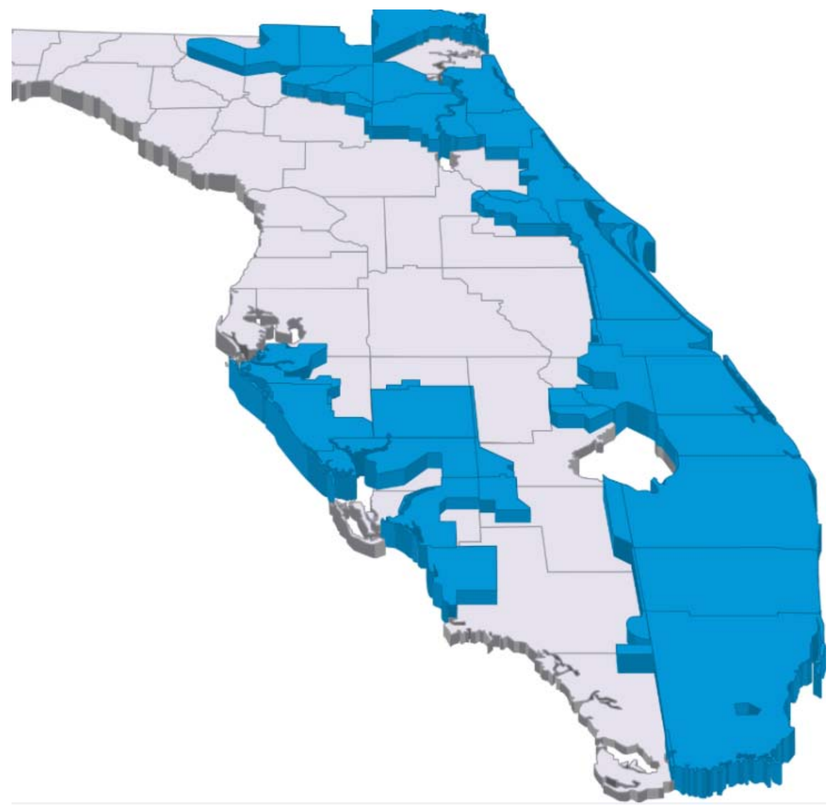
Rank	Market Cap	
1	$55,429	NextEra Energy
2	$54,916	
3	$53,893	
4	$46,402	
5	$46,109	
6	$44,521	
7	$42,347	
8	$41,627	
9	$37,534	
10	$33,881	
11	$31,802	
12	$30,408	
13	$29,802	
14	$26,726	
15	$26,089	
16	$25,597	
17	$23,839	
18	$23,337	
19	$22,640	
20	$22,467	

(1) Source: Factset

Florida Power & Light is one of the best utility franchises in the U.S.

Florida Power & Light

- One of the largest U.S. electric utilities
- Vertically integrated, retail rate-regulated
- 4.8 MM customer accounts
- 26.5 GW in operation[1]
- $11.7 B in operating revenues[2]
- $43 B in total assets

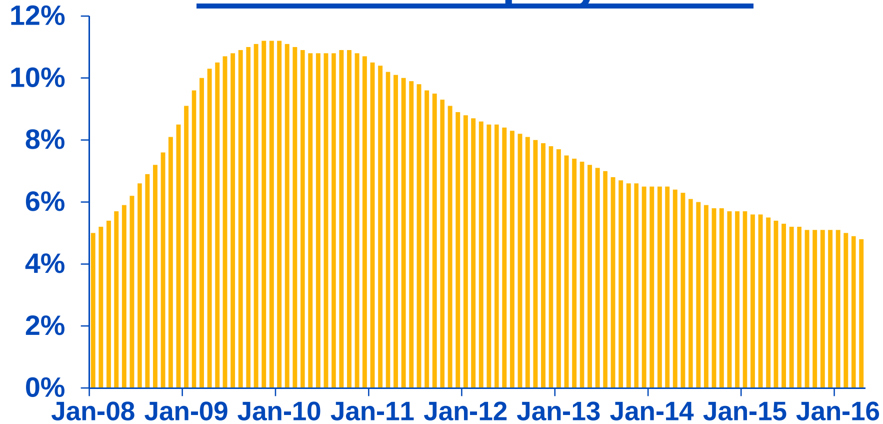


(1) As of April 2016
(2) As of year ended December 31, 2015
Note: All other data as of March 31, 2016

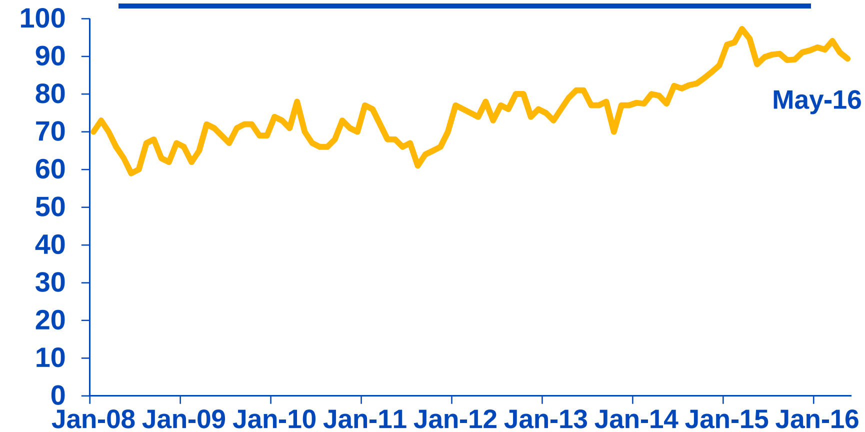
Florida's economic growth remains solid

Florida Economy

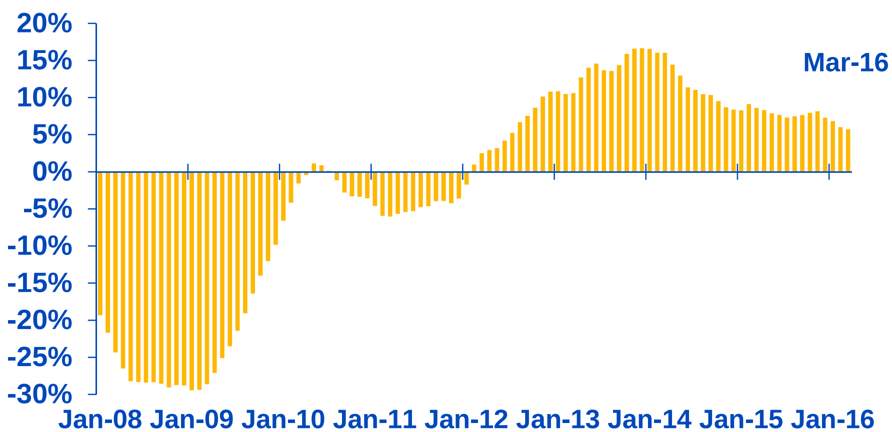
Florida Unemployment(1)



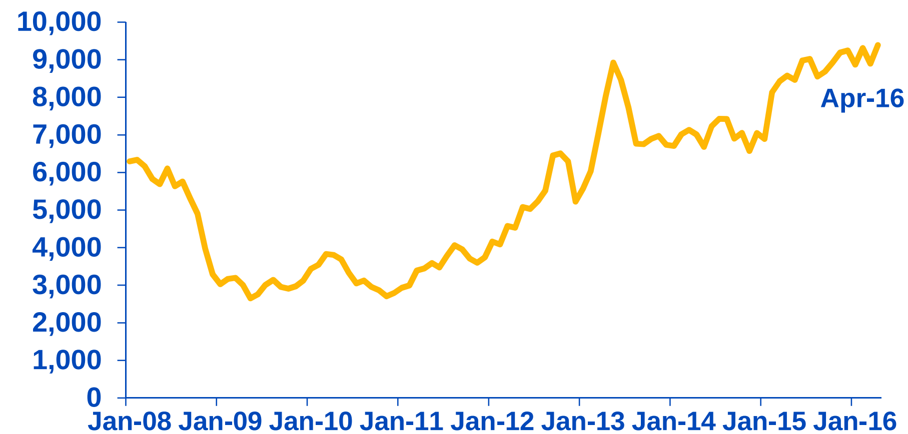
Florida Consumer Sentiment(2)



Florida Case-Shiller Annual Change(3)



Florida Building Permits(4)



(1) Source: Bureau of Labor Statistics through April 2016
(2) Source: Bureau of Economic and Business Research through May 2016
(3) Source: S&P Dow Jones Indices (FL-MIA MIXR-SA) through March 2016
(4) Three-month moving average; Source: The Census Bureau through April 2016

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2015**

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices and registrants' telephone number	IRS Employer Identification Number
1-8841	**NEXTERA ENERGY, INC.**	59-2449419
2-27612	**FLORIDA POWER & LIGHT COMPANY** 700 Universe Boulevard Juno Beach, Florida 33408 (561) 694-4000	59-0247775

State or other jurisdiction of incorporation or organization: Florida

Securities registered pursuant to Section 12(b) of the Act:

		Name of exchange on which registered
NextEra Energy, Inc.:	Common Stock, $0.01 Par Value	New York Stock Exchange
	5.799% Corporate Units	New York Stock Exchange
	6.371% Corporate Units	New York Stock Exchange

Florida Power & Light Company: None

Indicate by check mark if the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act of 1933.

NextEra Energy, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.

NextEra Energy, Inc. Yes ☐ No ☑ Florida Power & Light Company Yes ☐ No ☑

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) have been subject to such filing requirements for the past 90 days.

NextEra Energy, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months.

NextEra Energy, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrants are a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Securities Exchange Act of 1934.

NextEra Energy, Inc.	Large Accelerated Filer ☑	Accelerated Filer ☐	Non-Accelerated Filer ☐	Smaller Reporting Company ☐
Florida Power & Light Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-Accelerated Filer ☑	Smaller Reporting Company ☐

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☑

Aggregate market value of the voting and non-voting common equity of NextEra Energy, Inc. held by non-affiliates as of June 30, 2015 (based on the closing market price on the Composite Tape on June 30, 2015) was $44,190,491,194.

There was no voting or non-voting common equity of Florida Power & Light Company held by non-affiliates as of June 30, 2015.

Number of shares of NextEra Energy, Inc. common stock, $0.01 par value, outstanding as of January 31, 2016: 460,599,691

Number of shares of Florida Power & Light Company common stock, without par value, outstanding as of January 31, 2016, all of which were held, beneficially and of record, by NextEra Energy, Inc.: 1,000

DOCUMENTS INCORPORATED BY REFERENCE

Portions of NextEra Energy, Inc.'s Proxy Statement for the 2016 Annual Meeting of Shareholders are incorporated by reference in Part III hereof.

This combined Form 10-K represents separate filings by NextEra Energy, Inc. and Florida Power & Light Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Florida Power & Light Company makes no representations as to the information relating to NextEra Energy, Inc.'s other operations.

Florida Power & Light Company meets the conditions set forth in General Instruction I.(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

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DEFINITIONS

Acronyms and defined terms used in the text include the following:

Term	Meaning
AFUDC	allowance for funds used during construction
AFUDC - debt	debt component of AFUDC
AFUDC - equity	equity component of AFUDC
AOCI	accumulated other comprehensive income
Bcf	billion cubic feet
capacity clause	capacity cost recovery clause, as established by the FPSC
CO_2	carbon dioxide
DOE	U.S. Department of Energy
Duane Arnold	Duane Arnold Energy Center
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
Florida Southeast Connection	Florida Southeast Connection, LLC, a wholly owned NEER subsidiary
FPL	Florida Power & Light Company
FPL FiberNet	fiber-optic telecommunications business
FPSC	Florida Public Service Commission
fuel clause	fuel and purchased power cost recovery clause, as established by the FPSC
GAAP	generally accepted accounting principles in the U.S.
GHG	greenhouse gas(es)
IPO	initial public offering
ISO	independent system operator
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour(s)
Lone Star	Lone Star Transmission, LLC
Management's Discussion	Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
MMBtu	One million British thermal units
mortgage	mortgage and deed of trust dated as of January 1, 1944, from FPL to Deutsche Bank Trust Company Americas, as supplemented and amended
MW	megawatt(s)
MWh	megawatt-hour(s)
NEE	NextEra Energy, Inc.
NEECH	NextEra Energy Capital Holdings, Inc.
NEER	NextEra Energy Resources, LLC
NEET	NextEra Energy Transmission, LLC
NEP	NextEra Energy Partners, LP
NEP OpCo	NextEra Energy Operating Partners, LP
NERC	North American Electric Reliability Corporation
Note __	Note __ to consolidated financial statements
NOx	nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
O&M expenses	other operations and maintenance expenses in the consolidated statements of income
OCI	other comprehensive income
OTC	over-the-counter
OTTI	other than temporary impairment
PJM	PJM Interconnection, L.L.C.
PMI	NextEra Energy Power Marketing, LLC
Point Beach	Point Beach Nuclear Power Plant
PTC	production tax credit
PUCT	Public Utility Commission of Texas
PURPA	Public Utility Regulatory Policies Act of 1978, as amended
PV	photovoltaic
Recovery Act	The American Recovery and Reinvestment Act of 2009, as amended
regulatory ROE	return on common equity as determined for regulatory purposes
RFP	request for proposal
ROE	return on common equity
RPS	renewable portfolio standards
RTO	regional transmission organization
Sabal Trail	Sabal Trail Transmission, LLC, an entity in which a NEER subsidiary has a 33% ownership interest
Seabrook	Seabrook Station
SEC	U.S. Securities and Exchange Commission
SO_2	sulfur dioxide
U.S.	United States of America
WCEC	FPL's West County Energy Center

NEE, FPL, NEECH and NEER each has subsidiaries and affiliates with names that may include NextEra Energy, FPL, NextEra Energy Resources, NextEra, FPL Group, FPL Group Capital, FPL Energy, FPLE, NEP and similar references. For convenience and simplicity, in this report the terms NEE, FPL, NEECH and NEER are sometimes used as abbreviated references to specific subsidiaries, affiliates or groups of subsidiaries or affiliates. The precise meaning depends on the context.

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PART I

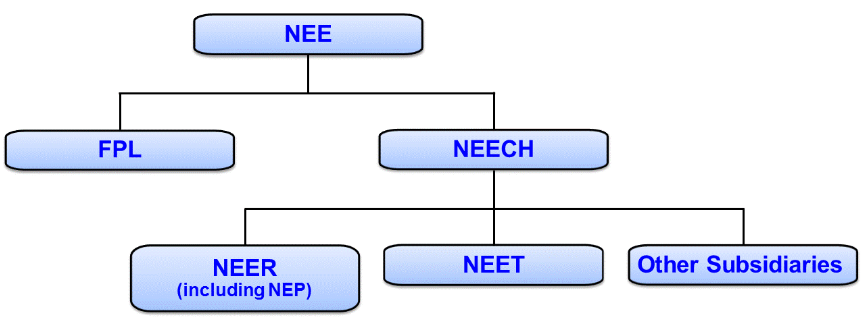
Item 1. Business

OVERVIEW

NextEra Energy, Inc. (hereafter, NEE), with approximately 46,400 MW of generating capacity, is one of the largest electric power companies in North America with electric generation facilities located in 27 states in the U.S. and 4 provinces in Canada, and employing approximately 14,300 people as of December 31, 2015. NEE provides retail and wholesale electric services to more than 5.3 million customers and owns generation, transmission and distribution facilities to support its services, as well as has investments in gas infrastructure assets. It also provides risk management services related to power and gas consumption related to its own generation assets and for a limited number of wholesale customers in selected markets. NEE, through NEER, is the largest generator in North America of renewable energy from the wind and sun based on MWh produced. In addition, NEE owns and operates approximately 15% of the installed base of U.S. wind power production capacity and owns and/or operates approximately 9% of the installed base of U.S. utility-scale solar power production capacity as of December 31, 2015. NEE also owns and operates one of the largest fleets of nuclear power stations in the U.S., with eight reactors at five sites located in four states, representing approximately 6% of U.S. nuclear power electric generating capacity as of December 31, 2015. NEE's business strategy has emphasized the development, acquisition and operation of renewable, nuclear and natural gas-fired generation facilities in response to long-term federal policy trends supportive of zero and low air emissions sources of power. NEE's generation fleet has significantly lower rates of emissions of CO_2, SO_2 and NOx than the average rates of the U.S. electric power industry with approximately 97% of its 2015 generation, measured by MWh produced, coming from renewable, nuclear and natural gas-fired facilities.

NEE was incorporated in 1984 under the laws of Florida and conducts its operations principally through two wholly owned subsidiaries, Florida Power & Light Company (hereafter, FPL) and NextEra Energy Resources, LLC (hereafter, NEER). NextEra Energy Capital Holdings, Inc. (hereafter, NEECH), another wholly owned subsidiary of NEE, owns and provides funding for NEER's and NEE's operating subsidiaries, other than FPL and its subsidiaries. NEE's two principal businesses also constitute NEE's reportable segments for financial reporting purposes. During 2014, NEE formed NEP to acquire, manage and own contracted clean energy projects with stable, long-term cash flows. See II. NEER for further discussion of NEP. NEE's and NEER's generating capacity discussed in this combined Form 10-K includes approximately 480 MW associated with noncontrolling interests related to NEP as of December 31, 2015. See Item 2. Properties.

NEE Organizational Chart



FPL is a rate-regulated electric utility engaged primarily in the generation, transmission, distribution and sale of electric energy in Florida. FPL is the largest electric utility in the state of Florida and one of the largest electric utilities in the U.S. based on retail MWh sales. FPL is vertically integrated, with approximately 25,300 MW of generating capacity as of December 31, 2015. FPL's investments in its infrastructure since 2001, such as modernizing less-efficient fossil generation plants to produce more energy with less fuel and fewer air emissions, increasing generating capacity at its existing nuclear units and upgrading its transmission and distribution systems to deliver service reliability that is the best of the Florida investor-owned utilities, have provided significant benefits to FPL's customers, all while providing residential and commercial bills that were among the lowest in Florida and below the national average based on a rate per kWh as of July 2015 (the latest date for which this data is available). With approximately 95% of its power generation coming from natural gas, nuclear and solar, FPL is also one of the cleanest electric utilities in the nation. Based on 2015 information, FPL's emissions rates for CO_2, SO_2 and NOx were 35%, 97% and 71% lower, respectively, than the average rates of the U.S. electric power industry.

NEER, with approximately 21,100 MW of generating capacity at December 31, 2015, is one of the largest wholesale generators of electric power in the U.S., with 20,120 MW of generating capacity across 25 states, and has 920 MW of generating capacity in 4

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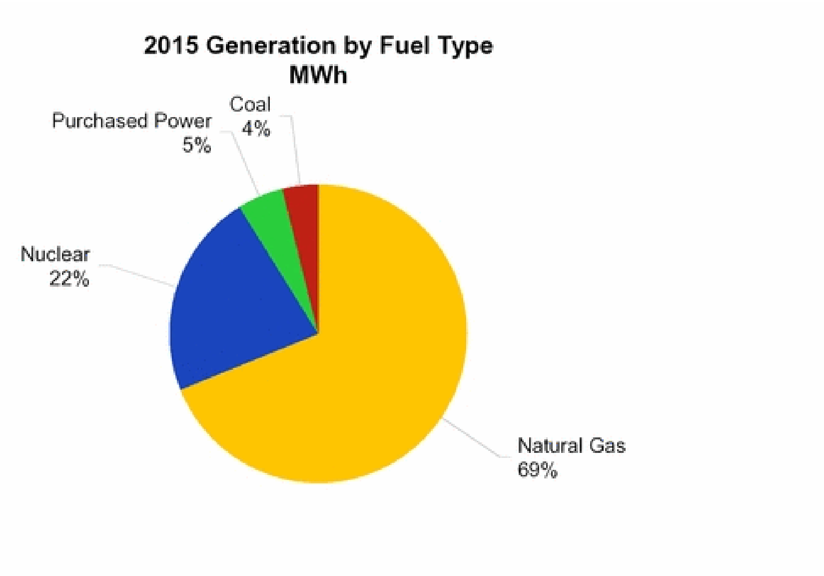
FPL SOURCES OF GENERATION

FPL relies upon a mix of fuel sources for its generation facilities, along with purchased power, in order to maintain the flexibility to achieve a more economical fuel mix by responding to market and industry developments. See descriptions of fossil, nuclear and solar operations below and a listing of FPL's generation facilities in Item 2. Properties - Generation Facilities.

FPL's 2015 fuel mix based on MWh produced, including purchased power, was as follows:



Oil and Solar are collectively less than 1%

Fossil Operations (Natural Gas, Coal and Oil)

At December 31, 2015, FPL owned and operated 70 units that used fossil fuels, primarily natural gas, and had a joint ownership interest in 3 coal units. Combined, the fossil fleet provided 21,766 MW of generating capacity for FPL. These fossil units are out of service from time to time for routine maintenance or on standby during periods of reduced electricity demand. A common industry benchmark for fossil unit reliability is the equivalent forced outage rate (EFOR), which represents a generation unit's inability to provide electricity when required to operate. For the five years 2010 - 2014, FPL's average annual EFOR was in the top decile among its electric utility fossil fleet peers in the U.S.

FPL's natural gas plants require natural gas transportation, supply and storage. FPL has firm transportation contracts in place for existing pipeline capacity with five different transportation suppliers. These agreements provide for an aggregate maximum delivery quantity of 2,069,000 MMBtu/day with expiration dates ranging from 2016 to 2036 that together are expected to satisfy substantially all of the currently anticipated needs for natural gas transportation through the end of 2016. To the extent desirable, FPL also purchases interruptible natural gas transportation service from these natural gas transportation suppliers based on pipeline availability. FPL has several short- and medium-term natural gas supply contracts to provide a portion of FPL's anticipated needs for natural gas. The remainder of FPL's natural gas requirements is purchased in the spot market. FPL has an agreement for the storage of natural gas that expires in 2017. See Note 14 - Contracts.

In 2013, the FPSC approved FPL's 25-year natural gas transportation agreements with each of Sabal Trail and Florida Southeast Connection for a quantity of 400,000 MMBtu/day beginning on May 1, 2017 and increasing to 600,000 MMBtu/day on May 1, 2020. These new agreements, when combined with FPL's existing agreements, are expected to satisfy substantially all of FPL's natural gas transportation needs through at least 2020. FPL's firm commitments under the new agreements are contingent upon the occurrence of certain events, including the FERC's approval of applications by each of Sabal Trail and Florida Southeast Connection for authorization of their pipeline projects and of the application by Transcontinental Gas Pipe Line Company, LLC (Transco) for authorization of a pipeline expansion project and the lease of pipeline capacity to Sabal Trail, as well as completion of construction of the pipeline system to be built by Sabal Trail and Florida Southeast Connection. In February 2016, the FERC issued an order granting the requested authorizations, subject to certain conditions. Sabal Trail, Florida Southeast Connection and Transco are

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FPL ENERGY MARKETING AND TRADING

FPL's Energy Marketing & Trading division (EMT) buys and sells wholesale energy commodities, such as natural gas, oil and electricity. EMT procures natural gas and oil for FPL's use in power generation and sells excess natural gas, oil and electricity. EMT also uses derivative instruments (primarily swaps, options and forwards) to manage the commodity price risk inherent in the purchase and sale of fuel and electricity. Substantially all of the results of EMT's activities are passed through to customers in the fuel or capacity clauses. See FPL Regulation - FPL Rate Regulation below, Management's Discussion - Energy Marketing and Trading and Market Risk Sensitivity and Note 3.

FPL REGULATION

FPL's operations are subject to regulation by a number of federal, state and other organizations, including, but not limited to, the following:

- the FPSC, which has jurisdiction over retail rates, service territory, issuances of securities, planning, siting and construction of facilities, among other things;
- the FERC, which oversees the acquisition and disposition of generation, transmission and other facilities, transmission of electricity and natural gas in interstate commerce, proposals to build interstate natural gas pipelines and storage facilities, and wholesale purchases and sales of electric energy, among other things;
- the NERC, which, through its regional entities, establishes and enforces mandatory reliability standards, subject to approval by the FERC, to ensure the reliability of the U.S. electric transmission and generation system and to prevent major system blackouts;
- the NRC, which has jurisdiction over the operation of nuclear power plants through the issuance of operating licenses, rules, regulations and orders; and
- the EPA, which has the responsibility to maintain and enforce national standards under a variety of environmental laws. The EPA also works with industries and all levels of government, including federal and state governments, in a wide variety of voluntary pollution prevention programs and energy conservation efforts.

FPL Rate Regulation

The FPSC sets rates at a level that is intended to allow FPL the opportunity to collect from retail customers total revenues (revenue requirements) equal to FPL's cost of providing service, including a reasonable rate of return on invested capital. To accomplish this, the FPSC uses various ratemaking mechanisms, including, among other things, base rates and cost recovery clauses.

Base Rates. In general, the basic costs of providing electric service, other than fuel and certain other costs, are recovered through base rates, which are designed to recover the costs of constructing, operating and maintaining the utility system. These basic costs include O&M expenses, depreciation and taxes, as well as a return on FPL's investment in assets used and useful in providing electric service (rate base). At the time base rates are established, the allowed rate of return on rate base approximates the FPSC's determination of FPL's estimated weighted-average cost of capital, which includes its costs for outstanding debt and an allowed ROE. The FPSC monitors FPL's actual regulatory ROE through a surveillance report that is filed monthly by FPL with the FPSC. The FPSC does not provide assurance that any regulatory ROE will be achieved. Base rates are determined in rate proceedings or through negotiated settlements of those proceedings. Proceedings can occur at the initiative of FPL or upon action by the FPSC. Base rates remain in effect until new base rates are approved by the FPSC.

In January 2013, the FPSC issued a final order approving a stipulation and settlement between FPL and several intervenors in FPL's base rate proceeding (2012 rate agreement). Key elements of the 2012 rate agreement, which is effective from January 2013 through December 2016, include, among other things, the following:

- New retail base rates and charges were established in January 2013 resulting in an increase in retail base revenues of $350 million on an annualized basis.
- FPL's allowed regulatory ROE is 10.50%, with a range of plus or minus 100 basis points. If FPL's earned regulatory ROE falls below 9.50%, FPL may seek retail base rate relief. If the earned regulatory ROE rises above 11.50%, any party to the 2012 rate agreement other than FPL may seek a review of FPL's retail base rates.
- Retail base rates will be increased by the annualized base revenue requirements for FPL's three modernization projects (Cape Canaveral, Riviera Beach and Port Everglades) as each of the modernized power plants becomes operational. (Cape Canaveral and Riviera Beach became operational in April 2013 and April 2014, respectively, and Port Everglades is expected to be operational by April 2016.)
- Cost recovery of WCEC Unit No. 3, which was placed in service in May 2011, will continue to occur through the capacity clause.
- Subject to certain conditions, FPL may amortize, over the term of the 2012 rate agreement, a depreciation reserve surplus remaining at the end of 2012 under a previous rate agreement (approximately $224 million) and may amortize a portion of FPL's fossil dismantlement reserve up to a maximum of $176 million (collectively, the reserve), provided that in any year of the 2012 rate agreement, FPL must amortize at least enough reserve to maintain a 9.50% earned regulatory ROE but may not amortize any reserve that would result in an earned regulatory ROE in excess of 11.50%. See below regarding a subsequent reduction in the reserve amount.

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- Future storm restoration costs would be recoverable on an interim basis beginning 60 days from the filing of a cost recovery petition, but capped at an amount that could produce a surcharge of no more than $4 for every 1,000 kWh of usage on residential bills during the first 12 months of cost recovery. Any additional costs would be eligible for recovery in subsequent years. If storm restoration costs exceed $800 million in any given calendar year, FPL may request an increase to the $4 surcharge to recover the amount above $800 million.
- An incentive mechanism whereby customers will receive 100% of certain gains, including, but not limited to, gains from the purchase and sale of electricity and natural gas (including transportation and storage), up to a specified threshold; gains exceeding that specified threshold will be shared by FPL and its customers (incentive mechanism).

In August 2015, the FPSC approved a stipulation and settlement between the Office of Public Counsel and FPL regarding issues relating to the ratemaking treatment for FPL's purchase of Cedar Bay. As part of this settlement, the amount of the reserve was reduced by $30 million to $370 million, unless FPL needs the entire $400 million reserve to maintain a minimum regulatory ROE of 9.50%. In October 2015, the Florida Industrial Power Users Group filed a notice of appeal challenging the FPSC's approval of this settlement, which is pending before the Florida Supreme Court.

In January 2016, FPL filed a formal notification with the FPSC indicating its intent to initiate a base rate proceeding, consisting of a four-year rate plan that would begin in January 2017 following the expiration of the 2012 rate agreement at the end of 2016. The notification stated that, based on preliminary estimates, FPL expects to request an increase to base annual revenue requirements of (i) approximately $860 million effective January 2017, (ii) approximately $265 million effective January 2018, and (iii) approximately $200 million effective when the proposed natural gas-fired combined-cycle unit in Okeechobee County, Florida becomes operational, which is expected to occur in mid-2019 (see FPL Sources of Generation - Fossil Operations - Capital Initiatives above). Under the proposed rate plan, FPL commits that if its requested adjustments to base annual revenue requirements are approved, it will not request further adjustments for 2020. In addition, FPL expects to propose an allowed regulatory ROE midpoint of 11.50%, which includes a 50 basis point performance adder. FPL expects to file its formal request to initiate a base rate proceeding in March 2016.

Cost Recovery Clauses. Cost recovery clauses, which are designed to permit full recovery of certain costs and provide a return on certain assets allowed to be recovered through the various clauses, include substantially all fuel, purchased power and interchange expense, certain construction-related costs and conservation and certain environmental-related costs. Cost recovery clause costs are recovered through levelized monthly charges per kWh or kW, depending on the customer's rate class. These cost recovery clause charges are calculated at least annually based on estimated costs and estimated customer usage for the following year, plus or minus true-up adjustments to reflect the estimated over or under recovery of costs for the current and prior periods. An adjustment to the levelized charges may be approved during the course of a year to reflect revised estimates.

Fuel costs and energy charges under the purchased power agreements are recovered from customers through the fuel clause, the most significant of the cost recovery clauses in terms of operating revenues. FPL uses a risk management fuel procurement program which has been approved by the FPSC. The FPSC reviews the program activities and results for prudence annually as part of its review of fuel costs. The program is intended to manage fuel price volatility by locking in fuel prices for a portion of FPL's fuel requirements. See FPL Energy Marketing and Trading above, Note 1 - Rate Regulation and Note 3. Costs associated with FPL's investments in natural gas production wells are also recovered through the fuel clause. See FPL Sources of Generation - Fossil Operations above.

Capacity payments to non-utility generators and other utilities, the cost of WCEC Unit No. 3 (reported as retail base revenues) and a portion of the acquisition cost of Cedar Bay, among other things, are recovered from customers through the capacity clause. See Note 1 - Rate Regulation. In accordance with the FPSC's nuclear cost recovery rule, FPL also recovers pre-construction costs and carrying charges (equal to a pretax AFUDC rate) on construction costs for new nuclear capacity through the capacity clause. As property related to the new nuclear capacity goes into service, construction costs and a return on investment are recovered through base rate increases effective beginning the following January. See FPL Sources of Generation - Nuclear Operations above.

Costs associated with implementing energy conservation programs are recovered from customers through the energy conservation cost recovery clause. Certain costs of complying with federal, state and local environmental regulations enacted after April 1993 and costs associated with FPL's three operating solar facilities are recovered through the environmental cost recovery clause (environmental clause).

The FPSC has the authority to disallow recovery of costs that it considers excessive or imprudently incurred. These costs may include, among others, fuel and O&M expenses, the cost of replacing power lost when fossil and nuclear units are unavailable, storm restoration costs and costs associated with the construction or acquisition of new facilities.

FERC

The Federal Power Act grants the FERC exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity and natural gas in interstate commerce. Pursuant to the Federal Power Act, electric utilities must maintain tariffs and rate schedules on file with the FERC which govern the rates, terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. The Federal Power Act also gives the FERC authority to certify and oversee a national electric reliability organization with authority to establish and independently enforce mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. See NERC below. Electric utilities are subject to accounting, record-keeping and

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reporting requirements administered by the FERC. The FERC also places certain limitations on transactions between electric utilities and their affiliates.

NERC

The NERC has been certified by the FERC as the national electric reliability organization. The NERC's mandate is to ensure the reliability and security of the North American bulk-power system through the establishment and enforcement of reliability standards approved by FERC. The NERC's regional entities also enforce reliability standards approved by the FERC. FPL is subject to these reliability standards and incurs costs to ensure compliance with continually heightened requirements, and can incur significant penalties for failing to comply with them.

FPL Environmental Regulation

FPL is subject to environmental laws and regulations and is affected by some of the emerging issues described in the NEE Environmental Matters section below. FPL expects to seek recovery through the environmental clause for compliance costs associated with any new environmental laws and regulations.

FPL EMPLOYEES

FPL had approximately 8,800 employees at December 31, 2015. Approximately 34% of the employees are represented by the International Brotherhood of Electrical Workers (IBEW) under a collective bargaining agreement with FPL that expires October 31, 2017.

II. NEER

NEER was formed in 1998 to aggregate NEE's competitive energy businesses. It is a limited liability company organized under the laws of Delaware and is a wholly owned subsidiary of NEECH. Through its subsidiaries, NEER currently owns, develops, constructs, manages and operates electric generation facilities in wholesale energy markets primarily in the U.S., as well as in Canada and Spain. See Note 15. NEER is one of the largest wholesale generators of electric power in the U.S., with 21,140 MW of generating capacity across 25 states, 4 Canadian provinces and 1 Spanish province as of December 31, 2015. NEER produces the majority of its electricity from clean and renewable sources as described more fully below. NEER is the largest generator in North America of electric power from wind and utility-scale solar energy projects based on MWh produced.

NEER also engages in energy-related commodity marketing and trading activities, including entering into financial and physical contracts, to hedge the production from its generation assets that is not sold under long-term power supply agreements. These contracts primarily include power and gas commodities and their related products, as well as providing full energy and capacity requirements services primarily to distribution utilities in certain markets and offering customized power and gas and related risk management services to wholesale customers. In addition, NEER participates in natural gas, natural gas liquids and oil production through non-operating ownership interests, and in pipeline infrastructure development, construction, management and operations, through either wholly owned subsidiaries or noncontrolling or joint venture interests, hereafter referred to as the gas infrastructure business. NEER also hedges the expected output from its gas infrastructure production assets to protect against price movements. During the fourth quarter of 2015, the natural gas pipeline projects that were previously reported in Corporate and Other were moved to the NEER segment reflecting the overall scale of the natural gas pipeline investments and management of these projects within NEER's gas infrastructure business. See Note 15.

As discussed in the Overview above, during 2014, NEP was formed to acquire, manage and own contracted clean energy projects with stable, long-term cash flows through a limited partner interest in NEP OpCo. Through an indirect wholly owned subsidiary, NEE owns 101,440,000 common units of NEP OpCo representing a noncontrolling interest in NEP's operating projects of approximately 76.8% as of December 31, 2015. NEE owns a controlling general partner interest in NEP and consolidates NEP for financial reporting purposes. See Note 1 - NextEra Energy Partners, LP. As of December 31, 2015, NEP, through the combination of NEER's contribution of energy projects to NEP OpCo in connection with NEP’s IPO in July 2014 and the acquisition of additional energy projects from NEER in 2015, owns a portfolio of 19 wind and solar projects with generating capacity totaling approximately 2,210 MW and long-term contracted natural gas pipeline assets as discussed below. In addition, NEP OpCo has a right of first offer for certain of NEER's assets (ROFO assets) if NEER should seek to sell the assets. The ROFO assets remaining as of December 31, 2015, include contracted wind and solar projects, some of which are under construction, with a combined capacity of approximately 1,076 MW. Included in the ROFO assets are three solar projects that, upon completion of construction, are expected to have a total generating capacity of 277 MW. In 2015, NEP OpCo issued 2 million NEP OpCo Class B Units to NEER in exchange for an approximately 50% ownership interest in the three solar projects. NEER, as holder of the Class B Units, will retain 100% of the economic interests if, and until, NEER offers to sell the economic interests to NEP and NEP accepts such offer. In October 2015, NEP completed the acquisition of the membership interests in NET Holdings Management, LLC (Texas pipeline business), a developer, owner and operator of a portfolio of seven intrastate long-term contracted natural gas pipeline assets located in Texas (Texas pipelines). See Generation and Other Operations - Contracted, Merchant and Other Operations - Other Operations below.

EXHIBIT NO. ___ (RAB-5)

QUESTION:
Regarding Hevert at 15:10-12. Please provide all bond rating agency reports, including credit ratings and bond ratings, for FPL from 2012 through the most current date.

RESPONSE:
Please see OPC's First Request for Production of Documents Nos. 9 and 12. Additional documents provided.

FitchRatings

Fitch Affirms IDRs of NextEra Energy, Inc. and its Subsidiaries; Outlook Stable

Fitch Ratings-New York-26 April 2013: Fitch Ratings has affirmed the Issuer Default Ratings (IDR) of NextEra Energy, Inc. (NEE) and NextEra Energy Capital Holdings (Capital Holdings) at 'A-'. Fitch has also affirmed the IDR of Florida Power & Light (FPL) at 'A'. The Rating Outlook is Stable. A list of debt instruments affected is provided at the end of this release.

RATING DRIVERS FOR FPL
FPL's ratings reflect the predictable nature of cash flows from regulated electric operations, a favorable outcome to the recently concluded base rate case that provides for at least four years of regulatory certainty, recovering electric sales in its service territory after a prolonged trough, and a strong balance sheet and liquidity profile. The ratings also reflect high-capex investments over 2013-16 as the utility spends on new generation and other infrastructure improvements.

The outcome of FPL's 2012 base rate case filing was quite constructive, in Fitch's opinion, and resulted in a $350 million base rate increase effective January 2013 and allows the utility to earn a return on equity (ROE) of up to a 100-basis point band around 10.5%. FPL was also granted a four-year generation base rate adjustment (GBRA) mechanism that automatically adjusts base rates on commercial operations of its new generation plants in 2013, 2014 and 2016, and reflects an approximately $3.5 billion addition to the rate base. While the order spans a four-year term (till December 2016), FPL could potentially delay filing a rate case for a longer period by proactively managing its costs. A favorable turnaround in the regulatory climate in Florida and an extended period of regulatory certainty for FPL is a key credit positive for the company and an important driver for Fitch's affirmation of the 'A' IDR.

A recovering Florida economy could drive FPL's electric sales growth rates above national averages over Fitch's forecast period. Adjusted for weather, FPL's retail kWH sales grew 1.7% in 2011 and 1.8% in 2012. Fitch's financial forecasts for FPL are based on a conservative 1.0% cumulative annual growth rate over 2013-16; any upside in sales growth would be positive for FPL's credit metrics. Conversely, a flat or declining growth environment could put pressure on FPL's financial performance. That said, FPL's credit metrics are expected to be quite robust in 2013 on the heels of a favorable rate decision and there exists adequate headroom to withstand a long period of flat-to-negative growth, which is what Fitch has assumed in its stress case. This is also a key factor in the stability of FPL's ratings, since the utility cannot implement a base rate increase outside the GBRA mechanism before December 2016.

FPL plans to spend over $9.2 billion in baseline capex through 2016. Of this amount, approximately $2.0 billion will be spent on modernizing its aging gas fleet at Cape Canaveral, Riviera Beach and Port Everglades, with the new gas-fired plants expected to be in service by 2013, 2014 and 2016, respectively. All these projects have been approved by the Florida Public Service Commission (FPSC). Recovery of these expenditures will be via the GBRA mechanism and is expected to result in only modest price increases for consumers due to the anticipated fuel cost savings. Infrastructure improvements and maintenance capex make up the bulk of the remaining capex budget.

In addition, FPL has identified another $4 billion-$5 billion of incremental investment opportunities in areas such as storm hardening, generation upgrades, solar investment, natural gas pipeline and other infrastructure/reliability improvements. The visibility around the incremental capex is low at present; Fitch has assumed that FPL spends between $3 billion-$3.5 billion in incremental capex over the forecast period. Fitch expects FPL to finance its capex needs using a mix of equity and debt so as to maintain its regulatory capital structure. Reflecting the additional capex in financial assumptions does pressure FPL's forecasted credit metrics, since there will likely be a regulatory lag associated with some of these incremental investments.

Fitch anticipates FPL's credit metrics to strengthen in 2013 and beyond as a result of the $350 million base rate increase effective 2013, stepped-up GBRA increases, and rate increases associated with the ongoing nuclear uprates. Fitch expects EBITDA coverage ratio to be 8.0-8.5x and Debt-to-EBITDA ratio to be in the 2.4x-2.6x range towards the end of the forecast period. The funds flow from operations (FFO)-based credit measures remain robust over 2013-14 due to bonus depreciation benefits, and decline to more normalized levels thereafter. Fitch forecasts FFO-to-Debt to be in the 25%-27% range and FFO-to-interest coverage to approximate 7.0x toward the end of the forecast period.

RATING DRIVERS FOR NEE AND CAPITAL HOLDINGS
NEE provides a full guarantee of Capital Holdings' debt and hybrids. Thus, Capital Holdings' ratings and Rating Outlook are identical to those of NEE. NEE's ratings reflect weak but recovering credit metrics, declining capex after hitting peak levels in 2012, and a continued shift in the business mix through 2016 towards regulated and highly contracted assets. Driving the favorable shift in cash flow mix are factors such as base rate increases at FPL as a result of the 2012 rate order, completion of the regulated Lone Star transmission line in 2013, the rising contribution from contracted solar and wind investments, and weak wholesale prices that limit the contribution of non-contracted generation assets.

Significant capex growth over the last few years, with $9.2 billion spent in 2012 alone, has weakened NEE's credit metrics considerably relative to its rating category and in comparison with historical levels. Future capex levels will continue to remain high both at FPL and Capital Holdings. Fitch's financial forecasts reflect approximate $9.0 billion capex at Capital Holdings over 2013-16, which is at the higher end of management's target range of $5.9 billion-$9.0 billion. As highlighted previously, Fitch has assumed $12.5 billion in capex at FPL over 2013-16. It is conceivable that certain investment opportunities for both FPL and Capital Holdings may not materialize as these are still in the development stage. In the current environment of low power prices and less political appetite for tax subsidies for renewables, Fitch sees lower potential for Capital Holdings to grow its renewable portfolio at the same pace as it has in recent years. To the extent that the capex levels fall short of Fitch's expectations, there could be upside to NEE's credit metrics given the enhanced financial flexibility that the company will gain.

Given the pressures on credit metrics today and elevated levels of forecasted capex, management's renewed emphasis on strengthening the balance sheet is warranted to maintain the current levels of ratings. In this regard, the company's recent announcement to issue up to $1.5 billion in equity in 2014 depending upon the level of capex spend, in addition to maturing equity units, is positive for NEE's credit. It is also Fitch's expectation that Capital Holdings is able to reduce recourse debt over the forecast period.

NEE's continued shift away from merchant businesses toward regulated investments and contracted non-regulated renewable assets is also supportive of its credit profile. Over 2013-16, NEE's cash flows from stable utility-type sources are expected to grow. At FPL, recovering retail sales and recently secured base rate increase will produce revenue uplift. At Capital Holdings, the new Texas electric transmission assets will result in predictable tariff revenues. Fitch forecasts that regulated businesses will contribute close to 55% of NEE's EBITDA for the next several years. Within the non-regulated businesses, management's emphasis remains on long-term contracted renewable generation, specifically solar and wind. Fitch expects contractual sources to drive another 30% of NEE's consolidated EBITDA over the next few years. For future growth investments, management is focusing on Federal Energy Regulated Commission (FERC) regulated gas pipelines and electricity transmission opportunities, which will further skew the business mix towards predictable cash flow sources.

On a consolidated basis, Fitch projects NEE to start generating significant free cash flow from 2016 as capex spending declines. NEE's cash flow has been buoyed by significant tax incentives (production and investment tax credits and accelerated depreciation and bonus depreciation benefits). NEE has accumulated tax incentives that Fitch assumes the company can continue to monetize against taxable income or via tax-oriented partnerships. Fitch forecasts NEE to start paying cash taxes beginning 2016 assuming no extension of bonus depreciation benefits, no incremental tax subsidies for U.S. wind projects, and no incremental renewable investments beyond the projects in the current pipeline.

NEE's credit metrics, as reported, show more leverage than 'A-' peers. However, Fitch considers several factors that mitigate debt leverage. First, within the non-regulated operations of NextEra Energy Resources (Energy Resources), Capital Holdings' wholly owned subsidiary, sales are supported by off-take contracts for a longer term than most other peers (more than 86% hedged over 2013-16 for existing assets). This provides NEE with greater insulation to commodity price movements as compared to other diversified peers. Second, NEE's non-utility generation is concentrated in renewable and nuclear resources with favorable environmental characteristics. Finally, about $6.3 billion of consolidated debt (as of Dec. 31, 2012) is made up of project finance loans that have limited or no corporate recourse. Fitch's adjusted consolidated credit metrics for NEE incorporate off-credit treatment to limited recourse debt at Energy Resources. This reflects Fitch's assumption that NEE would walk away from these projects in the event of financial deterioration, including those projects where a differential membership interest has been sold. Fitch accordingly excludes the debt, interest expense, EBITDA contribution and tax attributes from such projects and includes only the distributable cash flow.

Fitch expects NEE's EBITDA coverage ratio to be in a 6.0x-6.5x range and debt-to-EBITDA to be approximately 3.5x toward the end of the forecast period. Fitch forecasts NEE's FFO-to-debt to be close to 25% and FFO-to-interest coverage to approximate 6.3x toward the end of the forecast period, which is in-line with Fitch's guidelines for an 'A-' rated issuer.

NEE's ratings also reflect the company's strong access to the capital markets, commercial paper market and to banks for both corporate credit and project finance. Liquidity is robust with committed corporate credit facilities of the NEE group of companies aggregating approximately $8.4 billion, excluding limited recourse or non-recourse project financing arrangements. Debt maturities are manageable.

RATING SENSITIVITIES
Positive or negative rating actions for FPL and NEE look unlikely at this time. However, downward rating pressure could result from:

--Change in Florida Regulation: Unfavorable changes in current Florida regulatory policies for timely recovery of utility capital investments, fuel and purchased power costs, and storm-related costs would adversely affect ratings of FPL and NEE.
--Increase in Business Risk Profile: A change in strategy to invest in more speculative assets, non-contracted renewable assets or a lower proportion of cash flow under long-term contracts would increase business risk and could result in lower ratings for NEE.
--The high level of capital expenditures at both FPL and Capital Holdings creates completion risks, as well as funding risk.
--Aggressive Financial Strategy: Any deterioration in credit measures that result from higher use of leverage or outsized return of capital to shareholders could lead to negative rating actions for NEE. If parent NEE increases its debt leverage or changes its corporate strategy such that NEE's risk profile materially worsens, it could adversely affect FPL's ratings in line with Fitch's Parent and Subsidiary Rating Linkage Criteria.
--Change in Tax Laws or Regulations: Changes in tax rules that reduce NEE's ability to monetize its accumulated production tax credits, investment tax credits, and accumulated tax losses carried forward would work against NEE's cash flow credit measures.

Fitch has affirmed the following with Stable Outlook:

NextEra Energy, Inc.
--IDR at 'A-'.

NextEra Energy Capital Holdings, Inc.
--IDR at 'A-';
--Senior unsecured debentures at 'A-';
--Equity Units at 'A-';
--Jr. Subordinate hybrids at 'BBB';
--Short-term IDR and commercial paper at 'F1'.

FPL Group Capital Trust I
--Trust preferred stock at 'BBB'.

Florida Power & Light Company
--IDR at 'A';
--First mortgage bonds at 'AA-';
--Unsecured pollution control revenue bonds at 'A+';
--Short-term IDR and commercial paper at 'F1'.

Consistent with its credit policy, Fitch rates only the underlying senior unsecured debentures associated with equity units and is, therefore, withdrawing the 'A-' rating on NEE's equity units.

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Additional information is available at 'www.fitchratings.com'.

Applicable Criteria and Related Research:
--'Corporate Rating Methodology' (Aug. 8, 2012);
--'Recovery Ratings and Notching Criteria for Utilities' (Nov. 13, 2012);
--'Parent and Subsidiary Rating Linkage' (Aug. 8, 2012);
--'Treatment and Notching of Hybrids in Nonfinancial Corporate and REIT Credit Analysis'
(Dec. 13, 2012);
--'Rating North American Utilities, Power, Gas and Water Companies' (May 16, 2011)

Applicable Criteria and Related Research
Treatment and Notching of Hybrids in Nonfinancial Corporate and REIT Credit Analysis

FitchRatings

17 Nov 2015 2:54 PM EST

Fitch Rates Florida Power & Light Company's First Mortgage Bonds 'AA-'

Fitch Ratings-New York-17 November 2015: Fitch Ratings has assigned ratings of 'AA-' to Florida Power & Light Company's (FPL) issue of $600 million 3.125% series first mortgage bonds due Dec. 1, 2025. FPL plans to use the net proceeds from this offering to fund transaction costs incurred in connection with FPL's purchase of approximately $400 million in aggregate principal of several series of its first mortgage bonds in September 2015 and for general corporate purposes.

FPL's ratings reflect the predictable nature of cash flows from regulated electric operations, a favorable 2012 rate order that provides for at least four years of regulatory certainty, recovering electric sales in its service territory after a prolonged trough, management focus on O&M cost containment that is expected to drive returns close to the upper end of the authorized return on equity (ROE) range, and a strong balance sheet and liquidity profile.

KEY RATING DRIVERS

Constructive Regulation: A favorable turnaround in the regulatory climate in Florida and an extended period of regulatory certainty are key credit positives for FPL. The 2012 rate order spans a four-year term (until December 2016), set rates based on 10.5% ROE with a 100 basis points (bps) band and automatically adjusts base rates on commercial operations of new generation plants over 2013-2016.

Recovering Florida Economy: Florida's economy is recovering well after the recent prolonged recession, with most key indicators such as housing starts, employment statistics and consumer sentiment on an upward trend. Adjusted for weather, FPL's retail kilowatt hour sales grew 1.3% in 2014, driven by 1.2% customer growth and 0.1% usage increase. Fitch's financial forecasts for FPL are based on a 1% cumulative annual growth rate in retail sales over 2015-2018; any upside in sales growth would be positive for FPL's credit metrics.

High Capex: FPL has identified approximately $14.6 billion in capex through 2018. Fitch believes this target is likely to be exceeded, given the approval by the Florida Public Service Commission (FPSC) to invest up to $500 million annually in natural gas reserves projects. Fitch expects FPL to finance its capex and distribution to the parent using a mix of equity and debt so as to maintain its regulatory capital structure. FPL continues to make progress on its major capital projects. Specifically, the generation modernization project at Port Everglades remains on budget and scheduled to enter service in mid-2016. Additionally, FPL's development of three new large-scale solar energy centers remain (74-megawatts each) on schedule.

Robust Credit Metrics: FPL's forecasted funds from operations (FFO) credit metrics are expected to weaken from their current robust levels as benefits from bonus depreciation subside after 2015. Fitch expects the FFO fixed-charge coverage to be in the 7.0x-9.0x range over the forecast period, 2015-2018. FFO-adjusted leverage and adjusted debt/EBITDAR are expected to be 3.0x and 2.3x, respectively, by 2018. These metrics are quite robust compared with the 'A' rated financial profile for a regulated utility. As of Sept. 30, 2015, FPL's latest 12 months (LTM) total adjusted debt/operating EBITDAR and FFO adjusted leverage were 2.1x and 2.5x respectively.

KEY RATING ASSUMPTIONS

--Annual retail sales growth of 1% over 2015-2018;

--Base rate increases in mid-2016 for Port Everglades. Additional rate increase in 2017 to allow FPL to earn close to its current authorized ROE of 10.5%;

--O&M and other expenses growth of 1.5% from 2015-2018;

--Capex at FPL of approximately $15 billion over 2015-2018.

RATING SENSITIVITIES

Positive Rating Action: Given strong rating linkage with its parent company, NextEra Energy, Inc. (NextEra; rated 'A-' by Fitch), future positive rating actions appear unlikely.

Negative Rating Action: Downward rating pressure could result from unfavorable changes in current Florida regulatory policies for timely recovery of utility capital investments, fuel and purchased power costs, and storm-related costs; or increasing parent risk profile from higher debt leverage or aggressive corporate strategy. A downgrade in NextEra's ratings would adversely affect FPL's ratings, consistent with Fitch's parent and subsidiary rating linkage criteria.

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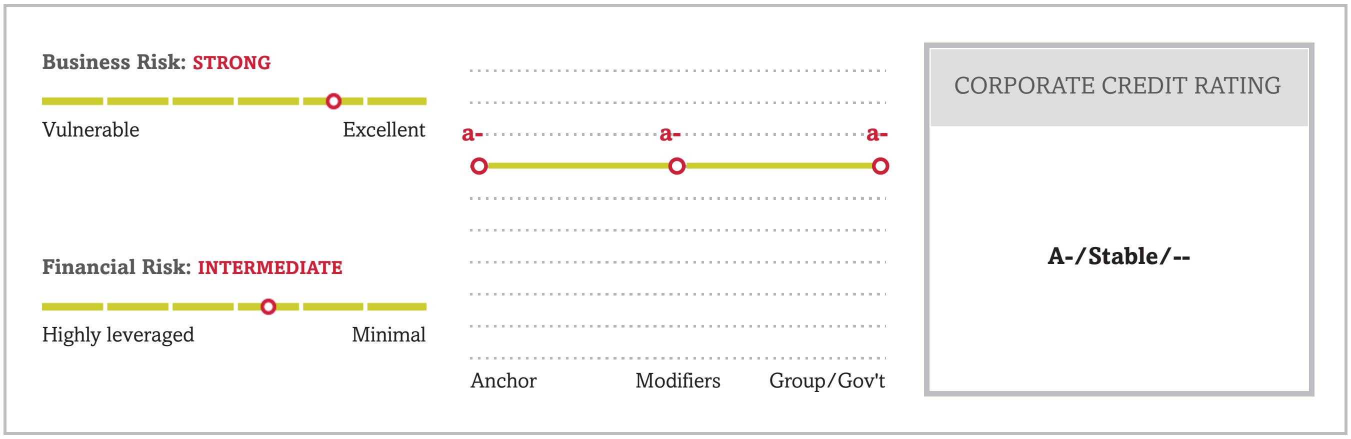
NextEra Energy Inc.



Rationale

Business Risk: Strong	Financial Risk: Intermediate
• Regulated utility operations have low business risk and support the overall credit profile. • Effective management of regulatory risk. • Non-utility operations are primarily engaged in unregulated power generation and materially increase business risk.	• Core credit ratios are at the lower end of the intermediate financial risk profile category. • Large capital spending program. • Financial policy commitment to maintain current financial risk profile.

Outlook: Stable

The stable rating outlook on NextEra Energy Inc. (NextEra) and its subsidiaries, Florida Power & Light Co. and NextEra Energy Capital Holdings Inc., reflects our expectation that the company will preserve its "strong" business risk profile while ensuring that its financial risk profile remains well within the "intermediate" category at all times, albeit toward the lower end of the category. The stable outlook is also predicated on the company effectively managing its growth and capital spending so that regulated operations continue to contribute about 60% of total operating income. Finally, the stable outlook anticipates that NextEra will fund the proposed merger with Hawaiian Electric Industries, Inc. in a credit-neutral manner while receiving approval to close the merger absent any restrictive regulatory provisions or requirements.

Downside scenario

We could lower the ratings on NextEra and its subsidiaries if financial performance weakens, with funds from operations (FFO) to debt that declines to less than 25% on a consistent basis, absent any reduction of business risk. Moreover, we could lower the ratings on NextEra if business risk increases through the growing contribution of unregulated operations or due to unfavorable regulatory outcomes.

Upside scenario

Under our base-case scenario, we do not anticipate raising the ratings on NextEra and its subsidiaries in the next 12 to 24 months, given the company's business risk profile and expected level of financial performance.

Standard & Poor's Base-Case Scenario

Assumptions

- We assume that NextEra's EBITDA grows by an average of 5% to 7% annually, reflecting recovery of invested capital at the regulated utility operations and margin growth from the renewable energy business.
- Capital spending of about $8 billion in 2015, $9.5 billion in 2016 and about $7 billion in 2017.
- Common dividends grow by an average of about 10% annually, in line with historical trends.

Key Metrics

	2014A	2015E	2016E
FFO/debt (%)	25.2	25-26	24–25
Debt/EBITDA (x)	3.5	3.3–3.5	3.5–3.8
OCF/debt (%)	22.5	24–25	23-24

A--Actual. E—Estimate. FFO—Funds from operations. OCF—Operating cash flow.

Company Description

NextEra conducts its regulated utility operations through Florida Power & Light Co. (FPL) while the company's non-utility operations are managed within NextEra Energy Capital Holdings Inc. (NEECH).

FPL is a vertically integrated electric utility serving about 4.7 million customers throughout the east coast of Florida, with about 25,100 megawatts (MW) of generation capacity.

The non-utility operations are largely conducted through NextEra Energy Resources LLC (NEER), a wholly owned subsidiary of NECCH. NEER is engaged in un-regulated generation through the ownership of about 19,800 MW of generation capacity with an emphasis on renewable energy sources, proprietary trading and marketing as well as retail supply and wholesale full requirements contracts.

NextEra has entered into an agreement to merge with Hawaiian Electric Industries Inc. (HEI). The companies expect that the merger could close by year-end 2015.

Business Risk: Strong

We assess NextEra's business risk profile as "strong" accounting for the company's regulated utility as well as its non-utility operations.

NextEra's regulated utility operations have low business risk and provide about 60% of consolidated operating income, lending support to the company's overall business risk profile within the "strong" category. The regulated business is conducted through Florida Power & Light (FPL) and benefits from operations under a constructive regulatory framework that provides for timely investment and fuel cost recovery. FPL has historically managed its regulatory risk effectively and this has resulted in earned returns that are consistently close to or at the authorized levels. The customer base is large with no meaningful industrial exposure and demonstrates above-average growth. The company has material exposure to natural-gas-fired generation, which, in combination with low natural gas prices and the company's efficient operations, contributes to overall competitive customer rates.

The company's non-utility operations are conducted under NextEra Energy Capital Holdings Inc. (NEECH). We ascribe significantly higher business risk to these non-utility operations compared to the regulated utility operations because they focus largely on unregulated generation, both merchant and contracted, with an emphasis on renewable energy projects and to a lesser extent on fossil-fired and nuclear generation. Integral to our view of NextEra's business risk profile as "strong" is that all merchant generation projects that are financed in a nonrecourse manner provide NextEra with only residual cash flows, an arrangement that we view as inherently weaker compared to NextEra having full access to all project cash flows. NextEra's non-utility operations also engage in proprietary trading and marketing as well as retail supply and wholesale full requirements contracts, businesses which can have significant liquidity needs and are generally characterized by small margins on a per unit basis, relying on large volumes to generate a meaningful contribution. Moreover, these operations require excellent risk management and disciplined hedging practices to limit a company's exposure to the fluctuation in commodity prices.

NextEra has created a yieldco entity which we expect will grow over time, in large part through asset purchases from NextEra, with NextEra benefiting not only from the asset sale proceeds but also from distributions. We expect that NextEra's ownership in the yieldco will decline over time while the company maintains the general partnership interest resulting in distributions that are disproportionate to the company's actual ownership interest. We view the yieldco structure as somewhat negative for credit quality since it makes cash distributions from the projects even more remote compared to direct ownership of the projects, with the detriment offset to some extent from the expected use of proceeds in a credit neutral manner at NextEra, such as supplementing the funding of future capital spending needs.

S&P Base-Case Operating Scenario

- NextEra continues to effectively manage regulatory risk as its regulated utility operations.
- Non-utility operations consistently contribute less than 50% of operating income.
- New renewable energy projects are completed on budget and on schedule.
- Yieldco ownership declines over time, but NextEra maintains ownership of general partner interest.

Peer comparison

NextEra Energy Inc. -- Peer Comparison

Industry Sector: Combo

	NextEra Energy Inc.	Dominion Resources Inc.	Public Service Enterprise Group Inc.	Duke Energy Corp.	Sempra Energy
Rating as of June 12, 2015	A-/Stable/--	A-/Negative/A-2	BBB+/Stable/A-2	A-/Stable/A-2	BBB+/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	14,857.5	12,883.0	9,894.0	22,715.7	10,413.0
EBITDA	5,642.4	4,860.2	3,349.3	8,567.2	3,284.0
Funds from operations (FFO)	4,861.1	3,680.5	2,631.3	6,942.4	2,424.1
Net income from cont. oper.	2,032.0	1,141.0	1,364.5	2,279.7	1,007.3
Cash flow from operations	4,585.1	3,674.9	2,756.5	6,425.3	2,035.8
Capital expenditures	7,560.7	4,514.4	2,716.2	5,459.7	2,818.7
Free operating cash flow	(2,975.7)	(839.6)	40.3	965.6	(782.9)
Discretionary cash flow	(4,227.7)	(2,197.4)	(691.0)	(1,100.8)	(1,446.9)
Cash and short-term investments	246.6	47.0	76.6	275.2	114.9
Debt	20,837.7	22,568.6	9,099.4	43,896.1	15,582.5
Equity	21,407.2	13,343.7	11,404.3	41,113.7	11,547.5
Adjusted ratios					
EBITDA margin (%)	38.0	37.7	33.9	37.7	31.5
Return on capital (%)	7.5	8.3	10.0	6.4	7.2
EBITDA interest coverage (x)	6.1	4.2	7.2	4.3	4.0
FFO cash int. cov. (X)	4.6	5.0	7.6	5.7	5.6
Debt/EBITDA (x)	3.7	4.6	2.7	5.1	4.7
FFO/debt (%)	23.3	16.3	28.9	15.8	15.6
Cash flow from operations/debt (%)	22.0	16.3	30.3	14.6	13.1
Free operating cash flow/debt (%)	(14.3)	(3.7)	0.4	2.2	(5.0)

NextEra Energy Inc. -- Peer Comparison (cont.)					
Discretionary cash flow/debt (%)	(20.3)	(9.7)	(7.6)	(2.5)	(9.3)

Financial Risk: Intermediate

We assess NextEra's financial risk profile as "intermediate" using the medial volatility financial ratio benchmarks. In determining the financial risk profile assessment we back out 75% of the debt that relates to project-financed renewable energy projects, leaving 25% on the balance sheet and viewing the project cash flows on a risk-adjusted basis. The adjustment accounts in part for the nonrecourse nature of the financing involved, but also reflects our view that this is a business which NextEra plans to continue growing but which has achieved enough scale and diversity such that no single project is critical to the parent, reducing the need or motivation to provide support to a failing project, if necessary. Under our base-case scenario we expect that NextEra's core credit ratios will remain in the lower end of the "intermediate" category with FFO to debt that averages about 25% over the next few years and debt to EBITDA of about 3.5x. Our assessment of financial risk also incorporates NextEra's commitment to support its financial profile such that it consistently remains well within the lower end of the "intermediate" category.

NextEra's "strong" business and "intermediate" financial risk profiles lead to an anchor of 'bbb+/a-'. We select the 'a-' anchor to capture primarily both the contribution and strength of NextEra's regulated utility operations to the overall credit profile.

S&P Base-Case Cash Flow And Capital Structure Scenario

- Financial performance continues to support an "intermediate" financial profile assessment, albeit at the low end of the range.
- Commitment to support financial profile within "intermediate" category.
- Debt from nonrecourse renewable energy projects receives partial off-credit treatment.
- Company benefits from asset sales proceeds to the yieldco and from distributions from the yieldco.

Financial summary

Table 2

NextEra Energy Inc.--Financial Summary					
Industry Sector: Combo					
	--Fiscal year ended Dec. 31--				
	2014	**2013**	**2012**	**2011**	**2010**
Rating history	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--	A-/Stable/--
(Mil. $)					
Revenues	15,969.8	14,724.7	13,877.9	14,926.7	15,009.0
EBITDA	6,150.3	5,918.5	4,858.6	5,003.6	5,180.6
Funds from operations (FFO)	5,367.4	5,171.6	4,044.2	4,350.6	4,667.9
Net income from continuing operations	2,465.0	1,720.0	1,911.0	1,923.0	1,935.5

Table 2

NextEra Energy Inc.--Financial Summary (cont.)					
Cash flow from operations	4,798.6	5,135.1	3,821.4	3,970.8	3,802.0
Capital expenditures	6,957.5	6,578.1	9,146.6	5,937.4	5,281.2
Free operating cash flow	(2,158.9)	(1,443.0)	(5,325.2)	(1,966.5)	(1,479.1)
Dividends paid	1,375.8	1,263.1	1,117.2	1,022.3	905.0
Discretionary cash flow	(3,534.7)	(2,706.0)	(6,442.3)	(2,988.8)	(2,384.1)
Debt	21,310.0	20,087.1	21,116.1	17,660.7	14,988.0
Preferred stock	3,239.0	3,427.1	3,279.5	1,929.5	1,176.5
Equity	23,407.0	21,467.1	19,347.5	16,872.5	16,390.5
Debt and equity	44,717.0	41,554.2	40,463.6	34,533.2	31,378.5
Adjusted ratios					
EBITDA margin (%)	38.5	40.2	35.0	33.5	34.5
EBITDA interest coverage (x)	6.6	6.3	5.4	6.7	7.3
FFO cash int. cov. (x)	4.8	4.9	4.2	4.6	5.6
Debt/EBITDA (x)	3.5	3.4	4.3	3.5	2.9
FFO/debt (%)	25.2	25.7	19.2	24.6	31.1
Cash flow from operations/debt (%)	22.5	25.6	18.1	22.5	25.4
Free operating cash flow/debt (%)	(10.1)	(7.2)	(25.2)	(11.1)	(9.9)
Discretionary cash flow/debt (%)	(16.6)	(13.5)	(30.5)	(16.9)	(15.9)
Net cash flow/Capex (%)	57.4	59.4	32.0	56.1	71.3
Return on capital (%)	7.8	7.5	7.3	8.4	8.7
Return on common equity (%)	12.1	8.7	10.7	12.0	13.5
Common dividend payout ratio (un-adj.) (%)	51.2	65.2	52.5	47.8	42.5

Liquidity: Adequate

We assess NextEra's liquidity as "adequate" to cover its needs over the next 12 months. We expect that the company's liquidity sources will exceed its uses by 1.1x or more, the minimum threshold for an adequate designation under our criteria and that the company will also meet our other criteria for such a designation.

NextEra has $7.85 billion in revolving credit facilities with $1.25 billion maturing in 2016 and the balance maturing in 2020. In addition, the company has a $270 million revolving credit facility and a $650 million letter-of-credit facility.

Principal Liquidity Sources	Principal Liquidity Uses
• Available credit facilities total about $7.5 billion; and • FFO of $6.8 to $7 billion annually.	• Debt maturities and outstanding commercial paper totaling about $4.7 billion in 2015 and debt maturities of about $1.3 billion in 2016; • Maintenance capital spending of about $5.5 billion in 2015 and about $6.7 billion in 2016; and • Dividends of about $1.4 billion to $1.6 billion annually.

OPC 009837
FPL RC-16

Debt maturities

As of Dec. 31, 2014:

- 2015: $3.515 billion
- 2016: $1.285 billion
- 2017: $2.608 billion
- 2018: $1.440 billion
- 2019: $1.943 billion

Covenant Analysis

As of Dec. 31, 2014, NextEra was in compliance with the funded debt to capitalization covenant included in its revolving credit facilities.

Compliance Expectations

- Although we believe the company will remain in compliance with its covenant under our base-case scenario, covenant headroom could decline absent adequate and timely recovery of capital investments that lead to an increase in debt without a corresponding increase in equity.

Other Credit Considerations

Our assessment of modifiers does not affect the anchor score.

Group Influence

NextEra is subject to the group rating methodology criteria, under which we assess NextEra as the parent of the group whose members are FPL and NEECH, both of which we assess as "core" members of the group. NextEra's group credit profile is 'a-' and its issuer credit rating is 'A-'.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/--

Business risk: Strong

- **Country risk:** Very low
- **Industry risk:** Low
- **Competitive position:** Strong

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-

Recovery Analysis/Issue Ratings

Senior unsecured debt obligations at NEECH are unconditionally guaranteed by NextEra and are effectively obligations of NextEra. As a result, we rate NEECH's senior unsecured debt one notch below the issuer credit rating to reflect the material amount of priority obligations throughout NextEra that encumbers more than 20% of the company's total assets.

We rate NEECH's commercial paper program 'A-2', accounting for the company's issuer credit rating and our assessment of NextEra's liquidity as "adequate".

Reconciliation

Table 3

Reconciliation Of NextEra Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2014--									
NextEra Energy Inc. reported amounts										
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**EBITDA**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	29,024.0	19,916.0	17,021.0	6,946.0	4,384.0	1,261.0	6,946.0	5,500.0	1,261.0	7,017.0
Standard & Poor's adjustments										
Interest expense (reported)	--	--	--	--	--	--	(1,261.0)	--	--	--
Interest income (reported)	--	--	--	--	--	--	80.0	--	--	--
Current tax expense (reported)	--	--	--	--	--	--	29.0	--	--	--
Equity-like hybrids	(1,750.0)	1,750.0	--	--	--	(22.4)	22.4	22.4	22.4	--

Table 3

Reconciliation Of NextEra Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)										
Intermediate hybrids reported as debt	(1,489.0)	1,489.0	--	--	--	(92.4)	92.4	92.4	92.4	--
Postretirement benefit obligations/deferred compensation	--	--	--	(122.0)	(122.0)	--	(124.9)	5.3	--	--
Surplus cash	(28.9)	--	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	128.0	(128.0)	(128.0)	--	(128.0)
Share-based compensation expense	--	--	--	83.0	--	--	83.0	--	--	--
Dividends received from equity investments	--	--	--	33.0	--	--	33.0	--	--	--
Nonrecourse debt	(5,022.0)	--	(979.0)	(979.0)	(477.0)	(477.0)	(502.0)	(502.0)	--	--
Securitized stranded costs	(331.0)	--	(72.2)	(72.2)	(17.2)	(17.2)	(55.0)	(55.0)	--	--
Power purchase agreements	699.9	--	--	117.5	49.0	49.0	68.5	68.5	--	68.5
Asset retirement obligations	--	--	--	108.0	108.0	108.0	48.0	(59.1)	--	--
Non-operating income (expense)	--	--	--	--	409.0	--	--	--	--	--
Non-controlling Interest/Minority interest	--	252.0	--	--	--	--	--	--	--	--
US decommissioning fund contributions	--	--	--	--	--	--	--	(146.0)	--	--
Debt - Accrued interest not included in reported debt	207.0	--	--	--	--	--	--	--	--	--
EBITDA - Valuation gains/(losses)	--	--	--	(309.0)	(309.0)	--	(309.0)	--	--	--
EBITDA - Other	--	--	--	345.0	345.0	--	345.0	--	--	--
D&A - Impairment charges/(reversals)	--	--	--	--	11.0	--	--	--	--	--
D&A - Other	--	--	--	--	(345.0)	--	--	--	--	--
Total adjustments	(7,714.0)	3,491.0	(1,051.2)	(795.7)	(348.2)	(324.1)	(1,578.6)	(701.4)	114.8	(59.5)
Standard & Poor's adjusted amounts										
	Debt	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	21,310.0	23,407.0	15,969.8	6,150.3	4,035.8	936.9	5,367.4	4,798.6	1,375.8	6,957.5

Related Criteria And Research

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers,

OPC 009840
FPL RC-16

Dec. 16, 2014

- Criteria - Corporates - Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	**a-/bbb+**	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of June 16, 2015)

NextEra Energy Inc.		
Corporate Credit Rating		A-/Stable/--
Junior Subordinated		BBB
Senior Unsecured		BBB
Senior Unsecured		BBB+
Corporate Credit Ratings History		
11-Mar-2010	*Foreign Currency*	A-/Stable/--
14-Jan-2010		A/Watch Neg/--
26-Oct-2006		A/Stable/--
11-Mar-2010	*Local Currency*	A-/Stable/--
14-Jan-2010		A/Watch Neg/--
26-Oct-2006		A/Stable/--
Related Entities		
Florida Power & Light Co.		
Issuer Credit Rating		A-/Stable/A-2
Commercial Paper		
Local Currency		A-2
Preferred Stock		BBB

OPC 009841
FPL RC-16

Ratings Detail (As Of June 16, 2015) (cont.)	
Senior Secured	A
Senior Secured	A/A-2
FPL Energy American Wind LLC	
Senior Secured	BB/Stable
FPL Energy National Wind LLC	
Senior Secured	BB/Negative
FPL Energy National Wind Portfolio LLC	
Senior Secured	B-/Stable
FPL Energy Wind Funding LLC	
Senior Secured	B-/Stable
FPL Group Capital Trust I	
Preferred Stock	BBB
NextEra Energy Capital Holdings Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated	BBB
Senior Unsecured	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Docket No. 160021-EI
FPL Data Responses
Exhibit No. ___ (RAB-5), Page 20 of 90

FitchRatings

Florida Power & Light Co.

Corporates Ratings Navigator
US Utilities

Corporates Ratings Navigator

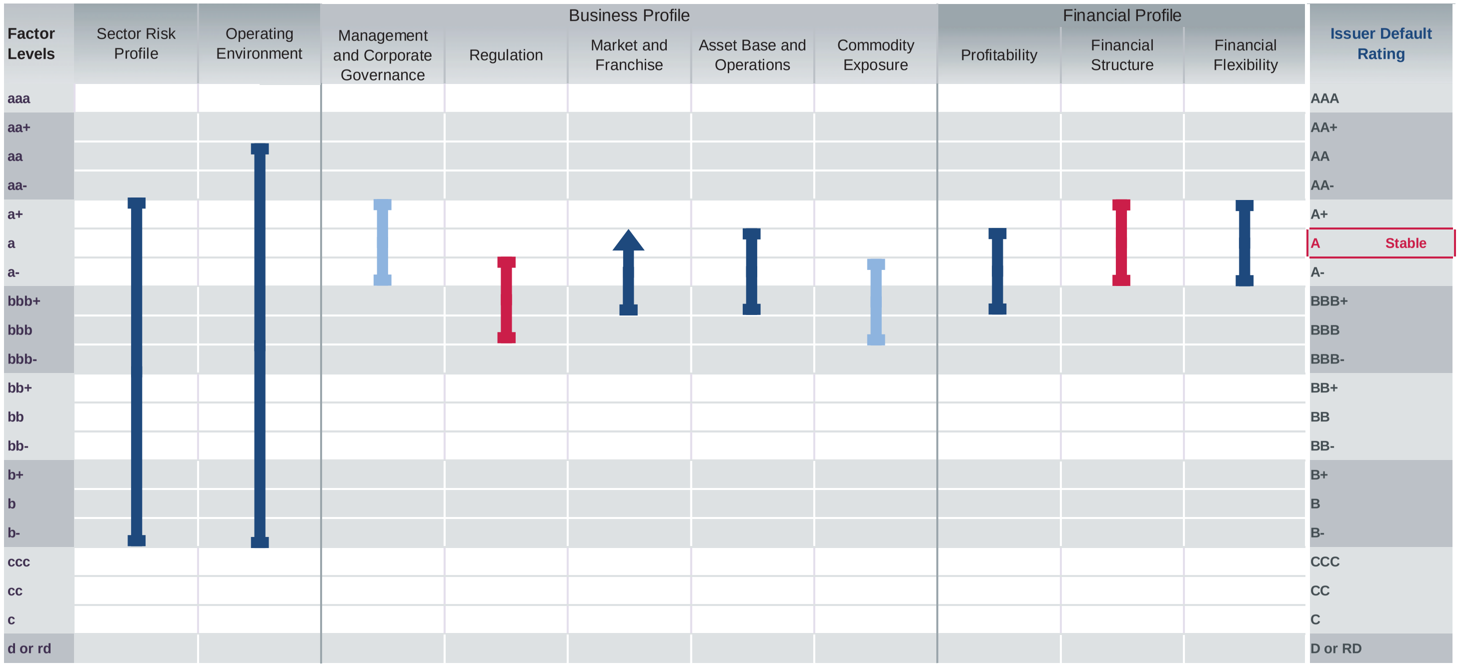
Publish Date:	3-Mar-15

Sector Details:

Sector:	US Utilities
Region:	Developed Markets - Americas
Country:	United States of America
Country IDR:	AAA Stable
Country IDR Action:	Affirmed
Country Action Date:	19-Sep-14
Country Ceiling:	AAA

Ratings History

Date	IDR		Action
4-Dec-14	A	Stable	Affirmed
1-Oct-14	A	Stable	Affirmed
25-Apr-14	A	Stable	Affirmed
26-Apr-13	A	Stable	Affirmed
27-Apr-12	A	Stable	Affirmed



Bar Chart Legend:

Vertical Bars = Range of Rating Factor

Bar Colors =Relative Importance

- Higher Importance
- Average Importance
- Lower Importance

Bar Arrows = Rating Factor Outlook

⇧ Positive ⇩ Negative
⇳ Evolving ☐ Stable

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Relevant Criteria & References

Introducing Ratings Navigators for Corporates
Corporate Rating Methodology
US Utilities: Ratings Navigator Companion

Direct Peer Group

Company Name	IDR		Action	Action Date
Georgia Power Company	A	Stable	Affirmed	30-Jan-2015
Wisconsin Electric Power Co.	A	Stable	Affirmed	01-Oct-2014
Duke Energy Florida, Inc.	BBB+	Stable	Affirmed	01-Oct-2014
Gulf Power Company	A-	Stable	Affirmed	18-Sep-2014
Oklahoma Gas & Electric Co.	A	Stable	Affirmed	01-Oct-2014

Drivers & Sensitivities

Constructive Regulatory Environment	A favorable turnaround in the regulatory climate in Florida and an extended period of regulatory certainty are key credit positives. The outcome of FPL's 2012 base rate case was constructive and provides rate certainty thorugh 2016.
Recovering Florida Economy	While Fitch has assumed a 1% CAGR in electric sales over 2015–2017, a recovering Florida economy could drive FPL's sales above expectations.
High Capex	Investment in new generation, storm hardening and reliability improvements will keep capex elevated thropugh 2017. The recent regulatory approval to rate base natural gas reserves could drive capex above Fitch's expectations.
Robust Credit Metrics	Fitch expects FFO fixed-charge coverage to be in the 7.0x–9.0x range over the forecast period. FFO-adjusted leverage and adjusted debt/EBITDAR are expected to be 3.0x and 2.4x, respectively, by 2017.
Positive Rating Sensitivities	Positive action is not anticipated at this time given the substantial non-utility investments by its parent, Nextera Energy, Inc. (A–).
Negative Rating Sensitivities	Unfavorable changes in current Florida regulatory policies for timely recovery of capital investments and operating costs can lead to negative rating actions. Increasing parent risk profile will also adversely affect FPL's ratings.

OPC 007992
FPL RC-16

FitchRatings

Florida Power & Light Co.

Corporates Ratings Navigator
US Utilities

Operating Environment

aa+	Economic Environment	aa	Very strong combination of countries where economic value is created and where assets are located.
aa	Financial Access	aa	Very strong combination of issuer specific funding characteristics and of the strength of the relevant local financial market.
	Systemic Governance	aa	Systemic governance (eg rule of law, corruption; government effectiveness) of the issuer's country of incorporation consistent with 'aa'.
b-			
ccc			

Management and Corporate Governance

aa-	Management Strategy	a	Coherent strategy and good track record in implementation.
a+	Governance Structure	bbb	Good CG track record but effectiveness/independence of board less obvious. No evidence of abuse of power even with ownership concentration.
A	Group Structure	a	Group structure shows some complexity but mitigated by transparent reporting.
a-	Financial Transparency	a	High quality and timely financial reporting.
bbb+			

Regulation

a	Degree of Transparency and Predictability	bbb	Generally transparent and predictable regulation with limited political interference.
a-	Timeliness of Cost Recovery	a	Minimal lag to recover capital and operating costs.
BBB+	Trend in Authorized ROEs	bbb	Average authorized ROE.
bbb	Mechanisms Available to Stabilize Cash Flows	bbb	Revenues partially insulated from variability in consumption.
bbb-	Mechanisms Supportive of Creditworthiness		n.a.

Market and Franchise

a+	Market Structure	a	Well-established market structure with complete transparency in price-setting mechanisms.
a	Consumption Growth Trend	bbb	Customer and usage growth in line with industry averages.
A-	Customer Mix	a	Favorable customer mix.
bbb+	Geographic Location	a	Favorable location or high geographic diversity.
bbb	Supply Demand Dynamics	a	Beneficial outlook for prices/rates.

Asset Base and Operations

a+	Diversity of Assets	a	High-quality and/or large-scale diversified assets.
a	Operations Reliability and Cost Competitiveness	a	Track record of reliable, low-cost operations.
A-	Exposure to Environmental Regulations	bbb	Limited or manageable exposure to environmental regulations.
bbb+	Capital and Technological Intensity of Capex	bbb	Moderate reinvestments requirements in established technologies.
bbb			

Commodity Exposure

a	Ability to Pass Through Changes in Fuel	bbb	Limited exposure to changes in commodity costs.
a-	Underlying Supply Mix	bbb	Low variable costs and moderate flexibility of supply.
BBB+	Hedging Strategy	a	Highly captive supply and customer base.
bbb			
bbb-			

Profitability

a+	Free Cash Flow	bbb	Structurally neutral to negative FCF across the investment cycle.
a	Volatility of Profitability	a	Higher stability and predictability of profits relative to utility peers.
a-			
bbb+			
bbb			

Financial Structure

aa-	Lease Adjusted FFO Gross Leverage	a	3.5x
a+	Total Adjusted Debt/Operating EBITDAR	a	3.25x
A			
a-			
bbb+			

Financial Flexibility

aa-	Financial Discipline	a	Clear commitment to maintain a conservative policy with only modest deviations allowed.
a+	Liquidity	a	Very comfortable liquidity. Well-spread maturity schedule of debt. Diversified sources of funding.
A	FFO Fixed Charge Cover	a	5.0x
a-			
bbb+			

How to Read This Page: The left column shows the three-notch band assessment for the overall Factor, illustrated by a bar. The right column breaks down the Factor into Sub-Factors, with a description appropriate for each Sub-Factor and its corresponding category.

Navigator Version: RN 1.37.5.0

FitchRatings

Corporates

Utilities, Power & Gas / U.S.A.

NextEra Energy, Inc.

Including NextEra Energy Capital Holdings, Inc.
Full Rating Report

Ratings

NextEra Energy, Inc.

Long-Term IDR	A–

NextEra Energy Capital Holdings, Inc.

Long-Term IDR	A–
Senior Unsecured	A–
Junior Subordinate Hybrids	BBB
Commercial Paper	F1

IDR – Issuer Default Rating.

Rating Outlook

Stable

Financial Data

NextEra Energy, Inc.

($ Mil.)	LTM 6/30/15	2014
Adjusted Revenue	17,702	16,945
Operating EBITDAR	7,661	6,870
CFFO	5,929	5,445
Total Adjusted Debt	27,985	27,204
Total Capitalization	51,075	48,861
Capex/ Depreciation (%)	280.9	281.1
FFO Fixed-Charge Coverage (x)	5.7	5.2
FFO-Adjusted Leverage (x)	3.7	3.8
Total Adjusted Debt/EBITDAR (x)	3.7	4.0

Related Research

U.S. Utilities Power & Gas Dashboard (Third-Quarter 2015) (October 2015)

Fitch Affirms NextEra at 'A–'' Following Acquisition Announcement by NEP; Outlook Stable (August 2015)

Florida Power & Light Co. (July 2015)

NextEra Energy, Inc. - Ratings Navigator (March 2015)

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Key Rating Drivers

Growing Regulated and Contracted Assets: The ratings for NextEra Energy, Inc. (NEE) reflect a continued shift in business mix toward regulated and highly contracted assets that comprise approximately 85% of adjusted EBITDA. Base rate increases at Florida Power and Light Co. (FPL), rising contributions from contracted renewable projects, and investments in regulated natural gas transmission are driving this favorable shift. The rating of NextEra Energy Capital Holdings, Inc. (Capital Holdings) is equalized with that of NEE given the full, irrevocable and unconditional guarantee.

Constructive Florida Environment: A favorable turnaround in Florida's regulatory climate and an extended period of regulatory certainty are supportive credit factors. FPL's 2012 rate order spans a four-year term through December 2016, sets rates based on a 10.5% ROE with a 100-bps band and automatically adjusts base rates on commercial operations of new generation plants. Florida's economy is recovering well. FPL continues to demonstrate robust credit metrics that compare favorably with an 'A' rated financial profile for a regulated utility.

Elevated Capex: After relatively modest investments in 2013–2015, capex plans are rising again, with about $18 billion projected to be invested in 2015–2016, divided about 45%/55% between FPL and other businesses. Fitch Ratings sees an upward bias to the utility capex plans as FPL evaluates incremental investments in generation and natural gas reserves. Capex for contractual renewable generation projects will likely increase management projections, with robust growth in the backlog for wind and solar projects.

Challenging Outlook for Yieldcos: Continued limited capital market access for yieldcos could constrain NEE's ability to grow NextEra Energy Partners, L.P. (NEP) and recycle its capital into new renewable projects. Permanent debt at NEP is viewed negatively for NEE's bondholders by Fitch because it increases the structural subordination. The pursuit of third-party acquisitions to drive growth at NEP and an accelerated rate of dropdowns are also concerns for Fitch.

Recovering Credit Metrics: On a fully consolidated basis, Fitch expects NEE's FFO fixed-charge coverage to be in the 5.5x–6.0x range over the forecast period of 2015–2018. Fitch expects both adjusted debt to EBITDAR and adjusted FFO leverage to approximate 3.5x by 2018.

Rating Sensitivities

Positive Rating Action: Positive rating actions for NEE appear unlikely at this time.

Negative Rating Action: Future developments that may, individually or collectively, lead to a negative rating action include a failure to achieve adjusted FFO leverage of 3.50x–3.75x by 2017 on a consolidated basis and any deterioration in credit measures that result from higher use of leverage or outsized return of capital to shareholders. An aggressive acquisitive or financial strategy at NEP or predominantly shareholder-focused use of sell down proceeds, a change in strategy to invest in noncontracted renewable/pipeline/electric transmission assets, more speculative assets, or a lower proportion of cash flow under long-term contracts could also lead to negative action.

Financial Overview

Liquidity and Debt Structure

NEE's ratings reflect the company's strong access to the capital markets, commercial paper market and to banks for both corporate credit and project finance. Liquidity is robust, with about $550 million in cash and more than $6 billion available under committed corporate credit facilities, aggregating approximately $9.7 billion for the NEE group of companies, excluding limited recourse or nonrecourse project financing arrangements, as of June 30, 2015.

FPL independently funds its short-term and long-term debt needs, while funding for other activities is aggregated under Capital Holdings. FPL's $3 billion bank revolving line of credit — $500 million maturing in May 2016 and the rest in 2020 — also provides a liquidity backstop for commercial paper funding, variable-rate tax-exempt revenue notes and issuance of LOCs. Capital Holding's $4.85 billion bank revolving line of credit ($750 million matures in May 2016, rest in 2020) is complemented by a $650 million LOC facility (maturity in 2017).

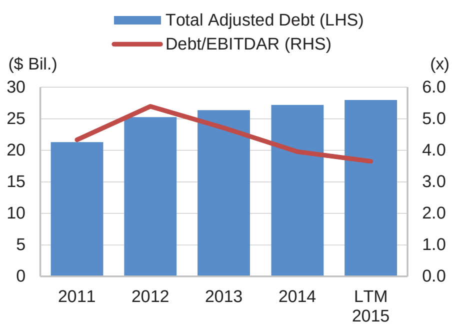
Debt maturities are manageable, as shown in the *Debt Maturities and Liquidity* table below. About $900 million of the 2015 maturities were repaid in recent months.

Debt Maturities and Liquidity

($ Mil., As of June 30, 2015)	
2015	2,684
2016	2,649
2017	2,879
2018	1,587
Thereafter	20,000
Cash and Cash Equivalents	551
Undrawn Committed Facilities	9,612

Source: Company data, Fitch.

Total Debt and Leverage



Source: Company data, Fitch.

Cash Flow Analysis

NEE generates negative FCF after dividends and capex. The sharp increase in capex in 2012, driven by a rush to develop wind projects due to the looming production tax credit (PTC) expiration, strained NEE's balance sheet. Moderation of capex and issuance of equity helped to right-size the balance sheet.

Capex is on the rise again and could exceed $9 billion in 2015 and $10 billion in 2016. It appears likely capex could remain elevated beyond 2016 given the sustained strong demand for renewable projects. Fitch forecasts NEE's capex to exceed CFFO in 2015 and 2016. NEE's financing needs in 2015 are intensified by its $700 million equity support of NEP to complete acquisitions in second-half 2015.

Fitch assumes NEE will continue to take a balanced approach to fulfilling its financing needs, with a mix of equity and debt issuance to maintain adjusted FFO leverage in the 3.5x–3.7x range consistent with its current ratings.

Related Criteria

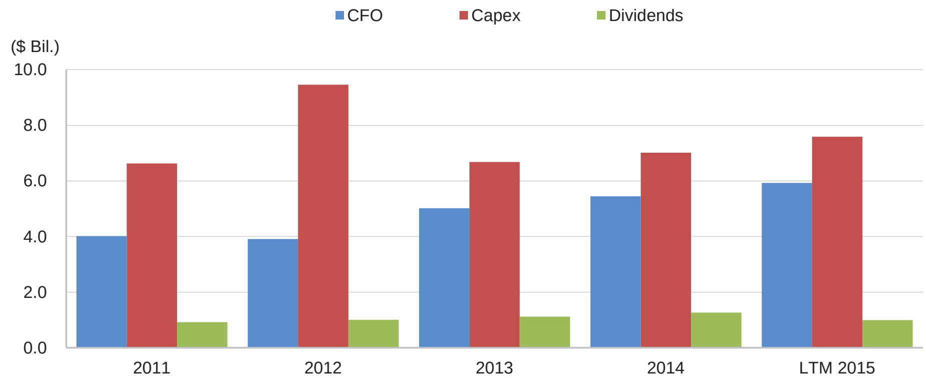
Corporate Rating Methodology — Including Short-Term Ratings and Parent and Subsidiary Linkage (August 2015)

Parent and Subsidiary Rating Linkage (August 2015)

Recovery Ratings and Notching Criteria for Utilities (March 2015)

Rating U.S. Utilities, Power and Gas Companies (Sector Credit Factors) (March 2014)

CFO and Cash Use



Source: Company data, Fitch.

Peer and Sector Analysis

Peer Group

Issuer	Country
A–	
OGE Energy Corp.	U.S.
BBB+	
Sempra Energy	U.S.
Dominion Resources, Inc.	U.S.

Source: Fitch.

Issuer Rating History

Date	LT IDR (FC)	Outlook/ Watch
Aug. 6, 2015	A–	Stable
April 24, 2015	A–	Stable
Dec. 4, 2014	A–	Stable
Oct. 1, 2014	A–	Stable
April 25, 2014	A–	Stable
April 26, 2013	A–	Stable
April 27, 2012	A–	Stable
May 2, 2011	A–	Stable
April 30, 2010	A–	Negative
Jan. 12, 2010	A	RWN
Oct. 29, 2009	A	Stable
Dec. 14, 2007	A	Stable
Dec. 20, 2006	A	Stable
Feb. 27, 2006	A	Stable
Dec. 19, 2005	A	Stable
Dec. 6, 2005	A	Stable
July 5, 2005	A	Stable
Feb. 4, 2005	A	Stable
July 29, 2003	A	Stable

LT IDR – Long-term Issuer Default Rating.
FC – Foreign currency.
RWN – Rating Watch Negative.
Source: Fitch.

Peer Group Analysis

($ Mil.)	NextEra Energy, Inc.	OGE Energy Corp.	Sempra Energy	Dominion Resources, Inc.
As of	6/30/15	6/30/15	6/30/15	6/30/15
IDR	A–	A–	BBB+	BBB+
Rating Outlook	Stable	Stable	Stable	Stable
Fundamental Ratios (x)				
Operating EBITDAR/(Gross Interest Expense + Rents)	5.8	5.7	4.9	4.8
FFO Fixed-Charge Coverage (x)	5.7	6.1	4.2	4.9
Total Adjusted Debt/Operating EBITDAR	3.7	3.5	4.7	5.3
FFO/Total Adjusted Debt (%)	27.2	30.0	22.5	19.5
FFO-Adjusted Leverage (x)	3.7	3.3	4.4	5.1
Common Dividend Payout (%)	45.2	45.9	33.1	73.1
Internal Cash/Capex (%)	60.8	141.3	55.3	53.6
Capex/Depreciation (%)	280.9	167.5	262.4	407.4
ROE (%)	14.6	13.2	11.9	16.7
Financial Information				
Revenue	17,702	2,519	10,611	12,149
Revenue Growth (%)	13.5	(7.9)	(1.1)	(7.0)
EBITDA	7,661	1,020	3,130	4,900
Operating EBITDA Margin (%)	43.2	41.5	29.8	40.5
FCF	(2,972)	206	(1,476)	(2,566)
Total Adjusted Debt with Equity Credit	27,985	3,646	15,099	26,574
Cash and Cash Equivalents	551	—	636	271
FFO	6,323	915	2,492	4,134
Capex	(7,587)	(499)	(3,091)	(5,532)

IDR – Issuer Default Rating.
Source: Company data, Fitch.

Key Rating Issues

Changing Business Mix to More Regulated/Contracted

NEE's continued shift from merchant businesses toward regulated investments and contracted nonregulated renewable assets is supportive of its credit profile. Driving the favorable shift in cash flow mix are such factors as significant rate base increases at NEE's regulated utility subsidiary FPL, planned investments in regulated electric and natural gas transmission projects, the rising contribution from contracted solar and wind investments, and the proposed acquisition of Hawaiian Electric Industries (HEI). Absent a significant recovery in the commodity environment, which Fitch is not expecting, the contribution from noncontracted generation assets and other nonregulated businesses will remain contained, in Fitch's opinion.

Regulated businesses composed approximately 60% of total adjusted EBITDA for NEE in 2014 and Fitch expects this proportion to sustain for the next several years. Within the nonregulated businesses, management's emphasis remains on long-term contracted renewable generation, specifically solar and wind. The adjusted EBITDA contribution from both regulated and contracted businesses at NEE was approximately 84% in 2014 and Fitch expects this to modestly increase to 85% over the next few years.

Constructive Regulation in Florida

Fitch views the current Florida regulatory environment for FPL as constructive and vastly improved from the highly politicized decision-making witnessed at the depths of the last recession. FPL was successful in securing a favorable rate order for its 2012 base rate case. The rate order, effective until December 2016, provides for regulatory certainty for four years. The authorized regulatory ROE is 10.5%, with a range of plus or minus 100 bps. FPL can seek rate relief if the regulatory ROE falls below 9.5% and can conversely be pulled into a rate review if the ROE exceeds 11.5%. FPL has the ability to amortize a depreciation reserve surplus of approximately $224 million and fossil dismantlement reserve of $176 million to keep the regulatory ROE within the band over the four-year period.

The rate order also provided for automatic adjustment to base rates to reflect FPL's three modernization projects (i.e. the completed Cape Canaveral and Riviera Beach projects, and Port Everglades, which is under construction). Fitch expects FPL to file a rate case in 2016 for new rates effective in January 2017.

High Regulated Capex

FPL's capex has been high over the last few years, mostly driven by new generation additions. As part of its fleet-modernization program, FPL constructed and placed into service the 1,210-MW Cape Canaveral and 1,212-MW Riviera Beach power plants in April 2013 and April 2014, respectively. FPL has also undertaken uprates at its nuclear facilities of St. Lucie and Turkey Point, which resulted in an incremental 522 MW of capacity at these units; the uprates were completed in 2013. Through a generation base rate adjustment mechanism, FPL has been able to receive rate recovery of its modernization projects without filing for a rate case. The nuclear uprate costs are being recovered through the nuclear clause and base rates.

Capex peaked in 2012 and has been moderating since, but is likely to pick up again. FPL has identified approximately $13.9 billion–$15.6 billion of capex in 2015–2018. FPL is targeting generation upgrades, a grid-modernization program and three solar photovoltaic projects (74 MW each) that are expected to be placed into service by the end of 2016. FPL has also issued a request for proposal for capacity need in 2019 and its self-build option includes a new natural gas-fired combined-cycle plant in Okeechobee County, FL.

FPL also acquired the coal-fired Cedar Bay facility for $520 million in September 2015 to terminate a long-term power purchase agreement and phase out its utilization. Furthermore, the regulators approved FPL's petition to invest in natural gas reserves and recover costs associated with the investment through its fuel clause. FPL may invest up to $500 million annually in future natural gas reserves. FPL is also in the process of obtaining a combined construction and operating license from the Nuclear Regulatory Commission for two additional nuclear units (2,200 MW) at its Turkey Point site.

Significant Non-Utility Capex

Management identified \$15.9 billion–\$17.5 billion of non-FPL capex over 2015–2018 at the beginning of the year, which included \$2.25 billion–\$2.45 billion of natural gas pipeline investments and \$1.10 billion–\$1.15 billion of regulated electric transmission investments. However, the bulk of the non-FPL capex reflected an expectation of 4,600 MW–5,100 MW of wind and solar development program at its indirect, wholly owned subsidiary, NEE Energy Resources (Energy Resources). In the second quarter earnings call, management increased its renewable development program by approximately 125 MW. A PTC extension could add additional 800 MW–1200 MW to the development pipeline.

The current terms of tax subsidies for wind and solar is pulling the construction of many projects forward into 2015–2016, increasing Energy Resources' capex spend and financing needs over the short term. While tax incentives currently improve the economic profile of projects, Fitch expects demand for wind and solar projects will remain elevated over the medium term, supported by environmental regulation and a competitive cost structure. Fitch views positively the expansion of this business line as it poses limited technology and construction risks while delivering a long stream of stable cash flows.

Contracted Wholesale Generation Limits Risk

The wholesale generation business within Energy Resources comprises a well-diversified fleet that has a lower risk than most of its merchant peers, in Fitch's opinion. Its geographic scope spans 25 states and four Canadian provinces, while its energy source on a generation basis was 42% wind, 28% nuclear, 27% natural gas, 2% solar and 1% other in 2014. The technology mix positions the company well to face upcoming environmental regulation and shifting society preferences. Earnings and cash flow visibility is also enhanced by the high proportion of assets — almost 70% — under long-term power sales agreements with remaining an average contract life of 15 years.

The outlook for NEE's noncontracted merchant assets is more challenging. Power prices remain depressed across the U.S., with little relief in sight given the anemic demand growth, robust reserve margins and depressed natural gas prices.

Prolonged Approval Process for HEI Acquisition

Fitch views the HEI acquisition as moderately positive for NEE, driven by a modest increase in earnings from regulated businesses, predominant use of equity to finance the acquisition, and attractive regulated investment opportunities at HEI's utility. Fitch's view is somewhat tempered by structural issues with the Hawaii service territory, with its excessive reliance on oil for power generation, high retail prices, increasing penetration of residential rooftop solar and need for significant capital investment to transition to cleaner fuel sources. This could put pressure on retail prices in the short to medium term. The transaction has been approved by HEI's shareholders and the Federal Energy Regulatory Commission (FERC), but remains subject to approval by the Hawaii Public Utilities Commission. The regulatory approval process is turning out to be more prolonged and challenging than Fitch's original expectation.

Difficult Environment for Yieldcos

Yieldco equities have come under tremendous pressure since summer 2015, challenging the industry's strategy of rapid growth through equity-funded dropdowns and acquisitions, as well as their fundamental purpose as a cheaper source of financing. Facing adverse financial market conditions, NEP relied on NEE to fund $700 million of equity ownership — proportionate to NEE's current ownership — in October 2015 to complete pending acquisitions, resulting in a modest consolidated leverage uptick.

NEP has been pursuing an aggressive growth strategy and dropdowns from NEE into NEP have occurred at an accelerated pace compared with Fitch's initial expectations. NEP's recent acquisition of seven natural gas pipelines in Texas adds welcomed diversification to its wind-heavy portfolio of assets, especially in the recent context of weather-induced, below average performance of wind projects. The pursuit of third-party acquisitions to drive growth at NEP, despite a large existing and healthy development pipeline of assets available at NEE for future dropdowns, is nonetheless a concern for Fitch.

Management, in its second-quarter earnings conference call, discussed the possibility of using non-amortizing debt to finance renewable assets, which is a departure from its traditional mode of project financings. Any permanent debt at NEP that replaces existing project debt would be credit negative for NEE's debtholders. The project debt is largely nonrecourse and Fitch believes NEP would walk away from a project if it became distressed.

Significant Dividend Increase

NEE announced a material increase in dividend with its second-quarter earnings release and is targeting a dividend payout ratio of 65% by 2018, down from 55% currently. Fitch considers dividends paid by utility holding companies as nondiscretionary use of cash, thus a material increase in dividend lowers the financial flexibility of the company. However, based on the current pipeline of investment opportunities at NEE, Fitch expects the company to have sufficient financial headroom to absorb the additional dividend without a material increase in leverage.

Stable Credit Metrics

NEE has improved its credit metrics significantly since 2012, when an unusually high pace of capex stretched the balance sheet. Adjusted FFO leverage was 3.7x at LTM June 30, 2015, compared with a peak of 4.8x in 2012. Adjusted debt to EBITDAR similarly improved to 3.7x from 5.4x over the same period. Fitch expects NEE's credit metrics to remain relatively stable over the rating horizon, with the assumption that management pursues a balanced approach to fund its numerous expansion initiatives. The limited capital market access for yieldcos currently constrains NEE's ability to recycle capital via selldown of assets into NEP.

Given the elevated level of forecast capex, management's emphasis on strengthening credit metrics is warranted to maintain the current level of ratings. Through a series of equity issuances, management has consistently improved the balance sheet, which became stressed in 2012. Management has reinforced its commitment to credit ratings in its public comments, and Fitch expects NEE to meet the targeted credit metrics on a consistent basis.

Treatment of Nonrecourse Debt

NEE's credit metrics, as reported, have historically shown more leverage than a median 'A–' financial profile for a utility or parent holding company. A large portion of Energy Resources' generation portfolio is project financed with debt that has limited or no corporate recourse. However, these projects tend to be highly leveraged, with a typically low investment-grade profile, which weakens the consolidated leverage metrics for NEE. In Fitch's view, a better way to analyze NEE's metrics is to deconsolidate a majority of the project-financed entities and only include the upstream distribution from these entities in NEE's credit analysis. The off-credit treatment to the limited recourse debt at Energy Resources reflects Fitch's assumption that NEE would walk away from these projects in the event of financial deterioration, including those projects where a differential membership interest has been sold. These projects typically comprise wind, solar and fossil assets. Nonrecourse debt associated with entities such as Lone Star Transmission (Lone Star) is not deconsolidated and NEP is proportionally consolidated.

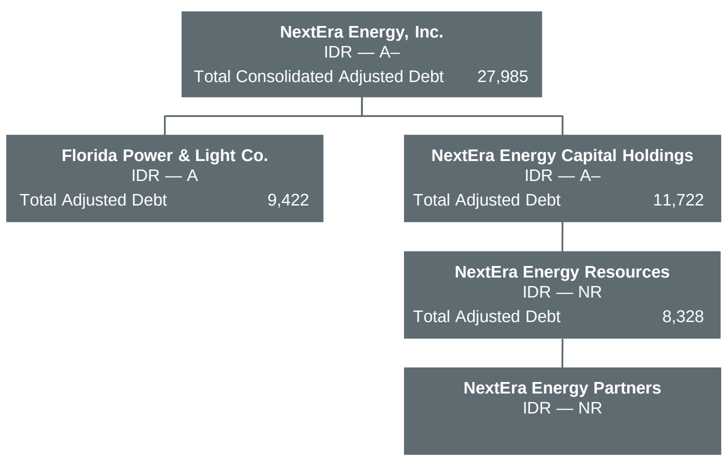
NEE's credit metrics look stronger in the alternative rating case. FFO fixed-charge coverage remains above 7.5x over the forecast period and FFO-adjusted leverage is forecast to improve to 3.0x by 2018 under this scenario.

Organizational Structure

The Issuer Default Rating (IDR) of Capital Holdings is equalized with that of NEE due to the full, irrevocable and unconditional guarantee from NEE. Fitch deems the rating linkage between NEE and FPL as strong, given the strategic importance of FPL in the overall portfolio and common financial ties. However, FPL's authorized regulatory capital structure and covenants in its debt indentures limit the cash distributions to NEE and provide for a one-notch differential between NEE's and FPL's IDRs.

Organizational and Debt Structure — NextEra Energy, Inc.

($ Mil., As of June 30, 2015)



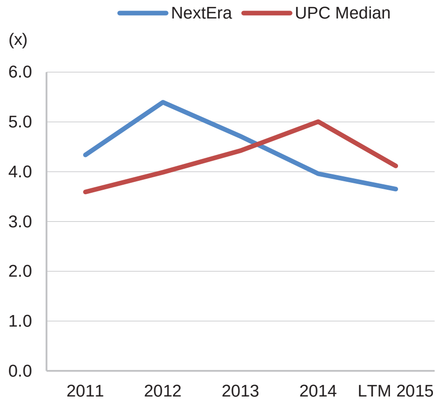
IDR – Issuer Default Rating. NR – Not rated.
Source: Company reports, Fitch analysis.

Key Metrics

Definitions

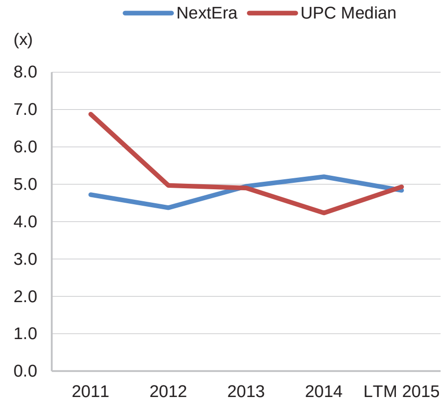
- Total Adjusted Debt/Op. EBITDAR: Total balance sheet adjusted for equity credit and off-balance sheet debt divided by operating EBITDAR.
- FFO Fixed-Charge Coverage: FFO plus gross interest minus interest received plus preferred dividends plus rental payments divided by gross interest plus preferred dividends plus rental payments.
- FFO-Adjusted Leverage: Gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock divided by FFO plus gross interest paid plus preferred dividends plus rental expense.

Total Adjusted Debt/Operating EBITDAR



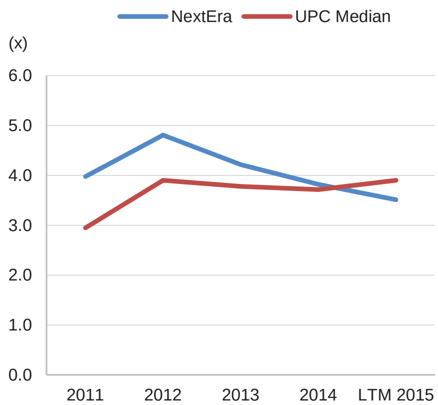
UPC – Utility parent company.
Source: Company data, Fitch.

FFO Fixed-Charge Coverage



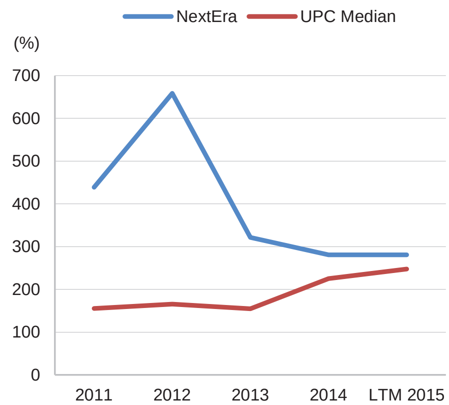
UPC – Utility parent company.
Source: Company data, Fitch.

FFO-Adjusted Leverage



UPC – Utility parent company.
Source: Company data, Fitch.

Capex/Depreciation



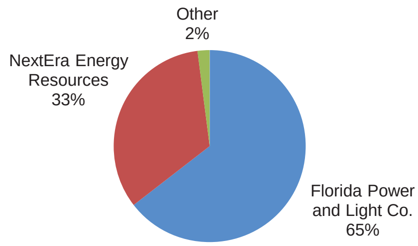
UPC – Utility parent company.
Source: Company data, Fitch.

Company Profile

NEE is a public utility holding company with over 42,000 MW in generating capacity. Its largest subsidiary is FPL, an integrated regulated utility in Florida with about 4.8 million customer accounts and 25,100 MW of generating capacity. The other primary subsidiary is Capital Holdings, which wholly owns Energy Resources, a wholesale generator of electric power with a portfolio of about 19,800 MW of capacity, with an emphasis on wind and solar projects. Capital Holdings also has approximately 80% ownership in NEP, a growth-oriented limited partnership focused on owning contracted energy projects.

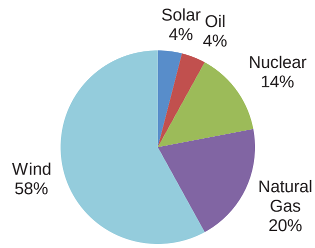
NEE also owns NextEra Energy Transmission, which owns transmission utilities and projects outside Florida, including Lone Star, a regulated transmission company in Texas. Another growth area for NEE is the regulated gas pipeline business. NEE plans to invest close to $1 billion in Sabal Trail Pipeline, which will be regulated by the FERC and is expected to be in service in mid-2017. Other pipeline investments include Florida Southeast Connection, in which NEE plans to invest $500 million, and Mountain Valley Pipeline, in which NEE will invest $1.0 billion–$1.3 billion.

EBITDA per Business Segment
(As of Dec. 31, 2014)



Source: Company data, Fitch.

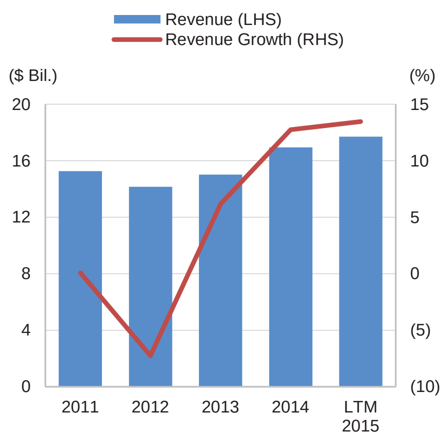
2014 Energy Resources' Generation Mix (MW)



Source: Company data, Fitch.

Business Trends

Revenue Dynamics



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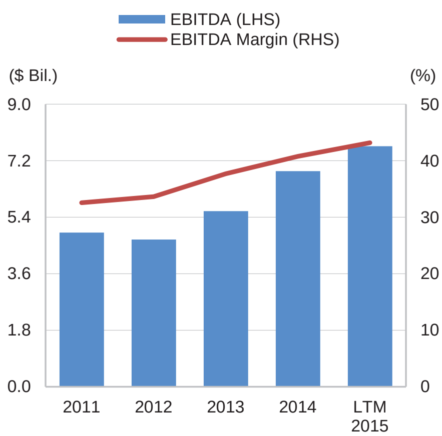
EBITDA Dynamics



Source: Company data, Fitch.

Financial Summary — NextEra Energy, Inc.

($ Mil., As of June 30, 2015; IDR: A–/Rating Outlook Stable)	2011	2012	2013	2014	LTM 6/30/15
Fundamental Ratios					
Operating EBITDAR/(Gross Interest Expense + Rents) (x)	4.3	3.9	4.4	5.0	5.8
FFO Fixed-Charge Coverage (x)	4.7	4.4	4.9	5.2	5.7
Total Adjusted Debt/Operating EBITDAR (x)	4.3	5.4	4.7	4.0	3.7
FFO/Total Adjusted Debt (%)	25.2	20.8	23.7	26.2	27.2
FFO-Adjusted Leverage (x)	4.0	4.8	4.2	3.8	3.7
Common Dividend Payout (%)	47.8	52.5	58.8	51.2	45.2
Internal Cash/Capex (%)	46.7	30.7	58.3	59.6	60.8
Capex/Depreciation (%)	438.7	658.4	321.7	281.1	280.9
ROE (%)	13.1	12.3	11.2	13.0	14.6
Profitability					
Revenues	15,260	14,152	15,028	16,945	17,702
Revenue Growth (%)	0.1	(7.3)	6.2	12.8	13.5
Net Revenues	9,004	9,031	10,070	11,343	12,191
Operating and Maintenance Expense	3,002	3,155	3,194	3,149	3,160
Operating EBITDA	4,915	4,690	5,596	6,870	7,661
Operating EBITDAR	4,915	4,690	5,596	6,870	7,661
Depreciation and Amortization Expense	1,511	1,437	2,077	2,496	2,701
Operating EBIT	3,404	3,253	3,519	4,374	4,960
Gross Interest Expense	1,135	1,204	1,266	1,368	1,332
Net Income for Common	1,923	1,911	1,908	2,465	2,909
Operating Maintenance Expense % of Net Revenues	33	35	32	28	26
Operating EBIT % of Net Revenues	38	36	35	39	41
Cash Flow					
Cash Flow from Operations	4,018	3,911	5,016	5,445	5,929
Change in Working Capital	(207)	(149)	24	(306)	(346)
Funds from Operations	4,225	4,060	4,992	5,751	6,275
Dividends	(920)	(1,004)	(1,122)	(1,261)	(1,314)
Capex	(6,628)	(9,461)	(6,682)	(7,017)	(7,587)
FCF	(3,530)	(6,554)	(2,788)	(2,833)	(2,972)
Net Other Investment Cash Flow	145	533	559	656	577
Net Change in Debt	2,279	5,079	1,255	755	308
Net Equity Proceeds	139	1,194	1,290	1,611	2,199
Capital Structure					
Short-Term Debt	1,349	1,411	691	1,142	1,771
Total Long-Term Debt	19,954	23,883	25,672	26,062	26,214
Total Debt with Equity Credit	21,303	25,294	26,363	27,204	27,985
Total Adjusted Debt with Equity Credit	21,303	25,294	26,363	27,204	27,985
Total Hybrid Equity and Minority Interest	1,177	1,627	1,677	1,741	1,752
Total Common Shareholders' Equity	14,943	16,068	18,040	19,916	21,338
Total Capital	37,423	42,989	46,080	48,861	51,075
Total Debt/Total Capital (%)	56.9	58.8	57.2	55.7	54.8
Total Hybrid Equity and Minority Interest/Total Capital (%)	3.1	3.8	3.6	3.6	3.4
Common Equity/Total Capital (%)	39.9	37.4	39.1	40.8	41.8

IDR – Issuer Default Rating.
Source: Company data, Fitch.

STANDARD & POOR'S RATINGS SERVICES
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Global Credit Portal®
RatingsDirect®

April 24, 2012

Summary:
Florida Power & Light Co.

Primary Credit Analyst:
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Summary:

Florida Power & Light Co.

Credit Rating: A-/Stable/A-2

Rationale

Standard & Poor's Ratings Services' bases its ratings on Florida Power & Light Co. (FP&L) on the consolidated credit profile of its parent, diversified energy holding company NextEra Energy Inc. The credit fundamentals on its regulated utility side have been among the strongest in the U.S., due primarily to low regulatory risk and an attractive service territory with healthy economic growth and a sound business environment. Both of those pillars have been shaken in recent years as Florida, and Florida Power & Light's (FP&L) service territory in particular, suffered during the recession, and regulators have responded in ways that reflect greater political influence over regulatory decisions. Although the utility has found maintaining financial strength despite mild regulatory upheaval and a moribund economy in Florida to be challenging, its actions to rebuild its regulatory risk profile have been effective. More importantly, the proportion of NextEra's unregulated businesses--the riskier merchant generation, marketing, and trading activities--could increase, which could further erode its consolidated business risk profile.

FP&L is a large, regulated public utility with integrated assets (generation, transmission, and distribution) in South Florida, along the populous eastern coastline and the growing lower western coastline of the state. FP&L owns more than 24,000 megawatts (MW) of efficient, well-operated, mostly natural-gas- and nuclear-fueled electric generating plants that serve primarily its own customers.

Standard & Poor's Ratings Services' ratings on all NextEra entities reflect the strength of the regulated cash flows from integrated electric utility FP&L, and the diverse and substantial cash-generation capabilities of its unregulated operations at subsidiary NextEra Energy Resources (NER). FP&L represents about half of the consolidated credit profile and has better business fundamentals than most of its integrated electric peers, with a better-than-average service territory, sound operations, and a credit-supportive regulatory environment in which the company has been able to manage its regulatory risk very well. A willingness to expand through acquisitions, fluctuating cash flows from NER's rapidly expanding portfolio of merchant generation assets and growing marketing and trading activities, and significant exposure at the utility to natural gas detract from credit quality, in our view.

We characterize FP&L's business risk profile as "excellent," NextEra's business risk profile as "strong," and the consolidated financial risk profile as "intermediate" under our criteria.

NextEra's business risk profile is anchored by the company's core electric utility operations in Florida, which exhibit proficiency in almost every area of analysis. The service territory has historically fared better than most of the rest of the country despite its lagging performance during the recession, the customer mix is mostly residential and commercial, costs and rates are low, and reliability and customer satisfaction are high. While Florida is not immune to overall economic trends, we expect the state to attract new residents and jobs over the long term and resume an above-average growth trajectory. NextEra's large and growing reliance on natural gas to fuel utility generation could eventually turn from an advantage (because of its favorable environmental status and currently low prices) to a weakness if gas prices are erratic over time.

FP&L has managed regulatory risk, the most important risk a utility faces, well. Despite a slight rise in regulatory risk in reaction to weak economic conditions amid keener attention in the political arena, the company has maintained the utility's financial performance and credit metrics and stabilized its regulatory risk. FP&L has filed a new rate case aimed at a 7% base rate increase (2.6% net of a proposed fuel clause decrease) to take effect when a rate freeze expires at the end of 2012. The conduct and outcome of the case will be an effective gauge of the state's regulatory environment.

NER, the main subsidiary under unregulated NextEra Energy Capital Holdings Inc., engages in electric generation, marketing, and trading throughout the U.S. NER's focus is on geographic and fuel diversity and on developing environmentally advantageous facilities that benefit from public policy trends. The merchant generator's capacity of almost 16,600 MW consists of more than half wind turbines, one-quarter natural-gas-fired stations, and the rest mainly nuclear facilities. More than three-quarters of the wind projects and almost 60% of the total portfolio operate under largely fixed-price, long-term contracts. The rest of the portfolio, including one nuclear plant, is merchant capacity that can be exposed to market prices for its output. While a policy of actively hedging the commodity price risk of plant inputs and outputs helps to reduce the risks associated with merchant energy activities, NER faces an inherent level of commodity price risk. In addition, NER's extensive project financing (approximately 46% of installed capacity) of its assets diminishes its cash flow quality, but this is offset by lower financial risk. NER's risks permanently hinder NextEra's credit quality, especially in light of the influence that marketing and high-risk proprietary trading results have on NER's earnings and cash flows.

We believe the governance and financial policies for managing risk are adequate. NextEra's financial risk profile is characterized by acceptable credit metrics, "adequate" liquidity under our criteria, and a management attitude toward credit quality that supports ratings. Importantly, sound but complex financial structures employed at the project level substantiate significant off-credit treatment of largely nonrecourse debt at NextEra. Any indication that management is using or is willing to use its own financial resources to aid a troubled project in support of strategic objectives could lead Standard & Poor's to reevaluate the adjustments we make to NextEra's reported debt. We also factor in large adjustments to the credit analysis regarding hybrid debt instruments and power-purchase agreements at FP&L. Adjusted credit metrics in current economic and market conditions support the intermediate financial profile. We expect the adjusted metrics to dip slightly in the near term and then return to historical levels, including funds from operations (FFO) to debt of around 25% and debt to capitalization about 50%.

Liquidity

The short-term rating on FP&L is 'A-2'. The parent manages liquidity (although FP&L has its own sources of liquidity), and we measure it on a consolidated basis. Liquidity is "adequate" under Standard & Poor's corporate liquidity methodology, which categorizes liquidity in five standard descriptors.

Projected sources of liquidity, mostly operating cash flow and available bank lines, exceed its projected uses, mainly necessary capital expenditures, debt maturities, and common dividends, by more than 1.2x. NextEra's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending or sell assets, its sound bank relationships, its solid standing in credit markets, and its generally prudent risk management further support our assessment of its liquidity as adequate.

Debt maturities total about $800 million in the next 12 months. The company has a $6.6 billion master revolving credit facility maturing in 2017 and more than $8 billion in total facilities, with about $4.7 billion currently available.

NextEra manages the liquidity needs of all its subsidiaries.

Liquidity is adequate based on the following factors and assumptions:

- We expect the company's liquidity sources (including FFO and credit facility availability) over the next 12 months to exceed its uses by more than 1.2x.
- Debt maturities over the next year are manageable.
- Even if EBITDA declines by 15%, we believe net sources will be well in excess of liquidity requirements.
- The company has good relationships with its banks, in our assessment, and has a good standing in the credit markets.

In our analysis, based on information available as of Dec. 31, 2011, we assumed liquidity of about $8.9 billion over the next 12 months, consisting of projected FFO and availability under the credit facility. We estimate the company could use up to $7 billion during the same period for capital spending, debt maturities, and shareholder dividends. NextEra's credit agreement includes a financial covenant limiting the consolidated debt-to-capitalization ratio, with which the company was compliant as of June 30, 2011.

Recovery analysis

We assign recovery ratings to FMBs issued by investment-grade U.S. utilities, which can result in issue ratings being notched above an issuer credit rating (ICR) on a utility depending on the rating category and the extent of the collateral coverage. We base our investment-grade FMB recovery methodology on the ample historical record of 100% recovery for secured bondholders in utility bankruptcies and on our view that the factors that supported those recoveries (the limited size of the creditor class, and the durable value of utility rate-based assets during and after a reorganization, given the essential service provided and the high replacement cost) will persist. Under our recovery criteria, when assigning issue ratings to utility FMBs, we consider our calculation of the maximum amount of FMB issuance under the utility's indenture or other legally binding limitations relative to our estimate of the value of the collateral pledged to bondholders, management's stated intentions on future FMB issuance, as well as any regulatory limitations on bond issuance. FMB ratings can exceed an ICR on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories.

FP&L's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+', which indicates our expectation for 100% recovery in a default scenario, and an issue rating one notch above the ICR.

Outlook

Our rating outlook on NextEra and its subsidiaries is stable and reflects a business profile that is equally affected by higher-risk merchant energy activities and a utility that still presents a better credit profile than its peers. We would consider a lower rating if regulatory risk worsened, operational efficiency at NER deteriorated, investment decisions at NER demonstrated a shift in risk appetite, or financial performance declined due to permanent changes in the Florida economy or merchant energy markets. We would consider a higher rating if a dramatic, sustainable shift in Florida's economic, political, and regulatory environment is accompanied by affirmative steps to reduce risk at NER.

We also base the stable outlook in part on Standard & Poor's baseline forecast that NextEra will attain adjusted FFO to debt of about 17% and adjusted debt to capital of about 52% over the near term, with those metrics improving thereafter. Although year-to-year fluctuations in weather (including hurricanes), fuel cost recovery, and burdensome spending on large solar projects may temporarily affect metrics, we expect the company to adapt its financial risk management and the pace of its capital spending to account for these and other factors so it can achieve better metrics. We could lower the ratings if the company falls short of these expectations.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Standard & Poor's Updates Its U.S. Utility Regulatory Assessments, March 12, 2010
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2008
- Criteria: Changes To Collateral Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds, Sept. 6, 2007

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April 24, 2012

Florida Power & Light Co.

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Florida Power & Light Co.

Major Rating Factors

Corporate Credit Rating
A-/Stable/A-2

Strengths:

- High-quality electric utility that generates steady earnings and cash flows;
- Active efforts by the parent to sustainably reduce commodity price risk exposure in highly diversified unregulated activities at the parent;
- Low regulatory risk in Florida and relatively strong service territory with good customer growth prospects and a predominantly residential and commercial base.

Weaknesses:

- Aggressive capital spending plans that stress financial metrics;
- Dependence on natural gas to generate electricity in Florida; and
- Higher-risk operations and less dependable cash flows from merchant generation, energy trading, and other unregulated activities.

Rationale

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Accounting

NextEra's and FP&L's financial statements are prepared under U.S. generally accepted accounting principles and audited by independent auditors Deloitte & Touche LLP, which issued an unqualified opinion. NextEra employs regulatory accounting under Statement of Financial Accounting Standards No. 71 for regulated utility FP&L, which permits the company to defer recognition of certain revenues and expenses in accordance with future probable regulatory decisions. As of Dec. 31, 2011, NextEra had about $1.8 billion of regulatory assets and $4.3 billion of regulatory liabilities on a balance sheet that contained $57 billion of total assets. It is uncommon for a utility to have greater regulatory liabilities than assets.

NextEra relies on tax incentives, including direct tax credits, in NER's project development efforts. Tax credits underpin the economics of the projects, and NextEra guarantees the payment of production tax credits to projects that have been funded by third parties in project financings. Deferred tax assets, in the form of carryforwards of tax credits and net operating losses, have been growing at an accelerated rate on NextEra's balance sheet, totaling about $2.1 billion in 2011. To realize these tax benefits, the company must, among other things, continue to produce growing taxable income to use the carryforwards. If the deferred tax asset grows unabated, we could make an analytical adjustment in our metric calculation if we eventually conclude that the company is unlikely to fully realize the tax benefit.

In analyzing the company's financial profile, Standard & Poor's makes several off-balance-sheet adjustments that are shown in the reconciliation table below. We treat NER's fossil-fuel-based projects as nonessential to the company's strategy. We remove the nonrecourse debt and related interest in our adjusted numbers. However, we consider the renewables portfolio to be an integral part of its growth strategy, so we deconsolidate only 75% of related nonrecourse project debt and interest in our adjustments. In addition, we remove associated effects on the reported income and cash flow statements and replace them with the pro rata share of actual distributable cash flow of the projects. Credit metrics fully reflect debt related to projects under construction and subject to completion guarantees. As of year-end 2011, we removed approximately $4 billion of nonrecourse debt from the balance sheet.

Other adjustments include a reduction in debt and interest expense for storm recovery bonds issued to securitize hurricane damage costs (which the company services through a separate, non-bypassable, legislatively mandated rate mechanism) and adjustments to reflect the equity treatment on hybrid debt securities in accordance with our criteria on hybrid capital. We add about $166 million of a debt-like obligation to the balance sheet to quantitatively capture the risks associated with proprietary trading activities. Also, we regard purchased-power agreements as fixed obligations and assign a portion of the value of the payments based on the risk factor as debt and impute an associated interest charge in calculating the adjusted coverage ratios. We use a 25% risk factor, reflecting the recovery of these costs through an adjustment clause, and apply a discount rate equal to the utility's average cost of debt to the fixed capacity payments. We impute a debt-like obligation of approximately $950 million to the balance sheet.

Rating Methodology

We base our ICRs on NextEra, FP&L, and Holdings on the consolidated credit profile of the entire NextEra conglomerate of companies, which is almost equally influenced by the utility and unregulated energy operations. We rate the unsecured debt at Holdings, which is unconditionally guaranteed by the parent and is effectively holding company debt, one notch below the ICR because of structural subordination. Although Holdings' debtholders would have access to assets apart from the utility in liquidation, we apply strict notching guidelines because of the extensive use of project-level debt and the complexity of the financing arrangements throughout Holdings. We rate the first mortgage bonds at FP&L one notch above the ICR in accordance with the recovery analysis detailed above.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Standard & Poor's Updates Its U.S. Utility Regulatory Assessments, March 12, 2010
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2008
- Criteria: Changes To Collateral Requirements For '1+' Recovery Ratings On U.S. Utility First Mortgage Bonds, Sept. 6, 2007

Table 1

NextEra Energy Inc. -- Peer Comparison

Industry Sector: Energy					
	NextEra Energy Inc.	**Entergy Corp.**	**Dominion Resources Inc.**	**Public Service Enterprise Group Inc.**	**Exelon Corp.**
Rating as of April 24, 2012	A-/Stable/--	BBB/Negative/--	A-/Stable/A-2	BBB/Positive/A-2	BBB/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	15,119.7	11,082.1	14,902.3	11,423.0	17,904.0
EBITDA	4,396.8	3,529.7	4,699.9	3,731.9	6,734.6

Table 1

NextEra Energy Inc. -- Peer Comparison (cont.)					
Net income from cont. oper.	1,824.5	1,296.2	1,886.0	1,514.3	2,588.0
Funds from operations (FFO)	3,897.7	3,171.3	3,299.8	2,788.6	5,912.1
Capital expenditures	3,948.2	2,707.2	3,601.2	1,979.6	3,700.0
Free operating cash flow	(58.2)	517.1	(495.7)	977.0	2,013.5
Dividends paid	920.8	600.3	1,150.5	686.3	1,396.5
Discretionary cash flow	(979.0)	(83.2)	(1,646.2)	290.7	617.0
Cash and short-term investments	305.7	1,232.8	70.7	469.6	1,556.0
Debt	15,887.2	13,687.4	19,263.1	8,858.2	18,717.7
Preferred stock	1,427.5	150.4	996.6	26.7	198.0
Equity	15,918.8	8,840.8	12,637.4	9,380.4	13,728.3
Debt and equity	31,806.0	22,528.2	31,900.5	18,238.6	32,446.0
Adjusted ratios					
EBITDA margin (%)	29.1	31.9	31.5	32.7	37.6
EBIT interest coverage (x)	3.9	3.2	3.6	6.5	5.7
Return on capital (%)	7.8	8.7	10.5	14.3	14.1
FFO int. cov. (X)	6.7	4.5	4.1	6.7	7.2
FFO/debt (%)	24.5	23.2	17.1	31.5	31.6
Free operating cash flow/debt (%)	(0.4)	3.8	(2.6)	11.0	10.8
Discretionary cash flow/debt (%)	(6.2)	(0.6)	(8.5)	3.3	3.3
Net cash flow/capex (%)	75.4	95.0	59.7	106.2	122.0
Debt/EBITDA (x)	3.6	3.9	4.1	2.4	2.8
Total debt/debt plus equity (%)	50.0	60.8	60.4	48.6	57.7
Return on capital (%)	7.8	8.7	10.5	14.3	14.1
Return on common equity (%)	12.5	13.8	15.7	16.5	19.5
Common dividend payout ratio (un-adj.) (%)	45.8	46.2	53.3	45.4	58.2

Table 2

NextEra Energy Inc. -- Financial Summary					
Industry Sector: Energy					
	--Fiscal year ended Dec. 31--				
	2011	**2010**	**2009**	**2008**	**2007**
Rating history	A-/Stable/--	A-/Stable/--	A/Stable/--	A/Stable/--	A/Stable/--
(Mil. $)					
Revenues	14,926.7	15,009.0	15,423.4	15,983.2	14,861.5
EBITDA	4,199.8	4,804.3	4,186.3	3,882.5	3,281.7
Net income from continuing operations	1,923.0	1,935.5	1,615.0	1,436.2	1,263.3
Funds from operations (FFO)	3,817.2	3,596.3	4,279.6	3,185.5	3,558.6
Capital expenditures	5,937.4	2,970.2	2,937.2	2,273.2	1,875.9
Dividends paid	1,022.3	905.0	835.1	772.5	700.1
Debt	17,943.5	15,214.5	14,503.5	13,798.8	10,770.2

Table 2

NextEra Energy Inc. -- Financial Summary (cont.)					
Preferred stock	1,929.5	1,176.5	1,176.5	1,005.0	1,004.5
Equity	16,872.5	16,390.5	14,493.5	12,686.0	11,739.5
Debt and equity	34,816.0	31,605.0	28,997.0	26,484.8	22,509.7
Adjusted ratios					
EBITDA margin (%)	28.1	32.0	27.1	24.3	22.1
EBIT interest coverage (x)	3.8	4.4	3.5	3.5	3.2
FFO int. cov. (x)	6.3	6.4	7.4	5.8	6.3
FFO/debt (%)	21.3	23.6	29.5	23.1	33.0
Discretionary cash flow/debt (%)	(18.7)	(0.1)	3.0	1.4	9.2
Net cash flow/capex (%)	47.1	90.6	117.3	106.2	152.4
Debt/debt and equity (%)	51.5	48.1	50.0	52.1	47.8
Return on capital (%)	7.2	8.6	7.5	8.3	8.4
Return on common equity (%)	12.0	13.5	12.1	11.7	11.5
Common dividend payout ratio (un-adj.) (%)	47.8	42.5	47.4	50.3	51.8

Table 3

Reconciliation Of NextEra Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

--Fiscal year ended Dec. 31, 2011--

NextEra Energy Inc. reported amounts

	Debt	Shareholders' equity	Revenues	EBITDA	Operating income	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	22,967.0	14,943.0	15,341.0	4,996.0	3,378.0	1,035.0	4,074.0	4,074.0	920.0	6,004.0
Standard & Poor's adjustments										
Equity-like hybrids	(753.0)	753.0	--	--	--	(20.3)	20.3	20.3	20.3	--
Intermediate hybrids reported as debt	(1,176.5)	1,176.5	--	--	--	(82.0)	82.0	82.0	82.0	--
Postretirement benefit obligations	--	--	--	(121.0)	(121.0)	--	52.7	52.7	--	--
Capitalized interest	--	--	--	--	--	124.0	(124.0)	(124.0)	--	(124.0)
Share-based compensation expense	--	--	--	49.0	--	--	--	--	--	--
Nonrecourse debt	(3,993.0)	--	(343.0)	(343.0)	(343.0)	(343.0)	--	--	--	--
Securitized utility cost recovery	(487.0)	--	(71.3)	(71.3)	(26.3)	(26.3)	(45.0)	(45.0)	--	--
Power purchase agreements	922.0	--	--	105.1	47.8	47.8	57.4	57.4	--	57.4
Reclassification of nonoperating income (expenses)	--	--	--	--	211.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	207.0	--	--

Table 3

Reconciliation Of NextEra Energy Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)										
US decommissioning fund contributions	--	--	--	--	--	--	(92.0)	(92.0)	--	--
Debt - Accrued interest not included in reported debt	464.0	--	--	--	--	--	--	--	--	--
EBITDA - Other	--	--	--	(415.0)	(415.0)	--	--	--	--	--
D&A - Impairment charges/(reversals)	--	--	--	--	51.0	--	--	--	--	--
FFO - Other	--	--	--	--	--	--	(415.0)	(415.0)	--	--
Total adjustments	(5,023.5)	1,929.5	(414.3)	(796.2)	(595.5)	(299.7)	(463.8)	(256.8)	102.3	(66.6)

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	17,943.5	16,872.5	14,926.7	4,199.8	2,782.5	735.3	3,610.2	3,817.2	1,022.3	5,937.4

Ratings Detail (As Of April 24, 2012)	
Florida Power & Light Co.	
Corporate Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Corporate Credit Ratings History	
11-Mar-2010	A-/Stable/A-2
14-Jan-2010	A/Watch Neg/A-1
26-Oct-2006	A/Stable/A-1
Business Risk Profile	Excellent
Financial Risk Profile	Intermediate
Debt Maturities	
(For parent) 2012: $808 mil. 2013: $2.4 bil. 2014: $2.0 bil. 2015: $1.8 bil. 2016: $695 mil.	
Related Entities	
FPL Group Capital Trust I	
Preferred Stock	BBB
NextEra Energy Capital Holdings Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated	BBB
Senior Unsecured	BBB+

Ratings Detail (As Of April 24, 2012) **(cont.)**	
NextEra Energy Inc.	
Issuer Credit Rating	A-/Stable/--

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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Summary:

Florida Power & Light Co.

Corporate Credit Rating	A-/Stable/A-2

Profile Assessments

BUSINESS RISK	EXCELLENT	Vulnerable — Excellent
FINANCIAL RISK	INTERMEDIATE	Highly leveraged — Minimal

Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• High-quality electric utility that generates steady earnings and cash flows • Low regulatory risk in Florida • Relatively strong service territory with good customer growth prospects and a predominantly residential and commercial base • Unregulated merchant energy activities at parent detract from consolidated business risk profile despite active efforts to reduce commodity price risk • Diversification in and among parent's competitive energy businesses offsets some of the weakness they bring to the credit profile • Aggressive capital spending plans depress financial measures • Dependence on natural gas to generate electricity in Florida could raise regulatory risk in a rising price environment	• Credit meassure only marginally support our assessment of the financial risk profile, but we project improvement • High capital spending and substantial common dividends create a persistent condition of negative discretionary cash flow that highlights reliance on external funding

Outlook: Stable

Our rating outlook on NextEra Energy Inc. (NextEra) and subsidiaries is stable and reflects a business profile that is almost equally affected by higher-risk merchant energy activities and a utility that presents a better credit profile than its peers. We would consider a lower rating if regulatory risk worsened, operational efficiency deteriorated, investment decisions demonstrated a shift in risk appetite, or financial performance declined due to fundamental changes in the Florida economy or merchant energy markets. We would consider a higher rating if a strengthened balance sheet supported durably improved credit measures and were accompanied by further steps to reduce exposure to higher-risk business activities.

We also base the stable outlook in part on Standard & Poor's baseline forecast that NextEra will experience improved bondholder protection measures, attaining adjusted funds from operations (FFO) to debt approaching 20% and adjusted debt to capital of about 52% over the near term, with modest improvement thereafter. Although year-to-year fluctuations in weather (including hurricanes), fuel cost recovery, and burdensome spending on renewables projects could temporarily affect measures, we expect the company to adapt its financial risk management and the pace of its capital spending to account for these and other factors so it can achieve better measures.

Downside scenario

We could lower ratings if financial measures do not improve and we think they will remain resiliently at less-supportive levels, including a FFO to debt ratio of less than 20%.

Upside scenario

We could raise ratings if cash flow measures considerably improve, such as FFO to debt of 25% on a sustained basis. In addition, we would expect debt to EBITDA of less than 3x and debt leverage of less than 50%.

Standard & Poor's Base-Case Scenario

Our base case scenario is based on healthy EBITDA growth from both sides of the business, growing capital spending, and stable debt leverage.

Assumptions	Key Metrics
Mid-single-digit base (excludes rate rider recovery) growth in EBITDA for the next three years Timely cost recovery through various rate surcharge mechanisms that helps Florida Power & Light Co. (FPL) achieve returns in the high end of the authorized range. High dividend and capital spending that results in negative discretionary cash flow, resulting in external funding requirements Annual capital spending forecasted to average $6 billion over next three years	(see table below)

	2012A	2013E	2014E
FFO/Debt	18.7%	20%-22%	22%-25%
Debt/EBITDA	5.1x	4x-5x	4x-4.5x
Total Debt/Total Capital	52.7%	52%-54%	50%-52%

Standard & Poor's adjusted consolidated financial ratios for NextEra include adjustments for nonrecourse debt, hybrid securities, long-term purchased power obligations, operating leases, pension-related items, accrued interest not included in reported debt, and asset retirement obligations. We also consider in our credit analysis, but do not publish, confidential adjustments to cash flow measures that account for the difference between the estimated distributions derived from projects with nonrecourse debt and the accounting-based cash flow measures related to those projects. A--Actual. E--Estimate.

Business Risk: Excellent

A mix of regulated and unregulated energy operations

FPL's credit fundamentals have been among the strongest in the U.S., due primarily to low regulatory risk and an attractive service territory with healthy economic growth and a sound business environment. Both of those long-standing pillars were shaken a few years ago as Florida, and the FPL service territory in particular, suffered during the recession, and regulators responded in ways that reflected greater political influence over regulatory decisions. Actions to rebuild its regulatory risk profile have been effective, and we now regard the regulatory status quo as almost fully restored.

FPL has managed regulatory risk, the most important risk a utility faces, well. Despite a slight rise in regulatory risk in reaction to weak economic conditions, the company has now positioned the utility for improved financial performance, especially its cash-based credit measures, amid a stabilized regulatory environment and an actively managed effort to reduce regulatory risk. A December 2012 rate decision, a product of a settlement among most major intervenors, authorizes higher base rates through the end of 2016 and discrete rate increases for major generation additions (offset by fuel savings). We project that FPL will be able to earn equity returns over the four-year agreement that approach the upper end of the authorized 9.5%-to-11.5%, with a greater proportion of those returns in cash despite the need to amortize purported excess depreciation reserves over this time.

Reflected in the business risk profile is our assessment of the company's management and governance as

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FPL RC-16

"satisfactory". We expect management to execute its strategy to expand both utility and merchant operations in a credit-supportive manner that helps maintain our business risk profile assessment.

Financial Risk: Intermediate

Large capital expenditures and improving measures

We call the consolidated financial risk profile "intermediate", reflecting adjusted financial measures that are in line with the rating. This assessment incorporates large capital expenditures. We consider the company's financial policies to be aggressive. The complicated balance sheet contributes to a moderately opaque financial picture that requires extensive adjustments and judgments to accurately assess financial risk. Elevated capital spending and dividend payments translate to negative discretionary cash flow over the forecast period, requiring management to maintain financial discipline and vigilant cost control to maintain cash flow measures. The negative discretionary cash flow also points to external funding needs. Adjusted credit measures in current economic and market conditions support the intermediate financial profile. We expect the adjusted measures to dip slightly in the near term and then return to historical levels, including FFO to debt of more than 20% and debt to capitalization about 50%.

Liquidity: Adequate

Liquidity, measured on a consolidated basis, is considered "adequate" under our liquidity methodology. We expect liquidity sources over the next 12 months will exceed its uses by more than 1.2x. We expect NextEra will need to access the capital markets over the next few years to meet its liquidity needs, particularly for debt maturities and capital spending. In our assessment, NextEra has good relationships with its banks and has a good standing in the credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
• FFO of about $5 billion for the next 12 months • Assumed credit facility availability of about $4.9 billion for the next 12 months • Working capital and cash of $300 million for the next 12 months	• Debt maturities of about $2.8 million for the next 12 months • Capital spending of at least $4.2 billion for the next 12 months • Cash dividends of $1.1 billion for the next 12 months

Covenant Analysis

As of Dec. 31, 2012, the company had an adequate cushion of compliance with its one financial covenant (debt to total capitalization at or below a stated ratio). Headroom could erode if debt rises rapidly without adequate growth in equity during this capital spending phase.

Recovery Analysis

We assign recovery ratings to first mortgage bonds (FMBs) issued by U.S. utilities, which can result in issue ratings being notched above a utility's corporate credit rating (CCR) depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of "secured utility bond" (SUB) that qualify for a recovery rating as defined in our criteria (see "Collateral Coverage and Issue Notching Rules for '1+' and '1' Recovery Ratings on Senior Bonds Secured by Utility Real Property", published Feb. 14, 2013)

The recovery methodology is supported by the ample historical record of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhanced those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist in the future.

Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed a utility's CCR by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories depending on the calculated ratio.

FPL's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of 1+ and an issue rating one notch above the CCR.

Related Criteria And Research

- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- 2008 Corporate Ratings Criteria: Ratios And Adjustments, April 15, 2008
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

Business And Financial Risk Matrix

	Financial Risk					
Business Risk	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA/AA+	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	B- or below

Note: These rating outcomes are shown for guidance purposes only. The ratings indicated in each cell of the matrix are the midpoints of the likely rating possibilities. There can be small positives and negatives that would lead to an outcome of one notch higher or lower than the typical matrix outcome. Moreover, there will be exceptions that go beyond a one-notch divergence. For example, the matrix does not address the lowest rungs of the credit spectrum (i.e., the 'CCC' category and lower). Other rating outcomes that are more than one notch off the matrix may occur for companies that have liquidity that we judge as "less than adequate" or "weak" under our criteria, or companies with "satisfactory" or better business risk profiles that have extreme debt burdens due to leveraged buyouts or other reasons. For government-related entities (GREs), the indicated rating would apply to the standalone credit profile, before giving any credit for potential government support.

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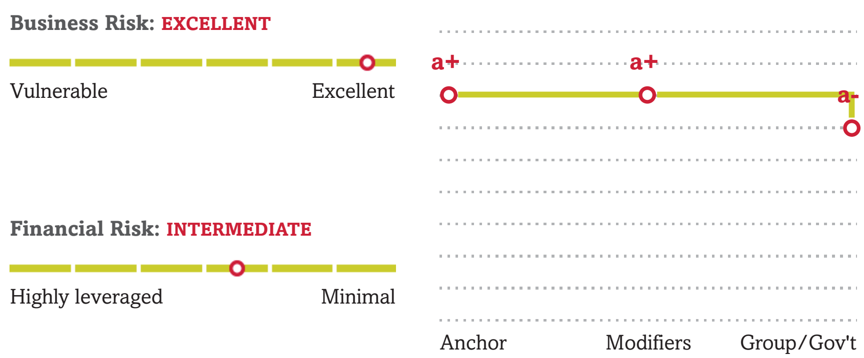
Summary:

Florida Power & Light Co.



CORPORATE CREDIT RATING

A-/Stable/A-2

Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• Regulated utility operations under generally constructive regulatory framework. • Large service territory with above-average growth but lacking geographic and regulatory diversity. • Efficient operations with material exposure to gas-fired generation. • Exposure to severe weather events that can strain liquidity and present operating challenges.	• Core credit ratios support an "intermediate" financial risk profile assessment. • Large capital spending program with predictable recovery.

OPC 008060
FPL RC-16

Outlook: Stable

The outlook on Florida Power & Light Co. (FPL) is stable and is based on the outlook of its parent, NextEra Energy Inc. (NEE). The stable rating outlook on NextEra and its subsidiaries, Florida Power & Light Co. and NextEra Energy Capital Holdings Inc., reflects our expectation that the company will preserve its "strong" business risk profile while ensuring that its financial risk profile remains well within the "intermediate" category at all times, albeit toward the lower end of the category. The stable outlook is also predicated on the company effectively managing its growth and capital spending so that regulated operations continue to contribute about 60% of operating income. Finally, the stable outlook anticipates that NextEra will fund the proposed merger with Hawaiian Electric Industries in a credit-neutral manner, while receiving approval to close the merger without any restrictive regulatory provisions or requirements.

Downside scenario

We could lower the ratings on NextEra and its subsidiaries if financial performance weakens, with funds from operations (FFO) to debt that declines to less than 25% on a consistent basis, absent any reduction of business risk. Moreover, we could lower the ratings on NextEra if business risk increases through the growing contribution of unregulated operations or unfavorable regulatory outcomes.

Upside scenario

Under our base-case scenario, we do not anticipate raising the ratings on NextEra and its subsidiaries in the next 12 to 24 months, given the company's business risk profile and expected level of financial performance.

Standard & Poor's Base-Case Scenario

Assumptions

- We assume that FPL's gross margins grow by an average of 4% to 6% annually, reflecting recovery of invested capital and the impact of load/customer growth.
- Capital spending of about $3.5 billion in 2015, about $4 billion in 2016, and about $3.6 billion in 2017.

Key Metrics

	2014A	2015E	2016E
FFO/debt (%)	34.1	34-35	34-35
Debt/EBITDA (x)	2.4	2-2.5	2–2.5
OCF/debt (%)	31.1	34-35	34–35

A--Actual. E—Estimate. FFO—Funds from operations. OCF—Operating cash flow.

Business Risk: Excellent

We assess FPL's business risk profile as "excellent," accounting for the company's regulated utility operations that benefit from a constructive regulatory framework, which provides for timely investment and fuel cost recovery. FPL has historically managed its regulatory risk effectively, resulting in earned returns that are consistently close to or at

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the authorized levels. The service territory is large and lacks geographic and regulatory diversity. FPL's customer base is large, with no meaningful industrial exposure and above-average growth. The company has material exposure to natural gas-fired generation, which, in combination with low natural gas prices and the company's efficient operations, contributes to overall competitive rates for its customers.

Financial Risk: Intermediate

We assess FPL's financial risk profile as being in the "intermediate" category using the medial volatility financial ration benchmarks. Under our base-case scenario we expect that FPL's financial profile will benefit largely from recovery of invested capital and load/customer growth, with FFO to debt that averages about 33% over the next few years and debt to EBITDA that remains consistently below 2.5x.

FPL's "excellent" business and "intermediate" financial risk profiles lead to an anchor of 'a+/a'. We select the 'a+' anchor because we view FPL's business risk profile as being at the upper end of the "excellent" category, relative to its peers.

Liquidity: Adequate

Because we view FPL as a "core" subsidiary of NextEra, we assess its liquidity on a consolidated basis with that of its parent. We assess NextEra's liquidity as "adequate" to cover its needs over the next 12 months. We expect that the company's liquidity sources will exceed its uses by 1.1x or more, the minimum threshold for an "adequate" designation under our criteria and that the company will also meet our other criteria for such a designation.

NextEra has $7.85 billion in revolving credit facilities, with $1.25 billion maturing in 2016 and the balance maturing in 2020. In addition, the company has a $270 million revolving credit facility and a $650 million letter-of-credit facility.

Principal Liquidity Sources	Principal Liquidity Uses
• Available credit facilities total about $7.5 billion; and • FFO of $6.8 billion to $7 billion annually.	• Debt maturities and outstanding commercial paper totaling about $4.7 billion in 2015 and debt maturities of about $1.3 billion in 2016; • Maintenance capital spending of about $5.5 billion in 2015 and about $6.7 billion in 2016; and • Dividends of about $1.4 billion to $1.6 billion annually.

Other Credit Considerations

Our assessment of modifiers does not affect the anchor score.

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FPL RC-16

Group Influence

FPL is subject to our group rating methodology criteria. We assess FPL as a "core" subsidiary of NextEra because it is highly unlikely to be sold, is integral to the group's overall strategy, possesses significant management commitment, is a significant contributor to the group, and is closely linked to the parent's reputation. As a result, the issuer credit rating on FPL is 'A-', in line with the 'a-' group credit profile of NextEra.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: a+

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a+

- **Group credit profile:** a-
- **Entity status within group:** Core (-2 notches from SACP)

Recovery Analysis/Issue Ratings

We assign recovery ratings to first-mortgage bonds (FMB), which, depending on the rating category and the extent of the collateral coverage, can result in issue ratings being notched above a corporate credit rating on a utility. The FMBs issued by U.S. utilities are a form of "secured utility bond" (SUB) that qualify for a recovery rating as defined in our criteria (see "Collateral Coverage And Issue Notching Rules for '1+' And '1' Recovery Ratings on Senior Bonds Secured by Utility Real Property," published Feb. 14, 2013).

The recovery methodology is supported by the ample historical record of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhanced those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist.

Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed an issuer credit rating on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories, depending on the calculated ratio.

FPL's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of over 3x supports a recovery rating of '1+' and an issue rating one notch above the ICR.

We rate FPL's commercial paper program 'A-2', accounting for the issuer credit rating on the company and our assessment of consolidated liquidity as "adequate".

Related Criteria And Research

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Collateral Coverage And Issue Notching Rules For ‘1+’ And ‘1’ Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

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Research Update:

NextEra Energy Ratings Affirmed, Hawaiian Electric Industries And Subsidiary Ratings On Watch Positive On Acquisition

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Research Update:

NextEra Energy Ratings Affirmed, Hawaiian Electric Industries And Subsidiary Ratings On Watch Positive On Acquisition

Overview

- NextEra Energy Inc. (NextEra) has announced that it has entered into an agreement to acquire Hawaiian Electric Industries Inc. (HEI) in a stock for stock transaction. As part of the transaction, HEI will spin off its banking operations, American Savings Bank FSB Honolulu HI (ASB), to existing shareholders by the close of the transaction.
- We are affirming the 'A-' issuer credit rating on NextEra and its subsidiaries, Florida Power & Light Co. and NextEra Energy Capital Holdings, Inc. The outlook remains stable.
- We are placing the 'BBB-' issuer credit rating on HEI and Hawaiian Electric Co. (HECO) on CreditWatch with positive implications.
- The outlook on NextEra is stable, reflecting our expectation that the company will preserve its "strong" business risk profile while ensuring that its financial risk profile remains well within the "intermediate" category at all times.

Rating Action

On Dec. 4, 2014, Standard & Poor's Ratings Services affirmed its issuer credit ratings on NextEra and its subsidiaries, Florida Power & Light Co. and NextEra Energy Capital Holdings Inc., while maintaining the stable outlook. At the same time, we placed our issuer credit ratings on Hawaiian Electric Industries Inc. and Hawaiian Electric Co. on CreditWatch with positive implications. The rating actions follow NextEra's announcement that it has entered into an agreement to acquire Hawaiian Electric Industries while spinning off that company's banking operations by the close of the transaction.

Rationale

NextEra has entered into an agreement to acquire HEI in a stock for stock transaction while assuming HEI's existing debt obligations totaling about $1.7 billion. HEI's bank operations are to be spun off by the close of the transaction, which we expect could be by year-end 2015.

We are affirming the ratings on NextEra based on the company's strong business and intermediate financial risk profiles. Our assessment of NextEra's business risk profile incorporates the impact of HEI upon the close of the transaction. We view the addition of HEI as modestly enhancing NextEra's currently "strong" business risk profile, without moving it to the "excellent" business risk profile category. This is because HEI's credit profile is considerably weaker than NextEra's; HEI's contribution to NextEra's operating income and cash flow will remain modest; and finally, because we view HEI as needing considerable support in order to improve its regulatory and operational performance and track record. Although there is potential for HEI to benefit from its affiliation with NextEra, we also think that any such improvements are likely to occur over time, especially given NextEra's lack of operating experience in Hawaii and the jurisdiction's historically challenging regulatory and operating environment. We view the proposed spinoff of HEI's banking operations as a neutral development regarding NextEra's business risk profile. Under the proposed transaction, ASB will be spun off to existing HEI shareholders by the close of the transaction.

In light of the level of NextEra's investment in HEI, NextEra's proposed method of funding the acquisition, opportunities for growth, and stated commitment from management, we assess HEI and HECO as "core" subsidiaries of NextEra. As a result, upon the close of the transaction, we expect to raise our issuer credit ratings on HEI and HECO to be aligned with that of ultimate parent NextEra.

We assess NextEra's financial risk profile as being in the "intermediate" category using the medial volatility financial ratio benchmarks. Under our base case scenario, we project that the company will maintain credit protection measures that remain well within the intermediate financial risk profile category, with FFO to debt of about 26% on a consistent basis after the close of the transaction.

Our base case scenario assumes:
- Operating income grows in the high single digits annually, benefiting from recent regulated investment recovery, transmission investment recovery, the growth of the renewable energy business, and the acquisition of HEI;
- Capital spending of about $7.5 billion to $8 billion annually over the next few years; and
- Dividends grow at about 10% annually.

Based on these assumptions, we arrive at the following credit measures:
- FFO to debt of about 26% annually over the next few years, and
- Debt to EBITDA that remains under 3.5x.

Liquidity

In our opinion, NextEra's liquidity is "adequate" to cover its needs over the next 12 to 18 months. We expect that the company's liquidity sources will exceed its uses by 1.1x or more, the minimum threshold for an adequate designation under our criteria and that the company will also meet our other criteria for such a designation.

NextEra has $7.85 billion in revolving credit facilities with $1.25 billion maturing in 2016 and the balance maturing in 2019.

Principal liquidity sources:

- We estimate FFO of about $6 billion annually in 2014 and 2015, and
- Average undrawn availability under the credit facilities of about $6.5 billion.

Principal liquidity uses:

- Maintenance capital spending averaging about $5.5 billion annually,
- Debt maturities of $3.766 billion in 2014 and $2.42 billion in 2015, and
- Dividends of about $1.3 billion annually.

Outlook

The stable rating outlook on NextEra and its subsidiaries reflects our expectation that the company will preserve its "strong" business risk profile while ensuring that its financial risk profile remains well within the "intermediate" category at all times, albeit toward the lower end of the category. Moreover, the stable outlook incorporates our expectation that NextEra will continue to effectively manage regulatory risk at its regulated utility operations in Florida while ensuring that regulated businesses contribute the majority of cash from operations.

Downside scenario

We would lower the ratings on NextEra if financial performance weakens, with FFO to debt that declines to less than 25% on a consistent basis, absent any lessening of business risk. Moreover, we would lower the ratings on NextEra if business risk increases through the growing contribution of unregulated operations or due to unfavorable regulatory outcomes.

Upside scenario

Under our base case scenario, we do not anticipate raising the ratings on NextEra in the next 12 to 24 months, given the company's business risk profile and expected level of financial performance.

Other Modifiers

We assess all modifiers as "neutral" resulting in no further changes to NextEra's 'a-' anchor score.

Group Influence

NextEra is subject to the group rating methodology criteria, under which we assess NextEra as the parent of the group. NextEra's group credit profile is 'a-' and leads to an issuer credit rating of 'A-'.

We assess the status of NextEra's subsidiaries, Florida Power & Light Co. and NextEra Energy Capital Holdings Inc., as core subsidiaries because we view them as integral to the group's identity, they are highly unlikely to be sold, and have strong management commitment given the company's emphasis on maintaining the size and scope of the regulated utility operations relative to unregulated operations. Because there are no structural or regulatory insulation provisions in place that could restrict NextEra's access to the assets and cash flows of its subsidiaries, the issuer credit rating on each subsidiary is 'A-', based on the group credit profile of NextEra.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/--
Business risk: Strong
- Country risk: Very low
- Industry risk: Low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/Leverage: Intermediate

Anchor: a-

Modifiers
- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-

- Group credit profile: a-
- Rating above the sovereign: (no impact)

Related Criteria And Research

Related Criteria
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Jan. 2, 2014
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Criteria - Corporates - Utilities: Collateral Coverage and Issue Notching Rules for ‘1+’ and ‘1’ Recovery Ratings on Senior Bonds Secured by Utility Real Property, Feb. 14, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013

- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Ratings List

Ratings Affirmed

NextEra Energy Inc.		
Corporate Credit Rating	A-/Stable/--	
Florida Power & Light Co.		
NextEra Energy Capital Holdings Inc.		
Corporate Credit Rating	A-/Stable/A-2	
NextEra Energy Inc.		
Senior Unsecured	BBB	
FPL Group Capital Trust I		
Preferred Stock	BBB	
Florida Power & Light Co.		
Senior Secured	A	
Recovery Rating	1+	
Preferred Stock	BBB	
Commercial Paper	A-2	
NextEra Energy Capital Holdings Inc.		
Senior Unsecured	BBB	
Senior Unsecured	BBB+	
Junior Subordinated	BBB	
Commercial Paper	A-2	
Placed On CreditWatch		
	To	From
Hawaiian Electric Industries Inc.		
Hawaiian Electric Co.		
Corporate Credit Rating	BBB-/WatchPos/A-3	BBB-/Stable/A-3
Commercial Paper	A-3/WatchPos	A-3

Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

Florida Power & Light Company
Docket No. 160021-EI
OPC's First Request for Production of Documents
Request No. 35
Page 1 of 1

QUESTION:
Capital Structure Correspondence. Please provide any e-mails or other written documentation from the past 4 years written by NextEra Energy or Florida Power & Light officials where capital structure was discussed.

RESPONSE:
FPL defines NEE "official" as Jim Robo and direct reports, and FPL "official" as Eric Silagy and direct reports. FPL has no responsive documents.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 62
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QUESTION:
Regarding Dewhurst at 5:10-11, 9:1. Please provide and identify all documents prepared by or for FPL in the past four years but prior to March 15, 2016 that discuss or analyze how increasing, decreasing or maintaining FPL's equity ratio would affect its "total cost of capital." If there are no such documents, please so state.

RESPONSE:
FPL does not have any responsive documents. The actual total cost of capital is not a function of such simple assumption changes, nor are such analyses practical.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 65
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QUESTION:
Regarding Dewhurst at 5:10-11, 16:7-18. Please provide and identify all documents prepared by or for FPL in the past four years but prior to March 15, 2016 that discuss or analyze how FPL's equity ratio affected its credit ratings. If there are no such documents, please so state.

RESPONSE:
Please see FPL's response to SFHHA's Second Set of Interrogatories No. 55. FPL does not have any responsive documents, nor would FPL have had the opportunity to create such documents. The question misunderstands the nature of discussions with the rating agencies.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Second Set of Interrogatories
Interrogatory No. 55
Page 1 of 1

QUESTION:
Regarding Dewhurst at 5:10-11 and 8:13-21. Please explain the process by which FPL determines what capital structure to employ on a going forward basis, including identifying the departments, office, and committees that are involved in that process and the material typically reviewed during such process. If FPL does not employ any processes for determining its target capital structure, please so state.

RESPONSE:
FPL does not utilize a formal, structured process; rather, consideration of FPL's capital structure is part of normal, ongoing capital planning and capital management. Capital structure is reviewed and considered at least once a year in conjunction with capital needs and meetings with rating agencies. Decisions are made jointly by the CEO of FPL and the CFO, with primary input from the Treasurer and VP of Finance and secondary input from Corporate Development. Inputs include the state of the capital market, the company's capital expenditure profile, rating agency input, investor input, and potential liquidity needs. There are no committees. Material typically reviewed includes financial plans, capital expenditure plans, credit metric analyses, and competitive analyses.

QUESTION:
Regarding Dewhurst at 16:7-17:2. Please provide and identify all documents prepared by or for FPL in the past four years but prior to March 15, 2016 that discuss the costs and the benefits of improving FPL's financial strength. If there are no such documents, please so state.

RESPONSE:
Please see FPL’s response to SFHHA’s Second Set of Interrogatories No. 55. FPL does not have any responsive documents.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 67
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QUESTION:
Regarding Dewhurst at 16:7-17:2. Please provide and identify all documents prepared by or for FPL in the past four years but prior to March 15, 2016 that discuss the costs and benefits of FPL maintaining its current credit rating. If there are no such documents, please so state.

RESPONSE:
Please see FPL's response to SFHHA's Second Set of Interrogatories No. 55. FPL does not have any responsive documents.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 60
Page 1 of 1

QUESTION:
Regarding Dewhurst at 3:14-15, 5:10-11, 8:13-17:16. Please provide and identify any documents describing FPL's target capital structure in the past four years. If there are no such documents, please so state.

RESPONSE:
FPL does not have any documents responsive to this request.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 62
Page 1 of 1

QUESTION:
Regarding Dewhurst at 5:10-11, 9:1. Please provide and identify all documents prepared by or for FPL in the past four years but prior to March 15, 2016 that discuss or analyze how increasing, decreasing or maintaining FPL's equity ratio would affect its "total cost of capital." If there are no such documents, please so state.

RESPONSE:
FPL does not have any responsive documents. The actual total cost of capital is not a function of such simple assumption changes, nor are such analyses practical.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 64
Page 1 of 1

QUESTION:
Regarding Dewhurst at 5:10-11, 16:7-18. Please provide and identify all documents prepared by or for FPL in the past four years but prior to March 15, 2016 that discuss or analyze how FPL's equity ratio affected its "financial strength" or access to capital. If there are no such documents, please so state.

RESPONSE:
Please see FPL's response to SFHHA's Second Set of Interrogatories No. 55. FPL does not have any responsive documents.

Florida Power & Light Company
Docket No. 160021-EI
FIPUG's First Set of Interrogatories
Interrogatory No. 3
Page 1 of 1

QUESTION:
Please identify all vertically integrated electric utilities that presently have an approved equity ratio of 59.6% based on investor sources.

RESPONSE:
FPL does not track and therefore is not able to provide this information. Further, given the variance in risk factors across companies and geographic locations, this information would not be useful or appropriate without the proper analysis of the relevant risk factors.

Florida Power & Light Company
Docket No. 160021-EI
FIPUG's First Request for Production of Documents
Request No. 2
Page 1 of 1

QUESTION:
Please produce all Orders approving an equity ratio comparable to 59.6% for an electric utility identified in Response to FIPUG Interrogatory No. 3.

RESPONSE:
FPL has no responsive documents.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 61
Page 1 of 1

QUESTION:
Regarding Dewhurst at 5:10-11, 8:17-18. Please provide FPL's study of the capital structures employed by "other financially strong utilities" performed prior to March 15, 2016. If there is none, please so state.

RESPONSE:
FPL has no specific analysis, however other capital structures are reviewed within the context of determining FPL's ongoing capital structure.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 63
Page 1 of 1

QUESTION:
Regarding Dewhurst at 15:16-16:18. Please provide copies of all studies that compare the financial strength of FPL to that of other U.S. electric utilities, including the associated data and work papers used in their preparation.

RESPONSE:
Please see FPL’s response to SFHHA’s Second Set of Interrogatories No. 55. FPL does not have any responsive documents.

Florida Power & Light Company
Docket No. 160021-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 146
Page 1 of 1

QUESTION:
For interrogatories numbered 133-146 please refer to the direct testimony of Witness Moray P. Dewhurst.

Please refer to Exhibit MD-3, page 1 of 6, attached to Witness Dewhurst's direct testimony. Provide the following metrics for each of the Major Southeastern Investor-Owned Utilities listed in the table.

a. Authorized equity ratio based on investor sources.
b. The non-fuel electric service amount for the Typical Residential Customer Bill, July 2015.
c. The fuel mix used to generate the electricity.

RESPONSE:
a. Please see Attachment No. 1.

b. FPL does not have this data and it does not appear to be readily available from external sources. Please see FPL's general and specific objections filed contemporaneously with this set of interrogatories.

c. Please see Attachment No. 2.

Florida Power & Light Company
Docket No. 160021-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 146
Attachment No. 1
Page 1 of 1

Southeast States: Authorized Equity Ratio

State	Company	Authorized Equity Ratio[1]
Florida	**Florida Power & Light Co.**	**59.60%**
South Carolina	Duke Energy Progress	N/A
Mississippi	Entergy Mississippi Inc.	N/A
Florida	Tampa Electric Co.	54.00%
North Carolina	Duke Energy Carolinas	53.00%
Virginia	Dominion Virginia Power	49.99%
Virginia	Appalachian Power Co.	42.89%
South Carolina	Duke Energy Carolinas	53.00%
North Carolina	Duke Energy Progress	53.00%
Florida	Duke Energy Florida Inc.	N/A
Alabama	Alabama Power	45.00%[2]
Mississippi	Mississippi Power	49.73%
Georgia	Georgia Power Co.	50.84%
Florida	Gulf Power Co.	N/A
South Carolina	South Carolina Electric & Gas	52.18%

1) Equity ratio provided based on decision or settlement which could be based on investor sources or a regulatory capital structure.

2) Estimated equity ratio that was utilized to calculate return on equity for Alabama Power

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Second Set of Interrogatories
Interrogatory No. 85
Page 1 of 1

QUESTION:
Regarding Hevert at 37:7. Please provide Mr. Hevert's study of each of the proxy company's "geographic risks" as compared to FPL created prior to March 15, 2016.

RESPONSE:
The cited section of Mr. Hevert's testimony discusses the risk FPL faces from sudden, unexpected damage from severe storms. Please see FPL's response to Staff's Eleventh Set of Interrogatories No. 239 for a discussion of Mr. Hevert's assessment of FPL's risk from severe weather.

QUESTION:
Interrogatories numbered 235-250 relate to FPL Witness Hevert's Direct Testimony. On page 37, line 15 through page 38, line 15, of witness Hevert's direct testimony, he testifies about the risk associated with severe weather in FPL's service territory.

a. Please explain if the legislative Statutes, storm bonds, and storm recovery factors have mitigated this risk.

b. Do the electric operating companies held by the IOUs in witness Hevert's proxy group listed in Exhibit RBH-10 have similar storm restoration cost recovery mechanisms?

c. Explain how FPL's risk is greater than other electric companies that operate in service territories exposed to different severe weather risk such as floods, tornadoes, earthquakes, or ice storms.

d. Explain how witness Hevert has accounted for FPL's storm hardening modernization initiatives in his assessment of FPL's severe weather risk. For reference, on page 3 of FPL witness Miranda's direct testimony, witness Miranda testifies that:

FPL's T &D electrical grid is one of the most storm-resilient and reliable in the nation. This has been achieved through the development and implementation of our forward-looking storm-hardening, reliability and grid modernization initiatives, combined with the use of cutting-edge technology and strong employee commitment. With these industry-leading initiatives and our proposed 2016-2018 plans, FPL will further strengthen its infrastructure, improve system reliability and develop a system even more capable of meeting ever-increasing needs and expectations.

RESPONSE:

a. As noted on pages 33-34 of Company Witness Moray Dewhurst direct testimony, FPL's storm cost recovery mechanism does not eliminate all risk. Specifically, in the event of significant storm damage, the storm reserve would be smaller than it otherwise would have been, and the resulting supplemental charge will be larger and/or will last longer than it otherwise might have. The lack of an adequate storm reserve underscores the need for a strong balance sheet to quickly access capital. Furthermore, although such mechanisms may mitigate some risk, the risk of storms still remains and the risks to investors remain (e.g., sales declines due to outages, financing risk, and cost recovery uncertainty).

b. Mr. Hevert did not believe it was necessary to perform the requested analysis for each of the electric operating companies held by the IOUs in his proxy group. In Mr. Hevert's experience, storm restoration cost recovery mechanisms are common.

For example, Mr. Hevert is aware of storm restoration or storm hardening cost recovery mechanisms in place at several proxy group operating companies, including:

- Oklahoma Gas & Electric Arkansas's Storm Damage Recovery Rider
- Oklahoma Gas & Electric Oklahoma's System Hardening Program Rider
- Several of American Electric Power Company's subsidiaries, including:
    - Ohio Power Company's the 2014 Electric Security Plan (which includes a $5 million major storm reserve and annual true-up mechanism.)
    - Indiana Michigan Power Company's (Indiana jurisdiction) Major Storm Reserve Fund true-up mechanism (See Indiana Utility Regulatory Commission order in Case No. 44075, p 72-73).
    - AEP Texas Central and AEP Texas North – Texas has a Distribution Cost Recovery Factor through which utilities can seek recovery of prudent storm restoration and hardening investments. See 16 TAC §25.243. Texas also allows for securitization of certain costs and true-up mechanism to recovery debt payments (See Tex. Util. Code Ann. §36.401 & §39.307).
    - Public Service Company of Oklahoma's System Reliability Rider.

c. As noted on page 8 of Company Witness Miranda's testimony, Florida is more exposed to tropical storms and hurricanes than other states, and FPL's service territory in particular is highly susceptible to severe storms as it includes approximately 500 miles of coastline exposed to storms from both the Atlantic Ocean and the Gulf of Mexico. As noted in Mr. Hevert's direct testimony at pages 37-38, FPL has experienced a significant amount of damage from recent storms. For example, FPL incurred more than $1.9 billion in storm recovery costs to restore electric transmission and distribution services during 2004 and 2005, which was equivalent to 15 percent of the average rate base for FPL in 2005. In Mr. Hevert's experience, those damages represent relatively large losses relative to the damage experienced by most other electric companies. In that regard, Mr. Hevert notes that although most companies discuss the risk of natural disasters generally, in its SEC Form 10-K FPL has noted that its operating territory has been prone to severe weather events:

> FPL operates in the east and lower west coasts of Florida, an area that historically has been prone to severe weather events, such as hurricanes. A disruption or failure of electric generation, transmission or distribution systems or natural gas production, transmission, storage or distribution systems in the event of a hurricane, tornado or other severe weather event, or otherwise, could prevent NEE and FPL from operating their business in the normal course and could result in any of the adverse consequences described above. Any of the foregoing could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

> At FPL and other businesses of NEE where cost recovery is available, recovery of costs to restore service and repair damaged facilities is or may be subject to regulatory approval, and any determination by the regulator not to permit timely and full recovery of the costs incurred could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

In Mr. Hevert's experience, severe damage from floods, ice storms and earthquakes tend to be less frequent. While tornadoes do cause significant damage, the effects are generally more localized (for example, Empire District Electric Company reported on page 24 of their December 31, 2012 SEC Form 10-K an estimated $27.3 million in storm restoration costs as of the result of the devastating EF-5 tornado that struck Joplin Missouri on May 22nd, 2011).

Further, FitchRatings' July 2015 ratings report on FPL noted that unfavorable changes in current Florida regulatory policies for storm related costs (among other policies) could result in downward rating pressure, which could increase the cost of capital. Similarly, S&P noted in its June 2015 credit ratings report the Company's "exposure to severe weather events that can strain liquidity and present operating challenges" as a risk factor. Please see Attachment Nos. 1 and 2.

d. The Company's need to invest heavily in storm hardening, resiliency, and grid modernization initiatives is a function of its significant severe weather and storm risk. As discussed on page 21 of Company Witness Dewhurst's direct testimony, much of the benefit of FPL's storm hardening efforts is related to reduced system down time after a storm. The Company's investments help mitigate the effect of severe weather, but don't remove it. Mr. Hevert also notes, as discussed on pages 38-39 of his direct testimony, the significant investment that is necessary to maintain reliability is also an important consideration. An ROE that supports the Company's financial strength and facilitates access to capital at reasonable rates benefits ratepayers.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 76
Page 1 of 1

QUESTION:
Regarding Hevert at 37:8, 38:16-41:23. Please provide Mr. Hevert's study of each of the proxy company's "need to access external capital" as compared to FPL created prior to March 15, 2016. If there is none, please so state.

RESPONSE:
Mr. Hevert's discussion of the importance of capital access was not a comparative assessment. Please also see FPL's response to Staff's Eleventh Set of Interrogatories No. 240.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 77
Page 1 of 1

QUESTION:
Regarding Hevert at 37:8-9, 42:1-46:14. Please provide Mr. Hevert's study of each of the proxy company's exposure to "the potential for new regulatory requirements associated with nuclear generation" as compared to FPL created prior to March 15, 2016. If there is none, please so state.

RESPONSE:
Mr. Hevert has not performed the requested study. Please note, Mr. Hevert's discussion of the risk associated with the FPL's nuclear generation was not a comparative assessment.

Florida Power & Light Company
Docket No. 160021-EI
SFHHA's Third Request for Production of Documents
Request No. 79
Page 1 of 1

QUESTION:
Regarding Hevert at 37:1-52:8. Please provide the company by company analysis of each proxy company's risk profiles performed prior to March 15, 2016. If there is none, please so state.

RESPONSE:
Please see FPL's response to Staff's Eleventh Set of Interrogatories No. 236.

Florida Power & Light Company
Docket No. 160021-EI
Staff's Eleventh Set of Interrogatories
Interrogatory No. 236
Page 1 of 1

QUESTION:
Interrogatories numbered 235-250 relate to FPL Witness Hevert's Direct Testimony. Other than the metrics discussed on page 15, line 13 through page 16, line 10 of witness Hevert's direct testimony, did witness Hevert conduct any additional analysis to demonstrate comparability between FPL and the IOUs owned by the companies in his proxy group? For purposes of this response, please identify any additional analysis conducted by witness Hevert beyond what was discussed in the referenced testimony.

RESPONSE:
Page 15, line 13 through page 16, line 10 of Mr. Hevert's direct testimony discuss the selection criteria used to identify a proxy group of comparable publically traded electric utility companies. Mr. Hevert did not believe it was necessary to perform any additional comparative risk analysis. As discussed on pages 37 to 46 of Mr. Hevert's direct testimony, however, Mr. Hevert also considered certain risks faced by FPL such as geographic risk, the magnitude of the Company's capital expenditure program, and the potential for new regulatory requirements associated with nuclear generation.

EXHIBIT NO. ___ (RAB-6)

COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		May-16	Apr-16	Mar-16	Feb-16	Jan-16	Dec-15
ALLETE	High Price ($)	58.490	56.800	58.340	54.960	53.740	51.850
	Low Price ($)	54.030	53.470	51.290	50.830	48.260	47.930
	Avg. Price ($)	56.260	55.135	54.815	52.895	51.000	49.890
	Dividend ($)	0.520	0.520	0.520	0.520	0.505	0.505
	Mo. Avg. Div.	3.70%	3.77%	3.79%	3.93%	3.96%	4.05%
	6 mos. Avg.	3.87%					
Alliant Energy	High Price ($)	74.210	75.180	74.350	70.250	65.350	64.250
	Low Price ($)	71.100	68.150	66.520	64.760	60.750	58.130
	Avg. Price ($)	72.655	71.665	70.435	67.505	63.050	61.190
	Dividend ($)	0.588	0.588	0.588	0.588	0.588	0.550
	Mo. Avg. Div.	3.24%	3.28%	3.34%	3.48%	3.73%	3.60%
	6 mos. Avg.	3.44%					
Avista Corp.	High Price ($)	42.170	41.370	41.310	39.300	37.100	37.780
	Low Price ($)	38.830	38.480	36.890	36.720	34.310	33.000
	Avg. Price ($)	40.500	39.925	39.100	38.010	35.705	35.390
	Dividend ($)	0.343	0.343	0.343	0.343	0.330	0.330
	Mo. Avg. Div.	3.39%	3.44%	3.51%	3.61%	3.70%	3.73%
	6 mos. Avg.	3.56%					
Consolidated Edison	High Price ($)	76.760	77.230	77.020	73.900	70.200	65.660
	Low Price ($)	70.310	70.730	68.440	69.080	63.470	60.300
	Avg. Price ($)	73.535	73.980	72.730	71.490	66.835	62.980
	Dividend ($)	0.670	0.670	0.670	0.670	0.650	0.650
	Mo. Avg. Div.	3.64%	3.62%	3.68%	3.75%	3.89%	4.13%
	6 mos. Avg.	3.79%					
Edison International	High Price ($)	73.250	72.410	72.340	69.240	62.340	61.350
	Low Price ($)	68.470	67.710	65.600	61.490	57.970	57.850
	Avg. Price ($)	70.860	70.060	68.970	65.365	60.155	59.600
	Dividend ($)	0.480	0.480	0.480	0.480	0.480	0.480
	Mo. Avg. Div.	2.71%	2.74%	2.78%	2.94%	3.19%	3.22%
	6 mos. Avg.	2.93%					
Eversource Energy	High Price ($)	58.260	59.090	58.810	56.920	54.150	52.240
	Low Price ($)	53.900	54.510	52.620	52.930	50.010	48.180
	Avg. Price ($)	56.080	56.800	55.715	54.925	52.080	50.210
	Dividend ($)	0.445	0.445	0.445	0.445	0.418	0.418
	Mo. Avg. Div.	3.17%	3.13%	3.19%	3.24%	3.21%	3.33%
	6 mos. Avg.	3.21%					
IDACORP	High Price ($)	74.470	74.990	74.960	73.820	69.960	69.990
	Low Price ($)	69.830	70.400	69.030	68.300	65.030	65.720
	Avg. Price ($)	72.150	72.695	71.995	71.060	67.495	67.855
	Dividend ($)	0.510	0.510	0.510	0.510	0.510	0.510
	Mo. Avg. Div.	2.83%	2.81%	2.83%	2.87%	3.02%	3.01%
	6 mos. Avg.	2.89%					

COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		May-16	Apr-16	Mar-16	Feb-16	Jan-16	Dec-15
Northwestern Corp.	High Price ($)	59.440	62.510	62.220	60.760	55.850	55.650
	Low Price ($)	55.340	55.910	57.460	55.490	52.160	51.950
	Avg. Price ($)	57.390	59.210	59.840	58.125	54.005	53.800
	Dividend ($)	0.500	0.500	0.500	0.480	0.480	0.480
	Mo. Avg. Div.	3.48%	3.38%	3.34%	3.30%	3.56%	3.57%
	6 mos. Avg.	3.44%					
OGE Energy	High Price ($)	31.070	29.620	28.740	27.810	26.520	27.040
	Low Price ($)	28.970	27.270	24.830	24.390	23.370	24.150
	Avg. Price ($)	30.020	28.445	26.785	26.100	24.945	25.595
	Dividend ($)	0.275	0.275	0.275	0.275	0.275	0.275
	Mo. Avg. Div.	3.66%	3.87%	4.11%	4.21%	4.41%	4.30%
	6 mos. Avg.	4.09%					
Portland General Electric	High Price ($)	41.940	40.030	39.900	40.480	39.020	37.800
	Low Price ($)	39.470	37.770	37.040	37.400	35.270	35.040
	Avg. Price ($)	40.705	38.900	38.470	38.940	37.145	36.420
	Dividend ($)	0.300	0.300	0.300	0.300	0.300	0.300
	Mo. Avg. Div.	2.95%	3.08%	3.12%	3.08%	3.23%	3.29%
	6 mos. Avg.	3.13%					
WEC Energy	High Price ($)	60.510	60.320	60.160	58.150	55.720	52.880
	Low Price ($)	57.250	55.460	54.850	54.730	50.440	47.980
	Avg. Price ($)	58.880	57.890	57.505	56.440	53.080	50.430
	Dividend ($)	0.495	0.495	0.495	0.495	0.458	0.458
	Mo. Avg. Div.	3.36%	3.42%	3.44%	3.51%	3.45%	3.63%
	6 mos. Avg.	3.47%					
Xcel Energy	High Price ($)	41.980	42.040	41.850	40.420	38.260	36.720
	Low Price ($)	39.690	38.430	38.260	36.250	35.190	34.330
	Avg. Price ($)	40.835	40.235	40.055	38.335	36.725	35.525
	Dividend ($)	0.340	0.340	0.340	0.320	0.320	0.320
	Mo. Avg. Div.	3.33%	3.38%	3.40%	3.34%	3.49%	3.60%
	6 mos. Avg.	3.42%					
Average Dividend Yield		3.44%					

Source: Yahoo! Finance

EXHIBIT NO. ___ (RAB-7)

COMPARISON GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) IBES
ALLETE, Inc.	3.50%	4.00%	3.00%	4.50%	3.00%
Alliant Energy Corporation	4.50%	6.00%	5.50%	6.10%	6.60%
Avista Corporation	4.00%	5.00%	3.50%	5.00%	5.00%
Consolidated Edison, Inc.	3.00%	1.50%	2.50%	2.30%	1.89%
Edison International	9.00%	3.50%	5.50%	4.90%	2.45%
Eversource Energy	6.00%	6.00%	4.00%	6.30%	6.01%
IDACORP, Inc.	7.50%	3.00%	3.50%	4.00%	4.00%
NorthWestern Corp.	5.50%	6.50%	4.00%	5.00%	5.00%
OGE Energy	9.50%	3.00%	3.50%	5.20%	4.30%
Portland General Electric Company	6.00%	5.50%	4.00%	6.40%	6.57%
WEC Energy	7.00%	6.00%	3.50%	6.30%	6.77%
Xcel Energy Inc.	6.00%	5.50%	4.00%	5.30%	5.27%
Averages	5.96%	4.63%	3.88%	5.11%	4.74%
Median Values	6.00%	5.25%	3.75%	5.10%	5.00%

Sources: Value Line Investment Survey, April 29, May 20, and June 17, 2016
Yahoo! Finance for IBES growth rates retrieved June 12, 2016
Zacks growth rates retrieved June 12, 2016

COMPARISON GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.44%	3.44%	3.44%	3.44%	3.44%
Average Growth Rate	5.96%	4.63%	5.11%	4.74%	5.11%
Expected Div. Yield	3.54%	3.52%	3.53%	3.52%	3.53%
DCF Return on Equity	***9.50%***	***8.15%***	***8.64%***	***8.26%***	***8.64%***
Method 2:					
Dividend Yield	3.44%	3.44%	3.44%	3.44%	3.44%
Median Growth Rate	6.00%	5.25%	5.10%	5.00%	5.34%
Expected Div. Yield	3.54%	3.53%	3.53%	3.52%	3.53%
DCF Return on Equity	***9.54%***	***8.78%***	***8.63%***	***8.52%***	***8.87%***

EXHIBIT NO. ___ (RAB-8)

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Comparison Group

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.44%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.34%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.10%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	5.94%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	8.28%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.44%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.40%
4	Risk Premium	
5	(Line 1 minus Line 3)	9.04%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.63%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	8.03%

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Comparison Group

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data	Avg. Yield
December-15	2.61%
January-16	2.49%
February-16	2.20%
March-16	2.28%
April-16	2.21%
May-16	2.22%
6 month average	2.34%

5 Year Treasury Bond Data	Avg. Yield
December-15	1.70%
January-16	1.52%
February-16	1.22%
March-16	1.38%
April-16	1.26%
May-16	1.30%
6 month average	1.40%

Source: www.federalreserve.gov, Selected Interest Rates (Dalily) - H.15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.84%
Estimated Market Return	9.88%
Value Line Projected 3-5 Yr. Median Annual Total Return	11.00%
Average of Projected Mkt. Returns	10.44%

Source: Value Line Investment Survey for Windows retreived June 12, 2016

Comparison Group Betas:	Value Line
ALLETE, Inc.	0.75
Alliant Energy Corporation	0.75
Avista Corporation	0.75
Consolidated Edison, Inc.	0.55
Edison International	0.70
Eversource Energy	0.75
IDACORP, Inc.	0.80
NorthWestern Corp.	0.70
OGE Energy	0.95
Portland General Electric Company	0.80
WEC Energy	0.65
Xcel Energy Inc.	0.65
Average	0.73

Source: Value Line Investment Survey

EXHIBIT NO. ___ (RAB-9)

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.07%	5.07%	
Historical Market Risk Premium	5.03%	7.03%	6.19%
Comparison Group Beta, Value Line	0.73	0.73	0.73
Beta * Market Premium	3.69%	5.16%	4.54%
Current 20-Year Treasury Bond Yield	2.34%	2.34%	2.34%
CAPM Cost of Equity, Value Line Beta	**6.02%**	**7.49%**	**6.87%**

Source: *Ibbotson SBBI 2015 Classic Yearbook,* Morningstar, pp. 39 - 40, 152, 157 - 158

EXHIBIT NO. ___ (RAB-10)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI

In the Matter of:

PETITION FOR INCREASE IN RATES
BY FLORIDA POWER & LIGHT COMPANY.
_________________________________/

VOLUME 4

Pages 353 through 488

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN RONALD A. BRISÉ
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Tuesday, August 21, 2012

TIME: Commenced at 9:33 a.m.
Concluded at 12:00 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

Commissioners, all of us at FPL work very hard every day to provide our customers with a value proposition and a customer experience that is second to none. And I commit to you that we will continue to strive for excellence every single day.

Thank you.

MR. LITCHFIELD: Mr. Silagy is available for cross-examination.

CHAIRMAN BRISÉ: All right. Mr. Moyle.

MR. MOYLE: Thank you, Mr., Mr. Chairman.

CROSS EXAMINATION

BY MR. MOYLE:

Q Good morning, Mr. Silagy.

A Good morning.

Q Your testimony, on page 4 you say that the purpose of the testimony is to provide an overview of FPL's filing and to introduce the, the witnesses who are submitting direct testimony. I take it from that that you have an overview understanding of, of the case as filed?

A That's correct.

Q Okay. So would you be comfortable if I have, in my cross-examination of you, you know, ask you questions, not necessarily designed to get down into the weeds, because I understand you have witnesses, but, you investing in technology that keeps the lights on efficiently and affordably next year and a decade down the road.

MR. MOYLE: Thank you for, for your time Appreciate it.

THE WITNESS: You're welcome.

CHAIRMAN BRISÉ: Is that it, Mr. Moyle?

MR. MOYLE: Yes.

CHAIRMAN BRISÉ: Thank you very much.

South Florida Hospital Association.

MR. SUNDBACK: Good morning. Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. SUNDBACK:

Q Good morning, sir.

A Good morning.

Q Let's look at what's been designated as your Exhibit ES-1, which is marked as 136, if the note taking at this end is correct.

You state there that you were Chief Development Officer at FPL?

A I'm sorry?

Q You state in that CV that you were Chief Development Officer at FPL.

A Oh, yes.

A I do.

Q Okay. Now, that competition comes from both utilities and nonutility entities; is that not correct?

A That's correct. We compete for capital on a global basis.

Q And, in fact, even within the NextEra Energy organization, presumably FPL has to justify access to capital; is that not correct?

A That's correct.

Q Okay. And you, you experienced that on both sides of the house, did you not, when you were working for the nonutility functions of NextEra Energy?

A That's correct.

Q Okay. On that same page, just before that reference to competition for capital, on lines 13 through 15 you reference a utility's ability to earn; do you see that?

A I'm sorry. Could you point me to -- oh, yes, on line 13? Yes, sir.

Q Yes. Yes, sir. I would like to explore that with you for just a moment. Presume that a company that's not rate regulated simply replaced some of its existing equity with debt, didn't change the overall level of capitalization, just changed its capitalization structure a hair.

In that instance, earnings per share of that enterprise would increase because the earnings would be spread over a smaller equity base; is that not correct?

A Again, I would defer, if this is getting into capital structure, to Witness Dewhurst.

Q You've testified, sir, about a utility's ability to earn; right?

A I have.

Q And I want to explore that with you just a bit, especially given your experience on both sides of the house. And you've said you have to compete with others to attain capital for FPL; correct?

A That's correct. We have to --

Q And I'd like to understand how that competition works. Now, are you unable to tell me of your own knowledge that if an unregulated enterprise simply reduces its equity component and ups -- substitutes for that equity more debt, that earnings per share will not increase because those earnings will be spread over a smaller equity base?

A No. I believe that would be correct.

Q Okay. If FPL's capital structure was changed, for instance, in this rate proceeding for regulatory purposes, by replacing some of its existing equity with debt, earnings per share of FPL would not increase automatically, would they? They could be reduced.

A Again, I would defer to Witness Dewhurst as to what the impacts overall of the corporation would be. The key on the capital structure, in my opinion, as somebody who is responsible for the operations of the company, is maintaining a strong financial position on the balance sheet so we can continue to access the capital markets when we need to to either invest in infrastructure or to address issues that come up in the regular course of business that are uncertain.

Q All right. So, Mr. Silagy, are you telling me that you don't even know, even though you're here testifying before the Commissioners now and spearheading the rate case, whether if, from a regulatory perspective, the capital structure of the company was deemed to include more debt and less equity, whether that would affect the level of equity per share, the dividends per share that could be paid, for instance, to the parent, NextEra Energy, Inc.?

A What I'm telling you is, is that I believe weakening the capital structure of the company has an adverse impact on our ability to be able to attract capital and operate the company in a manner that continues to provide what I think is exceptional service to our customers.

MR. SUNDBACK: Mr. Chairman, I'd move to strike the question -- the answer in its entirety. It was as straightforward as you can get. A yes or no works just fine. And if he wanted to provide an explanation, he could.

But it strains credulity to believe that the president of a utility cannot determine whether a change in the capital structure is going to affect, for instance, earnings per share of the utility.

I guess if his answer is I don't know, that's also useful information, but he hasn't even volunteered that. He hasn't said yes, no, I don't know. He's given you a different -- he's answered a different question.

MR. LITCHFIELD: Well, I object to counsel's characterization of the witness's answer. I think the witness is providing an answer to Mr. Sundback. It may not be the answer that Mr. Sundback would like to receive, but the witness is entitled to provide an answer consistent with his understanding.

CHAIRMAN BRISÉ: Okay. I think we'll, we'll strike the whole answer. You can pose the question again. Maybe if we start with a yes or no, and then move forward.

MR. SUNDBACK: Thank you, Mr. Chairman.

BY MR. SUNDBACK:

Q Do you need the question back, sir?

A Yes, please.

Q Let's see if we can pull it together.

A Thank you.

Q If FPL's capital structure was changed by replacing some of its existing equity with debt for purposes of setting rates, earnings per share of FPL would not automatically increase, would they?

A No.

Q Thank you.

And so in that sense there's a distinction between regulated, rate regulated entities and enterprises whose rates are not regulated concerning capital structure; is that right? In that sense.

A In that sense, there's a distinction between rate regulated entities and unregulated entities.

Q Okay. Let's look at your direct, page 16, if we could, lines 9 through 12.

A I'm there.

Q Thank you, sir. The referenced study of transmission substation average reliability, that study didn't adjust for differences in relative age of equipment between utilities, did it?

A I'm not familiar with the exact elements of

EXHIBIT NO. ___ (RAB-11)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY

COM 5
APA 1
ECR 10
GCL 1
RAD 1
SRC 1
ADM
OPC
CLK 1-RN
Crt.Rp. 1

TESTIMONY & EXHIBITS OF:

WILLIAM E. AVERA

Docket No. 120015-EI
Interest Rate Trends
Exhibit WEA-2, Page 1 of 1

	Current (a)	2012	2013	2014	2015	2016
30-Yr. Treasury						
Value Line (b)	3.4%	3.9%	4.1%	4.5%	5.0%	--
IHS Global Insight (c)	3.4%	3.3%	3.8%	4.5%	5.1%	5.3%
Blue Chip (d)	3.4%	3.7%	4.2%	4.8%	5.3%	5.5%
AAA Corporate						
Value Line (b)	4.2%	4.6%	4.7%	5.2%	5.7%	--
IHS Global Insight (c)	4.2%	4.2%	4.5%	5.1%	6.0%	6.2%
Blue Chip (d)	4.2%	4.3%	4.7%	5.4%	5.8%	6.2%
S&P (e)	4.2%	4.2%	4.6%	5.1%	6.0%	--
AA Utility						
IHS Global Insight (c)	4.3%	4.4%	4.9%	5.6%	6.5%	6.8%
EIA (f)	4.3%	4.7%	4.8%	5.7%	6.8%	6.9%

(a) Based on monthly average bond yields for the six-month period Jul. - Dec. 2011 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases/h15/data.htm.

(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 25, 2011).

(c) IHS Global Insight, *U.S. Economic Outlook* at 25 (Dec. 2011).

(d) *Blue Chip Financial Forecasts,* Vol. 30, No. 12 (Dec. 1, 2011).

(e) Standard & Poor's Corporation, "U.S. Economic Forecast: Just Like Ol' Times," *RatingsDirect* (Jan. 12, 2012).

(f) Energy Information Administration, *Annual Energy Outlook 2012, Early Release* (Jan. 23, 2012).

EXHIBIT NO. ___ (RAB-12)

FERC GDP GROWTH RATE

		2020	2040	2044	2070	
Energy Information Administration						
	Real GDP	18,801	29,898			
	GDP Deflatoı	1.211	1.73			
		22,768	51,724			4.19%
SSA Trustees Report		22,948			198,390	4.41%
Average GDP Growth Rate						4.30%

Sources:

Energy Information Administration, *Annual Energy Outlook 2015* (April 2015).
Social Security Administration, 2016 OASDI Trustees Report (June 22, 2016),
Table VI.G6 - Selected Economic Variables, Calendar Years 2015-90

EXHIBIT NO. ___ (RAB-13)

Reformulated Multi-Stage Growth Discounted Cash Flow Model
180 Day Average Stock Price
Average EPS Growth Rate Estimate in First Stage - Revised FERC Long-Term Growth Rate

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
		Stock	EPS Growth Rate Estimates				Long-Term	Payout Ratio			Iterative Solution		Terminal	Terminal
Company	Ticker	Price	Zacks	First Call	Value Line	Average	Growth	2016	2019	2026	Proof	IRR	P/E Ratio	PEG Ratio
ALLETE, Inc.	ALE	$49.47	5.00%	5.00%	6.50%	5.50%	4.30%	66.00%	59.00%	67.30%	($0.01)	9.07%	14.72	3.42
Alliant Energy Corporation	LNT	$59.67	5.40%	5.55%	6.00%	5.65%	4.30%	61.00%	63.00%	67.30%	($0.00)	9.11%	14.59	3.39
Ameren Corporation	AEE	$41.34	6.30%	6.00%	7.00%	6.43%	4.30%	62.00%	56.00%	67.30%	($0.01)	9.28%	14.10	3.28
American Electric Power Company, Inc.	AEP	$55.91	4.70%	4.43%	5.00%	4.71%	4.30%	64.00%	65.00%	67.30%	$0.01	8.95%	15.10	3.51
Avista Corporation	AVA	$32.85	5.00%	5.00%	5.00%	5.00%	4.30%	69.00%	65.00%	67.30%	$0.01	8.78%	15.67	3.64
CMS Energy Corporation	CMS	$34.36	6.10%	6.72%	5.50%	6.11%	4.30%	60.00%	62.00%	67.30%	($0.01)	8.61%	16.30	3.79
Dominion Resources, Inc.	D	$69.57	6.10%	5.49%	8.00%	6.53%	4.30%	74.00%	72.00%	67.30%	($0.00)	8.29%	17.58	4.09
DTE Energy Company	DTE	$79.11	5.60%	5.12%	5.00%	5.24%	4.30%	61.00%	60.00%	67.30%	($0.00)	9.42%	13.70	3.19
Great Plains Energy Inc.	GXP	$26.16	5.80%	5.07%	5.00%	5.29%	4.30%	60.00%	62.00%	67.30%	$0.01	9.11%	14.59	3.39
IDACORP, Inc.	IDA	$62.69	4.00%	4.00%	1.00%	3.00%	4.30%	53.00%	58.00%	67.30%	($0.01)	8.39%	17.18	4.00
NorthWestern Corporation	NWE	$52.75	5.00%	6.81%	6.50%	6.10%	4.30%	61.00%	59.00%	67.30%	$0.00	9.08%	14.67	3.41
OGE Energy Corp.	OGE	$28.22	5.70%	2.17%	3.00%	3.62%	4.30%	63.00%	72.00%	67.30%	($0.00)	9.44%	13.65	3.17
Otter Tail Corporation	OTTR	$26.76	NA	6.00%	9.00%	7.50%	4.30%	71.00%	59.00%	67.30%	($0.00)	9.76%	12.87	2.99
Pinnacle West Capital Corporation	PNW	$61.66	4.80%	4.95%	4.00%	4.58%	4.30%	64.00%	64.00%	67.30%	($0.01)	8.77%	15.72	3.66
PNM Resources, Inc.	PNM	$27.23	7.70%	9.30%	9.00%	8.67%	4.30%	51.00%	55.00%	67.30%	($0.00)	9.55%	13.37	3.11
Portland General Electric Company	POR	$35.66	4.40%	4.14%	6.00%	4.85%	4.30%	52.00%	53.00%	67.30%	($0.01)	8.89%	15.31	3.56
SCANA Corporation	SCG	$55.39	4.50%	4.45%	4.50%	4.48%	4.30%	56.00%	55.00%	67.30%	$0.01	9.34%	13.92	3.24
Westar Energy, Inc.	WR	$38.32	3.60%	3.50%	6.00%	4.37%	4.30%	61.00%	55.00%	67.30%	$0.01	8.83%	15.51	3.61
Xcel Energy Inc.	XEL	$34.55	5.00%	4.68%	4.50%	4.73%	4.30%	63.00%	65.00%	67.30%	($0.01)	8.87%	15.36	3.57
											MEAN	9.03%		
											MAX	9.76%		
											MIN	8.29%		

Docket No. 160021-EI
Reformulated Multi-Stage Growth Discounted Cash Flow Model
Exhibit No. ___ (RAB-13), Page 1 of 1

SPILMAN THOMAS & BATTLE, PLLC
ATTORNEYS AT LAW

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September 22, 2016

VIA HAND DELIVERY
Ms. Ingrid Ferrell
Executive Secretary
Public Service Commission of West Virginia
201 Brooks Street
Charleston, WV 25301

02:35 PM SEP 22 2016 PSC EXEC

Re: CASE NO. 16-0550-W-P
WEST VIRGINIA-AMERICAN WATER COMPANY
Petition for Approval of the 2017 Infrastructure Replacement Program Surcharge Mechanism

Dear Ms. Ferrell:

Please find enclosed for filing in the above-referenced case on behalf of the West Virginia Energy Users Group an original and twelve copies of the "*Direct Testimony and Exhibits of Richard A. Baudino.*"

Please contact me if you have any questions concerning this filing.

Sincerely,

Susan J. Riggs

Susan J. Riggs (WV State Bar #5246)
sriggs@spilmanlaw.com

Barry A. Naum (WV State Bar #12791)
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101
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SJR.sds.8840716
Enclosures
c: Certificate of Service

CERTIFICATE OF SERVICE

I, Susan J. Riggs, counsel to the West Virginia Energy Users Group, do hereby certify that on this 22nd day of September, 2016, a copy of the foregoing *"Direct Testimony and Exhibits of Richard A. Baudino"* was served upon the parties and/or counsel of record in this proceeding as follows:

VIA HAND DELIVERY

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Charleston, WV 25301
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VIA U.S. MAIL

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Susan J. Riggs

Susan J. Riggs (WV State Bar #5246)

WVEUG Exhibit RAB-D

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0550-W-P

WEST VIRGINIA-AMERICAN WATER COMPANY, a public utility, Charleston, West Virginia.
Petition for approval of a 2017 Infrastructure Replacement Program Surcharge Mechanism.

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

THE WEST VIRGINIA ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.

SEPTEMBER 22, 2016

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0550-W-P
WEST VIRGINIA-AMERICAN WATER COMPANY, a public utility
Charleston, West Virginia
Petition for approval of a 2017 Infrastructure Replacement Program Surcharge Mechanism

DIRECT TESTIMONY OF RICHARD A. BAUDINO

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to J. Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979. I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ___(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the West Virginia Energy Users Group ("WVEUG").[1]

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the Application For Approval of 2017 Infrastructure Replacement Program ("IRP") filed by West Virginia-American Water Company ("WVAW" or "Company"). In so doing, I will address relevant portions of the Application filed by the Company as well as the pre-filed Direct Testimony submitted by Company witnesses Jeffrey L. McIntyre and John S. Tomac.

[1] For the purpose of this proceeding, WVEUG's membership consists of The Chemours Company and Dow Chemical Company.

Q. What are your conclusions and recommendations to the Public Service Commission of West Virginia ("Commission")?

A. I recommend that the Commission reject the Company's proposed IRP. The Commission adequately addressed the Company's ongoing commitments to infrastructure replacement in its last rate case, Case No. 15-0676-W-42T. In that proceeding, the Commission allowed the Company to include certain system replacement projects expected to be completed after the end of the Company's historical test year and before the rate effective period began ("the Transition Period"). This modification to the Commission's traditional practice of using an historical test year for ratemaking purposes recognized WVAW's unique circumstances and effectively addressed the Company's need for system improvements and replacements. In this proceeding, WVAW failed to demonstrate that its proposed IRP is reasonable and necessary.

The Company's filed IRP represents a radical overreach of the more modest IRP proposed by Staff witness Terry Eads in Case No. 15-06760-W-42T, which WVEUG also opposed in that case. The Company has so broadly defined investments that would qualify for its IRP that it would likely never need to file a rate case before the Commission again. The proposed IRP fails on several important points, which are as follows:

- WVAW failed to show that its proposed IRP is necessary.
- WVAW's proposed categories of IRP-eligible facilities are overly broad and open ended.

- WVAW's proposed IRP fails to include an adequate review process that would ensure reasonableness of costs for eligible facilities.
- WVAW's proposed amendment process for its IRP would turn the surcharge and included costs into moving targets.
- WVAW has unreasonably proposed to collect costs associated with the projected average level of investment in IRP facilities between February 25 and December 31, 2016. Essentially, this proposal allows the Company to collect future test year costs that the Commission rejected in the last rate proceeding.
- WVAW's proposed IRP fails to provide adequate protections to customers from unreasonable costs and rate increases.

The legion of defects associated with WVAW's proposed IRP warrants its outright rejection by the Commission. The Company's proposed IRP would result in a "real time" ratemaking arrangement that will supplant the current regulatory paradigm with a system that irreparably harms West Virginia customers.

If the Commission chooses to accept the implementation of an IRP for WVAW, however, its proposed IRP should undergo a complete revision. Specifically, I recommend that the Commission incorporate the following principles and modifications into any IRP it may approve in this proceeding:

1. The IRP should be limited to a 2-year Pilot Program.

2. IRP eligible facilities should be limited to smaller diameter mains and services consistent with a recommendation made by Staff witness Mr. Fowler in Case No. 15-0676-W-42T.

3. IRP eligible facilities should be limited to non-revenue producing and non-expense reducing plant that serves to replace existing plant.

4. Facilities extended to serve new customers in areas that are underserved or unserved should be excluded from the IRP.

5. The yearly cap on IRP related rate increases from current authorized tariff rates should be limited to 2.5%.

6. The cumulative cap on customer IRP related rate increases over currently authorized tariff rates should be limited to 5%.

7. The yearly increase in WVAW's IRP eligible facilities should be limited to the general rate of inflation as measured by the Consumer Price Index.

8. The return on equity for IRP eligible facilities should be reduced by one percent from the Commission's last authorized return on equity. For the proposed Pilot Program, the allowed return on equity for any IRP eligible facilities should be 8.75%.

9. WVAW should be required to file a base rate proceeding within two years of IRP implementation. At that time, the IRP rate should be reset to zero and all facilities included in the IRP should be included in base rates.

10. The IRP revenue requirement should be collected using a fixed monthly charge.

<u>WVAW Proposed IRP</u>

Q. Please summarize WVAW's proposed IRP as contained in its Application and supporting Direct Testimony.

A. The Company's proposed IRP is described beginning on page 4 of its Application. WVAW proposes to include seven categories of what it considers to be non-revenue producing, non-expense reducing utility plant in its IRP. The seven categories of eligible facilities are described on pages 6 and 7 of the Application.

The IRP would be implemented covering IRP plant placed into service from February 25, 2016. WVAW stated it would invest approximately $32.5 million in IRP facilities in 2016 and 2017. Exhibit 2 to the Application contains the projected and budgeted IRP facilities through 2020.

On page 9 of its Application, WVAW states that when IRP projects are completed the Company would submit a work order package for review by Staff and the Consumer Advocate Division ("CAD") for auditing purposes. Also on page 9, the Company explains its reconciliation process in which the revenue requirement associated with the actual cost of IRP facilities would be compared with the revenue received from the "IRP Rate Component." Paragraph 18 on page 10 provides a description of WVAW's proposed IRP Rate Component. Costs recovered through the IRP Rate Component would include return on rate base, related income taxes, depreciation expense, state property taxes, and the West Virginia Business and Occupation ("B&O") tax.

WVAW also seeks inclusion of a revenue requirement associated with the projected average level of investment in IRP Facilities between February 25 and December 31, 2016. The Company claims that these costs should be included within the IRP scope "to bridge the gap in recovery between the current rate base cut-off period of February 24, 2016 and the beginning of a full-year IRP period beginning January 1, 2017." Application, pp. 11, 12.

The Application (Paragraph 32, page 15) also contains certain conditions on the Commission's approval of the IRP, including the relationship to base rate cases, an annual rate increase cap of 5%, a cumulative rate increase cap of 10%, and an earnings test.

Q. Should the Commission approve WVAW's proposed IRP?

A. No. WVAW's proposed IRP is unreasonable and should be rejected in its entirety.

Q. In general terms, please explain why the Company's proposed IRP should be rejected.

A. As I stated in my Direct Testimony in Case No. 15-0676-W-42T, I am not in favor of automatic adjustment clauses such as the IRP, as a general matter. Automatic adjustment clauses that allow the pass-through of capital costs simply do not allow the requisite amount of regulatory scrutiny that a full rate proceeding does. In a rate case, the Commission, its Staff, and other parties have time to conduct a detailed examination and review all of the elements of a utility's revenue requirement to ensure that the costs ratepayers are required to pay are prudently incurred. WVAW's proposed IRP would enable the Company to pass though significant new costs without this regulatory scrutiny. Although the utility and its shareholders certainly benefit from increased cash flows from such automatic clauses, ratepayers are far less assured that costs subject to this treatment are prudently incurred. As a result, these surcharges effectively shift the risk of investment from the utility and its shareholders to ratepayers. The regulatory paradigm is in turn shifted such that the balance is skewed between providing the utility with a monopoly and protecting captive ratepayers; the upshot is that surcharges like this one favor the utility to the disadvantage of its customers.

Q. Let us now move to your specific conclusions with respect to WVAW's proposed IRP. To begin with, did WVAW make a proper showing that an IRP of the magnitude it is proposing is necessary?

A. No. It is important to keep in mind that the Commission just granted the Company a 15.1% rate increase in its Order dated February 24, 2016, in Case No. 15-0676-W-42T.

In that Order, the Commission went beyond its traditional adherence to using an historical test year based on the facts and circumstances in that proceeding. The Commission approved inclusion of certain non-revenue producing additions in the Transition Period and established the Company's rate base at the beginning of the Rate Year. On page 26 of its Order, the Commission noted the following:

> Based on the evidence presented in this case, establishing rate base at the beginning of the Rate Year is reasonable because inclusion of additional investment in rate base elements for the Transition Period (i) will provide a reasonable level of known and measurable rate base that will be used and useful and in service at the time the new rates authorized in this proceeding become effective, (ii) will provide a better matching of revenues, expenses and rate base present in the Rate Year than would adherence to a non-representative HTY approach, and (iii) will better mitigate the impact of regulatory lag than would AFFAC. WVAWC should cease recording AFFAC on the effective date of new rates authorized in this case.[2]

In its Order, the Commission significantly expanded the manner in which costs and system investments are reflected in WVAW's rate base by including investments through the Transition Period. This Transition Period ran from January 2015 through February 29, 2016, a full 14 months after the end of the Company's 2014 historic test year. This expansion of rate recognition for non-revenue producing net plant essentially made WVAW whole with respect to infrastructure replacement investment through February of this year.

WVAW failed to provide any evidence of financial need for the sort of expansive IRP it is proposing in this proceeding. In my opinion, the Commission's Order in the base rate case more than adequately reflected the Company's infrastructure replacement

[2] West Virginia-American Water Company, Case No. 15-0676-W-42T (Order entered Feb. 24, 2016) ("Base Rate Case Order"), p. 26.

requirements for the rate effective year of 2016.

Q. On pages 6 and 7 of his Direct Testimony, Mr. McIntyre described seven categories of investment that are to be included in the Company's IRP. Should all of these categories of investment be included in an IRP?

A. No. All seven of the proposed investment categories are so broadly defined that they could include any and all future system investments by WVAW. In fact, nowhere in the investment descriptions provided by Mr. McIntyre do the words "infrastructure replacement" occur. An IRP should only include investments that replace existing infrastructure, such as replacement mains and services.

Especially objectionable are the following categories of investment for proposed inclusion:

> d. distribution mains and related facilities initially constructed under "shopping center agreements", etc.
>
> e. facilities the acquisition or construction of which are recommended or required by the Commission, the West Virginia Bureau for Public Health, etc.
>
> f. facilities that extend public water service to new customers in areas of the state that are unserved or underserved.
>
> g. other facilities the costs of which the Commission may later include within the definition of IRP facilities.[3]

Categories d., e., and g. are essentially "catch-all" categories that cover nearly every conceivable investment that WVAW may make in the future. Clearly, these proposed categories of investment have absolutely nothing to do with infrastructure replacement

[3] Application, pp. 6-7.

and should be rejected by the Commission.

Category f. should also be rejected. This definition was drawn from Senate Bill 390, a statute that does not apply to water utilities. I strongly recommend that the Commission reject language that would allow a water company to pass system expansion projects through an IRP.

Q. **Does the Company's proposed IRP provide for a reasonable review process to ensure that eligible costs are prudently incurred?**

A. No. In fact, WVAW's proposed IRP completely lacks any mechanism for Commission review to determine if costs passed through the IRP have been prudently incurred. WVAW's Application, page 9, paragraph 14, discusses a work order package that the Company will submit when individual main replacement projects are completed. These work order packages would be submitted to Staff and CAD "for auditing purposes." Mr. Tomac describes a mechanism to compare actual costs incurred and revenues received in order to determine any potential over-recovery or under-recovery. Direct Testimony of John S. Tomac, page 3, line 16 through page 4, line 5. The Company's proposed IRP, however, fails to include a prudence review process. Simple auditing and revenue reconciliation cannot assure customers that the costs for which they are being charged through the IRP are reasonable, and such measures provide no vehicle for the input of intervenors beyond Staff and CAD.

Q. On page 8 of his Direct Testimony, Mr. McIntyre describes the Company's proposal to amend its IRP filing in certain circumstances. Should the Company be allowed to amend its filing in the manner described by Mr. McIntyre?

A. No. The type of amendment process described by Mr. McIntyre would turn its IRP filing into a moving target and place the Staff, CAD, and other parties at a disadvantage in terms of evaluating the reasonableness of additions to the Company's IRP filing after it has been filed. If WVAW needs to "replace a major facility that suffers an unexpected failure" or make "substantial investment in a category of IRP facilities that was not included in the earlier filing covering the current IRP calendar year," as described by Mr. McIntyre, then the Company is free to file a base rate case and/or a certificate of convenience and necessity case and include such facilities in that filing. The Commission should not allow the Company to make changes in its IRP filing after it has been filed.

Q. On page 4 of his Direct Testimony, Mr. Tomac testifies that WVAW seeks to include investment in IRP facilities from February 25 through December 31, 2016. Should the Commission allow the Company to include this period in its proposed IRP?

A. Absolutely not. Mr. Tomac's proposal is an attempt to skirt normal regulatory lag between rate cases and to inappropriately fill a gap between the beginning of the Rate Year from the last base rate case and the implementation date of the proposed IRP.

Moreover, Mr. Tomac's proposal represents a back-door means of recovering future test year costs that the Commission Order rejected in the base rate case. The Commission stated in its Base Rate Case Order that allowing the Company to reflect certain costs through the Transition Period was a better match of revenues, expenses, and rate base for the Rate Year than would be achieved using an historical test year.[4] The Commission rejected the Company's fully projected future test year. Now in its IRP filing, the Company seeks to recover projected costs beyond the Transition Period. The Commission should reject the Company's attempt to recover investment from February 25 through December 31, 2016, in this proceeding.

Q. Do the proposed caps on yearly and cumulative rate increases adequately protect customers?

A. No. As I stated previously, the Commission just ordered a 15.1% increase for WVAW customers this year. The Company now wants further increases through an accelerated IRP process that could increase rates by another 5% – 10% over the next few years. Given the impact from the last rate case, if the Commission decides to approve an IRP, then I recommend lower caps on yearly and cumulative rate increases. I will describe my proposal more fully in the next section of my Direct Testimony.

In addition, as the Company acknowledged in response to CAD data request 01-23, attached as Exhibit___(RAB-2), the 10% cap as proposed would likely never be reached. Thus, this cap does not provide ratepayers with any real protection, unless the Company was to attempt to include capital expenditures "over the average annual $18.5 million

[4] See Base Rate Case Order, p. 26.

amount" currently proposed for inclusion in the surcharge. With a cap set so high, there would be very little reason for the Company to ever need to seek a base rate case.

Recommended Revisions to WVAW's Proposed IRP

Q. If the Commission decides to approve an IRP for WVAW, what are the main principles and elements that should be included?

A. I recommend that the following principles and elements be part of any IRP that the Commission approves for WVAW:

1. The IRP should be limited to an initial 2-year Pilot Program.

2. IRP eligible facilities should be limited to mains 3 inches in diameter and smaller and associated services. This recommendation is based on a recommendation made by Staff witness Fowler in Case No. 15-0676-W-42T.

3. IRP eligible facilities should be limited to non-revenue producing and non-expense reducing plant that serves to replace existing plant.

4. Facilities extended to serve new customers in areas that are underserved or unserved should be excluded from the IRP.

5. The yearly cap on IRP related rate increases from current authorized tariff rates

should be limited to 2.5%.

6. The cumulative cap on customer IRP related rate increases over currently authorized tariff rates should be limited to 5%.

7. The yearly increase in WVAW's IRP eligible facilities should be limited to the general rate of inflation as measured by the Consumer Price Index.

8. The return on equity for IRP eligible facilities should be reduced by 1% from the Commission's last authorized return on equity. For this proposed Pilot Program, the allowed return on equity for any IRP eligible facilities should be 8.75%.

9. WVAW should be required to file a base rate proceeding within two years of IRP implementation. At that time, the IRP rate should be reset to zero and all facilities included in the IRP should be included in base rates.

10. The IRP revenue requirement should be collected using a fixed monthly charge.

Q. Please explain why the IRP should be limited to a 2-year Pilot Program.

A. A 2-year pilot IRP is a reasonable first step for the Commission, its Staff, the CAD, and other parties to gauge the effectiveness and workability of an IRP for WVAW. It is important to bear in mind that an IRP represents a significant change in the way WVAW has been regulated by the Commission. In the Company's last base rate case, the

Commission approved a significant change to its traditional ratemaking approach by including plant in rate base through the Transition Period. This decision significantly expanded WVAW's historical thirteen-month rate base by $33.1 million. In its Base Rate Case Order, the Commission stated:

> *The Commission is at a crossroads regarding the rate base treatment that will provide WVAWC a reasonable opportunity to meet these challenges and at the same time moderate the impact on customer rates.* WVAWC has met its burden of proof regarding the inadequacy of the thirteen-month average HTY rate base approach in this case. The combination of declining per residential customer usage, little if any customer growth, and increased costly system replacements described in WVAWC and Staff testimony are unique to WVAWC and lead to the inescapable conclusion that the HTY approach, under current circumstances and operations for WVAWC, does not properly match revenues, expenses and rate base in the Rate Year. Further, the experimental AFFAC approach has provided minimal relief to WVAWC from regulatory lag and is not working as well as intended. The Commission believes it is time to cease the AFFAC approach and consider other alternatives.
>
> * * *
>
> Based on the evidence presented in this case, establishing rate base at the beginning of the Rate Year is reasonable because inclusion of additional investment in rate base elements for the Transition Period (i) will provide a reasonable level of known and measurable rate base that will be used and useful and in service at the time the new rates authorized in this proceeding become effective, (ii) will provide a better matching of revenues, expenses and rate base present in the Rate Year than would adherence to a non-representative HTY approach, and (iii) will better mitigate the impact of regulatory lag than would AFFAC. WVAWC should cease recording AFFAC on the effective date of new rates authorized in this case.[5]

Clearly, the Commission considered both the needs of WVAW and its customers in its decision to deviate from the historical test year and expand the Company's rate base in the last rate case. I recommend that the Commission continue a carefully considered

[5] Base Rate Case Order, p. 26 (emphasis added).

approach in implementing an IRP for WVAW in this proceeding as well.

WVAW's open-ended IRP proposal would continue indefinitely and could very well end future base rate cases for the Company. This is an unacceptable approach to ratemaking and one that cannot ensure just and reasonable rates for customers. Approving an IRP as a 2-year pilot program would enable the Company to include a certain level of necessary replacement projects, but with more limited regulatory review than would be afforded by a full rate proceeding. In my opinion, this strikes a reasonable balance between company, shareholder, and ratepayer interests.

Q. Please explain why IRP eligible facilities should be limited to mains 3 inches in diameter or less.

A. Limiting IRP eligible facilities to smaller mains and services continues a careful and moderate approach to IRP implementation for WVAW and its customers. Consistent with my recommendation for a 2-year pilot IRP, limiting eligible facilities to smaller mains and services represents a balancing of company and customer interests.

In Case No. 15-0676-W-42T, Staff witness Mr. Jonathan M. Fowler stated the following in his Direct Testimony:

> **Q: BASED ON YOUR REVIEW OF THE COMPANY'S INFRASTRUCTURE AS DISCUSSED ABOVE, WHAT ARE THE ENGINEERING DIVISION'S RECOMMENDATIONS AT THIS TIME?**

> A: The Engineering Division would encourage the Company to begin accelerating the replacement of their system, starting with the smaller diameter mains and services. While other aspects are in similar need of upgrade, this is where customers are most likely to see an immediate benefit in the form of improved service and reduced outages. In addition, this would provide an opportunity to make minor (i.e. low incremental cost) improvements in system hydraulics and performance; for instance upsizing small diameter mains by one nominal size (i.e. 2"-to-3" or 3"-to-4", etc.) may generally be accomplished at a very small incremental cost since labor, equipment, fuel and restoration costs are largely constant for smaller-size main construction and will not increase significantly as a result of sensible upsizing. (Such upsizing of smaller mains would improve system capacity, extend component life and enhance reliability at little incremental cost.)[6]

My conclusion based on Mr. Fowler's testimony is that only including smaller sized mains and associated services in the IRP would give ratepayers the most value for their money. This is very important considering the fact that ratepayers have just had a 15.1% rate increase approved by the Commission on February 24, 2016.

Q. Why should IRP facilities be limited to non-revenue producing and non-expense reducing plant?

A. This condition is consistent with the regulatory goal of only including facilities in an IRP that replace existing infrastructure. The IRP should not be used for new facilities that expand the Company's rate base and total revenues. This type of plant should only be included in a base rate proceeding so that the Commission, Staff, CAD, and other parties can evaluate the reasonableness of the cost of such facilities as well as whether such investment is used and useful.

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[6] Direct Testimony of Jonathan M. Fowler, Case No. 15-0676-W-42T, pp. 11-12.

Q. Please explain why facilities extended to serve unserved or underserved areas should be excluded from the IRP.

A. The basis for this condition is fundamentally the same as the basis for the prior condition regarding non-revenue producing and non-expense reducing plant. It is inappropriate to include the cost of facilities that expand the utility's system in an IRP. Such facilities should only be included in a base rate proceeding (and/or a certificate of convenience and necessity case), in which the Commission may properly evaluate the usefulness of such facilities as well as whether the costs were prudently incurred.

Q. Please provide the basis for the yearly and cumulative rate caps.

A. West Virginia customers need to be protected from excessive future rate increases that may flow through an IRP. As I mentioned earlier, the Commission just approved a 15.1% increase in the Company's rates on February 24, 2016. Now, WVAW is filing for an IRP that includes even more yearly rate increases for its customers. The Company proposed a yearly cap of 5% and a total cumulative rate increase cap of 10%. These caps do not provide enough rate impact protection for customers considering the recently approved 15.1% increase.

In order to mitigate future rate increases to West Virginia ratepayers, I recommend that the yearly increase to the Company's tariff rates be limited to 2.5% and that the total cumulative increase be limited to 5%. This recommendation is 50% lower than the Company's recommended caps, which fail to provide sufficient rate mitigation for customers.

Q. Why should any yearly increase in IRP eligible plant be limited to the rate of inflation as measured by the Consumer Price Index?

A. This condition places a reasonable upper limit on the amount of IRP eligible plant that the Company can be allowed to place into an IRP. The Company's current proposal provides no such tangible limit on the yearly plant increases that can be included in the IRP. Including an upper limit on the yearly increases in IRP eligible plant serves as another rate mitigation tool for the Commission. It also serves as a limit on the amount of plant that would be subject to a lower level of regulatory scrutiny compared to a base rate proceeding.

Q. Please explain why the return on equity for IRP eligible plant should be reduced by one percent from the current Commission authorized return on equity.

A. A reduction in the return on common equity for IRP eligible plant recognizes an important balancing of interests between shareholders and ratepayers. An IRP represents a shift in the current regulatory paradigm in favor of the utility's shareholders. IRP eligible plant will be receiving a current return as well as depreciation treatment in an expedited manner when compared with a traditional rate case. Such treatment is a clear benefit to shareholders, all other things held equal. Therefore, it is reasonable for the Commission to recognize a reduction in the return on equity for plant included in WVAW's IRP. A reduction of one percent from the Company's current authorized return on equity to 8.75% is a reasonable and conservative adjustment and assists in mitigating the rate impact to customers during the effective period of the IRP. Once WVAW files for a base rate case, plant included in the IRP should be rolled into its rate base and receive a full return on equity.

Q. Explain the basis for requiring WVAW to file a base rate case no later than two years after the implementation of the IRP.

A. At some point, the Commission should assess the workability and reasonableness of an IRP within a base rate case proceeding. The Company's proposed IRP has no provision for any such review by the Commission. Conceivably, WVAW could stay out of a base rate case indefinitely, especially considering the expansive categories of plant that it intends to include in its proposed IRP. This may be an advantageous arrangement for WVAW and its shareholders, but it places the Commission and West Virginia ratepayers at an extreme disadvantage with respect to properly reviewing the reasonableness of the costs of IRP eligible plant. A requirement that WVAW file a rate case within two years of the implementation of an IRP ensures that the Commission, Staff, and other parties can review the reasonableness of cost recovery from ratepayers.

Q. How should a review process be structured to ensure that costs passed through an IRP are prudent?

A. In IRP filings submitted by the Company after the initial year of implementation, WVAW should be required to submit detailed actual cost information for IRP investment for the prior year. The Staff, CAD, and other parties should be allowed to conduct discovery on this information for purposes of determining whether costs were prudently incurred, and should be allowed to submit testimony challenging any imprudently incurred costs. The Commission, after a hearing, could disallow any imprudent investment costs. Using this process will ensure that ratepayers are protected from unjust and unreasonable IRP investment costs.

Q. Do you agree with a volumetric charge to collect the costs associated with WVAW's IRP?

A. No. Consistent with my Rebuttal Testimony in the Company's last rate case, the costs subject to collection through the proposed IRP are all fixed costs. As such, they do not vary with water consumption. Thus, they should not be collected in a volumetric charge.

In addition, there are significant inter-class and intra-class inequities that are likely to occur using a volumetric rate. The problem is that high load factor customers will pay more than their fair share of costs and, conversely, lower load factor customers will pay less than their fair share. This is because high load factor customers use more water for a given level of demand than lower load factor customers.

A simple example will illustrate how this inequity occurs. Assume two large industrial customers with a maximum daily demand of 34,000 gallons each. Further assume that Customer 1 uses an average of 27,200 gallons per day and that Customer 2 uses an average of 13,600 gallons per day. Both have the same maximum demand (34,000 gallons), but Customer 1 has a higher load factor (80%) than Customer 2 (40%).

In terms of cost responsibility, Customers 1 and 2 have the same responsibility for WVAWC's IRP costs because their peak demands are the same. But since Customer 2 consumes less water in relation to its maximum daily demand, it will pay less than its fair share of the Company's IRP costs due to the use of a volumetric charge. On the flip side of the coin, Customer 1 will pay more than its fair share due to its relatively higher Mcf consumption.

If the Commission considers approval of an IRP, then costs should be collected through a fixed monthly charge per customer.

Q. How should the fixed monthly charge be structured?

A. Since I recommend that only smaller sized mains be included in an IRP, my recommendation at this time is for the same fixed monthly charge to be applied to all customers. This is because replacement of smaller mains will most likely benefit lower consumption users compared to high volume users that take service from larger sized mains. I understand that this may not be the preferred approach for some customer classes, but it is the correct means for collecting these demand-related costs. Unfortunately, the Company employs a unified rate for all customers, so a division by customer class – which I am aware the Commission has adopted in other surcharge contexts – is not easily feasible, short of the Company developing class-specific rate schedules.

Q. Does this conclude your Direct Testimony?

A. Yes.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0550-W-P

WEST VIRGINIA-AMERICAN WATER COMPANY, a public utility, Charleston, West Virginia.
Petition for approval of a 2017 Infrastructure Replacement Program Surcharge Mechanism.

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF

THE WEST VIRGINIA ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.

SEPTEMBER 22, 2016

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0550-W-P

WEST VIRGINIA-AMERICAN WATER COMPANY, a public utility, Charleston, West Virginia.
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SEPTEMBER 22, 2016

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area
Vermont Department of Public Service

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042-000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

**Expert Testimony Appearances
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As of September 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

**Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co.	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

Expert Testimony Appearances
of
Richard A. Baudino
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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
08/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital
08/16	R-2016-2537359	PA	AK Steel Corp.	West Penn Power Co.	Cost and revenue allocation
09/16	2016-00162	KY	Kentucky Office of the Attorney General	Columbia Gas of Ky.	Return on equity, cost of short-term debt
09/16	16-0550-W-P	WV	West Va. Energy Users Gp.	West Va. American Water Co.	Infrastructure Replacement Program Surcharge

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 16-0550-W-P

WEST VIRGINIA-AMERICAN WATER COMPANY, a public utility,
Charleston, West Virginia.
Petition for approval of a 2017 Infrastructure Replacement
Program Surcharge Mechanism.

EXHIBIT___(RAB-2)
OF
RICHARD A. BAUDINO

ON BEHALF OF

THE WEST VIRGINIA ENERGY USERS GROUP

J. KENNEDY AND ASSOCIATES, INC.

SEPTEMBER 22, 2016

WEST VIRGINIA-AMERICAN WATER
CASE NO. 16-0550-W-P
CONSUMER ADVOCATE DIVISION
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA
FIRST SET OF INTERROGATORIES

Date of Request: August 16, 2016
Prepared by: John Tomac, Manager, Rates & Regulatory Support, WVAW
Witness: John Tomac
Date Prepared: August 26, 2016

CAD 01-23

Refer to the testimony of WVAWC witness McIntyre at page 9.

a. Show all WVAWC projections of when it expects to reach the 5% annual cap.
b. Show all WVAWC projections of when it expects to reach a 10% cumulative annual cap.
c. Show all WVAWC projections of when it would expect to reach a lower 7.5% cumulative cap.
d. Include explanations and supporting calculations for your responses to parts a through c.

RESPONSE:

a. Please see CAD 01-23_Attachment 1 for a five-year projection of the Company's IRP. Based on the average capital spend of approximately $18.5 million for 2018-2020, the 5% annual cap will not be reached until 2020. The Company will likely file a rate application before 2020.

b. Based on my response to part a, I would not expect the cap to reach a cumulative 10% before a general rate application is filed unless a significant amount of capital over the average annual $18.5 million amount is included in the surcharge.

c. In order to reach an approximate 7.5 % cumulative cap, the average capital spend for the years 2018-2020 of $18.5 million would have to increase to $30.5 million. Please see CAD 01-23_Attachment 2.

e. Supporting calculations are attached.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF COLUMBIA GAS	**)**	
OF KENTUCKY, INC. FOR AN	**)**	**CASE NO. 2016-00162**
ADJUSTMENT IN RATES	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

SEPTEMBER 2, 2016

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF COLUMBIA GAS	)	
OF KENTUCKY, INC. FOR AN	)	**CASE NO. 2016-00162**
ADJUSTMENT IN RATES	)	

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT IN RATES	**)))**	**CASE NO. 2016-00162**

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service,

rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit ____(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to address the allowed return on equity for Columbia Gas of Kentucky, Inc. ("Columbia" or "Company"). I will also address the Company's requested cost of short-term debt. Finally, I will respond to the Direct Testimony of Mr. Paul Moul, witness for the Company.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows.

First, I recommend that the Kentucky Public Service Commission ("Commission") adopt a fair rate of return on equity of 9.0% for Columbia. My recommended return on equity ("ROE") is based on a Discounted Cash Flow ("DCF") analysis using a comparison group of regulated gas distribution companies. My recommended 9.0% ROE is completely consistent with current stock market data, expected growth rates, and today's low interest rate environment.

Second, I recommend that the Commission reject Columbia's requested cost of short-term debt. Columbia requested a short-term debt cost of 2.50%. This requested interest cost greatly exceeds the cost associated with NiSource Inc.'s ("NiSource") short-term credit facilities. NiSource reported in its 2015 10-K report that its cost of commercial paper for 2015 was 1.0% and 0.82% for 2014. Instead, I recommend that the Commission adopt a cost of short-term debt for Columbia of 1.0%.

Third, I recommend that the Commission reject Mr. Moul's recommended 11.0% cost of equity. For reasons that I shall explain in Section IV of my testimony, a cost of equity of 11.0% is grossly overstated, inconsistent with current market required returns, and would result in an excessive and burdensome revenue requirement for Columbia's Kentucky ratepayers.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Generally speaking, interest rates have declined over the last few years. Exhibit ____(RAB-2) presents a graphic depiction of the trend in interest rates from January 2008 through July 2016. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. In January 2008, the average public utility bond yield was 6.08% and the 20-year Treasury Bond yield was 4.35%. As of July 2016 the average public utility bond yield was 3.70%, representing a decline of 238 basis points, or 2.38 percentage points, from January 2008. Likewise, the 20-year Treasury bond declined to 1.82% in July 2016, a decline of 2.53 percentage points (253 basis points) from January 2008.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in Exhibit ____(RAB-2)?

A. Yes. In response to the 2007 financial crisis and severe recession that followed in December 2007, the Federal Reserve ("Fed") undertook a series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets."[1]

QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases.

QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury securities by the second quarter of 2011.[2]

Beginning in September 2011, the Federal Reserve initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist" was designed by the Federal Reserve to lower long-term interest rates and support the economic recovery.

QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities.

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[1] http://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm

[2] http://www.federalreserve.gov/newsevents/press/monetary/20101103a.htm

On June 19, 2013, the Federal Open Market Committee ("FOMC") issued a press release indicating that it intended to extend "Operation Twist." In its press release, the Federal Reserve stated:

> To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.

More recently, the Federal Reserve began to pare back its purchases of securities. For example, on January 29, 2014 the Federal Reserve stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Federal Reserve continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October.[3]

Q. Since the Federal Reserve's announcements of scaling back and finally ending its purchases of long-term Treasury securities, what has the trend been in long-term Treasury yields from 2014 through 2016?

A. The yield on the 20-year Treasury bond has actually declined since the beginning of 2014. The January 2014 yield on the 20-year Treasury bond was 3.52%. The

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[3] http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm

closing yield for July 2016 was 1.82%, a decline of 170 basis points since January 2014.

Q. Has the Federal Reserve recently indicated any important changes to its monetary policy?

A. Yes. Recently the Federal Reserve raised its target range for the federal funds rate to 1/4% to 1/2% from 0% to 1/4%. The Federal Reserve also issued a press release dated June 15, 2016 from the Federal Open Market Committee stating the following:

> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will strengthen. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of past declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to closely monitor inflation indicators and global economic and financial developments.
>
> Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.

Note that the stance of the Federal Reserve is one of accommodation and that it decided to maintain short-term interest rates at their present levels. This continues to favor lower expected returns on the part of investors for lower risk and higher yielding regulated utility stocks.

Q. Why is it important to understand the Fed's actions with respect to monetary policy since 2007?

A. The Fed's monetary policy actions since 2007 were deliberately undertaken to lower interest rates and support economic recovery. The Fed's actions have been quite successful in lowering interest rates given that the 20-year Treasury Bond yield in June 2007 was 5.29% and the public utility bond yield was 6.34%. The U.S. economy is currently in a low interest rate environment that, in my opinion, will likely continue at least through this year. As I will demonstrate later in my testimony, low interest rates have also significantly lowered investors' required return on equity for the stocks of regulated utilities.

Q. Are current interest rates indicative of investor expectations regarding future policy actions by the Federal Reserve?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> "A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information."[4]

I acknowledge that the U.S. economy is operating in a low interest rate environment. It is likely at some point in the near future that the Federal Reserve will raise short-term interest rates further. However, the timing and the level of any such move are not known at this time. It is important to realize that investor expectations of higher interest rates, if any, are already embodied in current securities prices, which include debt securities and stock prices.

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[4] Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.

The current low interest rate environment favors lower risk regulated utilities. As I shall demonstrate in Section III, all the market evidence I examined suggests that investors require lower rates of return on equity on regulated utility stocks.

Q. Has the Federal Reserve recently signaled its intentions as to whether it will increase interest rates this year?

A. The Federal Reserve Open Market Committee noted the following in its Minutes of the Meeting of July 26 - 27, 2016:

> "Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at ¼ to ½ percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.
>
> In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 per-cent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as in-formed by incoming data."[5]

My reading of this recent statement indicates that the Federal Reserve will continue its accommodative stance toward monetary policy and will not increase interest rates

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[5] *Minutes of the Federal Open Market Committee, July 26 - 27, 2016,* pages 13 and 14.

at this time. However, future increases are likely to be gradual and the target Federal Funds Rate will continue to remain low for the near future.

Q. How does the investment community regard the regulated gas distribution industry as a whole?

A. The Value Line Investment Survey's June 3, 2016 summary report on the Natural Gas Utility industry noted the following:

"Stocks within the Natural Gas Utility Industry ought to attract the interest of income-focused investors with a conservative bent, given that a number of these issues are ranked favorably for Safety and boast high marks for Price Stability. Those seeking outstanding short-term investment performance should find something to like here, too, such as Atmos Energy, Southwest Gas, UGI Corp. and Spire Inc. (formerly Laclede Group). It is important to mention that companies owning larger nonregulated operations might offer a higher potential for returns, but profits could be more volatile than for companies with a greater emphasis on the more stable utility segment."

Q. What do you conclude from the aforementioned quote from Value Line?

A. Utilities in general and gas utilities in particular continue to be safe, solid stock choices for investors. Even with uncertainty regarding the Federal Reserve's future moves on interest rates, utilities' stock prices have made solid gains since the beginning of 2016. For example, the Dow Jones utility average opened January 2016 at 574.51 and closed at 711.42 on July 31, 2016. This represents a gain of 23.8% since the beginning of this year.

It appears that the Fed will continue a relatively accommodating stance with respect to monetary policy in 2016 and has signaled that it does not intend to raise short-term interest rates at this time. The volatile economic conditions that were present in the 2008 - 2009 period are over and the U.S. economy continues to recover from the recession of 2007-2008.

Q. Briefly describe Columbia Gas.

A. Columbia Gas of Kentucky, Inc. is part of the Gas Distribution Operations segment of NiSource, Inc. According to NiSource's Form 10-K for the period ending 12/31/2015, its Gas Distribution Operations "serves approximately 3.4 million customers in seven states and operate approximately 59,000 miles of pipeline."[6] Columbia Gas is one of seven regulated gas utility companies owned by NiSource. Columbia Gas of Kentucky serves 135,000 customers within Kentucky through approximately 2,600 miles of distribution mains.

Table 1 below provides several descriptive statistics illustrating recent financial data for Columbia. This data was derived from Schedule K of the Company's filing and from Columbia's response to AG 1-27.

TABLE 1
Columbia Gas of Kentucky
Selected Statistics

	2015	2014	2013	2012	2011
Net Plant in Service (000s)	252,682	228,421	202,629	187,268	174,577
Return on Equity (%)	9.83%	11.25%	10.78%	9.20%	11.78%
AFUDC - % of Net Income	0.95%	1.26%	0.95%	0.49%	0.17%
Embedded Cost of Short-term Debt	0.72%	0.81%	0.71%	1.28%	1.62%
Embedded Cost of Long-term Debt	5.82%	5.82%	5.89%	5.68%	5.88%

Sources: Schedule K, Columbia Response to AG 1-27, Attachment A

[6] NiSource, Inc. Form 10-K, filed 02/18/16 for the Period Ending 12/31/15, page 6.

Since 2011, Columbia increased its net plant in service by 44.7%. The Commission-approved Accelerated Main Replacement Program ("AMRP") has supported this increase. On page 12 of his Direct Testimony, Company witness Herbert Miller noted that since the program began in 2008, Columbia replaced more than 108 miles of its priority pipe and associated services and appurtenances using the AMRP. Total return on equity over the last five years has ranged from 9.83% to 11.78%.[7] The amount of Allowance for Funds Used During Construction as a percentage of Columbia's net income has been low, ranging from 0.17% to 1.26%.

Q. Does Columbia have its own credit and bond ratings?

A. No. As part of the Gas Distribution Operations segment, Columbia does not have its own credit ratings.

Q. What are the current credit ratings for NiSource?

A. NiSource currently carries a BBB+ credit rating from Standard and Poor's ("S&P"), a Baa2 rating from Moody's, and a BBB rating from Fitch.

Effective July 1, 2015 NiSource effectuated a corporate separation of Columbia Pipeline Group. NiSource and Columbia Pipeline are now two separate publicly traded companies. This separation resulted in S&P raising NiSource's Issuer Credit

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[7] Columbia noted the following in its response to AG 1-27: "Please note that the calculation of ROE is based on actual unadjusted net income and common equity as shown in Columbia's financial statements and, therefore, includes items that are non-utility in nature and, accordingly, are not included in the determination of a revenue requirement for the purposes of developing base rates."

Rating ("ICR") from BBB- to BBB+, an upgrade of two notches. In its June 18, 2015 report on NiSource, S&P noted the following:

NiSource is nearing the spin-off of the higher-risk pipeline and midstream energy business, Columbia Pipeline Group (CPG), resulting in sufficient improvement in business risk to revise the company's business risk profile to "excellent" from "strong". Following this divestiture, NiSource's pro forma operating earnings will be about two-thirds low-risk regulated natural gas distribution utility operations and one-third vertically integrated electric utility operations. The "excellent" business risk assessment incorporates NiSource's focus only on regulated utility operations where there is geographical and operating diversity with numerous utilities that serve more than 3.3 million natural gas distribution customers in seven states from Indiana to Massachusetts and 450,000 electricity customers in northern Indiana."

We base our assessment of NiSource's business risk profile on the company's "strong" competitive position and "very low" industry risk derived from the regulated utility industry and the "very low" country risk of the U.S. where the company operates. NiSource's competitive position partly reflects the stable regulatory framework of the low-risk regulated utility operations. We consider the company's gas distribution operations to be above average, characterized by ample geographic diversity and integration with the company's gas transmission network, which provides operational flexibility. Nearly all of the gas distribution subsidiaries' needs are contracted, with roughly 70% of peak gas needs met with storage gas. This bolsters service reliability, thereby supporting the business risk profile. Cash flow variability is also low given material revenue stabilization and cost-tracking mechanisms.[8]

Moody's June 18, 2015 report on NiSource noted the following rating drivers:

- "NiSource set to become a fully regulated utility company on 1 July 2015
- Persistent high debt balance and elevated investment spend weigh on financial profile
- Stability of cash flows underpinned by supportive regulatory constructs that largely offset high leverage

[8] Columbia response to AG 1-26, Attachment O, pages 2 and 3.

- Regulated utility assets carry low business risk"[9]

Q. What is your overall assessment of Columbia's riskiness?

A. Columbia is a low-risk regulated gas distribution company that adds revenue and earnings stability to NiSource. The Commission-approved AMRP has successfully supported Columbia's capital expenditures since 2008. The Company's return on equity has been supported by excellent earnings quality, with AFUDC being a small percentage of its total net income.

In terms of the investor required return on equity for Columbia, it is reasonable to rely on a comparison group of regulated gas distribution utilities. In my opinion and based on my review of the credit rating reports for NiSource, Columbia's overall risk profile is reasonably comparable to an average gas distribution company.

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[9] Columbia response to AG 1-26, Attachment P, page 2.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for Columbia.

A. I employed a Discounted Cash Flow ("DCF") analysis using a group of regulated gas distribution utilities. In my opinion, they form a reasonable basis for estimating the investor required return on equity for Columbia.

My DCF analysis is my standard constant growth form of the model that employs four different growth rate forecasts from the Value Line Investment Survey, IBES, and Zacks. I also employed Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data. Although I did not rely on the CAPM for my recommended 9.0% ROE for Columbia, the results from the CAPM tend to support this recommendation.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) and Bluefield W.W. & Improv. Co. v. Public Service Comm'n, 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm’s cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm’s earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. Many regulated utility stocks are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody’s and Standard and Poor’s perform detailed analyses of factors that contribute to the risk of a particular investment. The end result of their analyses is a bond and/or credit rating that reflect these risks.

<u>Discounted Cash Flow (“DCF”) Model</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I typically employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}\!/_{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Embodied in this formula, it is assumed that "k" reflects the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for Columbia?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to Columbia. As a part of NiSource, Columbia is not a publicly traded company and, therefore, has no stock price and growth forecasts to use in a DCF analysis. Therefore, a group of natural gas distribution companies must be employed to estimate an investor required ROE for Columbia.

For purposes of this case, I will adopt the gas distribution group that Company witness Paul Moul employed. Mr. Moul's group provides a reasonable basis for estimating the cost of equity for Columbia.

Q. What was your first step in determining the DCF return on equity for the comparison groups of regulated gas utilities?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from February through July 2016. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the gas distribution group is 2.78%. These calculations are shown in Exhibit **____**(RAB-3).

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the comparison groups?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and

Thomson/IBES. This is the method I typically use for estimating growth for my DCF calculations.

Q. Please briefly describe Value Line, Zacks, and Thomson/IBES.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Plus Edition. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated gas utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, Thomson/IBES also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. Please explain how you used analysts' dividend and earnings growth forecasts in your constant growth DCF analysis.

Q. Columns (1) through (5) of Exhibit ____(RAB-4) shows the forecasted dividend, earnings, and retention growth rates from Value Line and the earnings growth forecasts from Thomson/IBES and Zacks for the companies in the gas distribution group. In my analysis I used four of these growth rates: dividend and earnings growth from Value Line and earnings growth from Zacks and Thomson/IBES. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows. Value Line is the only source of which I am aware that forecasts dividend growth and my approach gives this forecast equal weight with each of the three earnings growth forecasts.

Q. How did you proceed to determine the DCF return on equity for the two comparison groups?

A. To estimate the expected dividend yield (D_1), the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

Exhibit ____(RAB-4) presents my standard method of calculating dividend yields, growth rates, and return on equity for the gas distribution group of companies. The DCF Return on Equity Calculation section shows the application of each of four growth rates I used in my analysis to the current group dividend yield of 2.78% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. My DCF return on equity was calculated using two different methods. Method 1 uses the average growth rates and Method 2 utilizes the median growth rates.

Q. What are the results of your constant growth DCF model?

A. The results for Method 1 range from 7.66% to 9.17%, with the average of these results being 8.42%. The results for Method 2 range from 7.60% to 9.37%, with the average of these results being 8.71%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: *K* = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[10] There is evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

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[10] For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206 - 211, 2007 edition.

In the final analysis, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for August 16, 2016. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit ____(RAB-5). I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 9.84% to 10.0%. The average of these two market returns is 9.92%.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2015 Classic Yearbook*. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit ____(RAB-6) presents the calculation of the market returns using the historical data.

Q. Please explain how this historical risk premium is calculated.

A. Exhibit ____(RAB-6) shows both the geometric and arithmetic average of yearly historical stock market returns over the historical period from 1926 - 2014. The average annual income return for 20-year Treasury bond is subtracted from these historical stocks returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The historical market risk premium range is 5.03% - 7.03%.

Q. Did you add an additional measure of the historical risk premium in this case?

A. Yes. Morningstar reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001.[11] Morningstar recommended adjusting this growth in the P/E ratio for stocks out of the historical risk premium because "it is not believed that P/E will continue to increase in the future." Morningstar's adjusted historical arithmetic market risk premium is 6.19%, which I have also included in Exhibit ____(RAB-6).

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[11] *2015 Ibbotson SBBI Classic Yearbook*, Morningstar, pp. 156 - 158.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from February through July 2016. The 20-year Treasury bond may be used as a proxy for the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM return on equity may be estimated.

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the gas distribution group from most recent Value Line reports. The average of the Value Line betas for the comparison group is 0.73.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 7.53% - 7.77%. Using historical risk premiums, the CAPM results are 5.77% - 7.22%.

ROE Conclusions and Recommendations

Q. Please summarize the cost of equity results for your DCF and CAPM analyses.

A. Table 2 below summarizes my return on equity results using the DCF and CAPM for my comparison group of companies.

TABLE 2

COLUMBIA GAS OF KY.
ROE RESULTS SUMMARY

DCF Results:	
Average Growth Rates, Gas Group	
- High	9.17%
- Low	7.66%
- Average	8.42%
Median Growth Rates, Gas Group	
- High	9.63%
- Low	7.60%
- Average	8.71%
CAPM:	
- 5-Year Treasury Bond	7.53%
- 20-Year Treasury Bond	7.77%
- Historical Returns	5.77% - 7.22%

Q. What is your recommended return on equity for Columbia?

A. I recommend that the Commission adopt a 9.0% return on equity for Columbia. My recommendation is consistent with the middle of the range of DCF results that employed earnings growth forecasts for the gas distribution group (8.25% - 9.63%). Based on current market evidence, a 9.0% return on equity is fair and reasonable, even generous for a regulated natural gas distribution company such as Columbia Gas.

Q. Mr. Baudino, are you concerned that your recommended cost of equity is too low?

A. No, not at all. All of the market evidence I examined fully supports my ROE recommendation for Columbia in this proceeding. As I described in Section II of my testimony, the U. S. economy is in a low interest rate environment, one that has been supported in a deliberate and considered fashion by Federal Reserve monetary policy. Both my DCF and CAPM ROE estimates show that the investor required ROE for Columbia, as well as other regulated gas and water utilities, reflects this low interest rate environment. A 9.0% ROE recommendation for Columbia is by no means too low in the current economic and financial environment and is higher than the average DCF results.

Q. Please explain why you chose to move to the upper end of your range of DCF results in this particular proceeding.

A. There are good reasons for recommending the upper end of my DCF results for Columbia at this time in this particular case.

First, the dividend growth forecasts for my gas company comparison group are significantly lower than the earnings growth forecasts at this point in time. Referring to Exhibit ____(RAB-4), the DCF ROE estimates using dividend growth range from 7.60% to 7.66%. If these rather low DCF estimates are excluded from the averages, then the average DCF for Method 1 is 8.68% and the average DCF for Method 2 is 9.08%.

Second, in my opinion it is likely that interest rates may increase at some point in the near future. One cannot say when or by how much rates will go up at this time, but the Federal Reserve has signaled its willingness to raise rates later this year and into next year if conditions warrant. Of course, the Federal Reserve did not increase interest rates in July and August, but in my view it stands ready to do so if economic conditions warrant such an increase. Given this readiness on the part of the Federal

Reserve to raise interest rates, I believe that a modest upward adjustment to my return on equity recommendation is reasonable in this case.

Taking these two points into consideration and using my professional judgment, a 9.0% ROE is a reasonable and appropriate recommendation for Columbia in this case.

Q. Mr. Moul concluded that Columbia's capital costs are higher due to its greater risk.[12] Please respond to Mr. Moul's conclusion.

A. I disagree with Mr. Moul. The Moody's and S&P ratings reports for NiSource cite to the low risk regulated gas operations as support for NiSource's ratings. The lower credit quality of NiSource relative to the Gas Group is due in part to its higher corporate leverage. The Value Line Investment Survey's June 3, 2016 report on NiSource reported that its 2015 equity ratio was 39.3% and its expected 2016 common equity ratio was 38.0%. This is substantially lower than the 50.80% common equity ratio for Columbia, which Mr. Kollen recommends in his Direct Testimony. Columbia contributes both lower leverage and lower risk gas operations to NiSource, which in my opinion is in an overall riskier position than Columbia.

Q. How does Mr. Kollen's recommended common equity ratio compare to the gas company comparison group you used to estimate the DCF cost of equity?

[12] Moul Direct Testimony at page 20, lines 8 through 16.

A. Table 3 presents the 2015 common equity ratios for the companies in the gas comparison group. Table 3 shows the average for the group and the average excluding Chesapeake Utilities.

TABLE 3

GAS UTILITY GROUP
2015 COMMON EQUITY RATIOS

Atmos Energy	56.5%
Chesapeake Utilities	70.6%
New Jersey Resources	56.8%
Northwest Natural Gas	57.5%
South Jersey Industries	50.8%
Southwest Gas	50.7%
Spire Inc.	47.0%
WGL Holdings	56.1%
Average	55.8%
Average Excluding Chesapeake	53.6%

Source: Value Line Investment Survey

Mr. Kollen's recommended common equity ratio falls within the range of the gas utility group. For comparison purposes, it is important to exclude Chesapeake from the group average due to its excessive 70.6% common equity ratio. Clearly, this equity ratio is not appropriate for ratemaking purposes for a regulated gas utility company and including it would skew the group average upward.

Cost of Short-Term Debt

Q. Please explain how you adjusted Columbia's requested cost of short-term debt.

A. My recommended cost of short-term debt is based on Columbia's most recent embedded cost of short-term debt. Table 1 shows that Columbia's embedded cost of short-term debt was 0.81% in 2014 and 0.72% in 2015. In 2016 interest rates remain low. Therefore, I recommend that the Commission adopt a short-term debt cost rate for Columbia of 1.0%. This cost rate is slightly higher than Columbia's 2015 embedded cost of short-term debt and reasonably allows for the possibility that short-term interest rates may rise later this year and early next year.

Q. Please explain why the Commission should reject Columbia's requested short-term debt cost rate of 2.50%.

A. The 2.50% cost of short-term debt recommended by Mr. Moul is inconsistent with Columbia's embedded cost of short-term debt compared to 2015 and, in fact, is far higher than any year since at least 2011. Mr. Moul based this recommendation on a forecasted one-month London Interbank Offer Rate ("LIBOR") of 1.425% and a credit facility spread of 1.075%.[13] However, NiSource reported in its 2015 Form 10-K that its cost of short-term debt was 1.0% for 2015 and 0.82% for 2014.[14] These actual short-term rates are far lower than the 2.50% rate Mr. Moul recommends.

Q. What is the revised weighted cost of capital based on your recommendations?

A. Mr. Lane Kollen presents the revised weighted cost of capital on behalf of the Attorney General in his Direct Testimony.

[13] Moul Direct Testimony at page 25, lines 1 - 2.

[14] NiSource, Inc. 2015 Form 10-K, page 26.

IV. RESPONSE TO COLUMBIA GAS ROE TESTIMONY

Q. Have you reviewed the Direct Testimony of Mr. Moul?

A. Yes.

Q. Please summarize your conclusions with respect to Mr. Moul's testimony and approach to return on equity.

A. Based on my review of Mr. Moul's return on equity analyses, my conclusions are as follows:

1. With respect to this DCF analysis, Mr. Moul included a leverage adjustment to his DCF analysis that is inappropriate and led to a significant overstatement of his recommended DCF result. Mr. Moul also chose the high end of the range of expected growth rates he examined, which further inflated his DCF ROE recommendation.
2. Mr. Moul's risk premium model suffers from an improper analysis of historical stock market returns and risk premiums. For this reason, his risk premium result of 11.70% cannot be relied upon in this case.
3. Mr. Moul's recommended CAPM result of 11.45% is excessive due to an inappropriate beta adjustment, a small size adjustment that should be rejected, and his use of forecasted interest rates.
4. Mr. Moul's Comparable Earnings analysis is not applicable for ratemaking purposes and should be rejected. Further, the Commission has rejected the comparable earnings approach in a past case.

Q. Before you proceed to your critique of Mr. Moul's four methods of estimating the return on equity for Columbia, do you have any observations regarding the results from his analyses?

A. Yes. The results from Mr. Moul's risk premium model, CAPM, and comparable earnings model are so grossly in excess of recently allowed Commission returns that they should be rejected out of hand. Table 4 shows the latest allowed ROEs for the gas distribution group that Mr. Moul and I used in our ROE analyses. This data came from *AUS Monthly Utility Reports*, August 2016.

TABLE 4

GAS UTILITY GROUP
ALLOWED ROEs

	ROE	Order Date
Atmos Energy	9.81%	9/9/2014
Chesapeake Utilities	N/A	
New Jersey Resources	10.30%	10/1/2008
Northwest Natural Gas	9.80%	11/1/2013
South Jersey Industries	9.75%	10/1/2014
Southwest Gas	9.75%	8/12/2014
Spire Inc.	N/A	
WGL Holdings	9.58%	11/22/2013

Source: AUS Monthly Utility Reports, August 2016

Allowed ROEs for the utilities in the group range from 9.58% to 10.30%. The results Mr. Moul recommended from the risk premium, CAPM, and comparable earnings analyses range from 11.45% to 12.2%. Clearly, these ROE results cannot be considered reasonable in the context of recent Commission-allowed returns and in the current low interest rate environment. The Commission should give them no weight in its evaluation of a reasonable ROE for Columbia.

<u>Discounted Cash Flow Model</u>

Q. Please summarize Mr. Moul's DCF analysis.

A. Mr. Moul applied a constant growth DCF analysis to his Gas Group beginning on Attachment PRM-7. Mr. Moul explained that he considered both historical and projected growth rates that were presented in his Attachments PRM-8 and PRM-9.[15] Historical growth rates ranged from 4.88% to 5.88%. The forecasted growth rates ranged from 4.63% (Value Line dividend growth) to 5.94% (Value Line earnings per share growth). Mr. Moul recommended a 6.0% growth rate for his DCF model.

Mr. Moul also included a "leverage adjustment" in his DCF calculation. Mr. Moul began his discussion of the leverage adjustment on page 38 of his Direct Testimony. The calculation is shown as Attachment PRM-10. Mr. Moul testified that this adjustment accounts for the financial risk difference between market value and book value capital structures.[16] Mr. Moul presented his DCF analysis including the leverage adjustment on page 44 of his Direct Testimony. The constant growth DCF result, 9.11%, plus the leverage adjustment of 0.82% results in Mr. Moul's recommended DCF return on equity of 9.93%.

Q. Is Mr. Moul's leverage adjustment to his DCF result appropriate?

A. No. Mr. Moul's leverage adjustment is inappropriate, inflates his recommended DCF result, and should be rejected by the Commission.

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[15] Moul Direct Testimony, page 31, lines 16 - 20.

[16] Moul Direct Testimony at page 38, line 9-14.

First, setting the allowed cost of capital for ratemaking purposes properly utilizes book values of common equity, preferred stock, and long-term debt. The actual book values of capitalization support the utility's investment in plant in service. With respect to the allowed return on common equity, commissions utilize market returns on book value in order to fairly compensate the equity investor for the use of his or her capital. Market-based returns are used for common equity because, unlike debt, there is no contractual cost for common equity. Thus, the return on equity must be determined using current market data, and then applied to the percentage of equity in the capital structure based on book value.

It is inappropriate to inflate market-based ROE calculations from the DCF with the leverage adjustment Mr. Moul proposed. Market prices can deviate from book value for any number of reasons. For example, investors may expect utilities to earn more than their required rate of return on equity, which would cause an increase in market stock prices above book value per share. In uncertain times, investors may view regulated utilities as safe investments, causing a flight to quality and thereby bidding up stock prices. Further, in the current low interest rate environment investors find the higher dividend yields of relatively lower risk utility stocks attractive alternatives to bonds.

Market based cost of equity estimates applied to the book value of equity is the appropriate means in setting a fair rate of return on invested capital for a regulated utility. Results from the DCF should not be adjusted upward to account for or to prop up high market-to-book ratios, as Mr. Moul has done in this case.

In addition, it is highly doubtful that investors would take the complicated and circuitous route to measuring their required returns on equity that Mr. Moul proposed in his Direct Testimony. Instead, it is much more likely that investors would take a more direct approach and use market data on stock prices and expected growth to estimate a DCF return on equity.

Finally, I would note that bond rating agencies and securities analysts do not assess a utility company's risk based on the market value of its capital structure, but on the book value of its common equity. It is reasonable to assume that investors assess capital structure risk in the same manner. Mr. Moul provided no evidence that investors assess financial risk based on the market value of a firm's common equity.

Q. Are there other concerns with Mr. Moul's DCF analysis?

A. Yes. Mr. Moul selected a growth rate, 6.0%, which is slightly greater than the high end of the growth rates he considered in his analysis. If one considers the range of projected growth rates he used - 4.63% to 5.94% - the midpoint of this range is 5.3%. This is 0.70% lower than his recommended growth rate and would lower his recommended DCF return on equity to approximately 8.4%. If one then added Mr. Moul's leverage adjustment to this 8.4% result, his adjusted DCF ROE would be 9.2%.

Combining both the leverage adjustment and the excessive growth rate resulted in a significant overstatement of Mr. Moul's DCF ROE.

<u>Risk Premium Analyses</u>

Q. Briefly summarize Mr. Moul's risk premium analyses.

A. Mr. Moul's risk premium analysis employed a prospective yield on a long-term A-rated utility bond and an expected risk premium based on his analysis of historical risk premiums from the SBBI 2015 Classic Yearbook.

Mr. Moul concluded that a 5.0% prospective yield was reasonable for the long-term A-rated utility bond. His approach is described on pages 46 - 49 of his Direct Testimony. Mr. Moul developed an array of forecasted A-rated bond yields that is shown on page 48 of his Direct Testimony.

Mr. Moul's historical risk premium was developed from historical common equity risk premiums during periods of what he described as low, average, and high interest rates. This is presented on page 50 of his Direct Testimony. From this data, Mr. Moul used a risk premium of 6.5%.

Q. Is it appropriate to use forecasted interest rates in a risk premium analysis?

A. Definitely not. Current interest rates and bond yields embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted bond yields used by Mr. Moul are speculative at best and may never come to pass. Current interest rates provide tangible and verifiable market evidence of investor return requirements today, and these are the interest rates and bond yields that should be used in both the risk premium and CAPM analyses. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

Mr. Moul's projected A-rated bond yield of 5.0% is grossly excessive in comparison to current A-rated bond yields. For example, as of July 2016, the Mergent Bond Record reported that the average A-rated utility bond yield was 3.57%. The highest A-rated bond yield for 2016 was in January, when the yield was 4.27%. Mr. Moul's projected A-rated utility bond yield serves to inflate his risk premium ROE result.

Q. Is Mr. Moul's historical risk premium analysis reasonable?

A. No. First, I described the problem with using historical risk premiums earlier in my testimony. This approach naively assumes that earned returns and the resulting risk premiums in an historical period reflect current investor expectations. Such assumptions should be viewed with a good deal of caution and skepticism. Although historical risk premiums may provide rough guides to estimating current required returns, I believe that it is preferable to place the greatest weight on DCF calculations that employ current, rather than historic data.

Secondly, Mr. Moul's analysis of historical risk premiums is not applicable to public utilities. Rather, the historical stock returns used by Mr. Moul are for the S&P 500 Composite. Thus, Mr. Moul assumes without foundation that investors expect the return of regulated public utility stocks to be the same as the S&P 500. This is not correct. Investors expect higher returns for the unregulated stocks in the S&P 500 than they would for the stocks of regulated public utilities. This is borne out by the CAPM, used by both Mr. Moul and myself, which adjusts the market risk premium by the lower betas of utility stocks to estimate the ROE. Generally speaking, investors are willing to accept lower returns for utility stocks in return for their greater safety. Using the earned returns on the S&P 500 as Mr. Moul did would overstate the expected returns for regulated public utilities.

Q. Does the common equity risk premium analysis in Mr. Moul's Attachment PRM-13 make economic sense?

A. No. Table 5 presents Mr. Moul's common equity risk premium results from Attachment PRM-13.

TABLE 5

MOUL COMMON EQUITY RISK PREMIUMS

	Large Common Stocks Returns	Long-Term Corporate Bonds	Equity Risk Premium
Low Interest Rates	12.21%	4.85%	7.36%
Average Across All Int. Rates	12.07%	6.38%	5.69%
High Interest Rates	11.93%	7.95%	3.98%

Table 5 shows that no matter which set of interest rates are used, the return on large common stocks changes very little. The difference in large common stock returns for low interest rates and high interest rates is only 28 basis points, or 0.28%. The returns for long-term corporate bonds, however, show substantial variation, going from 4.85% to 7.95%, a difference of 310 basis points, or 3.10%. Although the historical earned returns for large common stock varied little over the time periods examined by Mr. Moul, it is highly unlikely that investors' required returns would have remained virtually unchanged in low and high interest rate environments given the large changes in interest rates in his analysis. This casts significant doubt on the reliability of Mr. Moul's risk premium analysis.

Capital Asset Pricing Model

Q. Briefly summarize Mr. Moul's CAPM analyses.

A. In formulating his CAPM ROE, Mr. Moul employed an unlevered beta, the formula for which may be found on page 53 of his Direct Testimony. Mr. Moul claimed that Value Line betas couldn't be used to directly estimate the CAPM when the market value of common stock is greater than its book value. Mr. Moul's leverage adjustment increased his Gas Group beta from 0.76 to 0.88.

For the risk-free rate of return, Mr. Moul used 3.75%, which considered the Blue Chip forecasts.[17]

For the market premium, Mr. Moul used the arithmetic mean of historical market performance and a forecasted return from Value Line and S&P, resulting in a market premium of 7.27%.[18]

Finally, Mr. Moul added a size adjustment of 1.10% to compensate for the smaller size of his Gas Group. Mr. Moul's recommended CAPM ROE was 11.45%.[19]

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[17] Moul Direct Testimony at page 55, lines 10 - 12.

[18] Moul Direct Testimony at page 56, lines 18-19.

Q. Please respond to Mr. Moul's CAPM analyses.

A. Mr. Moul's CAPM result is overstated and should be rejected by the Commission.

First, the Commission should reject Mr. Moul's reformulated beta estimate. The appropriate beta to use in the CAPM is one that investors expect based on a stock's relative price movements with the overall market. Mr. Moul introduced a highly questionable adjustment to published Value Line betas based on differences between market and book value capital structures. His claim that a leveraged beta should be used in the CAPM for ratemaking purposes is erroneous. He provided absolutely no evidence that investors in utility company stocks use the calculation of beta he presented in his testimony. It is more reasonable to assume that, to the extent investors rely on the CAPM model at all, they also are more likely to rely on widely published beta estimates from Value Line and other sources.

Second, Mr. Moul's size premium of 1.10% should be rejected as well. I acknowledge that the SBBI 2015 Classic Yearbook discusses the phenomenon of firm size and return extensively. However, the extent to which there is a firm size effect with respect to regulated gas companies is not evaluated or discussed. The Decile 3 through 5 companies that constitute mid-cap market capitalization have aggregate historical betas of 1.12 and obviously include many unregulated

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[19] Moul Direct Testimony at page 58, lines 8-9.

companies that carry far greater risk than Columbia. These betas are greatly in excess of Mr. Moul's group beta of 0.76. Therefore, a size premium of 1.10% is completely unwarranted and merely serves to inflate Mr. Moul's already overstated CAPM results.

Third, Mr. Moul should have used the current yield on 30-year Treasury Bonds, rather than a forecasted yield for the same reasons I stated in my response to his risk premium analysis. Current 30-year Treasury yields as July 2016 were 2.23%, according to the historical data provided by the Board of Governors of the Federal Reserve System. As of August 18, the yield on the 30-year Treasury Bond was 2.26%. Clearly, Mr. Moul's forecasted 30-year Treasury Bond yield of 3.75% is overstated.

Q. What is Mr. Moul's CAPM result if you remove the size adjustment and use the Value Line beta for his Electric Group?

A. The CAPM result is as follows:

3.75*% (RF Rate) + .76 x (7.27%) = 9.275%*

I note that this result would be even lower if recent 30-year Treasury bond yields are used. However, this example illustrates how much Mr. Moul overstated the CAPM results by including the beta and size adjustments in his analysis.

<u>Comparable Earnings</u>

Q. Briefly comment on Mr. Moul's comparable earnings analysis.

A. Mr. Moul performed a comparable earnings analysis on a group of unregulated companies from Value Line that was selected based on several criteria included in his Attachment PRM-15. Forecasted and historical rates of return were obtained from Value Line and then averaged. The resulting ROE was 12.2%.

I recommend that the Commission reject Mr. Moul's comparable earnings analysis. Forecasted earned returns on book equity are not reasonable proxies for investor expectations in the marketplace. Near-term book accounting returns do not necessarily reflect investor requirements and/or expected market returns. Accounting returns are not necessarily tied to current market forces such as interest rates and stock prices. Thus, they are poor indicators of investors' current required returns. A properly specified and estimated DCF model, which uses current stock prices, is a far more reasonable and accurate gauge of investor requirements.

Further, expected returns on book equity for unregulated companies have nothing to do with investor expected returns for lower-risk regulated gas utilities such as Columbia. And Mr. Moul's 12.2% comparable earnings ROE result is far greater than any Commission-allowed return in recent memory and fails the test of reasonableness on its face. I recommend that the Commission reject Mr. Moul's comparable earnings analyses.

Q. Has the Commission rejected the comparable earnings approach?

A. Yes. The Commission's Order in Case No. 98-474 discusses the comparable earnings approach on pages 97 and 98. The Commission stated the following in its Order:

"The Commission finds KU’s use of unregulated non-electric companies to be inappropriate for use as comparison companies in its DCF and other analyses for ratemaking purposes. Unregulated non-electric companies do not properly represent the environment in which KU operates. KU correctly states that it must compete with all companies, regulated or otherwise, to attract equity capital, not just with other electric utilities. However, investors do not look at Safety Rankings alone when deciding how to invest their money and are fully aware of risk differentials between regulated and unregulated companies. KU operates in an environment where it has an inalienable right to charge a rate that covers all its reasonable and prudent costs and provides its investors an opportunity to earn a reasonable return. Unregulated companies have no such right. A more appropriate set of comparison companies in analyzing investments with similar risk would be other electric utilities."

Q. Does this complete your Direct Testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF COLUMBIA GAS	**)**	
OF KENTUCKY, INC. FOR AN	**)**	**CASE NO. 2016-00162**
ADJUSTMENT IN RATES	**)**	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

SEPTEMBER 2, 2016

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area
Vermont Department of Public Service

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

**Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

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Richard A. Baudino
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Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

Expert Testimony Appearances
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Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
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As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD	Maryland Industrial Gr. & United States	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Richard A. Baudino
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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

**Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

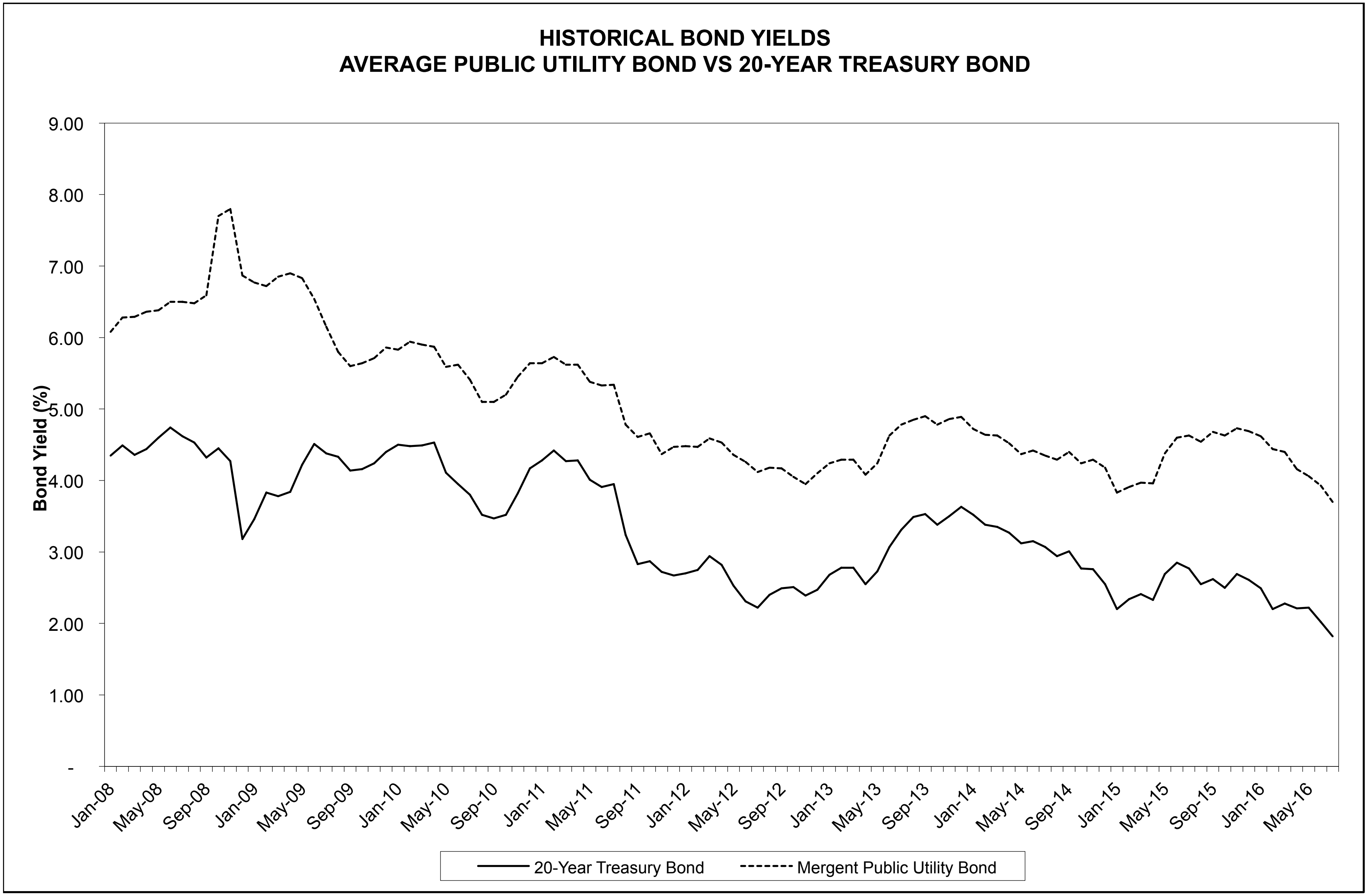
Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

Expert Testimony Appearances
of
Richard A. Baudino
As of September 2016

Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues
08/16	8710	VT	Vermont Dept. of Public Service	Vermont Gas Systems	Return on equity, cost of debt, cost of capital
08/16	R-2016-2537359	PA	AK Steel Corp.	West Penn Power Co.	Cost and revenue allocation
09/16	2016-00162	KY	Kentucky Office of the Attorney General	Columbia Gas of Ky.	Return on equity, cost of short-term debt

Exhibit ____(RAB-2)



COLUMBIA GAS OF KENTUCKY
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jul-16	Jun-16	May-16	Apr-16	Mar-16	Feb-16
Atmos Energy	High Price ($)	81.970	81.350	75.100	74.860	74.600	71.900
	Low Price ($)	78.390	72.420	70.840	70.410	68.600	67.940
	Avg. Price ($)	80.180	76.885	72.970	72.635	71.600	69.920
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.420
	Mo. Avg. Div.	2.10%	2.19%	2.30%	2.31%	2.35%	2.40%
	6 mos. Avg.	2.27%					
Chesapeake Utilities	High Price ($)	67.500	66.190	63.950	63.280	63.840	67.360
	Low Price ($)	63.120	57.430	56.560	58.970	56.100	61.450
	Avg. Price ($)	65.310	61.810	60.255	61.125	59.970	64.405
	Dividend ($)	0.305	0.305	0.288	0.288	0.288	0.288
	Mo. Avg. Div.	1.87%	1.97%	1.91%	1.88%	1.92%	1.79%
	6 mos. Avg.	1.89%					
New Jersey Resources	High Price ($)	38.920	38.560	37.170	36.880	36.850	36.570
	Low Price ($)	36.270	35.140	33.910	34.550	33.320	33.370
	Avg. Price ($)	37.595	36.850	35.540	35.715	35.085	34.970
	Dividend ($)	0.240	0.240	0.240	0.240	0.240	0.240
	Mo. Avg. Div.	2.55%	2.61%	2.70%	2.69%	2.74%	2.75%
	6 mos. Avg.	2.67%					
Northwest Natural Gas	High Price ($)	66.170	64.840	57.950	54.290	54.510	53.880
	Low Price ($)	63.260	55.060	51.120	49.460	48.900	49.410
	Avg. Price ($)	64.715	59.950	54.535	51.875	51.705	51.645
	Dividend ($)	0.468	0.468	0.468	0.468	0.468	0.468
	Mo. Avg. Div.	2.89%	3.12%	3.43%	3.61%	3.62%	3.62%
	6 mos. Avg.	3.38%					
South Jersey Industries	High Price ($)	32.000	31.640	28.970	28.550	29.140	26.940
	Low Price ($)	30.870	28.520	26.290	27.170	25.270	24.540
	Avg. Price ($)	31.435	30.080	27.630	27.860	27.205	25.740
	Dividend ($)	0.264	0.264	0.264	0.264	0.264	0.264
	Mo. Avg. Div.	3.36%	3.51%	3.82%	3.79%	3.88%	4.10%
	6 mos. Avg.	3.74%					
Southwest Gas	High Price ($)	79.580	79.430	70.510	66.600	67.290	62.430
	Low Price ($)	75.500	69.180	64.390	62.750	59.490	58.070
	Avg. Price ($)	77.540	74.305	67.450	64.675	63.390	60.250
	Dividend ($)	0.450	0.450	0.450	0.405	0.405	0.405
	Mo. Avg. Div.	2.32%	2.42%	2.67%	2.50%	2.56%	2.69%
	6 mos. Avg.	2.53%					

COLUMBIA GAS OF KENTUCKY
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jul-16	Jun-16	May-16	Apr-16	Mar-16	Feb-16
Spire Inc.	High Price ($)	71.210	70.870	66.200	68.400	68.790	66.430
	Low Price ($)	67.670	63.150	61.000	62.650	64.390	63.310
	Avg. Price ($)	69.440	67.010	63.600	65.525	66.590	64.870
	Dividend ($)	0.490	0.490	0.490	0.490	0.490	0.490
	Mo. Avg. Div.	2.82%	2.92%	3.08%	2.99%	2.94%	3.02%
	6 mos. Avg.	2.96%					
WGL Holdings	High Price ($)	72.180	70.810	70.090	72.840	74.100	69.200
	Low Price ($)	69.310	65.100	63.060	65.000	67.230	62.930
	Avg. Price ($)	70.745	67.955	66.575	68.920	70.665	66.065
	Dividend ($)	0.488	0.488	0.488	0.488	0.463	0.463
	Mo. Avg. Div.	2.76%	2.87%	2.93%	2.83%	2.62%	2.80%
	6 mos. Avg.	2.80%					
6-month Average Dividend Yield		2.78%					

Source: Yahoo! Finance

Exhibit ____(RAB-4)

COLUMBIA GAS OF KENTUCKY
GAS DISTRIBUTION COMPANY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson/ IBES
Atmos Energy	6.50%	6.50%	5.50%	7.20%	7.30%
Chesapeake Utilities	6.00%	8.50%	8.00%	N/A	3.00%
New Jersey Resources	3.00%	1.00%	5.00%	6.50%	6.50%
Northwest Natural Gas	2.00%	7.00%	3.50%	4.00%	4.00%
South Jersey Industries	6.50%	3.00%	1.50%	10.00%	6.00%
Southwest Gas	8.50%	7.00%	6.00%	4.50%	4.00%
Spire Inc.	3.50%	9.00%	5.00%	4.60%	4.78%
WGL Holdings	2.50%	3.50%	3.50%	7.30%	8.00%
Average Growth Rates	4.81%	5.69%	4.75%	6.30%	5.45%
Median Growth Rates	4.75%	6.75%	5.00%	6.50%	5.39%

Sources: Zack's and Thomson Earnings Reports, retrieved August 24, 2016
Value Line Investment Survey, September 2, 2016

COLUMBIA GAS OF KENTUCKY
GAS DISTRIBUTION COMPANY GROUP
DCF RETURN ON EQUITY CALCULATION

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) Thomson Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	2.78%	2.78%	2.78%	2.78%	2.78%
Average Growth Rate	4.81%	5.69%	6.30%	5.45%	5.56%
Expected Div. Yield	2.85%	2.86%	2.87%	2.86%	2.86%
DCF Return on Equity	***7.66%***	***8.55%***	***9.17%***	***8.31%***	***8.42%***
Method 2:					
Dividend Yield	2.78%	2.78%	2.78%	2.78%	2.78%
Median Growth Rate	4.75%	6.75%	6.50%	5.39%	5.85%
Expected Div. Yield	2.85%	2.88%	2.87%	2.86%	2.86%
DCF Return on Equity	***7.60%***	***9.63%***	***9.37%***	***8.25%***	***8.71%***

COLUMBIA GAS OF KENTUCKY
Capital Asset Pricing Model Analysis

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.92%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.13%
4	Risk Premium	
5	(Line 1 minus Line 3)	7.79%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	5.65%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.77%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.92%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.23%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.68%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.30%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.53%

COLUMBIA GAS OF KENTUCKY
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
February-16	2.20%
March-16	2.28%
April-16	2.21%
May-16	2.22%
June-16	2.02%
July-16	1.82%
6 month average	2.13%

5 Year Treasury Bond Data

	Avg. Yield
February-16	1.22%
March-16	1.38%
April-16	1.26%
May-16	1.30%
June-16	1.17%
July-16	1.07%
6 month average	1.23%

Source: www.federalreserve.gov, Selected Interest Rates (Daily) - H.15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.80%
Estimated Market Return	9.84%
Value Line Projected 3-5 Yr. Median Annual Total Return	10.00%
Average of Projected Mkt. Returns	9.92%

Source: Value Line Investment Survey for Windows retreived August 16, 2016

Gas Distribution Company Group Betas

Atmos Energy	0.75
Chesapeake Utilities	0.60
New Jersey Resources	0.80
Northwest Natural Gas	0.65
South Jersey Industries	0.80
Southwest Gas	0.75
Spire, Inc.	0.70
WGL Holdings	0.75
Average	0.73

Source: Value Line Investment Survey, June 3, 2016

CAPITAL ASSET PRICING MODEL ANALYSIS
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.07%	5.07%	
Historical Market Risk Premium	5.03%	7.03%	6.19%
Gas Distribution Group Beta, Value Line	0.73	0.73	0.73
Beta * Market Premium	3.65%	5.10%	4.49%
Current 20-Year Treasury Bond Yield	2.13%	2.13%	2.13%
CAPM Cost of Equity, Value Line Beta	**5.77%**	**7.22%**	**6.61%**

Source: *Ibbotson SBBI 2015 Classic Yearbook,* Morningstar, pp. 39, 40, 152, 157 - 158

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July 6, 2016

David J. Collins
Executive Secretary
Public Service Commission
State of Maryland
6 St. Paul Street, 16th Floor
Baltimore, MD 21202

Re: *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy, Case No. 9418*

Dear Mr. Collins:

Enclosed please find an original and seventeen (17) copies of the Direct Testimony and Exhibits of Mr. Richard Baudino, on behalf of the Healthcare Council of the National Capital Area in the above-referenced docket. Mr. Baudino's testimony and exhibits have been e-filed and served electronically on July 6, 2016. The paper copies will be either sent by fed-ex or hand delivered according to the Commission's rules regarding e-filing.

If you have any questions, please do not hesitate to contact me at (202) 662-2715 or by e-mail at kwiseman@andrewskurth.com.

Very truly yours,

/s/ Kenneth L. Wiseman
Kenneth L. Wiseman

BEFORE THE

PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
RETAIL RATES FOR THE DISTRIBUTION	**)**	
OF ELECTRIC ENERGY	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

HEALTHCARE COUNCIL OF THE NATIONAL CAPITAL AREA

July 2016

BEFORE THE

PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
RETAIL RATES FOR THE DISTRIBUTION	**)**	
OF ELECTRIC ENERGY	**)**	

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BEFORE THE

PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
RETAIL RATES FOR THE DISTRIBUTION	**)**	
OF ELECTRIC ENERGY	**)**	

DIRECT TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit No. ___ (RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Healthcare Council of the National Capital Area ("HCNCA").

Q. What is the purpose of your Direct Testimony?

A. The purpose of my testimony is to offer my conclusions and recommendations to the Maryland Public Service Commission ("Commission") on cost of equity, revenue requirements, and cost and revenue allocation for Potomac Electric Power Company ("Pepco" or "Company").

Q. Please summarize your Direct Testimony regarding the cost of equity.

A. I recommend that the Commission approve a rate of return on equity (“ROE”) for Pepco of 9.00%. This recommendation is based on the results from my Discounted Cash Flow (“DCF”) analyses for a comparison group of electric companies that has similar bond ratings to Pepco. I also employed the Capital Asset Pricing Model (“CAPM”). Those results are set forth below. In my opinion, a return on equity of 9.00% is a reasonable estimate of the required return on equity for a low-risk, financially robust electric company such as Pepco. As I will demonstrate in the following sections of my testimony, the market evidence I examined supports my ROE recommendation.

The Commission should reject the return on equity recommendation of 10.6% of Pepco witness Robert Hevert. I will demonstrate in detail in Section IV of my Direct Testimony that Mr. Hevert’s ROE analyses significantly inflated the investor required return for Pepco. Mr. Hevert’s recommended return on equity of 10.6% is unsupported by an objective evaluation of current financial markets.

Q. Please summarize the adjustments you recommend to Pepco's requested revenue requirement.

A. I have made a number of adjustments to Pepco's proposed ratemaking adjustments (“RMAs”) in this proceeding. These adjustments are as follows:

- Extend the amortization periods for RMAs 6, 23, 24, and 25 to 10 years from 5 years. The yearly amortization and return amounts should be reflected as an annuity payment.
- Extend the amortization period for RMA 7 to 10 years and disallow the Company's requested return on the unamortized balance.

- Disallow the reversal of the Commission's return on the tax compensation payment.

The total amount of the adjustments reduced Pepco's requested revenue increase by $19.94 million, independent of my capital cost recommendations.

Q. Please summarize your recommendations with respect to cost and revenue allocation.

A. I recommend that the Commission reject Pepco's revenue allocation proposal. I will demonstrate that the Company's past revenue allocation approach has failed to move classes materially closer to paying their fair shares of Pepco's cost of service.

I recommend that the Commission adopt a different revenue allocation proposal that fairly balances the principles of cost responsibility with gradualism. I recommend that the Commission allocate 40% of the revenue increase to the classes that are furthest below their allocated cost to serve. I recommend that the remaining 60% be allocated to the remaining customers classes, with the exception of three customer classes who are already paying excessive revenues to the Company. My proposal will move customers more toward paying rates reflective of the underlying cost to serve them, while at the same time avoiding rate shock.

II. REVIEW OF ECONOMIC AND FINANCIAL CONDITIONS

Q. Mr. Baudino, what has the trend been in long-term capital costs over the last few years?

A. Generally speaking, interest rates have declined over the last few years. Exhibit No. ___ (RAB-2) presents a graphic depiction of the trend in interest rates from January 2008 through May 2016. The interest rates shown in this exhibit are for the 20-year U.S. Treasury Bond and the average public utility bond from the Mergent Bond Record. In January 2008, the average public utility bond yield was 6.08% and the 20-year Treasury Bond yield was 4.35%. As of May 2016 the average public utility bond yield was 4.06%, representing a decline of 202 basis points, or 2.02 percentage points, from January 2008. Likewise, the 20-year Treasury bond declined to 2.22% in May 2016, a decline of 2.13 percentage points (213 basis points) from January 2008.

Q. Was there a significant change in Federal Reserve policy during the historical period shown in Exhibit No. ___(RAB-2)?

A. Yes. In response to the 2007 financial crisis and severe recession that followed in December 2007, the Federal Reserve ("Fed") undertook a series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets." Exhibit No. ___ (RAB-3) at pp. 1-2 (also available at: http://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm).

QE1 was implemented from November 2008 through approximately March 2010. During this time, the Fed cut its key Federal Funds Rate to nearly 0% and purchased $1.25 trillion of mortgage-backed securities and $175 billion of agency debt purchases.

QE2 was implemented in November 2010 with the Fed announcing that it would purchase an additional $600 billion of Treasury securities by the second quarter of 2011. Exhibit No. ___ (RAB-3) at pp. 3-4 (also available at: http://www.federalreserve.gov/newsevents/press/monetary/20101103a.htm).

Beginning in September 2011, the Fed initiated a "maturity extension program" in which it sold or redeemed $667 billion of shorter-term Treasury securities and used the proceeds to buy longer-term Treasury securities. This program, also known as "Operation Twist," was designed by the Fed to lower long-term interest rates and support the economic recovery.

QE3 began in September 2012 with the Fed announcing an additional bond purchasing program of $40 billion per month of agency mortgage backed securities. On June 19, 2013, the Federal Open Market Committee ("FOMC") issued a press release indicating that it intended to extend "Operation Twist." In its press release, the Federal Reserve stated:

> To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace

> of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.
>
> [Exhibit No. ___ (RAB-3) at pp. 5-6 (also available at: https://www.federalreserve.gov/newsevents/press/monetary/20130619a.htm).]

More recently, the Fed began to pare back its purchases of securities. For example, on January 29, 2014 the Fed stated that beginning in February 2014 it would reduce its purchases of long-term Treasury securities to $35 billion per month. The Fed continued to reduce these purchases throughout the year and in a press release issued October 29, 2014 announced that it decided to close this asset purchase program in October. Exhibit No. ___ (RAB-3) at pp. 7-8 (also available at: http://www.federalreserve.gov/newsevents/press/monetary/20141029a.htm).

Q. Since the Fed's announcements of scaling back and finally ending its purchases of long-term Treasury securities, what has the trend been in long-term Treasury yields from 2014 through 2016?

A. The yield on the 20-year Treasury bond has actually declined since the beginning of 2014. The January 2014 yield on the 20-year Treasury bond was 3.52%. Exhibit No. ___ (RAB-2). The closing yield for May 2016 was 2.22%, a decline of 130 basis points since January 2014. Exhibit No. ___ (RAB-2).

Q. Has the Fed recently indicated any important changes to its monetary policy?

A. Yes. Recently the Fed raised its target range for the federal funds rate to 1/4% to 1/2% from 0% to 1/4%. The Federal Reserve also issued a press release on March

16, 2016 stating that it would continue to maintain this target range at present. Exhibit No. ___ (RAB-3) at pp. 9-10 (also available at: http://www.federalreserve.gov/newsevents/press/monetary/20160316a.htm). This press release also stated:

> The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will continue to strengthen. However, global economic and financial developments continue to pose risks. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to monitor inflation developments closely.
>
> Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.

Q. Why is it important to understand the Fed's actions with respect to monetary policy since 2007?

A. The Fed's monetary policy actions since 2007 were deliberately undertaken to lower interest rates and support economic recovery. The Fed's actions have been quite successful in lowering interest rates given that the 20-year Treasury Bond yield in June 2007 was 5.29% and the public utility bond yield was 6.34%. The U.S. economy is currently in a low interest rate environment that, in my opinion, will likely continue at least through this year. As I will demonstrate later in my testimony, low interest rates have also significantly lowered investors' required return on equity for the stocks of regulated utilities.

Q. Have recent developments reinforced the prevailing low interest rate environment?

A. Yes. Several central banks have implemented *negative* interest rates. Exhibit No. __ (RAB-3) at pp. 11-12 (noting that the Swiss National Bank set its benchmark interest rate at minus 0.75% and that nearly the entirety of Switzerland's yield curve was negative; yield curves for Japan and Germany are also provided showing negative interest rates for bonds with a duration of up to 10 years). Indeed, Federal Reserve Chairman Yellen has discussed the possibility of negative interest rates (available at: http://www.bloomberg.com/news/articles/2016-05-12/yellen-doesn-t-rule-out-negative-rates-in-letter-to-congressman (last visited July 2, 2016) (in written responses Thursday to questions from Representative Brad Sherman, Yellen said that "while I would not completely rule out the use of negative interest rates in some future very adverse scenario, policy makers would need to consider a wide range of issues before employing this tool in the United States, including the potential for unintended consequences.").

Q. Are current interest rates indicative of investor expectations regarding future policy actions by the Federal Reserve?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Roger Morin pointed out in *New Regulatory Finance:*

> A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information.

I acknowledge that the U.S. economy is operating in a low interest rate environment. It is likely at some point in the near future that the Fed will raise short-term interest rates further. However, the timing and the level of any such move are not known at this time. It is important to realize that investor expectations of higher interest rates, if any, are already embodied in current securities prices, which include debt securities and stock prices.

The current low interest rate environment favors lower risk regulated utilities. As I shall demonstrate in Section III, market evidence indicates that investors require lower rates of return on equity on regulated utility stocks than many other types of enterprises. It would not be advisable for utility regulators to raise ROEs in anticipation of higher interest rates that may or may not occur**.**

Q. How does the investment community regard the electric utility industry as a whole?

A. The Value Line Investment Survey noted the following in its May 20, 2016 report on the Electric Utility (East) Industry:

> So far, 2016 has been an excellent year for electric utility stocks. Every issue we cover is up, year to date, and most have risen at a low double-digit pace. With interest rates as low as they are, some investors are reaching for yield. This is reflected in the high valuation of many electric company equities. Most are trading at a market premium, and have recent quotations within our 2019-2021 Target Price Range. The average dividend yield of this group is just 3.4%, which is low by historical standards. The average 3- to 5-year total return potential is just 3%, which is low by any standard.

Value Line also noted the following in its June 17, 2016 report on the Electric Utility (Central) Industry:

> Merger and acquisition activity (or speculation of deals) is just one factor in the strong performance of electric utility equities so far in 2016. The price of every issue under our coverage is up, year to date, and in most cases, the rise has been significant: between 10% and 20%. Another factor is the ongoing low-interest rate environment, and the belief that the Federal Reserve will be slow to raise rates. With minuscule returns available on savings accounts, CDs, and money-market funds, many income-oriented investors have reached for yield by putting money into utility stocks.

> As long as the interest-rate environment remains benign, this would be good for electric utility stocks. If interest rates are higher over the 3- to 5-year period, as we expect, that would probably be unfavorable for the equities in the group.

Q. Briefly describe Pepco.

A. Pepco is an electric transmission and distribution company serving approximately 842,000 customers in Maryland and the District of Columbia, according to the Company's 2015 10-K report. Pepco's Maryland jurisdiction consists of 560,000 customers and accounts for 57% of the Company's kWhs sold.

Until this year, Pepco was a subsidiary of PEPCO Holdings, Inc. PEPCO Holdings, Inc. was recently merged into Exelon Corp. ("Exelon"). The merger was completed on March 23, 2016. Prior to the merger, Exelon reported in its 2015 10-K Report that it was engaged in the energy and power marketing business as well as the energy delivery business through its subsidiaries Commonwealth Edison ("ComEd"), PECO Energy ("PECO"), and Baltimore Gas and Electric Company ("BGE"). Exelon's Generation segment consists of 32,741 megawatts ("mW") of owned generation and 7,419 mWs of long-term purchased power contracts. On page 20 of Exelon's 2015 Form 10-K, it reported that it served a total of 7.2 million retail electric and natural gas customers through ComEd, PECO, and BGE.

Q. What are the current senior secured bond ratings for Pepco?

A. Pepco's senior secured ratings are A by Standard & Poor's ("S&P"), A2 by Moody's, and A- by Fitch. Moody's long-term issuer rating is Baa1. S&P's credit rating for the Company is BBB+. The recent credit rating agency reports since 2014 have been affected by the Company's proposed merger with Exelon, which as I noted earlier was completed this year. PEPCO's ratings were affirmed by S&P in a recent report after the merger was completed.

Exelon's credit ratings are generally lower than Pepco's, although still investment grade. Exelon's long-term issuer rating from Moody's is Baa2. Exelon's S&P credit rating is BBB.

Q. How has Moody's assessed Pepco and affiliates?

A. Moody's affirmed ratings for Exelon and PHI and changed its outlook for PHI from Developing to Stable in August 2015, even after the District of Columbia Public Service Commission's initial rejection of the Exelon-PHI merger. In an August 31, 2015 press release, Moody's stated that "PHI's Baa3 rating reflects the company's low business risk profile, anchored by a portfolio of regulated T&D utilities." https://www.moodys.com/research/Moodys-Affirms-Exelon-and-Pepco-Holdings-changes-Pepco-Holdings-rating--PR_333541 (retrieved June 29, 2016). Moody's explained that "The Baa3 rating also reflects the reduction to prior unregulated business activities, a credit positive . . . ." However, Moody's cautioned that with regard to Exelon's ratings, a "shift in strategic focus could . . . trigger a rating downgrade, especially where the shift resulted in a material increase in the consolidated business risk profile, presumably somewhat more toward the unregulated business segment within” Exelon Generating Company LLC.

Q. What happened after those statements?

A. On March 24, 2016, Moody’s upgraded PHI’s ratings, from Baa3 to Baa2, with an outlook of “stable.” Moody’s stated that “For Exelon . . . the acquisition of PHI is credit positive because it helps transition the company towards a more regulated business. PHI brings an incremental $8 billion in rate base to Exelon’s roughly $20 billion, and adds regulatory diversity with new service territories in DC, Delaware and New Jersey.” https://www.moodys.com/research/Moodys-Upgrades-Pepco-Holdings-Changes-Rating-Outlook-to-Stable-from--PR_346277 (retrieved June 30, 2016).

Q. What is the consequence of the merger?

A. According to the Washington Post, the PHI-Exelon merger created the largest publicly-held utility in the U.S. (March 23, 2016: “DC Regulators Green-light Pepco-Exelon merger, creating largest utility in the nation”). https://www.washingtonpost.com/local/dc-politics/in-a-surprise-move-dc-regulators-give-green-light-to-pepco-exelon-merger/2016/03/23/4ace2bc0-f10e-11e5-89c3-a647fcce95e0_story.html (retrieved June 30, 2016).

Q. Mr. Baudino, what is your conclusion regarding the financial health and overall risk of Pepco?

A. Pepco remains a low cost and low risk electric utility with strong A/A senior secured bond ratings. The completion of the merger with Exelon Corp. has removed substantial uncertainty from Pepco's credit outlook. This will have a positive effect on the Company moving forward, including the required return on equity by investors.

III. DETERMINATION OF FAIR RATE OF RETURN

Q. Please describe the methods you employed in estimating a fair rate of return for Pepco.

A. I employed a Discounted Cash Flow ("DCF") analysis for a group of comparison electric companies to estimate the cost of equity for the Company's regulated electric operations. I also employed several Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data.

Q. What are the main guidelines to which you adhere in estimating the cost of equity for a firm?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) and *Bluefield W.W. & Improv. Co. v. Public Service Comm'n,* 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to at least what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by at least what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of comparable investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is comparable to the return being offered by other risk-comparable firms.

Q. What are the major types of risk faced by utility companies?

A. In general, risk associated with the holding of common stock can be separated into three major categories: business risk, financial risk, and liquidity risk. Business risk refers to risks inherent in the operation of the business. Volatility of the firm's sales, long-term demand for its product(s), the amount of operating leverage, and quality of management are all factors that affect business risk. The quality of regulation at the state and federal levels also plays an important role in business risk for regulated utility companies.

Financial risk refers to the impact on a firm's future cash flows from the use of debt in the capital structure. Interest payments to bondholders represent a prior call on the firm's cash flows and must be met before income is available to the common shareholders. Additional debt means additional variability in the firm's earnings, leading to additional risk.

Liquidity risk refers to the ability of an investor to quickly sell an investment without a substantial price concession. The easier it is for an investor to sell an investment for cash, the lower the liquidity risk will be. Stock markets, such as the New York and American Stock Exchanges, help ease liquidity risk substantially. Investors who own stocks that are traded in these markets know on a daily basis what the market prices of their investments are and that they can sell these investments fairly quickly. The stocks of numerous enterprises owning electric utilities are traded on the New York Stock Exchange and are considered liquid investments.

Q. Are there any sources available to investors that quantify the total risk of a company?

A. Bond and credit ratings are tools that investors use to assess the risk comparability of firms. Bond rating agencies such as Moody's and Standard and Poor's perform detailed analyses of factors that contribute to the risk of a particular investment. The end result of their analyses is a bond and/or credit rating that reflects these risks.

<u>**Discounted Cash Flow ("DCF") Model**</u>

Q. Please describe the basic DCF approach.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: V = *asset value*
R = *yearly cash flows*
r = *discount rate*

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 = *the next period dividend*
P_0 = *current stock price*
g = *expected growth rate*
k = *investor-required return*

Under the formula, it is apparent that "k" must reflect the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. What was your first step in conducting your DCF analysis for Pepco?

A. My first step was to construct a comparison group of companies with a risk profile that is reasonably similar to Pepco.

Q. Please describe your approach for selecting a comparison group of electric companies.

A. I used several criteria to select a comparison group. First, using the June 2016 issue of AUS Utility Reports, I selected electric companies whose bonds were rated at least A by Moody's and/or Standard and Poor's. Pepco currently carries senior secured bond ratings of A from S&P and A2 from Moody's, so using the either/or criterion for an A rating assures that the companies in the comparison group carry bond ratings that are similar to Pepco.

From that group, I selected companies that had at least 50% of their revenues from electric operations and that had long-term earnings growth forecasts from Value Line and either Zacks Investment Research ("Zacks") or Thomson Financial. I will describe Zacks and Thomson Financial later in my testimony. From this group, I then eliminated companies that had recently cut or eliminated dividends, or were recently or currently involved in significant merger activities.

The resulting comparison group of 12 electric companies that I used in my analysis is shown in the table below.

TABLE 1
COMPARISON GROUP

	Company	S&P Bond Rating	Moody's Bond Rating
1	ALLETE, Inc. (NYSE-ALE)	A-	A3
2	Alliant Energy Corporation (NYSE-LNT)	A-	A2/A3
3	Avista Corporation (NYSE-AVA)	A-	Baa1
4	Consolidated Edison, Inc. (NYSE-ED)	A-/BBB+	A3
5	Edison International (NYSE-EIX)	BBB+	A2/A3
6	Eversource Energy (NYSE-ES)	A-	A3/Baa1
7	IDACORP, Inc. (NYSE-IDA)	A-	A3
8	NorthWestern Corporation (NYSE-NWE)	NR	A3
9	OGE Energy Corp. (NYSE-OGE)	BBB+	A3
10	Portland General Electric Company (NYSE-POR)	A-	A3
11	Wisconsin Energy Corporation (NYSE-WEC)	A-/BBB+	A1/A2
12	Xcel Energy Inc. (NYSE-XEL)	A-	A3

Source: AUS Monthly Utility Report, June 2016

Q. What was your first step in determining the DCF return on equity for the comparison group?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from December 2015 through May 2016. I obtained historical prices and dividends from

Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the group is 3.44%. These calculations are shown in Exhibit No. ____(RAB-4).

Q. Having established the average dividend yield, how did you determine the investors' expected growth rate for the electric comparison group?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no arbitrary cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

In this analysis, I relied on three major sources of analysts' forecasts for growth. These sources are Value Line, Zacks, and Thomson Financial.

Q. Please briefly describe Value Line, Zacks, and Thomson Financial.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand companies in its Plus Edition. It is updated quarterly and probably represents the most comprehensive of all investment information services. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

According to Zacks' website, Zacks "was formed in 1978 to compile, analyze, and distribute investment research to both institutional and individual investors." Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth.

Like Zacks, Thomson Financial also provides detailed investment research on numerous companies. Thomson also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from Yahoo! Finance.

Q. Why did you rely on analysts' forecasts in your analysis?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. How did you utilize your data sources to estimate growth rates for the comparison group?

A. Exhibit No. ___ (RAB-5) presents the Value Line, Zacks, and Thomson Financial forecasted growth estimates. These earnings and dividend growth estimates for the comparison group are summarized on Columns (1) through (5) of Exhibit No. ___ (RAB-5).

I also utilized the sustainable growth formula in estimating the expected growth rate. The sustainable growth method, also known as the retention ratio method, recognizes that the firm retains a portion of its earnings to fuel growth in dividends. These retained earnings, which are plowed back into the firm's asset base, are expected to earn a rate of return. This, in turn, generates growth in the firm's book value, market value, and dividends.

The sustainable growth method is calculated using the following formula:

$$G = B * R$$

Where: *G = expected retention growth rate*
B = the firm's expected retention ratio
R = the expected return

In its proper form, this calculation is forward-looking. That is, the investors' expected retention ratio and return must be used in order to measure what investors anticipate will happen in the future. Data on expected retention ratios and returns may be obtained from Value Line.

The expected sustainable growth estimates for the comparison group are presented in Column (3) on page 1 of Exhibit No. ____(RAB-5). The data came from the Value Line forecasts for the comparison group.

Q. How did you approach the calculation of earnings growth forecasts in this case?

A. For purposes of this case, I looked at two different methods for calculating the expected growth rates for my comparison group. For Method 1, I calculated the average of all the growth rates for the companies in my comparison group using Value Line, Zacks, and Thomson. For Method 2, I calculated the median growth rates for my comparison group. The median value represents the middle value in a data range and is not influenced by excessively high or low numbers in the data set. The median growth rate for each forecast provides additional valuable information regarding expected growth rates for the group.

The expected growth rates produced from these two methods fall in a range from 3.75% to 6.00%.

Q. How did you proceed to determine the DCF return of equity for the electric comparison group?

A. To estimate the expected dividend yield (D_1) for the group, the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

I then added the expected growth rates to the expected dividend yield. The calculations of the resulting DCF returns on equity for both methods are presented on Exhibit No. ___ (RAB-5), page 2.

Q. Please explain how you calculated your DCF cost of equity estimates.

A. Exhibit No. ___ (RAB-5) presents the DCF results utilizing the two different methods I described earlier. I used the Value Line earnings and dividend growth forecasts and the consensus analysts' forecasts. Using the average group growth rate in Method 1, the DCF results range from 8.15% to 9.50%, with an average ROE for the group of 8.64%. For Method 2, which employs median growth rates, the DCF results range from 8.52% to 9.54%, with an average ROE of 8.87%.

Capital Asset Pricing Model

Q. Briefly summarize the Capital Asset Pricing Model ("CAPM") approach.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies. Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: K = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Conceptually, any stock's required return can be determined by multiplying its beta by the market risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. In general, are there concerns regarding the use of the CAPM in estimating the return on equity?

A. Yes. There is some controversy surrounding the use of the CAPM.[1] There is evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk.

There is also substantial judgment involved in estimating the required market return. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500 or the return on Value Line's stock market composite. However, these are limited sources of information with respect to estimating the investor's required return for all investments. In practice, the total

[1] For a more complete discussion of some of the controversy surrounding the use of the CAPM, refer to *A Random Walk Down Wall Street* by Burton Malkiel, pp. 206 - 211, 2007 edition.

market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the risk-free rate and market return portions of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. How did you estimate the market return portion of the CAPM?

A. The first source I used was the Value Line Investment Analyzer, Plus Edition, for June 12, 2016. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual return on page 2 of Exhibit No. ___ (RAB-6). I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 9.88% to 11.0%. The average of these two market returns is 10.44%.

Q. Why did you use median growth rate estimates rather than the average growth rate estimates for the Value Line companies?

A. Using median growth rates is likely a more accurate method of estimating the central tendency of Value Line's large data set compared to the average growth rates. Average earnings and book value growth rates may be unduly influenced by very high or very low 3 - 5 year growth rates that are unsustainable in the long run. For example, Value Line's Statistical Summary shows both the highest and lowest value for earnings and book value growth forecasts. For earnings growth, Value Line showed the highest earnings growth forecast to be 98% and the lowest growth rate to be -30.7%. The highest book value growth rate was 73.5% and the lowest was -40.0%. None of these levels of growth is compatible with long-run growth prospects for the market as a whole. The median growth rate is not influenced by such extremes because it represents the middle value of a very wide range of earnings growth rates.

Q. Please continue with your market return analysis.

A. I also considered a supplemental check to the Value Line projected market return estimates. Morningstar publishes a study of historical returns on the stock market in its *Ibbotson SBBI 2015 Classic Yearbook*. Some analysts employ historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit No. **___** (RAB-7) presents the calculation of the market returns using the historical data.

Q. Please explain how this historical risk premium is calculated.

A. Exhibit No. **___** (RAB-7) shows both the geometric and arithmetic average of yearly historical stock market returns over the historical period from 1926 - 2014. The average annual income return for 20-year Treasury bond is subtracted from these historical stocks returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The historical market risk premium range is 5.03% - 7.03%.

Q. Did you add an additional measure of the historical risk premium in this case?

A. Yes. Morningstar reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001.[2] Morningstar recommended adjusting this growth in the P/E ratio for stocks out of the historical risk premium because "it is not believed that P/E will continue to increase in the future." Morningstar's adjusted historical arithmetic market risk premium is 6.19%, which I have also included in Exhibit No. ___ (RAB-7).

Q. Mr. Baudino, you testified that you used the SBBI 2015 Yearbook. Does Morningstar still publish the SBBI Yearbook?

A. No. Morningstar discontinued publication of the SBBI Yearbook this year. However, I present the analyses in Exhibit No. ___ (RAB-7) as additional information and perspective with respect to historical risk premiums of common stocks over long-term Treasury bonds.

Q. How did you determine the risk free rate?

A. I used the average yields on the 20-year Treasury bond and five-year Treasury note over the six-month period from December 2015 through May 2016. The 20-year

[2] *2015 Ibbotson SBBI Classic Yearbook,* Morningstar, pp. 156 - 158.

Treasury bond may be used as a proxy for the risk-free rate, but it contains a significant amount of interest rate risk. The five-year Treasury note carries less interest rate risk than the 20-year bond and is more stable than three-month Treasury bills. Therefore, I have employed both of these securities as proxies for the risk-free rate of return. This approach provides a reasonable range over which the CAPM return on equity may be estimated.

Q. How did you determine the value for beta?

A. I obtained the betas for the companies in the electric distribution group from the most recent Value Line reports. The average of the Value Line betas for the comparison group is 0.73.

Q. Please summarize the CAPM results.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 8.03% - 8.28%. Using historical risk premiums, the CAPM results are 6.02% - 7.49%.

<u>Conclusions and Recommendations Regarding Authorized ROE</u>

Q. Please summarize the cost of equity you recommend the Commission adopt for Pepco.

A. I recommend that the Commission adopt the DCF model I developed and the cost of equity estimates for the comparison group of electric utility companies that I compiled. Table 2 below summarizes the results of my ROE analyses.

TABLE 2
SUMMARY OF ROE ESTIMATES

Baudino DCF Methodology:	
Average Growth Rates	
- High	9.50%
- Low	8.15%
- Average	8.64%
Median Growth Rates:	
- High	9.54%
- Low	8.52%
- Average	8.87%
CAPM:	
- 5-Year Treasury Bond	8.03%
- 20-Year Treasury Bond	8.28%
- Historical Returns	6.02% - 7.49%

The results for the electric company comparison group using the constant-growth DCF model and the expected growth rate forecasts ranged from 8.64% to 8.87%. Based on this range of results, I recommend that the Commission adopt a 9.00% return on equity for Pepco in this proceeding. Based on a comparison of current bond ratings, Pepco has slightly lower risk utility relative to my comparison group, which contains several companies with BBB/Baa bond ratings. Nonetheless, for purposes of the ROE ranges I recommend, I am placing Pepco at the top of the range and rounding upward to 9.0%. I offer this recommendation to the Commission as a just and reasonable estimate of investor return on equity requirements for a lower risk transmission and distribution electric company such as Pepco.

Finally, it should be noted that the CAPM results are significantly lower than the DCF results in this proceeding. This is the case with both the forward-looking and the historical versions of the CAPM. I do not rely on the CAPM for my ROE recommendation, but these results suggest that my recommended ROE of 9.00% is reasonable, even generous, based on current capital market conditions.

Q. Please present the results of your ROE recommendation in the context of the Company's proposal for debt costs and capital structure.

A. My recommended ROE, combined with Pepco's proposed capital structure and cost of debt as contained in Mr. McGowan's Direct Testimony, yields a weighted cost of capital of 7.22%.

TABLE 3

	Pct.	Cost	Weighted Cost
Long-Term Debt	50.45%	5.48%	2.76%
Common Equity	49.55%	9.00%	4.46%
Total	100.00%		7.22%

IV. RESPONSE TO PEPCO ROE TESTIMONY

Q. Have you reviewed the Direct Testimony of Mr. Robert Hevert?

A. Yes.

Q. Please summarize Mr. Hevert's testimony and approach to return on equity.

A. Mr. Hevert employed four methods to estimate the investor required rate of return for Pepco: (1) the constant growth DCF model, (2) a multi-stage DCF model, (3) the CAPM, and (4) the bond yield plus risk premium model.

For his constant growth DCF approach, he used Value Line, First Call, and Zacks for the investor expected growth rate. Mr. Hevert's mean growth rate ROE results for his proxy group of companies ranged from 9.19% to 9.27%. Pepco Witness Hevert Direct at 19, Table 2.

With respect to the DCF model, Mr. Hevert used 30-day, 90-day, and 180-day average stock prices ending January 15, 2016 to estimate the dividend yield for the companies in his proxy group.

Regarding his multi-stage DCF analysis, Mr. Hevert used the same proxy group. This model consisted of three distinct stages with assumptions regarding growth rates and payout ratio changes. Mr. Hevert used a forecast of growth in nominal Gross Domestic Product ("GDP") for his long-term growth rate. The results for this method using the mean growth rate for his proxy group ranged from 10.19% to 10.41%. Pepco Witness Hevert Direct at 26, Table 5.

With respect to the CAPM, Mr. Hevert's results ranged from 8.92% to 12.84%. Pepco Witness Hevert Direct at 32, Table 6a. Mr. Hevert also included an Empirical CAPM model that, in his view, adjusted the CAPM results upward for so-called "low beta" stocks. The results of his ECAPM ranged from 9.90% to 13.46%. Pepco Witness Hevert Direct at 32, Table 6b.

Mr. Hevert's formulation of the bond yield plus risk premium approach resulted in a ROE estimate range of 10.04% - 10.47%. Schedule ___ (RBH)-6.

Mr. Hevert also recommended imputing an adjustment for flotation costs of 12 basis points to his DCF calculations. Pepco Witness Hevert Direct at 36-38.

Based on the results of his analyses and judgment, Mr. Hevert recommended a ROE range for Pepco of 10.0% to 10.75%, concluding that the cost of equity is 10.60%. Pepco Witness Hevert Direct at 52:15-18.

Q. You and Mr. Hevert used different proxy groups to estimate Pepco's ROE in this proceeding. Do you have any comments with respect to Mr. Hevert's proxy group of companies?

A. Yes. Mr. Hevert's group includes Dominion Resources, Great Plains Energy, and Westar Energy. These three companies are involved in significant merger activity and should not be included in a proxy group for purposes of estimating the return on equity for Pepco.

<u>Constant Growth DCF Analyses</u>

Q. You summarized the range of Mr. Hevert's average, or mean, constant growth DCF results to be 9.19% - 9.27%. Did Mr. Hevert properly account for the constant growth DCF results in his recommended ROE range for Pepco?

A. No. In fact, Mr. Hevert apparently rejected the mean constant growth DCF results in their entirety, so far as they fall below the low end of his recommended ROE range (10.0%).

It is improper for Mr. Hevert to ignore the results of the constant growth DCF model in his recommended ROE for Pepco. The constant growth DCF model utilizes public, verifiable information with respect to investor return requirements for electric utilities such as Pepco. Current stock prices are the best indicators we have of investor return requirements and expectations. Analysts' earnings and dividend growth forecasts may reasonably be assumed to influence investor expectations. Simply discarding this information, as Mr. Hevert has apparently done, merely serves to overstate his recommended investor required return for a low-risk utility investment like Pepco.

Q. On page 52, lines 8 through 12 of his Direct Testimony, Mr. Hevert testified that the constant growth DCF models "should be viewed with caution, because they do not adequately reflect the high levels of volatility and instability, whereas the Risk Premium-based methods directly reflect such changing capital market conditions and measures of risk." Do you agree with Mr. Hevert on this point?

A. No, especially as Mr. Hevert applied this argument to regulated utilities. I will demonstrate later in my testimony that despite the short-term uptick in market volatility, investors have chosen utility stocks as protection from this volatility. In 2016, utility stocks have done very well and reflect investors' apparent view of them as a safe harbor in uncertain times. The constant growth DCF model, which uses current stock prices, shows that investor required returns are lower for utility stocks given their relative safety and security relative to the stock market as a whole. Mr. Hevert's statement should be rejected.

Q. Are the stock prices Mr. Hevert used in his DCF analyses out of date?

A. Yes, they are quite dated. Mr. Hevert used stock prices ending January 15, 2016, making them nearly six months out of date. The Commission should not rely on ROE analyses that use such stale data.

Q. Beginning on page 36 of his Direct Testimony, Mr. Hevert urges the imputation of flotation costs in the allowed ROE. Should the Commission add a flotation cost adjustment to the cost of equity for Pepco?

A. No. In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. I do not believe that this is an appropriate assumption. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors. To the extent that the Commission has allowed a very conservative flotation cost adjustment in the past, I recommend that the Commission reconsider flotation costs in this proceeding and reject Mr. Hevert's proposed adjustment for flotation costs.

<u>Multi-stage DCF Model</u>

Q. Please summarize the components of Mr. Hevert's multi-stage DCF model.

A. Mr. Hevert described the structure and the inputs for his multi-stage DCF model on pages 21 through 26 of his Direct Testimony. The main elements of Mr. Hevert's multi-stage DCF analyses are as follows:

- 30, 90, and 180 average stock prices.
- First stage of growth based on the average earnings growth rates from Value Line, Zacks, and First Call.
- A transition period from near-term to long-term growth.
- Long-term growth estimated using GDP growth based on historical real GDP growth from 1929 through 2014 and a forecasted inflation rate (5.35%).
- Expected dividend in the final year divided by solved cost of equity less long-term growth rate.
- Payout ratio assumptions based on Value Line for the first stage, a transition period, and a long-term expected payout ratio.

Q. As a practical matter, is it likely that investors would use the multi-stage model presented by Mr. Hevert?

A. No. In my opinion, it is highly unlikely that investors would employ the complicated structure and set of assumptions used by Mr. Hevert. Mr. Hevert presented no evidence whatsoever that investors use such a model in forming their required return for an electric utility such as Pepco. He presented no evidence that investors use GDP growth in their evaluation of expected growth in dividends and earnings for electric utility companies. Nor did he show that investors utilize his assumptions regarding the transition period or payout ratio forecasts.

Q. In your opinion, did Mr. Hevert overstate expected GDP growth?

A. Yes. There are two publicly available forecasts of GDP growth that are relied upon by the Federal Energy Regulatory Commission ("FERC") in the determination of the second stage of the two-stage growth rate in its DCF return on equity formula. These forecasts come from the Energy Information Administration ("EIA"), and the Social Security Administration ("SSA") Trustees Report.[3] The latest EIA GDP forecast shows expected growth in nominal GDP of 4.19%. The SSA Report forecasts nominal growth in GDP of 4.41%. The average of these two long-term GDP forecasts is 4.30%. I include the calculations of these two GDP growth rates on Exhibit No. ___ (RAB-8). My calculations are based on my understanding of how the FERC Staff uses the data contained in the EIA and SSA documents to calculate long-term GDP growth for the second stage of its two-stage DCF model.

These independent sources are forecasting nominal GDP growth to be substantially lower than the forecast used by Mr. Hevert (4.33% vs. Mr. Hevert's forecast of 5.35%). In my opinion, Mr. Hevert's GDP forecast contributes to a significant overstatement of his multi-stage DCF results.

CAPM

Q. Briefly summarize the main elements of Mr. Hevert's CAPM approach.

A. On page 30 of his Direct Testimony, Mr. Hevert testified that he used several different measures of the risk-free interest rate: the current 30-day average yield on

[3] Please see the Energy Information Administration, *Annual Energy Outlook 2015* (April 2015) and Social Security Administration, 2016 OASDI Trustees Report, Table VI.G6 - Selected Economic Variables, Calendar Years 2015-90.

the 30-year Treasury bond (2.96%) and near term and long term projected yields on 30-year Treasury bonds (3.45% - 4.65%). Mr. Hevert did not consider any shorter maturity bonds, such as the 5-year Treasury note.

Mr. Hevert then calculated ex-ante measures of total market returns using data from Bloomberg and Value Line. Total market returns from these two sources were a 13.63% market return using Bloomberg data and a 12.82% return using Value Line data. Schedule (RBH)-3 at 1.

Mr. Hevert used two different estimates for beta from Bloomberg and Value Line.

Q. Is it appropriate to use forecasted or projected bond yields in the CAPM?

A. Definitely not. Current interest rates and bond yields embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted bond yield used by Mr. Hevert is speculative at best and may never come to pass. Current interest rates provide tangible and verifiable market evidence of investor return requirements today, and these are the interest rates and bond yields that should be used in both the CAPM and in the bond yield plus risk premium analyses. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

Q. Should Mr. Hevert have considered shorter-term Treasury yields in his CAPM analyses?

A. Yes. In theory, the risk-free rate should have no interest rate risk. 30-year Treasury Bonds do face this risk, which is the risk that interest rates could rise in the future and lead to a capital loss for the bondholder. Typically, the longer the duration of the bond, the greater the interest rate risk. The 5-year Treasury note has much less interest rate risk than 20-year or 30-year Treasury Bonds and may be considered one reasonable proxy for a risk-free security. My CAPM analysis shows that the ROE using a 5-year Treasury note would be only 8.00% using the expected market return. This is much lower than any of the CAPM estimates provided by Mr. Hevert.

Q. Please comment on Mr. Hevert's use of Bloomberg and Value Line earnings growth estimates for the S&P 500.

A. Mr. Hevert used earnings growth estimates from these two sources to estimate the expected market return for his CAPM. Using the supporting spreadsheet provided in Pepco's response to Staff Data Request 1-2, Attachment W, Tabs MRP Bloomberg and MRP Value Line, the average Value Line growth rate is 10.18% and the average Bloomberg growth rate is 10.06%.

These are by no means long-run sustainable growth rates. They are about double the long-term GDP growth forecast of 5.35% presented by Mr. Hevert. If forecasted GDP growth is used, then both Mr. Hevert's and my own market return estimates would fall significantly. Obviously, using 5.35% as a proxy for long-term growth for the S&P 500 companies would reduce Mr. Hevert's market return of 12.82% and 13.63% quite substantially. This would also apply to my forward-looking CAPM analyses as well.

Q. Is the S&P 500 a good proxy for the market when estimating a CAPM return on equity?

A. No. That is because the S&P 500 is limited to the stocks of the 500 largest companies in the United States. The market return portion of the CAPM should represent the most comprehensive estimate of the total return for all investment alternatives, not just a small subset of publicly traded stocks. In practice, of course, finding such an estimate is difficult and is one of the more thorny problems in estimating an accurate ROE when using the CAPM. If one limits the market return to stocks, then there are more comprehensive measures of the stock market available, such as the Value Line Investment Survey that I used in my CAPM analysis. Value Line's projected earnings growth used a sample of 2,209 stocks and its book value growth estimate used 1,527 stocks. Value Line's projected annual percentage return included 1,680 stocks. These are much broader samples than Mr. Hevert's limited sample of the S&P 500.

Q. Do the market returns you used in your CAPM suggest that Mr. Hevert's estimated market returns are excessive?

A. Yes. The market returns I estimated from Value Line ranged from 9.88% to 11.00%, far lower than Mr. Hevert's estimated returns on the S&P 500.

Q. Beginning on page 29 of his Direct Testimony, Mr. Hevert described the Empirical CAPM ("ECAPM") analysis. Is this a reasonable method to use to estimate the investor required ROE for Pepco?

A. No. The ECAPM is supposed to account for the possibility that the CAPM understates the return on equity for companies with betas of less than 1.0. I believe it is highly unlikely that investors use the ECAPM formulation shown in Mr. Hevert's testimony to “correct” CAPM returns for electric utilities. To the extent investors use the CAPM to estimate their required returns, I believe it is much more likely that they use the traditional CAPM equation that I used in Section III of my testimony. The Company witnesses presented no evidence that investors use the more labor intensive and complex adjustment factors contained their ECAPM analyses. Moreover, the use of an adjustment factor to "correct" the CAPM results for companies with betas less than 1.0 suggests that published betas by such sources as Value Line are incorrect and that investors should not rely on them.

Bond Yield Plus Risk Premium Analysis

Q. Please summarize Mr. Hevert's risk premium approach.

A. Mr. Hevert developed a historical risk premium using Commission-allowed returns for regulated electric and gas utility companies and 30-year Treasury bond yields from January 1980 through January 15, 2016. He used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. Applying the regression coefficients to the average risk premium and using both current and projected 30-year Treasury yields I discussed earlier, Mr. Hevert's risk premium ROE estimate ranges from 10.04% to 10.47%. Pepco Witness Hevert Direct at 35.

Q. Please respond to Mr. Hevert's risk premium analysis.

A. First, the bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time. As such, this approach is a "blunt instrument" for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on a historical risk premium analysis over a certain period of time.

Second, I recommend that the Commission reject the use of the forecasted Treasury bond yields for the same reasons I described in my response to Mr. Hevert's CAPM approach. The Blue Chip Consensus 30-Year Treasury yield forecasts resulted in ROEs of 10.04% - 10.47%, the highest of the three results obtained from Mr. Hevert's analysis. Changing Mr. Hevert's analysis only to use the current 30-Year Treasury yield, without addressing other potential shortcomings of that analysis, would result in a ROE of 10.04%. *See* Schedule (RBH)-6 at p. 1.

<u>Capital Market Environment</u>

Q. Beginning on page 38 of his Direct Testimony, Mr. Hevert discussed current capital market conditions. Could you please respond to Mr. Hevert's discussion of these conditions?

A. Yes. As I described in Section II of my testimony, the United States continues to be low interest rate environment that suggests lower ROEs for regulated utilities. Even though the Federal Reserve has considered raising interest rates this year, it has delayed any such move for the time being. In a press release dated June 15, 2016 the Federal Open Market Committee stated the following:

> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will strengthen. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of past declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to closely monitor inflation indicators and global economic and financial developments.
>
> Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby

> supporting further improvement in labor market conditions and a return to 2 percent inflation. [Exhibit No. ___ (RAB-3) at p.13].

Note that the stance of the Federal Reserve is one of accommodation and that it decided to maintain short-term interest rates at their present levels. This continues to favor lower expected returns on the part of investors for lower risk and higher yielding regulated utility stocks.

Q. Beginning on page 42, Mr. Hevert discusses equity market volatility. Please respond to his discussion on this point.

A. On page 46 of his Direct Testimony, Mr. Hevert testified: "in light of the fact that volatility now is considerably above its prior levels, it is difficult to conclude that fundamental risk aversion and investor return requirements have fallen."

I would agree with Mr. Hevert that the indices of overall market volatility he presented suggest that market volatility has increased so far in 2016. I would further suggest that market volatility will most likely increase further with Great Britain voting to leave the European Union on June 23, 2016. However, I would note that with respect to the stocks of regulated utilities, investors appear to be seeking safe havens for their money by purchasing utility stocks. For example, the Dow Jones Utilities Average ("DJU") began the year, January 4, 2016 at 574.51. The DJU closed on Friday, June 24 at 685.71, an increase of 19.4%. On June 24, 2016, the day after the "Brexit" vote, the DJU closed up from the prior day by 1.0%. Contrast this with the overall market. The S&P 500 lost 3.6% and the Dow Jones Industrial average lost 3.4%.

Investors appear to continue to view regulated utilities as safe, stable investments compared with the market as a whole. Recent stock market movements underscore my recommendation of 9.0% as reasonable, indeed generous, for a financially strong and low risk utility investment.

V. PEPCO RATEMAKING ADJUSTMENTS

Q. Did you review Pepco's proposed ratemaking adjustments?

A. Yes. I will address certain of the RMAs included by Pepco witness VonSteuben in his Direct Testimony.

Q. Please continue with your analysis of Pepco's requested RMAs.

A. Mr. VonSteuben included several RMAs in which he requested amortization periods of five years for certain items. In summary, these RMAs are as follows:

- RMA 6 - Amortize the deferred regulatory balances associated with Pepco's AMI investment over 5 years. Pepco Witness VonSteuben Direct at 16.
- RMA 23 - Amortization of storm costs associated with winter storm PAX over 5 years. Pepco Witness VonSteuben Direct at 23 and 24.
- RMA 24 - Amortization of storm costs associated with winter storm Jonas over 5 years. Pepco Witness VonSteuben Direct at 24.
- RMA 25 - Amortization of the costs to achieve ("CTA") related to the Exelon-Pepco Holdings merger over 5 years.

Q. Do you agree with Mr. VonSteuben's proposed 5-year amortization for these items?

A. No, I do not.

Q. Please present your recommended amortization period for the cost items contained in RMAs 6, 23, 24, and 25.

A. Regarding RMAs 6, 23, 24, and 25 I recommend that the Commission order Pepco to adopt a 10-year amortization period for these cost items. Using my recommended amortization periods for these RMAs would lower the Company's revenue requirement increase - and save Maryland ratepayers - $10.86 million compared to using Pepco's requested 5-year amortization period. Please refer to my Exhibit No. ___ (RAB-9), which shows the calculation of the revenue requirement savings for each of these RMAs and contains the detailed adjustments I made to Mr. VonSteuben's RMAs. I developed this exhibit from the spreadsheet provided by Pepco that supported Mr. VonSteuben's updated exhibits.

Q. Please explain why it is preferable for the Commission to use your recommended amortization periods for these items.

A. First, using my recommended extended amortization periods lowers Pepco's revenue increase to its customers, which currently stands at $126.8 million, or 29% on its base distribution service revenues. Extending the amortization periods would lessen the burden of Pepco's requested revenue increase on its Maryland ratepayers. Placing the unamortized balance in rate base will enable Pepco to collect the total amount of costs subject to the RMAs with a return so that the Company is fully compensated for the time value of money over the 10-year amortization periods. In my opinion, my recommended amortization periods fairly balance the interests of the Company, its shareholders and ratepayers.

Second, the initial year that a deferred cost or asset is placed into rate base is the year in which the revenue requirement for that item is the highest. This is because the deferred rate base item has been depreciated the least in the first year. As the amortization period unfolds, the unamortized balance will decline. However, unless the Company comes in for a rate case each year to reflect the lower depreciable balance, the Company will continue to collect the higher level of first-year revenue requirements until it does come in. Using 10-year amortization periods will lessen the impact of this simply because the yearly amortization amount is lower.

Q. How do you recommend that the Commission reflect the amortization amounts and the return amounts associated with the unamortized balances for RMAs 6, 23, 24, and 25.

A. I recommend that these RMAs be reflected in Pepco's rates as an annuity payment. My adjustments to these RMA show the annuity payment for each one based on a 10-year amortization of the regulatory assets at Pepco's requested cost of capital, which is 8.01%. This annuity payment is similar to a home mortgage payment. The purpose of allowing Pepco to collect its amortization and return in this fashion is to account for a levelized payment over time, rather than reflecting the highest payment amount at the beginning of the amortization period as I described earlier. Collecting the amortization and return in this manner relieves Maryland ratepayers from an excessive payment of costs and gives Pepco its return over time as well.

If the Commission decides that Pepco's return on rate base should be reduced, then the annuity payments for these items should be adjusted to reflect the lower payment amount that would result.

Q. Is there another reason that Pepco's proposed amortization period for RMA 23, which are costs arising from historic storms, should be longer than 5 years?

A. Yes. According to Pepco, the number of truck rolls during storms (Pepco Witness Lefkowitz Direct at 22:14-17) and the duration of outages during storms (*id.)* will be reduced by the new AMI equipment. According to Witness Lefkowitz:

> **Q54: Is the cost savings greater for outages caused by storms that cause significant outages? (OPR14)**

> A54: Yes. The potential for avoided cost savings during storms that cause widespread outages is significant and includes reduced overtime mutual assistance and Pepco crew time, reduced costs to feed and house out-of-town crews, fewer hours of auxiliary call center costs, reduced costs for staging area rentals, and reduced district office operations. [Pepco Witness Lefkowitz Direct at 39:20-40:3]

Pepco claims that its new equipment was already saved $400,000 in the 2012 Sandy and Derecho events. Pepco Witness Lefkowitz Direct at 40:4-13.

Q. Was the AMI program fully operational when the historic storms subject to RMA 23 occurred?

A. No. Only a fraction of the total Pepco Maryland service territory had activated AMI meters. *See* Exhibit No. ___ (RAB-10) at pp. 1-2 (Pepco Responses to Staff Data Request No. 4, Questions 10 and -11). At most 96,000 AMI were activated.

Q. Why is that significant?

A. If the Company's claim of AMI savings is correct, then a storm of the same force today would result in lower costs for Pepco compared to the costs that were incurred for Hurricane Sandy and the Derecho.

Q. Why are these claimed savings relevant?

A. The cost of future storms should be less than they would otherwise have been without the equipment upgrades, meaning lower storm costs going forward than was the case historically. Therefore, it makes sense to spread some of the historic storm costs out over a longer amortization period than proposed by Pepco in this case.

Q. How much does Pepco project in savings on storm damage costs because of its new equipment?

A. Pepco estimates an NPV in excess of benefits not credited to the AMI regulatory asset of $4.625 million in avoided truck rolls and related crew time for a ten year projection period, or about $462,500/year.

Q. How much would changing the amortization period from 5 years to 10 years save customers with respect to RMAs 23 and 24?

A. Maryland customers would save $0.32 million per year.

Q. Regarding RMA 25, are there additional reasons for employing a 10-year amortization period for the CTA from the merger between PHI and Exelon?

A. Yes. As illustrated by the table in Schedule (KMM)-2, p. 1, for Pepco Maryland about 90% of the costs to achieve the merger occur prior to the end of the year following closing; but about 90% of the *synergies* are projected to be achieved *after that*. This mismatch could be disadvantageous if Pepco decides not to file rate cases during the projection period (*i.e.*, the next 5 years).

Q. Do you believe the revenue requirements should be adjusted to better synchronize costs and benefits of the merger with Exelon?

A. Yes, most definitely. It is important to note that, in my opinion, the Commission expressed this view in its Order No. 87591 in Case No. 9406, slip opinion at pages 123 and 124. The Commission stated the following:

> We are very concerned that the timing of BGE's next rate case could jeopardize synergy savings that BGE professed would inure to Maryland ratepayers. We also are concerned about the seeming asymmetry between BGE's proposed treatment of costs to achieve and synergy savings.

Amortizing Pepco's CTA over a 10-year period will more closely match collection of those costs with the synergy savings over time.

Q. What is the revenue requirement effect of amortizing the CTA over a 10-year period?

A. This adjustment reduces Pepco's revenue requirement by $1.86 million.

Q. Mr. VonSteuben cited past Commission precedent for using his proposed 5-year amortization for these items. Do you believe that the Commission is bound by its past findings for the RMAs in this case?

A. No, I do not. I acknowledge that the Commission has adopted a five-year amortization in past cases for storm costs and the recovery of the CTA from the Exelon-BGE merger. However, the Commission may certainly use a different amortization period based on the circumstances in this particular case.

Given the large increase that Pepco proposes, longer amortization fairly balances the interest of the Company, its shareholders, and its Maryland customers. The Company will collect all of its costs associated with the RMAs and will be compensated for the time value of money by receiving a rate base return on these items. Ratepayers will experience some much needed rate relief through a lower level of cost recovery. This ratemaking treatment is just and reasonable and I recommend that the Commission adopt a 10-year amortization for these RMAs in this case.

Q. What is Pepco's proposal regarding RMA 7?

A. It seeks a 10-year amortization with its capital return.

Q. Has Pepco received different treatment of amortized legacy meter costs in other jurisdictions?

A. Yes. Please refer to Exhibit No. ___ (RAB-11), which is a response from Pepco to Staff Data Request No. 17, Question No. 17. The Company stated that in Delaware and the District of Columbia, the Commission authorized 15-year amortization periods for the regulatory assets associated with legacy meters. In addition, the Commission's Order No. 87591 in BGE Case No. 9406 found that BGE was not entitled to a return on the recovery of legacy meters.

Q. What is your recommendation regarding RMA 7?

A. I recommend that the Commission adopt a 10-year amortization period for the recovery of the costs of Pepco's legacy meters with no return on the unamortized balance. The reduction to Pepco's requested revenue requirement increase is $7.286 million.

Q. On page 19 of Mr. VonSteuben's Direct Testimony, he included RMA 10, which reversed the Commission's adjustment from the last case regarding the return on tax compensation payments. Do you agree with the Commission's decision on this item?

A. Yes. I believe the Commission was correct to make a carrying cost adjustment to the tax compensation payment in its Order No. 86711. The Commission properly identified that the ratepayers should be compensated for the time value of money for the tax compensation payment so that the timing of the Company's rate proceedings does not disadvantage ratepayers.[4] The Company should not be allowed to reverse the adjustment ordered by the Commission in the last case. Mr. VonSteuben's RMA 10 should be rejected.

[4] See Maryland Public Service Commission Order No. 87611, page 26.

VI. COST ALLOCATION AND RATE DESIGN

Q. Did you review the class cost of service study ("CCOSS") submitted by Pepco in this proceeding?

A. Yes. Pepco witness Christopher Nagle presented the Company's CCOSS.

Q. Please explain how Pepco proposed to allocate its requested revenue increase.

A. Company witness Janocha presented Pepco's proposed class revenue allocation in his Schedule (JFJ)-1. The specific elements of Mr. Janocha's revenue allocation proposal are as follows:

- Summarize the current rate of return and unitized rate of return ("UROR") for each customer class.
- Allocate the Company's revenue requirement increase using a two-step process.
- Step One allocates 25% of the revenue increase to classes that are significantly below a UROR of 1.0. Those classes are R, RTM, and GS-LV.
- Step Two allocates 75% of the revenue increase to all classes based on each class' proportion of current annualized distribution revenue. Rate classes GT-3B and TN did not receive increases due to having URORs significantly above 1.0.
- Limit the maximum percentage increase to 1.5 times the overall system average increase.
- Ensure that the final UROR for a rate class with an existing UROR above 1.0 does not increase or move to a level below 1.0.
- Ensure that the final UROR for a rate class with an existing UROR below 1.0 does not decrease or move to a level above 1.0.

Q. Mr. Baudino, has the 25%/75% method of allocating Pepco's revenue increase to customers been effective in bringing Pepco's rates into parity?

A. No, it has failed to do so. Table 4 presents the earned URORs for the Residential classes in Case Nos. 9286, 9311, and 9336.

Table 4

Unitized Rate of Return
Residential Classes

	Case No. 9418	Case No. 9336	Case No. 9311	Case No. 9286
Residential	0.60	0.75	0.61	0.03
RTM	0.70	0.73	0.59	0.06

The URORs for Case No. 9336 were taken from Mr. Janocha's Schedule (JFJ-S)-1 in that case. The URORs for Case No. 9286 were taken from Mr. Tanos' PEPCO (EPT)-2. The URORs for Case Nos. 9418 and 9311 were taken from the Commission Orders in those cases.

It is clear from these results that over time, the rates for Residential class service have chronically failed to meet the cost of providing that service. The approach of allocating 25% of the increase to classes that are significantly below 1.0 is simply not working. *In fact, the Residential class is further below its cost to serve than it was in Pepco's last rate case.*

Q. What is your recommended approach to allocating Pepco's revenue increase in this case?

A. I recommend that the Commission utilize a greater percentage of the Company's requested revenue increase in the first step of the revenue allocation process, in order to begin to move towards parity on a more lasting basis. I recommend that 40% of Pepco's revenue increase be allocated to the Residential, RTM, and GS-LV classes. The remaining 60% should be allocated to all the classes, with the exception of GT-LV, GT-3B and TN, based on each class' proportionate share of annualized distribution revenues.

Q. Please explain why the GT-LV class should receive no revenue increase in this case.

A. The GT-LV class' current rate of return is 7.81% and its UROR is 2.0. This means that GT-LV customers are already paying double the system average rate of return. Viewed another way, the 7.81% current return for GT-LV is already nearly the same as Pepco's requested rate of return after its revenue increase of 8.01%. Because of this excessive current return, the GT-LV class should be treated the same as the GT-3B and TN classes.

Q. Please present the results of your recommended revenue allocation.

A. Exhibit No. ___ (RAB-12) presents the results of my recommended revenue allocation. This exhibit was developed using the spreadsheet provided by Pepco that supported Mr. Janocha's Schedule (JFJ-S)-1.

The results of my recommended revenue allocation are as follows:

- Most customer classes fall within a UROR range of 0.90 - 1.10.

- The Residential, RTM, and GS-LV classes receive increases that are 1.31 times the system average increase, far below Mr. Janocha's limit of 1.5 times the system average increase.
- The Residential, RTM, and GS-LV classes move materially toward the system rate of return, although they *still* do not have a UROR of 1.0.

Q. Does your recommended revenue allocation fairly balance the principles of cost responsibility and gradualism?

A. Yes, it does.

With respect to cost responsibility, my revenue allocation moves the Residential and RTM classes closer to their allocated cost of service than Mr. Janocha's proposal. I have demonstrated that the 25%/75% revenue allocation proposal is not working and needs to have a greater percentage of the total revenue increase collected from the customer classes that are significantly and persistently paying far less than the cost to serve them. My proposal to collect 40% of the proposed increase in Step One responsibly moves to address the fact that some classes have not paid anywhere close to their fair share of costs for many years. Indeed, even more movement could be made and a greater increase could be applied to the Residential class; however, my proposal moves residential customers to within 10% of the UROR (0.94 UROR).

My revenue allocation proposal also factors in the principle of gradualism and is consistent with Mr. Janocha's proposed limit of 1.5 times the system average increase. The proposed increases to Residential, RTM, and GS-LV are 1.31 times the system average increase. This strikes an equitable balance between cost responsibility and the resulting rate impact to customers.

Q. On pages 11 and 12 of his Direct Testimony, Mr. Janocha described his approach to rate design for rate schedules MGT-LV, MGT-3A, GT-LV, and GT-3A. Do you agree in principle with Mr. Janocha's proposed rate design for these classes?

A. Yes. Mr. Janocha's emphasis on collecting more of the revenue requirement from the fixed customer and demand charges is appropriate and moves the unit charges away from the volumetric rate component. Mr. Janocha's rate design proposal is based on the principle of collecting the fixed costs of the transmission and distribution system through demand/reservation charges. I recommend that the Commission adopt Mr. Janocha's rate design for rate schedules MGT-LV, MGT-3A, GT-LV, and GT-3A.

Of course, the rates for GT-LV should be designed in a revenue neutral manner so that this class received no revenue increase. The remaining classes should have rates designed to collect the level of revenue increase that I recommend.

Q. Does this complete your prepared Direct Testimony?

A. Yes, subject to the right to modify or supplement this testimony based upon additional information obtained or reviewed after the date of this testimony.

BEFORE THE

PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF POTOMAC ELECTRIC POWER	**)**	
COMPANY FOR ADJUSTMENTS TO ITS	**)**	**CASE NO. 9418**
RETAIL RATES FOR THE DISTRIBUTION	**)**	
OF ELECTRIC ENERGY	**)**	

EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

HEALTHCARE COUNCIL OF THE NATIONAL CAPITAL AREA

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2016

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant -** Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist -** Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Kentucky Office of the Attorney General
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor
Utah Office of Consumer Services
Healthcare Council of the National Capital Area

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

Expert Testimony Appearances
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Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

Expert Testimony Appearances
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As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

Expert Testimony Appearances
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As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

Expert Testimony Appearances
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Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

**Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

Expert Testimony Appearances
of
Richard A. Baudino
As of July 2016

Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T	WV	West Virginia Energy Users Group	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR-09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009-2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010-2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010-2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010-2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010-2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010-2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011-2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5
3/16	39971	GA	GA Public Service Comm. Staff	Southern Company / AGL Resources	Credit quality and service quality issues
04/16	2015-00343	KY	Kentucky Office of the Attorney General	Atmos Energy	Cost of equity, cost of short-term debt, capital structure
05/16	16-G-0058 16-G-0059	NY	City of New York	Brooklyn Union Gas Co., KeySpan Gas East Corp.	Cost and revenue allocation, rate design, service quality issues
06/16	16-0073-E-C	WV	Constellium Rolled Products Ravenswood, LLC	Appalachian Power Co.	Complaint; security deposit
07/16	9418	MD	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of equity, cost of service, Cost and revenue allocation
07/16	160021-EI	FL	South Florida Hospital and Health Care Association	Florida Power and Light Co.	Return on equity, cost of debt, capital structure
07/16	16-057-01	UT	Utah Office of Consumer Svcs.	Dominion Resources, Questar Gas Co.	Credit quality and service quality issues

Case No. 9418
Exhibit No. ___ (RAB-2)
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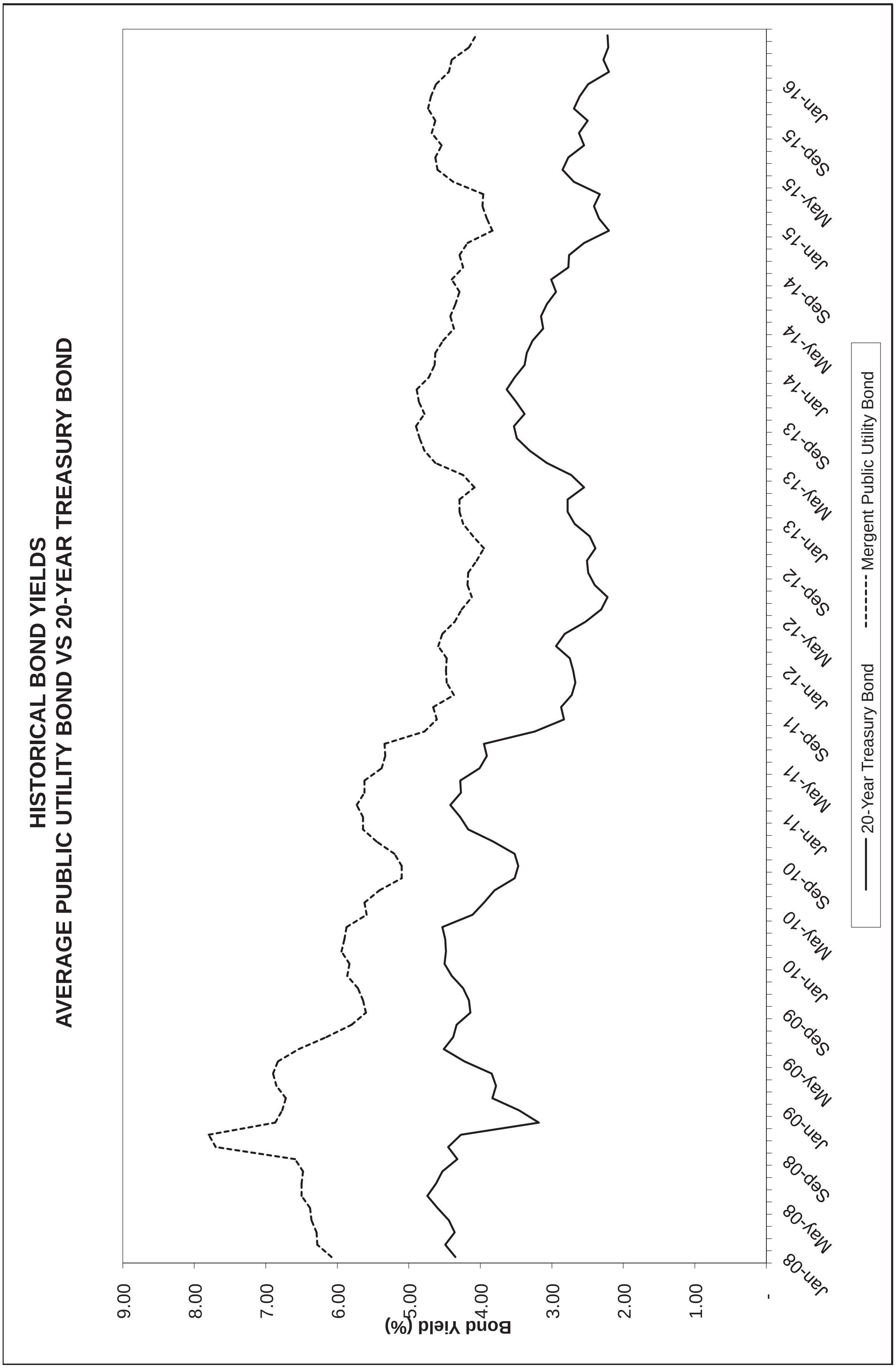

Credit and Liquidity Programs and the Balance Sheet

The Federal Reserve's response to the financial crisis and actions to foster maximum employment and price stability

The Federal Reserve responded aggressively to the financial crisis that emerged in the summer of 2007, including the implementation of a number of programs designed to support the liquidity of financial institutions and foster improved conditions in financial markets. These programs led to significant changes to the Federal Reserve's balance sheet.

While these crisis-related special programs have expired or been closed, the Federal Reserve continues to take actions to fulfill its statutory objectives for monetary policy: maximum employment and price stability. Over recent years, many of these actions have involved substantial purchases of longer-term securities aimed at putting downward pressure on longer-term interest rates and easing overall financial conditions.

Related

The Crisis and Policy Response
Speech by Chairman Ben S. Bernanke, Jan. 13, 2009

The Federal Reserve's Policy Actions during the Financial Crisis and Lessons for the Future
Speech by Vice Chairman Donald L. Kohn, May 13, 2010

The tools described in this section can be divided into three groups. The first set of tools, which are closely tied to the central bank's traditional role as the lender of last resort, involve the provision of short-term liquidity to banks and other depository institutions and other financial institutions. The traditional discount window falls into this category, as did the crisis-related Term Auction Facility (TAF), Primary Dealer Credit Facility (PDCF), and Term Securities Lending Facility (TSLF). Because bank funding markets are global in scope, the Federal Reserve also approved bilateral currency swap agreements with several foreign central banks. The swap arrangements assist these central banks in their provision of dollar liquidity to banks in their jurisdictions.

A second set of tools involved the provision of liquidity directly to borrowers and investors in key credit markets.

The crisis-related Commercial Paper Funding Facility (CPFF), Asset-Backed Commercial Paper Money Market Mutual Fund Liquidity Facility (AMLF), Money Market Investor Funding Facility (MMIFF), and the Term Asset-Backed Securities Loan Facility (TALF) fall into this category.

As a third set of instruments, the Federal Reserve expanded its traditional tool of open market operations to support the functioning of credit markets, put downward pressure on longer-term interest rates, and help to make broader financial conditions more accommodative through the purchase of longer-term securities for the Federal Reserve's portfolio. For example, starting in September 2012, the FOMC decided to increase policy accommodation by purchasing agency-guaranteed mortgage-backed securities (MBS) at a pace of $40 billion per month in order to support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate. In addition, starting in January 2013, the Federal Reserve began purchasing longer-term Treasury securities at a pace of $45 billion per month. Starting in January 2014, the FOMC reduced the pace of asset purchases in measured steps, and concluded the purchases in October 2014.

Additional information on closed facilities

As noted above, the Federal Reserve's crisis-related special credit and liquidity programs have expired or been closed. Information on these programs is available on the Information on closed programs page.

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Press Release

FEDERAL RESERVE press release

Release Date: November 3, 2010

For immediate release

Information received since the Federal Open Market Committee met in September confirms that the pace of recovery in output and employment continues to be slow. Household spending is increasing gradually, but remains constrained by high unemployment, modest income growth, lower housing wealth, and tight credit. Business spending on equipment and software is rising, though less rapidly than earlier in the year, while investment in nonresidential structures continues to be weak. Employers remain reluctant to add to payrolls. Housing starts continue to be depressed. Longer-term inflation expectations have remained stable, but measures of underlying inflation have trended lower in recent quarters.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. Currently, the unemployment rate is elevated, and measures of underlying inflation are somewhat low, relative to levels that the Committee judges to be consistent, over the longer run, with its dual mandate. Although the Committee anticipates a gradual return to higher levels of resource utilization in a context of price stability, progress toward its objectives has been disappointingly slow.

To promote a stronger pace of economic recovery and to help ensure that inflation, over time, is at levels consistent with its mandate, the Committee decided today to expand its holdings of securities. The Committee will maintain its existing policy of reinvesting principal payments from its securities holdings. In addition, the Committee intends to purchase a further $600 billion of longer-term Treasury securities by the end of the second quarter of 2011, a pace of about $75 billion per month. The Committee will regularly review the pace of its securities purchases and the overall size of the asset-purchase program in light of incoming information and will adjust the program as needed to best foster maximum employment and price stability.

The Committee will maintain the target range for the federal funds rate at 0 to 1/4 percent and continues to anticipate that economic conditions, including low rates of resource utilization, subdued inflation trends, and stable inflation expectations, are likely to warrant exceptionally low levels for the federal funds rate for an extended period.

The Committee will continue to monitor the economic outlook and financial developments and will employ its policy tools as necessary to support the economic recovery and to help ensure that inflation, over time, is at levels consistent with its mandate.

Voting for the FOMC monetary policy action were: Ben S. Bernanke, Chairman; William C. Dudley, Vice Chairman; James Bullard; Elizabeth A. Duke; Sandra Pianalto; Sarah Bloom Raskin; Eric S. Rosengren; Daniel K. Tarullo; Kevin M. Warsh; and Janet L. Yellen.

Voting against the policy was Thomas M. Hoenig. Mr. Hoenig believed the risks of additional securities purchases outweighed the benefits. Mr. Hoenig also was concerned that this continued high level of monetary accommodation increased the risks of future financial imbalances and, over time, would cause an increase in long-term inflation expectations that could destabilize the economy.

Statement from Federal Reserve Bank of New York

Press Release

FEDERAL RESERVE press release

Release Date: June 19, 2013

For immediate release

Information received since the Federal Open Market Committee met in May suggests that economic activity has been expanding at a moderate pace. Labor market conditions have shown further improvement in recent months, on balance, but the unemployment rate remains elevated. Household spending and business fixed investment advanced, and the housing sector has strengthened further, but fiscal policy is restraining economic growth. Partly reflecting transitory influences, inflation has been running below the Committee's longer-run objective, but longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with appropriate policy accommodation, economic growth will proceed at a moderate pace and the unemployment rate will gradually decline toward levels the Committee judges consistent with its dual mandate. The Committee sees the downside risks to the outlook for the economy and the labor market as having diminished since the fall. The Committee also anticipates that inflation over the medium term likely will run at or below its 2 percent objective.

To support a stronger economic recovery and to help ensure that inflation, over time, is at the rate most consistent with its dual mandate, the Committee decided to continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and longer-term Treasury securities at a pace of $45 billion per month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. Taken together, these actions should maintain downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative.

The Committee will closely monitor incoming information on economic and financial developments in coming months. The Committee will continue its purchases of Treasury and agency mortgage-backed securities, and employ its other policy tools as appropriate, until the outlook for the labor market has improved substantially in a context of price stability. The Committee is prepared to increase or reduce the pace of its purchases to maintain appropriate policy accommodation as the outlook for the labor market or inflation changes. In determining the size, pace, and composition of its asset purchases, the Committee will continue to take appropriate account of the likely efficacy and costs of such purchases as well as the extent of progress toward its economic objectives.

To support continued progress toward maximum employment and price stability, the Committee expects that a highly accommodative stance of monetary policy will remain appropriate for a considerable time after the asset purchase program ends and the economic recovery strengthens. In particular, the Committee decided to keep the target range for the federal funds rate at 0 to 1/4 percent and currently anticipates that this exceptionally low range for the federal funds rate will be appropriate at least as long as the unemployment rate remains above 6-1/2 percent, inflation between one and two years ahead is projected to be no more than a half percentage point above the Committee's 2 percent longer-run goal, and longer-term inflation expectations continue to be well anchored. In determining how long to maintain a highly accommodative stance of monetary policy, the Committee will also consider other information, including additional measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial developments. When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent.

Voting for the FOMC monetary policy action were: Ben S. Bernanke, Chairman; William C. Dudley, Vice Chairman; Elizabeth A. Duke; Charles L. Evans; Jerome H. Powell; Sarah Bloom Raskin; Eric S. Rosengren; Jeremy C. Stein; Daniel K. Tarullo; and Janet L. Yellen. Voting against the action was James Bullard, who believed that the Committee should signal more strongly its willingness to defend its inflation goal in light of recent low inflation readings, and Esther L. George, who was concerned that the continued high level of monetary accommodation increased the risks of future economic and financial imbalances and, over time, could cause an increase in long-term inflation expectations.

Press Release

FEDERAL RESERVE press release

Release Date: October 29, 2014

For immediate release

Information received since the Federal Open Market Committee met in September suggests that economic activity is expanding at a moderate pace. Labor market conditions improved somewhat further, with solid job gains and a lower unemployment rate. On balance, a range of labor market indicators suggests that underutilization of labor resources is gradually diminishing. Household spending is rising moderately and business fixed investment is advancing, while the recovery in the housing sector remains slow. Inflation has continued to run below the Committee's longer-run objective. Market-based measures of inflation compensation have declined somewhat; survey-based measures of longer-term inflation expectations have remained stable.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with appropriate policy accommodation, economic activity will expand at a moderate pace, with labor market indicators and inflation moving toward levels the Committee judges consistent with its dual mandate. The Committee sees the risks to the outlook for economic activity and the labor market as nearly balanced. Although inflation in the near term will likely be held down by lower energy prices and other factors, the Committee judges that the likelihood of inflation running persistently below 2 percent has diminished somewhat since early this year.

The Committee judges that there has been a substantial improvement in the outlook for the labor market since the inception of its current asset purchase program. Moreover, the Committee continues to see sufficient underlying strength in the broader economy to support ongoing progress toward maximum employment in a context of price stability. Accordingly, the Committee decided to conclude its asset purchase program this month. The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that the current 0 to 1/4 percent target range for the federal funds rate remains appropriate. In determining how long to maintain this target range, the Committee will assess progress--both realized and expected--toward its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial developments. The Committee anticipates, based on its current assessment, that it likely will be appropriate to maintain the 0 to 1/4 percent target range for the federal funds rate for a considerable time following the end of its asset purchase program this month, especially if projected inflation continues to run below the Committee's 2 percent longer-run goal, and provided that longer-term inflation expectations remain well anchored. However, if incoming information indicates faster progress toward the Committee's employment and inflation objectives than the Committee now expects, then increases in the target range for the federal funds rate are likely to occur sooner than currently anticipated. Conversely, if progress proves slower than expected, then increases in the target range are likely to occur later than currently anticipated.

When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent. The Committee currently anticipates that, even after employment and inflation are near mandate-consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels the Committee views as normal in the longer run.

Voting for the FOMC monetary policy action were: Janet L. Yellen, Chair; William C. Dudley, Vice Chairman; Lael Brainard; Stanley Fischer; Richard W. Fisher; Loretta J. Mester; Charles I. Plosser; Jerome H. Powell; and Daniel K. Tarullo. Voting against the action was Narayana Kocherlakota, who believed that, in light of continued sluggishness in the inflation outlook and the recent slide in market-based measures of longer-term inflation expectations, the Committee should commit to keeping the current target range for the federal funds rate at least until the one-to-two-year ahead inflation outlook has returned to 2 percent and should continue the asset purchase program at its current level.

Statement Regarding Purchases of Treasury Securities and Agency Mortgage-Backed Securities

Press Release

FEDERAL RESERVE press release

Release Date: March 16, 2016

For release at 2:00 p.m. EDT

Information received since the Federal Open Market Committee met in January suggests that economic activity has been expanding at a moderate pace despite the global economic and financial developments of recent months. Household spending has been increasing at a moderate rate, and the housing sector has improved further; however, business fixed investment and net exports have been soft. A range of recent indicators, including strong job gains, points to additional strengthening of the labor market. Inflation picked up in recent months; however, it continued to run below the Committee's 2 percent longer-run objective, partly reflecting declines in energy prices and in prices of non-energy imports. Market-based measures of inflation compensation remain low; survey-based measures of longer-term inflation expectations are little changed, on balance, in recent months.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will continue to strengthen. However, global economic and financial developments continue to pose risks. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to monitor inflation developments closely.

Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.

In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.

The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction, and it anticipates doing so until normalization of the level of the federal funds rate is well under way. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

Voting for the FOMC monetary policy action were: Janet L. Yellen, Chair; William C. Dudley, Vice Chairman; Lael Brainard; James Bullard; Stanley Fischer; Loretta J. Mester; Jerome H. Powell; Eric Rosengren; and Daniel K. Tarullo. Voting against the action was Esther L. George, who preferred at this meeting to raise the target range for the federal funds rate to 1/2 to 3/4 percent.

Implementation Note issued March 16, 2016

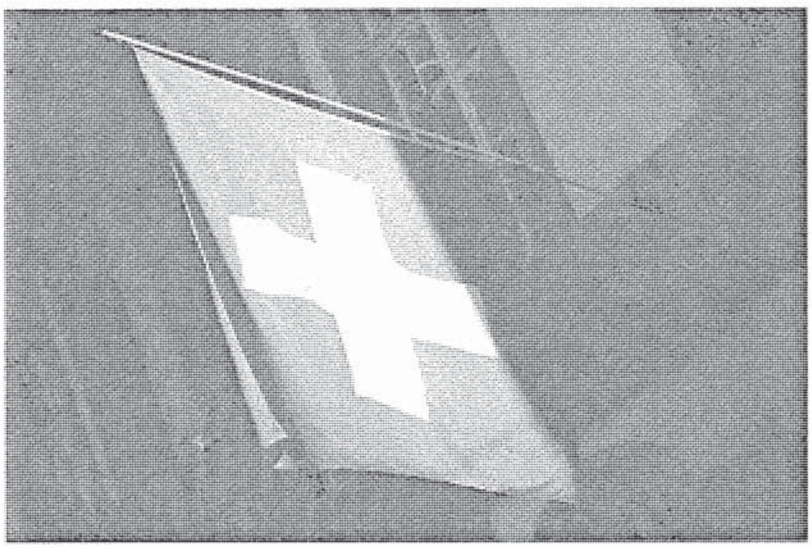
THE WALL STREET JOURNAL.

http://blogs.wsj.com/moneybeat/2016/06/16/from-1-month-to-33-years-almost-the-entire-yield-curve-for-swiss-bonds-is-negative/

MONEYBEAT

From 1 Month to 33 Years, Almost the Entire Yield Curve for Swiss Bonds is Negative

Switzerland has outdone Germany: the country's bonds have negative yields all the way out to 2049



The Swiss national flag is illuminated by evening sunlight as it hangs from a building in Bern, Switzerland, on Sunday, June 28, 2015. *PHOTO: BLOOMBERG NEWS*

By **MIKE BIRD**
Jun 16, 2016 11:19 am ET

Switzerland's government bonds have outdone Germany's this week: Though the 10-year German bund yields dipped into negative territory on Tuesday, Swiss sovereign bonds now have subzero yields all the way out to 33 years.

The benchmark 30 year bond dipped below zero to minus 0.004%, from a close of 0.04% at the end of trading on Wednesday.

Though Switzerland does have some longer-dated bonds with very narrowly positive yields, the country's yield curve is the lowest in the world, outdoing Japan.

Shorter dated Swiss bond yields are even lower, with a 10-year yield at minus 0.53%

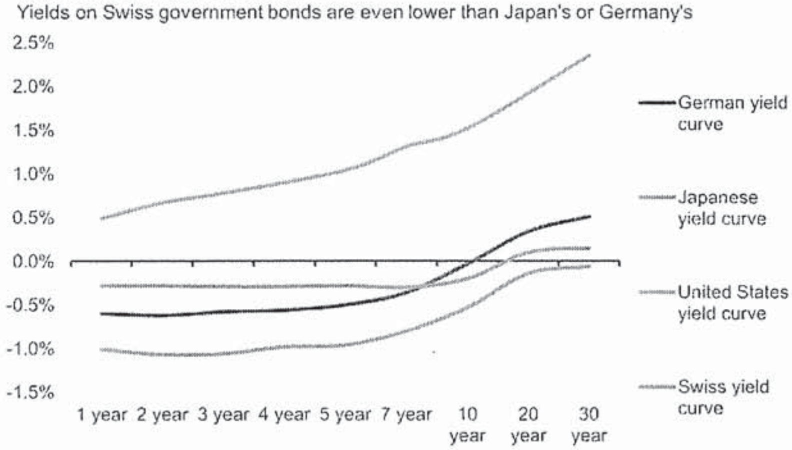
Bond yields move inversely to prices, so more demand for the bonds drives returns lower. The Swiss National Bank has set its benchmark interest rate at minus 0.75%, one of the most steeply negative in the world, in an effort to stave off its persistent deflation.

The flight to safety hitting global markets this week is particularly acute in Europe, with polls suggesting growing levels of support for Brexit, ahead of the U.K's June 23 referendum on its European Union membership.

Swiss assets are widely regarded as safe havens from financial turmoil, and the Swiss franc also climbed to its strongest level in nearly six months against the euro during Thursday trading.

Sub Zero Switzerland

Yields on Swiss government bonds are even lower than Japan's or Germany's



Press Release

FEDERAL RESERVE press release

Release Date: June 15, 2016

For release at 2:00 p.m. EDT

Information received since the Federal Open Market Committee met in April indicates that the pace of improvement in the labor market has slowed while growth in economic activity appears to have picked up. Although the unemployment rate has declined, job gains have diminished. Growth in household spending has strengthened. Since the beginning of the year, the housing sector has continued to improve and the drag from net exports appears to have lessened, but business fixed investment has been soft. Inflation has continued to run below the Committee's 2 percent longer-run objective, partly reflecting earlier declines in energy prices and in prices of non-energy imports. Market-based measures of inflation compensation declined; most survey-based measures of longer-term inflation expectations are little changed, on balance, in recent months.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee currently expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market indicators will strengthen. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of past declines in energy and import prices dissipate and the labor market strengthens further. The Committee continues to closely monitor inflation indicators and global economic and financial developments.

Against this backdrop, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.

In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.

The Committee is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities and of rolling over maturing Treasury securities at auction, and it anticipates doing so until normalization of the level of the federal funds rate is well under way. This policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions.

Voting for the FOMC monetary policy action were: Janet L. Yellen, Chair; William C. Dudley, Vice Chairman; Lael Brainard; James Bullard; Stanley Fischer; Esther L. George; Loretta J. Mester; Jerome H. Powell; Eric Rosengren; and Daniel K. Tarullo.

Implementation Note issued June 15, 2016

COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		May-16	Apr-16	Mar-16	Feb-16	Jan-16	Dec-15
ALLETE	High Price ($)	58.490	56.800	58.340	54.960	53.740	51.850
	Low Price ($)	54.030	53.470	51.290	50.830	48.260	47.930
	Avg. Price ($)	56.260	55.135	54.815	52.895	51.000	49.890
	Dividend ($)	0.520	0.520	0.520	0.520	0.505	0.505
	Mo. Avg. Div.	3.70%	3.77%	3.79%	3.93%	3.96%	4.05%
	6 mos. Avg.	3.87%					
Alliant Energy	High Price ($)	74.210	75.180	74.350	70.250	65.350	64.250
	Low Price ($)	71.100	68.150	66.520	64.760	60.750	58.130
	Avg. Price ($)	72.655	71.665	70.435	67.505	63.050	61.190
	Dividend ($)	0.588	0.588	0.588	0.588	0.588	0.550
	Mo. Avg. Div.	3.24%	3.28%	3.34%	3.48%	3.73%	3.60%
	6 mos. Avg.	3.44%					
Avista Corp.	High Price ($)	42.170	41.370	41.310	39.300	37.100	37.780
	Low Price ($)	38.830	38.480	36.890	36.720	34.310	33.000
	Avg. Price ($)	40.500	39.925	39.100	38.010	35.705	35.390
	Dividend ($)	0.343	0.343	0.343	0.343	0.330	0.330
	Mo. Avg. Div.	3.39%	3.44%	3.51%	3.61%	3.70%	3.73%
	6 mos. Avg.	3.56%					
Consolidated Edison	High Price ($)	76.760	77.230	77.020	73.900	70.200	65.660
	Low Price ($)	70.310	70.730	68.440	69.080	63.470	60.300
	Avg. Price ($)	73.535	73.980	72.730	71.490	66.835	62.980
	Dividend ($)	0.670	0.670	0.670	0.670	0.650	0.650
	Mo. Avg. Div.	3.64%	3.62%	3.68%	3.75%	3.89%	4.13%
	6 mos. Avg.	3.79%					
Edison International	High Price ($)	73.250	72.410	72.340	69.240	62.340	61.350
	Low Price ($)	68.470	67.710	65.600	61.490	57.970	57.850
	Avg. Price ($)	70.860	70.060	68.970	65.365	60.155	59.600
	Dividend ($)	0.480	0.480	0.480	0.480	0.480	0.480
	Mo. Avg. Div.	2.71%	2.74%	2.78%	2.94%	3.19%	3.22%
	6 mos. Avg.	2.93%					
Eversource Energy	High Price ($)	58.260	59.090	58.810	56.920	54.150	52.240
	Low Price ($)	53.900	54.510	52.620	52.930	50.010	48.180
	Avg. Price ($)	56.080	56.800	55.715	54.925	52.080	50.210
	Dividend ($)	0.445	0.445	0.445	0.445	0.418	0.418
	Mo. Avg. Div.	3.17%	3.13%	3.19%	3.24%	3.21%	3.33%
	6 mos. Avg.	3.21%					
IDACORP	High Price ($)	74.470	74.990	74.960	73.820	69.960	69.990
	Low Price ($)	69.830	70.400	69.030	68.300	65.030	65.720
	Avg. Price ($)	72.150	72.695	71.995	71.060	67.495	67.855
	Dividend ($)	0.510	0.510	0.510	0.510	0.510	0.510
	Mo. Avg. Div.	2.83%	2.81%	2.83%	2.87%	3.02%	3.01%
	6 mos. Avg.	2.89%					

COMPARISON GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		May-16	Apr-16	Mar-16	Feb-16	Jan-16	Dec-15
Northwestern Corp.	High Price ($)	59.440	62.510	62.220	60.760	55.850	55.650
	Low Price ($)	55.340	55.910	57.460	55.490	52.160	51.950
	Avg. Price ($)	57.390	59.210	59.840	58.125	54.005	53.800
	Dividend ($)	0.500	0.500	0.500	0.480	0.480	0.480
	Mo. Avg. Div.	3.48%	3.38%	3.34%	3.30%	3.56%	3.57%
	6 mos. Avg.	3.44%					
OGE Energy	High Price ($)	31.070	29.620	28.740	27.810	26.520	27.040
	Low Price ($)	28.970	27.270	24.830	24.390	23.370	24.150
	Avg. Price ($)	30.020	28.445	26.785	26.100	24.945	25.595
	Dividend ($)	0.275	0.275	0.275	0.275	0.275	0.275
	Mo. Avg. Div.	3.66%	3.87%	4.11%	4.21%	4.41%	4.30%
	6 mos. Avg.	4.09%					
Portland General Electric	High Price ($)	41.940	40.030	39.900	40.480	39.020	37.800
	Low Price ($)	39.470	37.770	37.040	37.400	35.270	35.040
	Avg. Price ($)	40.705	38.900	38.470	38.940	37.145	36.420
	Dividend ($)	0.300	0.300	0.300	0.300	0.300	0.300
	Mo. Avg. Div.	2.95%	3.08%	3.12%	3.08%	3.23%	3.29%
	6 mos. Avg.	3.13%					
WEC Energy	High Price ($)	60.510	60.320	60.160	58.150	55.720	52.880
	Low Price ($)	57.250	55.460	54.850	54.730	50.440	47.980
	Avg. Price ($)	58.880	57.890	57.505	56.440	53.080	50.430
	Dividend ($)	0.495	0.495	0.495	0.495	0.458	0.458
	Mo. Avg. Div.	3.36%	3.42%	3.44%	3.51%	3.45%	3.63%
	6 mos. Avg.	3.47%					
Xcel Energy	High Price ($)	41.980	42.040	41.850	40.420	38.260	36.720
	Low Price ($)	39.690	38.430	38.260	36.250	35.190	34.330
	Avg. Price ($)	40.835	40.235	40.055	38.335	36.725	35.525
	Dividend ($)	0.340	0.340	0.340	0.320	0.320	0.320
	Mo. Avg. Div.	3.33%	3.38%	3.40%	3.34%	3.49%	3.60%
	6 mos. Avg.	3.42%					
Average Dividend Yield		3.44%					

Source: Yahoo! Finance

COMPARISON GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) IBES
ALLETE, Inc.	3.50%	4.00%	3.00%	4.50%	3.00%
Alliant Energy Corporation	4.50%	6.00%	5.50%	6.10%	6.60%
Avista Corporation	4.00%	5.00%	3.50%	5.00%	5.00%
Consolidated Edison, Inc.	3.00%	1.50%	2.50%	2.30%	1.89%
Edison International	9.00%	3.50%	5.50%	4.90%	2.45%
Eversource Energy	6.00%	6.00%	4.00%	6.30%	6.01%
IDACORP, Inc.	7.50%	3.00%	3.50%	4.00%	4.00%
NorthWestern Corp.	5.50%	6.50%	4.00%	5.00%	5.00%
OGE Energy	9.50%	3.00%	3.50%	5.20%	4.30%
Portland General Electric Company	6.00%	5.50%	4.00%	6.40%	6.57%
WEC Energy	7.00%	6.00%	3.50%	6.30%	6.77%
Xcel Energy Inc.	6.00%	5.50%	4.00%	5.30%	5.27%
Averages	5.96%	4.63%	3.88%	5.11%	4.74%
Median Values	6.00%	5.25%	3.75%	5.10%	5.00%

Sources: Value Line Investment Survey, April 29, May 20, and June 17, 2016
Yahoo! Finance for IBES growth rates retrieved June 12, 2016
Zacks growth rates retrieved June 12, 2016

COMPARISON GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.44%	3.44%	3.44%	3.44%	3.44%
Average Growth Rate	5.96%	4.63%	5.11%	4.74%	5.11%
Expected Div. Yield	3.54%	3.52%	3.53%	3.52%	3.53%
DCF Return on Equity	***9.50%***	***8.15%***	***8.64%***	***8.26%***	***8.64%***
Method 2:					
Dividend Yield	3.44%	3.44%	3.44%	3.44%	3.44%
Median Growth Rate	6.00%	5.25%	5.10%	5.00%	5.34%
Expected Div. Yield	3.54%	3.53%	3.53%	3.52%	3.53%
DCF Return on Equity	***9.54%***	***8.78%***	***8.63%***	***8.52%***	***8.87%***

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Comparison Group

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.44%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.34%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.10%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	5.94%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	8.28%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	10.44%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.40%
4	Risk Premium	
5	(Line 1 minus Line 3)	9.04%
6	Comparison Group Beta	0.73
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.63%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	8.03%

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Comparison Group

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
December-15	2.61%
January-16	2.49%
February-16	2.20%
March-16	2.28%
April-16	2.21%
May-16	2.22%
6 month average	2.34%

5 Year Treasury Bond Data

	Avg. Yield
December-15	1.70%
January-16	1.52%
February-16	1.22%
March-16	1.38%
April-16	1.26%
May-16	1.30%
6 month average	1.40%

Source: www.federalreserve.gov, Selected Interest Rates (Dalily) - H.15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.84%
Estimated Market Return	9.88%
Value Line Projected 3-5 Yr. Median Annual Total Return	11.00%
Average of Projected Mkt. Returns	10.44%

Source: Value Line Investment Survey for Windows retreived June 12, 2016

Comparison Group Betas:	Value Line
ALLETE, Inc.	0.75
Alliant Energy Corporation	0.75
Avista Corporation	0.75
Consolidated Edison, Inc.	0.55
Edison International	0.70
Eversource Energy	0.75
IDACORP, Inc.	0.80
NorthWestern Corp.	0.70
OGE Energy	0.95
Portland General Electric Company	0.80
WEC Energy	0.65
Xcel Energy Inc.	0.65
Average	0.73

Source: Value Line Investment Survey

COMPARISON GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.07%	5.07%	
Historical Market Risk Premium	5.03%	7.03%	6.19%
Comparison Group Beta, Value Line	0.73	0.73	0.73
Beta * Market Premium	3.69%	5.16%	4.54%
Current 20-Year Treasury Bond Yield	2.34%	2.34%	2.34%
CAPM Cost of Equity, Value Line Beta	**6.02%**	**7.49%**	**6.87%**

Source: *Ibbotson SBBI 2015 Classic Yearbook,* Morningstar, pp. 39 - 40, 152, 157 - 158

FERC GDP GROWTH RATE

		2020	2040	2044	2070	
Energy Information Administration						
	Real GDP	18,801	29,898			
	GDP Deflator	1.211	1.73			
		22,768	51,724			4.19%
SSA Trustees Report		22,948			198,390	4.41%
Average GDP Growth Rate						4.30%

Sources:

Energy Information Administration, *Annual Energy Outlook 2015* (April 2015).
Social Security Administration, 2016 OASDI Trustees Report (June 22, 2016),
Table VI.G6 - Selected Economic Variables, Calendar Years 2015-90

HCNCA

Summary of Adjustments to Company Proposed RMAs
Twelve Months Ended December 31, 2015 (12+0)

	(Thousands of Dollars)	As Filed Rate Base	As Filed Operating Income	As Filed Revenue Requirement	HCNCA Adjusted Rate Base	HCNCA Adjusted Operating Income	HCNCA Adjusted Revenue Requirement
	Unadjusted Results	$ 1,596,664	$ 97,241		$ 1,596,664	$ 97,241	
	Revenue Requirement Based on Unadjusted Results			$ 52,551			$ 52,551
	Ratemaking Adjustments						
1	Annualization of Test Year Reliability Plant Closings	$ 22,478	$ (2,047)	$ 6,596	$ 22,478	$ (2,047)	$ 6,596
2	Post Test Year Reliability Closings (Jan thru Aug 2016)	42,814	(3,614)	12,076	$ 42,814	$ (3,614)	$ 12,076
3	Post Test Year Reliability Closings (Sep thru Oct 2016)	18,470	(233)	2,936	$ 18,470	$ (233)	$ 2,936
4	Post Test Year Reliability Closings (Nov thru Dec 2016)	31,232	(412)	4,995	$ 31,232	$ (412)	$ 4,995
5	Case 9385 Depreciation Rates	(5,785)	(11,545)	18,999	(5,785)	(11,545)	18,999
6	AMI Regulatory Asset Amortization	32,218	(11,020)	23,317	-	(8,644)	14,820
7	Legacy Meter Regulatory Asset Amortization	53,049	(5,808)	17,243	-	(5,808)	9,957
8	Reflection of 2014 NOL Accrual	(1,851)	-	(254)	(1,851)	-	(254)
9	Tax Compensation Carrying Costs	-	1,050	(1,800)	-	1,050	(1,800)
10	Reversal of Tax Compensation Carrying Costs	-	(1,050)	1,800	-	-	-
11	Reflection of Uncollectible Write-Offs	-	141	(242)	-	141	(242)
12	Annualization of Wage Increases	-	(1,554)	2,664	-	(1,554)	2,664
13	Reflection of Employee Health & Welfare Cost Increases	-	(478)	820	-	(478)	820
14	Reflection of 3-Year Average AIP Costs	-	279	(478)	-	279	(478)
15	Exclusion of Executive Incentive Costs	-	1,789	(3,067)	-	1,789	(3,067)
16	Reflection of 50% SERP Liability and Expense	(4,913)	1,077	(2,521)	(4,913)	1,077	(2,521)
17	Current Rate Case Costs	-	(11)	18	-	(11)	18
18	Reflection of 3-Year Avg Auto & General Claim Payments	-	3	(5)	-	3	(5)
19	Exclusion of Institutional & Promotional Ad Expense	-	598	(1,025)	-	598	(1,025)
20	Exclusion of 50% Employee Activity Costs	-	47	(81)	-	47	(81)
21	Test Period Reg Asset Removal	(23)	435	(749)	(23)	435	(749)
22	Electric Vehicle Pilot Costs	-	(90)	154	-	(90)	154
23	Winter Storm PAX	381	(84)	196	-	(63)	108
24	Winter Storm Jonas	994	(221)	515	-	(164)	282
25	Reflection of Synergies and CTA	8,704	1,290	(1,017)	-	1,782	(3,054)
26	Inclusion of Commission Authorized Interest Expense	-	(208)	357	-	(208)	357
27	AFUDC Synchronization	-	260	(446)	-	260	(446)
28	Adjustments to Cash Working Capital Allowance	(5,673)	-	(779)	(5,673)	-	(779)
29	Tax Effect of Proforma Interest Expense	-	2,140	(3,669)	-	2,140	(3,669)
30	Removal of Benning Environmental Remediation Cost	-	1,449	(2,484)	-	1,449	(2,484)
	Total ratemaking adjustments	192,095	(27,817)	$ 74,070	96,749	(23,821)	$ 54,126
	Total revenue requirement at 8.01% rate of return based on adjusted results	$ 1,788,759	$ 69,424	$ 126,620	$ 1,693,413	$ 73,420	$ 106,677

HCNCA

Maryland Distribution
Ratemaking Adjustment Calculation
Twelve Months Ended December 31, 2015 (12+0)

(Thousands of Dollars)

Line No.	Adjustment 6 - AMI Regulatory Assets		As Filed - 5 Yr	HCNCA Adjust - 10 Yr	HCNCA Adjust - 10 Yr
1	AMI regulatory assets		$ 60,024		$ 60,024
2					
3	Adjustment to amortization expense to amortize AMI deferred costs over 5 years (Line 1 ÷ 5 years)	12,005	12,005	8,949	8,949
4					
5	Ongoing Costs	4,620	4,620	4,620	4,620
6					
7	FIT Permanent Adjustment to Add Back Equity Portion of Return	(2,738)		(1,369)	
8					
9	Taxable Income	(13,887)		(12,200)	
10					
11	Adjustment to Maryland income tax expense	(1,146)		(1,007)	
12					
13	Adjustment to federal income tax expense	(4,459)	(5,605)	(3,918)	(4,925)
14					
15	**Total Expense**		11,020		8,644
16					
17	**Earnings**		$ (11,020)		$ (8,644)
18					
19					
20	Average MD regulatory asset balance	$ 60,024		$ -	
21					
22	Decline in balance after year 1	(6,003)		-	
23					
24	Adjustment to Maryland regulatory assets		54,022		-
25					
26	Adjustment to accumulated deferred income taxes		(21,804)		-
27					
28	**Rate Base**		$ 32,218		$ -

HCNCA

Maryland Distribution
Ratemaking Adjustment Calculation
Twelve Months Ended December 31, 2015 (12+0)

(Thousands of Dollars)

Line No.	Adjustment 7 - Unrecovered Investment in Legacy Meters	As Filed	As Filed	HCNCA Adjusted	HCNCA Adjusted
1	Legacy meter regulatory assets		$ 93,635		$ 93,635
2					
3	Adjustment to amortization expense to amortize legacy meter costs over 10 years (Line 1 ÷ 10 years)	9,364	9,364	9,364	9,364
4					
5	FIT Permanent Adjustment to Add Back Equity Portion of Return	(554)		(554)	
6					
7	Taxable Income	8,810		8,810	
8					
9	Adjustment to Maryland income tax expense	(727)		(727)	
10					
11	Adjustment to federal income tax expense	(2,829)	(3,556)	(2,829)	(3,556)
12					
13	**Total Expense**		5,808		5,808
14					
15	**Earnings**		$ (5,808)		$ (5,808)
16					
17					
18	Average MD regulatory asset balance	$ 93,635		$ -	
19					
20	Decline in balance after year 1	(4,682)		-	
21					
22	Adjustment to Maryland regulatory assets		88,953		-
23					
24	Adjustment to accumulated deferred income taxes		(35,904)		-
25					
26	**Rate Base**		$ 53,049		$ -

HCNCA

Maryland Distribution
Ratemaking Adjustment Calculation
Twelve Months Ended December 31, 2015 (12+0)

(Thousands of Dollars)

Line No.	Adjustment 23 - Reflect Winter Storm PAX Costs	As Filed	As Filed	HCNCA Adjusted	HCNCA Adjusted
1	February 2014 storm preparation deferred balance		$ 711		$ 711
2					
3	Adjustment to amortization expense to amortize Winter Storm PAX costs over 5 years (Line 1 ÷ 5 years)		142		106
4					
5	Adjustment to Maryland income tax expense	(12)		(9)	
6					
7	Adjustment to federal income tax expense	(46)	(58)	(34)	(43)
8					
9	**Total Expense**		84		63
10					
11	**Earnings**		$ (84)		$ (63)
12					
13					
14	Average MD regulatory asset balance	$ 711		$ -	
15					
16	Decline in balance After Year 1	(71)		-	
17					
18	Adjustment to Maryland regulatory assets		640		-
19					
20	Adjustment to accumulated deferred income taxes		(259)		-
21					
22	**Rate Base**		$ 381		$ -

HCNCA

Maryland Distribution
Ratemaking Adjustment Calculation
Twelve Months Ended December 31, 2015 (12+0)

(Thousands of Dollars)

Line No.	Adjustment 24 - Reflect Winter Storm Jonas Costs	As Filed	As Filed	HCNCA Adjusted	HCNCA Adjusted
1	Winter Storm Jonas deferred balance		$ 1,853		$ 1,853
2					
3	Adjustment to amortization expense to amortize January 2016 major storm costs over 5 years (Line 1 ÷ 5 years)		371		276
4					
5	Adjustment to Maryland income tax expense	(31)		(23)	
6					
7	Adjustment to federal income tax expense	(119)	(150)	(89)	(112)
8					
9	**Total Expense**		221		164
10					
11	**Earnings**		$ (221)		$ (164)
12					
13					
14	Average MD regulatory asset balance	$ 1,853		$ -	
15					
16	Decline in balance After year 1	(186)		-	
17					
18	Adjustment to Maryland regulatory assets		1,668		-
19					
20	Adjustment to accumulated deferred income taxes		(673)		-
21					
22	**Rate Base**		$ 994		$ -

HCNCA

Maryland Distribution
Ratemaking Adjustment Calculation
Twelve Months Ended December 31, 2015 (12+0)

(Thousands of Dollars)

Line No.	Adjustment 25 - Reflection of Synergies and the Amortization of Cost to Achieve	As Filed	As Filed	HCNCA Adjusted	HCNCA Adjusted
1	Anticipated year 1 Pepco MD synergies		$ (6,000)		$ (6,000)
2					
3	Anticipated Costs to Achieve (CTA)	18,000		18,000	
4					
5	Adjustment to amortize CTA over 5 years (Line 5 ÷ 5)		3,600		2,684
6					
7	Net synergies - Pepco MD		(2,400)		(3,316)
8					
9	Allocation to distribution (labor ratio)		0.9009		0.9009
10					
11	Adjustment to amortization expense		(2,162)		(2,988)
12					
13	Adjustment to Maryland income tax expense	178		246	
14					
15	Adjustment to federal income tax expense	694	872	960	1,206
16					
17	**Total Expense**		(1,290)		(1,782)
18					
19	**Earnings**		$ 1,290		$ 1,782
20					
21					
22	Average MD regulatory asset balance	$ 18,000			
23					
24	Decline in balance After Year 1	(1,800)			
25					
26	Adjustment to Maryland regulatory assets		16,200		
27					
28	Allocation to distribution (labor ratio)		0.9009		
29					
30	Adjustment to Maryland distribution regulatory assets		14,595		
31					
32	Adjustment to accumulated deferred income taxes		(5,891)		
33					
34	**Rate Base**		$ 8,704		

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO STAFF DATA REQUEST NO. 4

QUESTION NO. 10

HOW MANY AMI METERS WERE INSTALLED PRIOR TO HURRICANE SANDY?

RESPONSE:

Prior to Hurricane Sandy, project-to-date approximately 332,000 meters were installed and 96,000 meters were activated for billing. As of late October 2012, 33.7% of AMI residential meters had been activated. Meters not activated for billing may not have been reachable by ping because communications had not been optimized. See the Q3 2012 Quarterly Advanced Metering Infrastructure Performance Metrics Reporting Plan-Phase I filed in compliance with Order No. 83571, Case No. 9207, (ML #143658).

SPONSOR: Karen R. Lefkowitz

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO STAFF DATA REQUEST NO. 4

QUESTION NO. 11

HOW MANY AMI METERS WERE INSTALLED PRIOR TO DERECHO?

RESPONSE:

Prior to the Derecho, project-to-date approximately 263,000 meters were installed and 36,000 meters were activated for billing. Meters not activated for billing may not have been reachable by ping because communications had not been optimized. See the Q2 2012 Quarterly Advanced Metering Infrastructure Performance Metrics Reporting Plan-Phase I filed in compliance with Order No. 83571, Case No. 9207, (ML #142026)

SPONSOR: Karen R. Lefkowitz

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO STAFF DATA REQUEST NO. 17

QUESTION NO. 17

PER RMA 7 RELATED TO AMORTIZATION OF THE REGULATORY ASSET OF LEGACY METERS, PLEASE CITE TO PRECEDENT IN OTHER EXELON/PEPCO JURISDICTIONS (AND OTHER JURISDICTIONS) WHERE STATE REGULATORY AGENCIES HAVE APPROVED THE TREATMENT OF LEGACY METERS AS PEPCO PROPOSES IN THIS CASE, INCLUDING FULL RECOVERY "OF" AND "ON" THESE LEGACY METERS, AND INCLUDING A 10-YEAR AMORTIZATION PERIOD.

RESPONSE:

In addition to Maryland, AMI deployment has been executed in Delaware and the District of Columbia in the PHI service territory. In Delaware in Docket No. 11-528, the Commission authorized recovery of the net book value of the legacy meters to be amortized over a 15 year period with the unamortized amount included in rate base. In the District of Columbia in Formal Case No. 1087, the Commission authorized recovery of the net book value of the legacy meters to be amortized over a 15 year period with the unamortized amount included in rate base.

SPONSOR: W. Michael VonSteuben

HCNCA RECOMMENDED REVENUE ALLOCATION

	TOTAL MARYLAND RETAIL		RESIDENTIAL	RTM	GS-LV	MGT-LV	MGT-3A	GT-LV	GT-3B	GT-3A	TM-RT	SL	SSL	TN
Cost of Service Study Results														
Operating Income	$ 69,424,057		$ 19,417,673	$ 4,250,605	$ 1,842,274	$ 27,638,832	$ 290,066	$ 7,506,945	$ 1,239,428	$ 4,648,519	$ 869,063	$ 370,293	$ 1,194,252	$ 156,108
Distribution Rate Base	$ 1,788,760,182		$ 844,003,266	$ 159,563,236	$ 68,228,669	$ 464,937,192	$ 5,489,993	$ 96,120,557	$ 3,716,054	$ 94,615,555	$ 14,390,766	$ 6,961,211	$ 29,880,366	$ 853,317
ROR	3.88%		2.30%	2.66%	2.70%	5.94%	5.28%	7.81%	33.35%	4.91%	6.04%	5.32%	4.00%	18.29%
Unitized ROR	1.00		0.6	0.7	0.7	1.5	1.4	2.0	8.6	1.3	1.6	1.4	1.0	4.7

Rate Schedule Specific Revenue Increase Allocation

Revenue Requirement	$ 126,620,000	
Operating Income Deficiency PEPCO	$ 73,856,743	
ROR PEPCO	8.01%	

			RESIDENTIAL	RTM	GS-LV	MGT-LV	MGT-3A	GT-LV	GT-3B	GT-3A	TM-RT	SL	SSL	TN
Step 1 Forty Percent of Revenue Requirement	$ 50,648,000	0.40	$ 40,028,680	$ 6,789,971	$ 3,829,349	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Step 2 Sixty Percent of Revenue Requirement	$ 75,972,000	0.60	$ 38,436,313	$ 6,519,861	$ 3,677,015	$ 20,620,279	$ 231,236	$ -	$ -	$ 3,998,256	$ 612,047	$ 270,370	$ 1,606,622	$ -
Revenue Requirement	$ 126,620,000		$ 78,464,994	$ 13,309,832	$ 7,506,365	$ 20,620,279	$ 231,236	$ -	$ -	$ 3,998,256	$ 612,047	$ 270,370	$ 1,606,622	$ -

Proposed Revenue Allocation		RESIDENTIAL	RTM	GS-LV	MGT-LV	MGT-3A	GT-LV	GT-3B	GT-3A	TM-RT	SL	SSL	TN
ROR	8.01%	7.72%	7.53%	9.12%	8.53%	7.74%	7.81%	33.35%	7.38%	8.52%	7.58%	7.13%	18.29%
Incremental Income	$ 73,856,743	$ 45,768,195.01	$ 7,763,551.01	$ 4,378,420.80	$ 12,027,694.45	$ 134,878.48	$ -	$ -	$ 2,332,160.57	$ 357,003.62	$ 157,705.07	$ 937,133.88	$ -
Revenue Conversion Factor	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144	1.7144
Revenue Requirement	$ 126,620,000	$ 78,464,994	$ 13,309,832	$ 7,506,365	$ 20,620,279	$ 231,236	$ -	$ -	$ 3,998,256	$ 612,047	$ 270,370	$ 1,606,622	$ -
Final Unitized ROR	1.00	0.96	0.94	1.14	1.07	0.97	0.98	4.16	0.92	1.06	0.95	0.89	2.28

Rate Schedule Specific Revenue Increase Allocation

Cost of Service Classification Rate Schedule	Total	RESIDENTIAL	RTM	GS-LV	MGT-LV	MGT-3A	GT-LV	GT-3B	GT-3A	TM-RT	SL	SSL	TN
Annualized Current Distribution Revenue	$ 435,480,550	$ 205,733,415	$ 34,898,074	$ 19,681,516	$ 110,371,680	$ 1,237,707	$ 25,532,946	$ 2,899,394	$ 21,400,983	$ 3,276,030	$ 1,447,175	$ 8,599,573	$ 402,058
Revenue Change ($)	$ 126,620,000	$ 78,464,994	$ 13,309,832	$ 7,506,365	$ 20,620,279	$ 231,236	$ -	$ -	$ 3,998,256	$ 612,047	$ 270,370	$ 1,606,622	$ -
Proposed Revenue	$ 562,100,550	$ 284,198,408	$ 48,207,906	$ 27,187,881	$ 130,991,959	$ 1,468,943	$ 25,532,946	$ 2,899,394	$ 25,399,239	$ 3,888,077	$ 1,717,544	$ 10,206,196	$ 402,058
Revenue Change based on Annualized Current Revenue (%)	29.1%	38.14%	38.14%	38.14%	18.68%	18.68%	0.00%	0.00%	18.68%	18.68%	18.68%	18.68%	0.00%
Service Classification Rate Change as a Percentage of Overall Distribution Change		1.31	1.31	1.31	0.64	0.64	-	-	0.64	0.64	0.64	0.64	-

Case No. 9418
Exhibit No. ___ (RAB-12)
Page 1 of 1

CERTIFICATE OF SERVICE
CASE NO. 9418

I HEREBY CERTIFY that a copy of the foregoing has been furnished by electronic mail, U.S. Mail or Federal Express, this 5th day of July, 2016 to the following:

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/s/ Kevin C. Siqveland
Kevin C. Siqveland

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**:**	
OF BALTIMORE GAS AND ELECTRIC	**:**	
COMPANY FOR REVISIONS IN ITS	**:**	**Case No. 9406**
ELECTRIC AND GAS BASE RATES	**:**	

REBUTTAL TESTIMONY

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

MARYLAND ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.

MARCH 4, 2016

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**:**	
OF BALTIMORE GAS AND ELECTRIC	**:**	
COMPANY FOR REVISIONS IN ITS	**:**	**Case No. 9406**
ELECTRIC AND GAS BASE RATES	**:**	

REBUTTAL TESTIMONY OF RICHARD A. BAUDINO

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Did you submit Direct Testimony and Exhibits in this proceeding?

A. Yes. I submitted Direct Testimony and Exhibits on behalf of the Maryland Energy Group (“MEG”).

Q. What is the purposed of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to issues relating to cost allocation, revenue allocation, and rate design that were raised in the Direct Testimony filed by the Staff of the Maryland Public Service Commission ("Staff") and the Office of Public Counsel ("OPC").

<u>**Commission Staff Direct Testimony**</u>

Q. How did Mr. Blaise propose to allocate Staff's recommended electric service revenue increase of $87.6 million to Baltimore Gas and Electric Company's ("BGE" or "Company") rate classes?

A. Mr. Blaise described his recommended revenue allocation procedure beginning on page 9 of his Direct Testimony. Mr. Blaise recommended a two-step revenue increase process. In the first step, 17% of the increase is allocated to classes that are not earning the system average rate of return based on their proportional revenues, namely Schedules R and RL. In the second step, the remaining 83% is allocated to all rate classes, excluding Schedules SL, PL and T, based on their proportionate share of base revenues. On page 9, lines 23 through 25, Mr. Blaise testified that his proposed revenue allocation "aims addressing any potential issues of inter- and intra-class imbalances while avoiding any disproportionate increase that would negatively impact the Company's customers." Mr. Blaise also rejected Baltimore Gas and Electric's proposal to reduce Schedule T revenues by 25%.

According to Mr. Blaise's Table 5 on page 11 of his Direct Testimony, his revenue allocation proposal resulted in relative rates of return ("RROR") of 0.81 for Schedule R and 0.76 for Schedule RL. The RROR for Schedule T was 4.74, meaning that Schedule T customers would be supporting a rate of return of 47.3%, compared to Staff's recommended system return of 9.98%.

Q. Is Mr. Blaise's electric revenue allocation proposal reasonable?

A. No. First and most importantly, Mr. Blaise's proposed revenue allocation failed to address the grossly excessive revenues being paid by Schedule T customers. It simply is not enough for Schedule T to receive no rate increase in this case. Schedule T's rates are so extremely misaligned with costs that they must be reduced if these customers are to ever have any opportunity to pay rates based on the cost to serve them. Schedule T customers are subsidizing all customer classes and I recommended that the Commission approve BGE's proposed 25% reduction in revenues to Schedule T.

Second, Mr. Blaise's revenue allocation proposal failed to bring Schedule R and RL customers within the +/- 10% RROR band. Schedules R and RL can certainly be moved within the 10% RROR band without rate shock occurring. For example, Mr. Frain's proposed distribution revenue increase to Schedule R was 14.4%, compared to the overall system increase of 10.4%. This represents an increase to Schedule R that is 1.38 times the system average increase, which is not an excessive multiple of the system average and, in my opinion, does not result in rate shock to Schedule R customers given the overall percentage increase the Company is seeking.

Q. On page 18 of his Direct Testimony, Mr. Blaise presented his recommended rate design for Schedule P. Is Mr. Blaise's proposed rate design for Schedule P reasonable?

A. No. Mr. Blaise presented his proposed Schedule P rate design on Table 18, page 18 of his Direct Testimony. He proposed a 10.8% increase in the Distribution Charge and a 5.1% increase in the Demand Charge. Mr. Blaise's proposed rate design is inconsistent with the results of the Company's electric cost of service study ("ECOSS"), which shows that cost-based Schedule P demand charges should be much higher than Mr. Blaise proposed. In fact, given that the costs of BGE's distribution system are fixed, one could argue that the variable Distribution Charge, to which Mr. Blaise gave the largest increase, should collect none of the costs.

Furthermore, Mr. Blaise's proposed rate design would detrimentally impact high load factor Schedule P customers, whose energy usage is efficient relative to their peak demands compared to lower load factor customers. The more that demand-related fixed costs are collected through the variable energy charge, lower load factor customers who use less energy relative to their peak demands pay less of those costs than they should. This results in intra-class inequities for Schedule P.

In addition, Mr. Blaise's proposed rate design would send confusing and inaccurate pricing signals to Schedule P customers. This is because the Distribution Rate is overpriced and the Demand Charge is underpriced. An overpriced Distribution Charge tells customers that the cost of using energy is higher than it really is. Likewise, the underpriced Demand Charge sends the signal that the cost of BGE's distribution capacity, or fixed cost, is much lower than it really is.

Mr. Blaise did not follow appropriate rate design principles for Schedule P and, thus, the Commission should reject his proposed rate design. I recommend that the Commission adopt BGE's proposed rate design for Schedule P customers.

Q. On page 21, lines 14 through 15 Mr. Blaise testified that the use of the 34 kV conduit fee provided a "non-arbitrary way to fairly allocate the conduit fee increase." Please address Mr. Blaise's testimony on this point.

A. I disagree with Mr. Blaise for the same reasons that I disagreed with Mr. Frain's use of the 34 kV allocator to allocate the conduit fee increase. The Company uses the PLTDUGLN allocator in its electric class cost of service study ("ECOSS") to allocate the level of conduit fees that is currently collected in base rates. As I stated in my Direct Testimony, the 34 kV allocator allocates too much costs responsibility to Schedule P customers due to its failure to recognize customer class responsibility for Secondary distribution costs.

Q. On page 42, lines 19 through 21 of his Direct Testimony Mr. Norman recommended that the conduit fees from the November 2015 through June 2016 time period be amortized over 5 years. Do you agree with this proposal?

A. No. I continue to recommend that the Commission disallow collection of the conduit fees during the November 2015 through June 2016 time period. In addition to the reasons for disallowance that I described in my Direct Testimony, simply allowing a deferred or current collection of these costs could reduce BGE's incentive for fully litigating the reasonableness of these costs in court. BGE should have some "skin in the game" as an incentive to vigorously pursue its position before the court on behalf of its shareholders and ratepayers.

Q. On page 10 of his Direct Testimony, Mr. Pongsiri presented the results of his recommended gas revenue allocation. Please comment on Mr. Pongsiri's recommended revenue allocation.

A. Mr. Pongsiri's gas revenue allocation fails to bring the IS and ISS classes within the +/- 10% RROR band. Mr. Pongsiri's Table 2 on page 10 shows that the RRORs for IS and ISS are 1.181 and 1.186, respectively, based on his revenue allocation.

In my opinion, it would not be unreasonable for the Commission to reduce revenues for the IS class in the first step in order to bring this class to the top of the 10% RROR range. In my Direct Testimony, I showed that this approach would not unduly impact the other rate classes given the modest size of the Step One decrease for IS.

Q. Mr. Pongsiri's Exhibit TJP-2 presents his proposed rate design for Schedules IS and ISS. Do you agree with Mr. Pongsiri's rate design?

A. No. Mr. Pongsiri proposed equal percentage increases to the Demand Price and Delivery Price for Schedules IS and ISS. Mr. Frain proposed appropriately higher increases for the Demand Prices, which follow the results of BGE's gas cost of service study ("GCOSS") and recognize that the costs of BGE's gas distribution system are fixed, not variable. The Demand Price should be increased at a greater percentage in order to more fully reflect the cost to serve IS and ISS customers. Overpriced Delivery Prices would create intra-class rate disparities and favor lower load factor customers over high load factor customers. My arguments here are similar to those I presented in response to Mr. Blaise's proposed rate design for Schedule P.

I recommend that the Commission approve BGE's general approach to rate design for Schedule IS and ISS.

Office of Public Counsel Direct Testimony

Q. On page 11 of his Direct Testimony, Mr. Wallach recommended rejection of BGE's proposed revenue allocation based on its 2014 ECOSS. Instead, Mr. Wallach recommended that the Commission's authorized revenue increase be allocated to all rate classes except for Schedules T and PL in proportion to each class' current base distribution revenues. What is your conclusion with respect to Mr. Wallach's revenue allocation proposal?

A. The Commission should reject Wallach's proposed allocation of the Company's revenue increase.

Mr. Wallach presented a deeply flawed description of cost causation beginning on page 7, line 5 of his Direct Testimony. Mr. Wallach claimed that the Company's ECOSS allocated more Smart Grid Initiative costs to the residential class than if these costs were allocated on the basis of cost causation. In fact, BGE's 2014 ECOSS directly assigned the costs of the Smart Grid system to those customer classes that incurred those costs. In this sense there was no allocation of jointly used costs, such as distribution mains, that required an allocation factor, such as class non-coincident peak demands. As Mr. Greenberg noted on page 17, lines 3 through 5 of his Direct Testimony Smart Grid costs were allocated to Schedules R, RL, G, GS, and GL since customers in those rate schedules are included in the Smart Grid deployment and received smart metering. The other rate classes, such as Schedules P and T, were not included in the assignment of the Smart Grid costs since they were not included in this program. Thus, BGE's ECOSS did assign the Smart Grid Initiative costs based on cost causation, contrary to the mistaken argument made by Mr. Wallach.

Q. On page 10, lines 7 through 20, Mr. Wallach discussed the allocation of Smart Grid revenue requirements in connection with a "more comprehensive analysis" of operational and market benefits over the life of the Smart Grid asset. Please respond to Mr. Wallach's testimony on this point.

A. I strongly recommend that the Commission reject a cost allocation approach based on projected market benefits of the Smart Grid Initiative. The fact is that the rate classes to which the Smart Grid Initiative costs were assigned will reap the projected benefits of that program over time. The important ratemaking principle to follow is that costs should either be assigned or allocated to the classes that cause the Company to incur those costs. With respect to the Smart Grid Initiative, BGE's ECOSS followed this principle and assigned costs to those classes that incurred the Smart Grid costs.

Q. On page 23 of his Direct Testimony, Mr. Wallach recommends that the Rider 5 conduit fees be collected through a per kWh charge. Please respond to Mr. Wallach's proposed recovery of conduit fees using a kWh charge.

A. For Schedule P customers, I recommend that BGE's proposed fixed charge per customer be adopted. This recovery is consistent with the fact that conduit fees are designed to recover fixed costs, not variable costs.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**:**	
OF BALTIMORE GAS AND ELECTRIC	**:**	
COMPANY FOR ADJUSTMENTS TO ITS	**:**	**Case No. 9406**
ELECTRIC AND GAS BASE RATES	**:**	

DIRECT TESTIMONY AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE

MARYLAND ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.

FEBRUARY 8, 2016

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	:	
OF BALTIMORE GAS AND ELECTRIC	:	
COMPANY FOR ADJUSTMENTS TO ITS	:	**Case No. 9406**
ELECTRIC AND GAS BASE RATES	:	

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DIRECT TESTIMONY OF RICHARD BAUDINO

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a consultant to Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Exhibit No.____(RAB-1) summarizes my expert testimony experience.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Maryland Energy Group ("MEG").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address class cost of service, revenue allocation, rate design and tariff issues for Baltimore Gas and Electric's ("BGE" or "Company") electric and gas operations. In so doing, I will address the Direct Testimony of BGE witnesses David Vahos, John Frain, and David Greenberg.

With respect to electric service rate design, my focus will be on electric service Schedule P (Primary Service) and Schedule T (Transmission Service). With respect to gas service rate design, I will address the Company's revenue allocation proposals for Schedules IS (Large Interruptible) and ISS (Small Interruptible). I will also provide recommendations regarding BGE's proposed Rider 5, which seeks to collect increased costs associated with the City of Baltimore's underground conduit fees.

Q. Please summarize your conclusions and recommendations to the Maryland Public Service Commission ("MPSC" or "Commission").

A. With respect to revenue allocation for BGE's electric operations, I recommend that the Commission adopt BGE's approach to revenue allocation, including a proposed 25% revenue reduction to Schedule T.

With respect to BGE's proposed Rider 5, I recommend that the Commission disallow the Company's request to collect $18.97 million of increased Baltimore City conduit fees during the period of November 2015 through June 2016. I will also demonstrate that BGE's proposed allocation is unreasonable, inconsistent with the manner in which conduit fees are currently allocated in the Company's cost of service study, and allocates far too much cost responsibility to Schedule P customers.

Finally, with respect to gas cost and revenue allocation, Schedule IS is earning a class rate of return that falls outside the Commission's +/- 10% rate of return band. Therefore, Schedule IS should receive a lower than system average percentage revenue increases in this proceeding.

II. ELECTRIC CLASS COST OF SERVICE AND RATE DESIGN

Q. Please summarize BGE's approach to its electric cost of service study ("ECOSS").

A. BGE witness Greenberg presented the Company's ECOSS in his Direct Testimony. In most respects, the ECOSS follows the methodology that has been approved by the Maryland Public Service Commission in past cases. Mr. Greenberg noted on page 11 of his Direct Testimony one notable change in both the ECOSS and gas cost of service study ("GCOSS") from the studies filed in Case No. 9355. In the Settlement Agreement in that docket the Company agreed to provide: "(1) a five (5) year comparison of annual system class demand allocators and allocations; and (2) a study of how any trends or changes affect the relative rates of return of the various electric rate classes." BGE undertook the study for electric demands and Mr. Greenberg included this analysis in his Company Exhibit DEG-5. BGE also performed a similar study for gas demands and included the results in Company Exhibit DEG-6. I will discuss the results of this study in more detail in Section IV of my Direct Testimony.

Mr. Greenberg also explained that the Company included Smart Grid costs in its ECOSS and allocated those costs to Schedules R, RL, G, GS, and GL.

On page 19 of his Direct Testimony, Mr. Greenberg testified that BGE incorporated the five-year average of demand allocators in its 2014 ECOSS. Mr. Greenberg testified that the five-year average of NCP and CP allocators "provide for an appropriate alternative allocation of demand-driven costs that incorporate demand patterns over a longer time horizon."

Q. What are your conclusions with respect to BGE's ECOSS analysis contained in Company Exhibit DEG-5?

A. In this case, I do not oppose BGE's use of a five-year average for its demand allocators. The five-year study provides useful information for the Commission and could provide for greater continuity of ECOSS class results when used in conjunction with a one-year study. However, the ECOSS results were not significantly different for 2014 and for the five-year average in this docket. For example, Schedule P's relative rate of return ("RROR") was identical for 2014 and for the five-year average (1.08). Both Schedules R and RL showed higher RRORs using the five-year average compared to 2014.

I recommend that the Commission order BGE to continue to provide the five-year study and year-by-year comparisons in future rate cases, similar to Mr. Frain's presentation in Company Exhibit DEG-5. This information provides valuable additional insight and guidance for the Commission, Staff, and the parties with respect to cost and revenue allocation. In future cases, the Commission, Staff, and other parties may also need to rely on the one-year cost allocation study if that study appears to be the more reasonable based on circumstances at that time.

Q. How did the Company allocate its proposed electric revenue increase to its customer classes?

A. Company witness Frain presented BGE's allocation of its proposed electric revenue increase on page 20 of his Direct Testimony. Mr. Frain adopted a two-step approach that generally followed past Commission Orders in Case Nos. 9299 and 9326. Given Schedules R/RL's low RROR, Mr. Frain allocated $38.5 million of the Company's proposed increase in order to bring those classes to a RROR of 0.90. Mr. Frain also proposed a 25% base distribution revenue reduction to Schedule T.

In the second step, Mr. Frain allocated the remaining increase to customer classes, excluding Schedules T and PL, based on each class' proportionate share of base distribution revenues. Mr. Frain presented the revised class increases on page 3 of his Supplemental Direct Testimony. Table 1 below shows the Company's proposed base revenue increases and the percentage increases for each class from the E Sheets in Company Exhibit JCF-2 Actual.

TABLE 1
BGE Rate Schedule Increases

		$ Increase (miillions)	% Increase
Schedule R/RL	$	85.54	14.8%
Schedule G/GS	$	9.34	7.6%
Schedule GU	$	0.02	7.7%
Schedule GL	$	18.60	7.7%
Schedule P	$	5.93	7.1%
Schedule T	$	(0.75)	-16.8%
Schedule SL	$	2.18	7.3%
Schedule PL	$	-	0.0%
TOTAL	$	120.86	10.4%

Q. Is Schedule T's revenue reduction justified in this case?

A. It most definitely is justified. As Mr. Frain pointed out on page 19 of his Direct Testimony, Schedule T's RROR in this case is similar to its RROR in Case No. 9355 in which the Commission lowered Schedule T revenues by 10%. Clearly, Schedule T customers are providing a substantial subsidy to other rate classes that must be addressed. *According to the Company's ECOSS, Schedule T's revenues would have to be reduced by $1.4 million in order to achieve the system-wide rate of return.*

Although Schedule T customers still have a long way to go until their rates are in line with their cost to serve, Mr. Frain's proposed reduction represents a sound and reasonable step in the right direction.

Q. What are your conclusions with respect to BGE's proposed class revenue allocation in this case?

A. I recommend that the Commission accept BGE's proposed class revenue allocation. Mr. Frain's revenue allocation proposal reasonably balances customer rate impacts with cost of service allocations. Schedules R received a substantial revenue increase in order to bring its RROR up to the lower bound of the RROR band. In addition, Schedule R customers will have to pay their fair share of increased costs that BGE seeks to collect through Rider 5. Viewed from this perspective, it makes sense in this case not to reduce the revenues of other rate classes in Step One, with the exception of Schedule T.

The 25% revenue reduction for Schedule T is certainly justified given this class' persistently excessive RROR, which has seen no real improvement despite the Commission's past rate reductions for this rate schedule. It is not fair for Schedule T customers to continue to pay costs for which the other rate classes are responsible.

If the Commission orders a lower revenue requirement in this case, then the Step Two increase should be lowered to account for the lower overall revenue requirement.

Q. Please summarize BGE's proposed rate design for Schedule P.

A. Mr. Frain proposed to collect the entire allocated Schedule P revenue increase by increasing the demand charge. However, Mr. Frain also designed the Schedule P demand rate to collect the current amount of Schedule P's EmPOWER Maryland energy efficiency charges as part of BGE's proposal to collect reviewed and approved energy efficiency charges into customers' base rates. The energy efficiency charge is currently collected on a kWh basis from all customers, including Schedule P and T.

As shown in Mr. Frain's Company Exhibit JCF-2, Sheet E-7, his rate design proposal results in an extremely large increase in Schedule P's demand charge. Revenues collected in Schedule P's demand charge would rise from $33.4 million to $49.9 million, an increase of 49.1%. The demand charge would rise from the current rate of $2.85 per kW to $4.25 per kW. This total increase in revenues collected through the demand charge would consist of the $5.9 million base revenue increase proposed by BGE and the current level of EmPOWER Maryland revenues of $10.48 million.

Q. Do you agree with rolling EmPOWER Maryland revenues into Schedule P's demand charge?

A. Yes. This change is justified by BGE's ECOSS and would provide for a more equitable and cost based rate design for Schedule P customers.

III. RIDER 5 - LOCAL GOV'T-OWNED CONDUIT SYSTEM CHARGE

Q. Please summarize BGE's proposed Rider 5 - Local Government-Owned Conduit System Charge.

A. Mr. Frain explained in his Direct Testimony that BGE is proposing Rider 5 to collect "any local government-imposed lease expense, rent, charges, or fees incurred by the Company for the administration, maintenance, operation, improvement, reconstruction, and expansion of a local government-owned or controlled conduit system above any level of similar costs included in base rates as of October 31, 2015." Frain Direct page 37, line 19 through page 38, line 1.

Mr. Frain proposed two options for the collection of these costs. Option A is a monthly fixed charge that would direct the conduit fee increase to the Company's customers residing in the City of Baltimore. Option B is a monthly fixed charge that would be collected by all BGE customers taking service under the applicable rate schedules. Under both options, Mr. Frain proposed that all incremental conduit costs be allocated based on the 34kV Non-Coincident Peak hourly peak loads for each rate class. The 34 kV allocation factors and resulting rates for both options are shown in Mr. Frain's Exhibit JCF-7.

Q. Before you address the allocation of costs that BGE proposes for Rider 5, does MEG have concerns with respect to the increased City of Baltimore conduit fees for which BGE seeks collection in this proceeding?

A. Yes. MEG is greatly concerned about the effect of the increased conduit fees for which BGE is seeking collection in this case. The total of these increased fees is $48.6 million, $18.97 million for November 2015 through June 2016 and $29.6 million for July 2016 through June 2017. This large increase is in addition to the Company's proposed base revenue increase of $120.8 million. The total of these two increases amounts to $169.4 million, which is a 14.6% increase in total electric distribution revenues.

Q. Should the Commission approve BGE's proposed Rider 5 as proposed?

A. No. First, I recommend that the Commission reject the Company's request to collect increased fees of $18.97 million from November 2015 to June 2016. Second, the Commission should approve an allocation of costs to customer classes using the PLTDUGLN allocation factor. This is the allocator that the Company used in its ECOSS to allocate the pre-increase level of conduit fees in base rates.

Q. Briefly summarize BGE's proposal to collect the increased conduit fees imposed by the City of Baltimore.

A. Mr. Vahos and Mr. Frain presented BGE's proposals with respect to how BGE would account for and collect the increased conduit fees from the City of Baltimore. On pages 18 and 19 of his Direct Testimony, Mr. Vahos explained that BGE intends to collect the increased conduit fees through Rider 5, rather than through an increase in base rates. Mr. Vahos explained that using a rider ensures that customers will only pay actual costs, no more no less, and that if the City of Baltimore were to be required to reimburse monies to BGE for conduit fee overpayments, those dollars would be refunded to ratepayers through Rider 5.

Beginning on page 20, line 1 of his Direct Testimony Mr. Vahos explained BGE's proposed accounting entries to reflect the increased conduit fees in base rates for the period from November 1, 2015 through the beginning of the rate effective period in early June 2016. One of the entries established a regulatory asset of $15.4 million for the net increase in conduit fees during that 7-month period. Mr. Vahos testified that this asset would be amortized over five years "consistent with other regulatory asset amortization periods approved by the Commission." Vahos Direct Testimony, page 20, lines 10 - 11. On page 21, Mr. Vahos recommended the reversal of this regulatory asset and the amortization of that asset in order to transfer the revenue requirements from base rates to Rider 5.

In his Direct Testimony, Mr. Frain proposed to collect the increased revenue requirement associated with the 7-month period from November 2015 through June 2016 during the first year of Rider 5's operation. This amount is $18.97 million. The annualized increase of the conduit fees over the current level of these fees in base rates is $29.6 million, making the first-year total collected through Rider 5 equal to $48.6 million.

Q. Should BGE be allowed to collect $18.97 million associated with the 7-month period from November 2015 through June 2016?

A. No. The Commission should reject BGE's request to collect the $18.97 million associated with the 7-month period from the time the increase became effective on November 1, 2015 until the time new rates go into effect for the Company.

Q. Please explain why the Commission should disallow the $18.97 million of increased conduit fees associated with this 7-month period.

A. In my opinion, BGE is attempting to overcome the normal operation of regulatory lag for one isolated expense item. This is inappropriate and should be rejected by the Commission. Revenues and expenses should be measured and annualized for known and measurable changes within the test year. With respect to the increased conduit fees, BGE certainly should be allowed to collect the annualized difference between the existing level of conduit fees in base rates and the higher level of these fees that began on November 1, 2015 since it was still within BGE's test period.

However, BGE should only be allowed to collect the increased conduit fees when new rates become effective in this case. Essentially, BGE is attempting to collect the higher conduit fees before rates become effective. I recommend that the Commission reject this attempt to bypass regulatory lag. BGE should not be allowed to pick and choose one of its cost elements that increased during the test year and then try to collect this increase before rates become effective later this year. This would be a highly undesirable regulatory precedent, as it would open the possibility for BGE and other Maryland utilities to try to collect any test year cost increases before rates actually go into effect, either through riders or regulatory deferrals. It also raises the question of whether cost decreases and revenue increases should be recognized before rates go into effect and flowed through to ratepayers via similar mechanisms. This sort of approach actually would extend the standard 12-month test year another 7 months to capture the effect of selected cost and revenue changes. Obviously, this would be a burdensome and unworkable situation for the Commission, Staff, and the parties.

In evaluating BGE's request, the timing of the increased conduit fee should also be considered. What if the City of Baltimore had increased the conduit fees in June of

2015? In this instance, an entire year of additional conduit fees would be added on top of the annualized increase in these fees of $29.6 million, raising BGE's request to $59.2 million. It is simply unreasonable for BGE's ratepayers to shoulder this kind of cost burden. BGE should only be allowed to collect the annualized increase in conduit fees when new rates become effective.

Q. Did BGE receive an accounting order to defer the higher conduit fees from the City of Baltimore?

A. No. BGE did not receive an accounting order allowing the Company to defer the higher conduit fees.

Q. Is there a way for BGE to recoup the higher conduit fees during the 7-month period before new rates become effective?

A. Yes. BGE should be able to keep any refund of excessive fees associated with the 7-month period from November 1, 2015 through June 2016, or when new rates become effective in this case. After that, ratepayers should receive any overcharges associated with increased conduit fees collected through Rider 5.

Q. Is the 34 kV allocator appropriate for the allocation and collection of local conduit fees to BGE's customer classes?

A. No, it is not. I will demonstrate that BGE's proposal to allocate the collection of conduit fees using the 34 kV allocator does not track how these costs are currently collected in its ECOSS and, as a result, would collect an excessive amount of these costs from BGE's Schedule P customers.

Q. How are the conduit fees currently collected in BGE's ECOSS?

A. According to BGE's response to MEG Data Request MEGDR01-02, conduit use and maintenance fee are included in Federal Energy Regulatory Commission ("FERC") Account 594 - Underground Lines and allocated based on an internally generated demand allocator named PLTDUGLN. PLTDUGLN is based on the composite of FERC Accounts 366 - Underground Conduit and 367 - Underground Conductors. These accounts are allocated by voltage level (34 kV, 13 kV, and Secondary) based each class' corresponding NCP allocators. I have attached BGE's response to MEGDR01-02 as Exhibit No. ___(RAB-2).

In essence, the PLTDUGLN allocator recognizes the fact that BGE's customers take service at different voltage levels and allocates the costs in Accounts 366 and 367 on that basis. For example, it would be inappropriate for BGE's transmission and primary service customers to be allocated costs associated with the Secondary distribution system because those customers are not served at that voltage level and, hence, have no responsibility for those costs.

Q. What are the BGE assets that are contained in the City of Baltimore's conduit system?

A. On page 17 of his Direct Testimony, Mr. Vahos testified that BGE's electric assets in the conduit system include electric cables, switches, transformers, street lighting cable, and communication cable.

Q. Does BGE track these costs by voltage level?

A. No. According to BGE's response to MEGDR01-03, the company does not track these costs by location. Please refer to Exhibit No. ___(RAB-3) for this response.

Q. Please demonstrate how Schedule P's PLTDUGLN allocator is developed based on the method you just described.

A. Table 2 below shows how Schedule P's allocation is developed from the Company's ECOSS.

TABLE 2
DEVELOPMENT OF SCHEDULE P PLTDUGLN ALLOCATOR

	(1) Total Company	(2) Schedule P Allocator	(3) Schedule P Allocation
Acct. 366 Underground Conduit			
Demand Subtransmission	$69,051,799	13.959%	$9,638,853
Demand Primary	$231,881,369	10.677%	$24,757,209
Demand Secondary	$603,072	0.000%	$0
Acct. 367 Underground Conductors			
Demand Subtransmission	$113,553,724	13.959%	$15,850,819
Demand Primary	$821,974,115	10.677%	$87,759,464
Demand Secondary	$354,855,387	0.000%	$0
Total Acct. 366 and 367 (PLTDUGLN)	$1,591,919,466	8.669%	$138,006,345

Table 2, Column (1) shows the total BGE amounts of Subtransmission (34 kV), Primary (13 kV), and Secondary plant in Accounts 366 and 367. These plant amounts are allocated to BGE's customer classes based on their respective NCP allocation factors at each voltage level. Column (2) shows Schedule P's allocators at each voltage level for both accounts. The total amount allocated to Schedule P is $138.006 million. Its resulting PLTDUGLN allocator is 8.669%. This is how the PLTDUGLN allocator is developed for all of BGE's customer classes.

Q. Please compare the 34 kV NCP and the PLTDUGLN class allocation factors.

A. Table 3 below provides a comparison of the 34 kV and PLTDUGLN class allocation factors for each customer class.

TABLE 3

34kV NCP and PLTDUGLN Class Allocation Factors

	34 kV NCP	PLTDUGLN
R	46.93%	50.31%
RL	4.17%	4.46%
G & GU	9.52%	10.21%
GS	0.33%	0.35%
GL	24.00%	24.82%
P	13.96%	8.67%
SL	0.80%	0.86%
PL	0.30%	0.32%
Total	100.00%	100.00%

The difference between these two allocation factors is the inclusion of Primary and Secondary NCP demands in the PLTDUGLN allocator. This is why the Residential Class (R) has a lower 34 kV NCP allocator (46.93%) than its PLTDUGLN allocator (50.31%), which reflects Schedule R's responsibility for the costs of BGE's Secondary distribution system. In contrast, Schedule P has a lower PLTDUGLN allocator than its 34 kV NCP allocator, showing that Schedule P has no responsibility for BGE's Secondary distribution system.

Q. Mr. Baudino, is it likely that BGE has Secondary distribution system assets in the City of Baltimore's conduit system?

A. Yes. In my opinion, that is why the conduit fees are currently being allocated using the PLTDUGLN allocation factor in BGE's ECOSS. However, as I mentioned earlier BGE does not track these costs by voltage level.

Q. Is it appropriate to allocate Rider 5 costs using BGE's 34 kV allocation factor?

A. No. The 34 kV NCP allocator is not consistent with the way BGE allocates conduit fees in the ECOSS. Further, since it is likely that BGE has Secondary distribution assets in the City of Baltimore's conduit system, using the 34 kV NCP allocator would lead to Schedule P customers being allocated the costs of Secondary facilities. This would be inappropriate and unfair to Schedule P customers.

Q. If the Commission approves the pass-through of incremental City of Baltimore conduit fees with Rider 5, how should these costs be allocated to BGE's customer classes?

A. Local government-owned conduit fees should be allocated to customer classes using the PLTDUGLN allocator. This allocator is shown in my Table 3.

IV. GAS COST OF SERVICE AND RATE DESIGN

Q. Please summarize BGE's general approach to its gas cost of service study ("GCOSS").

A. As I mentioned earlier in my Direct Testimony, Mr. Greenberg presented BGE's GCOSS in his Direct Testimony. Mr. Greenberg also presented the results of a five-year study of demand allocation factors and the effects on the Company's GCOSS and on the rate schedule RRORs. Mr. Greenberg presented the results of the five-year study in Company Exhibit DEG-6.

On page 36 of his Direct Testimony, Mr. Greenberg testified that BGE determined that the five-year average of NCP and CP allocators provided an "appropriate alternative allocation of demand-driven costs." Thus, BGE's GCOSS incorporated the five-year average of NCP and CP allocation factors in its cost and revenue allocation approach in this case.

Q. Should the Commission accept BGE's recommended use of five-year average allocation factors in its GCOSS in this case?

A. I do not oppose BGE's use of the five-year average NCP and CP allocation factors in this case. As I stated in the section on BGE's ECOSS, BGE's five-year study of its demand allocation factors in the GCOSS provided additional useful information for the Commission, Staff, and the other parties. I recommend that the Commission order BGE to continue to provide both five-year and year-by-year comparisons of GCOSS results in future rate cases similar to Mr. Greenberg's presentation in Company Exhibit DEG-6.

Q. Briefly summarize the Company's revenue allocation proposal.

A. On page 30 of his Direct Testimony, Mr. Frain proposed to allocate the proposed increase in gas revenues based on each class' proportionate share of base distribution revenues, with the exception of Schedule PLG.

Q. Do you agree with BGE's proposed revenue allocation?

A. No. Schedule IS is currently outside the +/- 10% band, with a RROR of 1.15. Furthermore, Schedule IS actually received a slightly higher than system average increase of 19.5%, compared to the system average increase of 19.0%.

Q. What is your recommendation for allocating any revenue increase to customer classes in this proceeding?

A. Given Schedule IS' higher RROR, I recommend that the Commission utilize a two-step process to allocate the revenue increase to customer classes. I recommend that in Step One, Schedule IS receive a decrease in order to bring it to a RROR within the band of 1.10. According to the Company's GCOSS, the Step One decrease is -$0.3 million. In Step Two, the remaining increase should be allocated to customer classes based on their proportionate share of base distribution revenues, excluding Schedule PLG. Table 4 below summarizes the customer class increases under this proposal. Please refer to Exhibit No. ___(RAB-4) for detailed calculations of the two-step process I recommend the Commission adopt in this proceeding.

TABLE 4
MEG Recommended Class Increases

	Current Gas Distribution Revenues	MEG Recommended Increases	Pct. Increases
Schedule D	$ 294,260,264	$ 56,054,234	19.0%
Schedule C	$ 102,164,673	$ 19,515,674	19.1%
Schedule PLG	$ 33,037	$ -	0.0%
Schedule IS	$ 20,882,943	$ 3,711,896	17.8%
Schedule ISS	$ 1,906,682	$ 212,196	11.1%
Total	$ 419,247,600	$ 79,494,000	19.0%

Please note that moving Schedule IS to a RROR of 1.10 had a negligible impact on the remaining rate classes.

Q. How should the Company reflect any increases in revenues to Schedules IS and ISS?

A. I agree with the Company's proposal to collect 50% of the increase from the Demand Price and 50% from the Delivery Charge.

Q. Does this conclude your Direct Testimony?

A. Yes.

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COMPANY FOR ADJUSTMENTS TO ITS	**:**	**Case No. 9406**
ELECTRIC AND GAS BASE RATES	**:**	

EXHIBITS OF

RICHARD A. BAUDINO

ON BEHALF OF THE

MARYLAND ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.

FEBRUARY 8, 2016

RESUME OF RICHARD A. BAUDINO

EDUCATION

New Mexico State University, M.A.
Major in Economics
Minor in Statistics

New Mexico State University, B.A.
Economics
English

Thirty-two years of experience in utility ratemaking and the application of principles of economics to the regulation of electric, gas, and water utilities. Broad based experience in revenue requirement analysis, cost of capital, rate of return, cost and revenue allocation, and rate design.

REGULATORY TESTIMONY

Preparation and presentation of expert testimony in the areas of:

Cost of Capital for Electric, Gas and Water Companies
Electric, Gas, and Water Utility Cost Allocation and Rate Design
Revenue Requirements
Gas and Electric industry restructuring and competition
Fuel cost auditing
Ratemaking Treatment of Generating Plant Sale/Leasebacks

RESUME OF RICHARD A. BAUDINO

EXPERIENCE

1989 to Present: **Kennedy and Associates: Consultant** - Responsible for consulting assignments in the area of revenue requirements, rate design, cost of capital, economic analysis of generation alternatives, electric and gas industry restructuring/competition and water utility issues.

1982 to 1989: **New Mexico Public Service Commission Staff: Utility Economist** - Responsible for preparation of analysis and expert testimony in the areas of rate of return, cost allocation, rate design, finance, phase-in of electric generating plants, and sale/leaseback transactions.

CLIENTS SERVED

Regulatory Commissions

Louisiana Public Service Commission
Georgia Public Service Commission
New Mexico Public Service Commission

Other Clients and Client Groups

Ad Hoc Committee for a Competitive Electric Supply System
Air Products and Chemicals, Inc.
Arkansas Electric Energy Consumers
Arkansas Gas Consumers
AK Steel
Armco Steel Company, L.P.
Assn. of Business Advocating Tariff Equity
CF&I Steel, L.P.
Climax Molybdenum Company
Cripple Creek & Victor Gold Mining Co.
General Electric Company
Holcim (U.S.) Inc.
IBM Corporation
Industrial Energy Consumers
Kentucky Industrial Utility Consumers
Lexington-Fayette Urban County Government
Large Electric Consumers Organization
Newport Steel
Northwest Arkansas Gas Consumers
Maryland Energy Group
Occidental Chemical
PSI Industrial Group
Large Power Intervenors (Minnesota)
Tyson Foods
West Virginia Energy Users Group
The Commercial Group
Wisconsin Industrial Energy Group
South Florida Hospital and Health Care Assn.
PP&L Industrial Customer Alliance
Philadelphia Area Industrial Energy Users Gp.
West Penn Power Intervenors
Duquesne Industrial Intervenors
Met-Ed Industrial Users Gp.
Penelec Industrial Customer Alliance
Penn Power Users Group
Columbia Industrial Intervenors
U.S. Steel & Univ. of Pittsburg Medical Ctr.
Multiple Intervenors
Maine Office of Public Advocate
Missouri Office of Public Counsel
University of Massachusetts - Amherst
WCF Hospital Utility Alliance
West Travis County Public Utility Agency
Steering Committee of Cities Served by Oncor

**Expert Testimony Appearances
of
Richard A. Baudino
As of February 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
10/83	1803, 1817	NM	New Mexico Public Service Commission	Southwestern Electric Coop.	Rate design.
11/84	1833	NM	New Mexico Public Service Commission Palo Verde	El Paso Electric Co.	Service contract approval, rate design, performance standards for nuclear generating system
1983	1835	NM	New Mexico Public Service Commission	Public Service Co. of NM	Rate design.
1984	1848	NM	New Mexico Public Service Commission	Sangre de Cristo Water Co.	Rate design.
02/85	1906	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
09/85	1907	NM	New Mexico Public Service Commission	Jornada Water Co.	Rate of return.
11/85	1957	NM	New Mexico Public Service Commission	Southwestern Public Service Co.	Rate of return.
04/86	2009	NM	New Mexico Public Service Commission	El Paso Electric Co.	Phase-in plan, treatment of sale/leaseback expense.
06/86	2032	NM	New Mexico Public Service Commission	El Paso Electric Co.	Sale/leaseback approval.
09/86	2033	NM	New Mexico Public Service Commission	El Paso Electric Co.	Order to show cause, PVNGS audit.
02/87	2074	NM	New Mexico Public Service Commission	El Paso Electric Co.	Diversification.
05/87	2089	NM	New Mexico Public Service Commission	El Paso Electric Co.	Fuel factor adjustment.
08/87	2092	NM	New Mexico Public Service Commission	El Paso Electric Co.	Rate design.
10/87	2146	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Financial effects of restructuring, reorganization.
07/88	2162	NM	New Mexico Public Service Commission	El Paso Electric Co.	Revenue requirements, rate design, rate of return.

Expert Testimony Appearances
of
Richard A. Baudino
As of February 2016

Date	Case	Jurisdict.	Party	Utility	Subject
01/89	2194	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Economic development.
1/89	2253	NM	New Mexico Public Service Commission	Plains Electric G&T Cooperative	Financing.
08/89	2259	NM	New Mexico Public Service Commission	Homestead Water Co.	Rate of return, rate design.
10/89	2262	NM	New Mexico Public Service Commission	Public Service Co. of New Mexico	Rate of return.
09/89	2269	NM	New Mexico Public Service Commission	Ruidoso Natural Gas Co.	Rate of return, expense from affiliated interest.
12/89	89-208-TF	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Rider M-33.
01/90	U-17282	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
09/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Cost of equity.
09/90	90-004-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Cost of equity, transportation rate.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission	Gulf States Utilities	Cost of equity.
04/91	91-037-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Transportation rates.
12/91	91-410-EL-AIR	OH	Air Products & Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Cost of equity.
05/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Cost of equity, rate of return.
09/92	92-032-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost of equity, rate of return, cost-of-service.
09/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost of equity, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
09/92	92-009-U	AR	Tyson Foods	General Waterworks	Cost allocation, rate design.
01/93	92-346	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Cost allocation.
01/93	39498	IN	PSI Industrial Group	PSI Energy	Refund allocation.
01/93	U-10105	MI	Association of Businesses Advocating Tariff Equality (ABATE)	Michigan Consolidated Gas Co.	Return on equity.
04/93	92-1464-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Return on equity.
09/93	93-189-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Transportation service terms and conditions.
09/93	93-081-U	AR	Arkansas Gas Consumers	Arkansas Louisiana Gas Co.	Cost-of-service, transportation rates, rate supplements; return on equity; revenue requirements.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Historical reviews; evaluation of economic studies.
03/94	10320	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Trimble County CWIP revenue refund.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Evaluation of the cost of equity, capital structure, and rate of return.
5/94	R-00942993	PA	PG&W Industrial Intervenors	Pennsylvania Gas & Water Co.	Analysis of recovery of transition costs.
5/94	R-00943001	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania charge proposals.	Evaluation of cost allocation, rate design, rate plan, and carrying
7/94	R-00942986	PA	Armco, Inc., West Penn Power Industrial Intervenors	West Penn Power Co.	Return on equity and rate of return.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Return on equity and rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/94	8652	MD	Westvaco Corp. Co.	Potomac Edison	Return on equity and rate of return.
9/94	930357-C	AR	West Central Arkansas Gas Consumers	Arkansas Oklahoma Gas Corp.	Evaluation of transportation service.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Return on equity.
9/94	8629	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Transition costs.
11/94	94-175-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Cost-of-service, rate design, rate of return.
3/95	RP94-343-000	FERC	Arkansas Gas Consumers	NorAm Gas Transmission	Rate of return.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Return on equity.
6/95	U-10755	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Revenue requirements.
7/95	8697	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost allocation and rate design.
8/95	95-254-TF U-2811	AR	Tyson Foods, Inc.	Southwest Arkansas Electric Cooperative	Refund allocation.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	Systems Energy Resources, Inc.	Return on Equity.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Investigation into Electric Power Competition.
5/96	96-030-U	AR	Northwest Arkansas Gas Consumers	Arkansas Western Gas Co.	Revenue requirements, rate of return and cost of service.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,Potomac Electric Power Co. and Constellation Energy Corp.	Return on Equity.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Return on equity, rate of return.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/97	RP96-199-000	FERC	The Industrial Gas Users Conference	Mississippi River Transmission Corp.	Revenue requirements, rate of return and cost of service.
3/97	96-420-U	AR	West Central Arkansas Gas Corp.	Arkansas Oklahoma Gas Corp.	Revenue requirements, rate of return, cost of service and rate design.
7/97	U-11220	MI	Association of Business Advocating Tariff Equity	Michigan Gas Co. and Southeastern Michigan Gas Co.	Transportation Balancing Provisions.
7/97	R-00973944	PA	Pennsylvania American Water Large Users Group	Pennsylvania-American Water Co.	Rate of return, cost of service, revenue requirements.
3/98	8390-U	GA	Georgia Natural Gas Group and the Georgia Textile Manufacturers Assoc.	Atlanta Gas Light	Rate of return, restructuring issues, unbundling, rate design issues.
7/98	R-00984280	PA	PG Energy, Inc. Intervenors	PGE Industrial	Cost allocation.
8/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Return on equity, rate of return.
10/98	U-23327	LA	Louisiana Public Service Commission	SWEPCO, CSW and AEP	Analysis of proposed merger.
12/98	98-577	ME	Maine Office of the Public Advocate	Maine Public Service Co.	Return on equity, rate of return.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity, rate of return.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co	Return on equity.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Return on equity.
4/99	R-984554	PA	T. W. Phillips Users Group	T. W. Phillips Gas and Oil Co.	Allocation of purchased gas costs.
6/99	R-0099462	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Balancing charges.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States,Inc.	Cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/99	R-00994782	PA	Peoples Industrial Intervenors	Peoples Natural Gas Co.	Restructuring issues.
10/99	R-00994781	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Restructuring, balancing charges, rate flexing, alternate fuel.
01/00	R-00994786	PA	UGI Industrial Intervenors	UGI Utilities, Inc.	Universal service costs, balancing, penalty charges, capacity Assignment.
01/00	8829	MD & United States	Maryland Industrial Gr.	Baltimore Gas & Electric Co.	Revenue requirements, cost allocation, rate design.
02/00	R-00994788	PA	Penn Fuel Transportation	PFG Gas, Inc., and	Tariff charges, balancing provisions.
05/00	U-17735	LA	Louisiana Public Service Comm.	Louisiana Electric Cooperative	Rate restructuring.
07/00	2000-080	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric Co.	Cost allocation.
07/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket E)	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Stranded cost analysis.
09/00	R-00005654	PA	Philadelphia Industrial And Commercial Gas Users Group.	Philadelphia Gas Works	Interim relief analysis.
10/00	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring, Business Separation Plan.
11/00	R-00005277 (Rebuttal)	PA	Penn Fuel Transportation Customers	PFG Gas, Inc. and North Penn Gas Co.	Cost allocation issues.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/01	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Stranded cost analysis.
04/01	U-21453 U-20925 (SC), U-22092 (SC) (Subdocket B) (Addressing Contested Issues)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Restructuring issues.
04/01	R-00006042	PA	Philadelphia Industrial and Commercial Gas Users Group	Philadelphia Gas Works	Revenue requirements, cost allocation and tariff issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
03/02	14311-U	GA	Georgia Public Service Commission	Atlanta Gas Light	Capital structure.
08/02	2002-00145	KY	Kentucky Industrial Utility Customers	Columbia Gas of Kentucky	Revenue requirements.
09/02	M-00021612	PA	Philadelphia Industrial And Commercial Gas Users Group	Philadelphia Gas Works	Transportation rates, terms, and conditions.
01/03	2002-00169	KY	Kentucky Industrial Utility Customers	Kentucky Power	Return on equity.
02/03	02S-594E	CO	Cripple Creek & Victor Gold Mining Company	Aquila Networks – WPC	Return on equity.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Return on equity.
10/03	CV020495AB	GA	The Landings Assn., Inc.	Utilities Inc. of GA	Revenue requirement & overcharge refund
03/04	2003-00433	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric	Return on equity, Cost allocation & rate design
03/04	2003-00434	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Return on equity
4/04	04S-035E	CO	Cripple Creek & Victor Gold Mining Company, Goodrich Corp., Holcim (U.S.) Inc., and The Trane Co.	Aquila Networks – WPC	Return on equity.
9/04	U-23327, Subdocket B	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Fuel cost review
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission	Southwestern Electric Power Company	Return on Equity
06/05	050045-EI	FL	South Florida Hospital and HeallthCare Assoc.	Florida Power & Light Co.	Return on equity
08/05	9036	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirement, cost allocation, rate design, Tariff issues.
01/06	2005-0034	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Return on equity.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	05-1278-E-PC-PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Return on equity.
04/06	U-25116 Commission	LA	Louisiana Public Service	Entergy Louisiana, LLC	Transmission Issues
07/06	U-23327 Commission	LA	Louisiana Public Service	Southwestern Electric Power Company	Return on equity, Service quality
08/06	ER-2006-0314	MO	Missouri Office of the Public Counsel	Kansas City Power & Light Co.	Return on equity, Weighted cost of capital
08/06	06S-234EG	CO	CF&I Steel, L.P. & Climax Molybdenum	Public Service Company of Colorado	Return on equity, Weighted cost of capital
01/07	06-0960-E-42T Users Group	WV	West Virginia Energy	Monongahela Power & Potomac Edison	Return on Equity
01/07	43112	AK	AK Steel, Inc.	Vectren South, Inc.	Cost allocation, rate design
05/07	2006-661	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric	Return on equity, weighted cost of capital.
09/07	07-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power	Return on equity, weighted cost of capital
10/07	05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Return on equity
11/07	29797	LA	Louisiana Public Service Commission	Cleco Power :LLC & Southwestern Electric Power	Lignite Pricing, support of settlement
01/08	07-551-EL-AIR	OH	Ohio Energy Group	Ohio Edison, Cleveland Electric, Toledo Edison	Return on equity
03/08	07-0585, 07-0585, 07-0587, 07-0588, 07-0589, 07-0590, (consol.)	IL	The Commercial Group	Ameren	Cost allocation, rate design
04/08	07-0566	IL	The Commercial Group	Commonwealth Edison	Cost allocation, rate design
06/08	R-2008-2011621	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Cost and revenue allocation, Tariff issues
07/08	R-2008-2028394	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Cost and revenue allocation, Tariff issues

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Date	Case	Jurisdict.	Party	Utility	Subject
07/08	R-2008-2039634	PA	PPL Gas Large Users Group	PPL Gas	Retainage, LUFG Pct.
08/08	6680-UR-116	WI	Wisconsin Industrial Energy Group	Wisconsin P&L	Cost of Equity
08/08	6690-UR-119	WI	Wisconsin Industrial Energy Group	Wisconsin PS	Cost of Equity
09/08	ER-2008-0318	MO	The Commercial Group	AmerenUE	Cost and revenue allocation
10/08	R-2008-2029325	PA	U.S. Steel & Univ. of Pittsburgh Med. Ctr.	Equitable Gas Co.	Cost and revenue allocation
10/08	08-G-0609	NY	Multiple Intervenors	Niagara Mohawk Power	Cost and Revenue allocation
12/08	27800-U	GA	Georgia Public Service Commission	Georgia Power Company	CWIP/AFUDC issues, Review financial projections
03/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Capital Structure
04/09	E002/GR-08-1065	MN	The Commercial Group	Northern States Power	Cost and revenue allocation and rate design
05/09	08-0532	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation
07/09	080677-EI	FL	South Florida Hospital and Health Care Association	Florida Power & Light	Cost of equity, capital structure, Cost of short-term debt
07/09	U-30975	LA	Louisiana Public Service Commission	Cleco LLC, Southwestern Public Service Co.	Lignite mine purchase
10/09	4220-UR-116	WI	Wisconsin Industrial Energy Group	Northern States Power	Class cost of service, rate design
10/09	M-2009-2123945	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Smart Meter Plan cost allocation
10/09	M-2009-2123944	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Smart Meter Plan cost allocation
10/09	M-2009-2123951	PA	West Penn Power Industrial Intervenors	West Penn Power	Smart Meter Plan cost allocation
11/09	M-2009-2123948	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Smart Meter Plan cost allocation
11/09	M-2009-2123950	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance, Penn Power Users Group	Metropolitan Edison, Pennsylvania Electric Co., Pennsylvania Power Co.	Smart Meter Plan cost allocation

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Date	Case	Jurisdict.	Party	Utility	Subject
03/10	09-1352-	WV E-42T	West Virginia Energy Users Group	Monongahela Power	Return on equity, rate of return Potomac Edison
03/10	E015/GR- 09-1151	MN	Large Power Intervenors	Minnesota Power	Return on equity, rate of return
04/10	2009-00459	KY	Kentucky Industrial Utility Consumers	Kentucky Power	Return on equity
04/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
05/10	10-0261-E- GI	WV	West Virginia Energy Users Group	Appalachian Power Co./ Wheeling Power Co.	EE/DR Cost Recovery, Allocation, & Rate Design
05/10	R-2009- 2149262	PA	Columbia Industrial Intervenors	Columbia Gas of PA	Class cost of service & cost allocation
06/10	2010-00036	KY	Lexington-Fayette Urban County Government	Kentucky American Water Company	Return on equity, rate of return, revenue requirements
06/10	R-2010- 2161694	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities	Rate design, cost allocation
07/10	R-2010- 2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Return on equity
07/10	R-2010- 2161592	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Cost and revenue allocation
07/10	9230	MD	Maryland Energy Group	Baltimore Gas and Electric	Electric and gas cost and revenue allocation; return on equity
09/10	10-70	MA	University of Massachusetts-Amherst	Western Massachusetts Electric Co.	Cost allocation and rate design
10/10	R-2010- 2179522	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Cost and revenue allocation, rate design
11/10	P-2010- 2158084	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Transmission rate design
11/10	10-0699- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. & Wheeling Power Co.	Return on equity, rate of Return
11/10	10-0467	IL	The Commercial Group	Commonwealth Edison	Cost and revenue allocation and rate design
04/11	R-2010- 2214415	PA	Central Pen Gas Large Users Group	UGI Central Penn Gas, Inc.	Tariff issues, revenue allocation
07/11	R-2011- 2239263	PA	Philadelphia Area Energy Users Group	PECO Energy	Retainage rate

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Date	Case	Jurisdict.	Party	Utility	Subject
08/11	R-2011-2232243	PA	AK Steel	Pennsylvania-American Water Company	Rate Design
08/11	11AL-151G	CO	Climax Molybdenum	PS of Colorado	Cost allocation
09/11	11-G-0280	NY	Multiple Intervenors	Corning Natural Gas Co.	Cost and revenue allocation
10/11	4220-UR-117	WI	Wisconsin Industrial Energy Group	Northern States Power	Cost and revenue allocation, rate design
02/12	11AL-947E	CO	Climax Molybdenum, CF&I Steel	Public Service Company of Colorado	Return on equity, weighted cost of capital
07/12	120015-EI	FL	South Florida Hospitals and Health Care Association	Florida Power and Light Co,	Return on equity, weighted cost of capital
07/12	12-0613-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal for Century Aluminum
07/12	R-2012-2290597	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities Corp.	Cost allocation
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Class cost of service, cost and revenue allocation, rate design
09/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Consumers	Louisville Gas and Electric, Kentucky Utilities	Return on equity.
10/12	9299	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design Cost of equity, weighted cost of capital
10/12	4220-UR-118	WI	Wisconsin Industrial Energy Group	Northern States Power Company	Class cost of service, cost and revenue allocation, rate design
10/12	473-13-0199	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Return on equity, capital structure
01/13	R-2012-2321748 et al.	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation
02/13	12AL-1052E	CO	Cripple Creek & Victor Gold Mining, Holcim (US) Inc.	Black Hills/Colorado Electric Utility Company	Cost and revenue allocations
06/13	8009	VT	IBM Corporation	Vermont Gas Systems	Cost and revenue allocation, rate design
07/13	130040-EI	FL	WCF Hospital Utility Alliance	Tampa Electric Co.	Return on equity, rate of return
08/13	9326	MD	Maryland Energy Group	Baltimore Gas and Electric	Cost and revenue allocation, rate design, special rider

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Date	Case	Jurisdict.	Party	Utility	Subject
08/13	P-2012-2325034	PA	PP&L Industrial Customer Alliance	PPL Electric Utilities, Corp.	Distribution System Improvement Charge
09/13	4220-UR-119	WI	Wisconsin Industrial Energy Group	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
11/13	13-1325-E-PC	WV	West Virginia Energy Users Group	American Electric Power/APCo	Special rate proposal, Felman Production
06/14	R-2014-2406274	PA	Columbia Industrial Intervenors	Columbia Gas of Pennsylvania	Cost and revenue allocation, rate design
08/14	05-UR-107	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Co.	Cost and revenue allocation, rate design
10/14	ER13-1508 et al.	FERC	Louisiana Public Service Comm.	Entergy Services, Inc.	Return on equity
11/14	14AL-0660E	CO	Climax Molybdenum Co. and CFI Steel, LP	Public Service Co. of Colorado	Return on equity, weighted cost of capital
11/14	R-2014-2428742	PA	AK Steel	West Penn Power Company	Cost and revenue allocation
12/14	42866	TX	West Travis Co. Public Utility Agency	Travis County Municipal Utility District No. 12	Response to complain of monopoly power
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric, Kentucky Utilities	Return on equity, cost of debt, weighted cost of capital
3/15	2014-00396	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	Return on equity, weighted cost of capital
6/15	15-0003-G-42T	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Cost and revenue allocation, Infrastructure Replacement Program
9/15	15-0676-W-42T	WV	West Virginia Energy Users Gp.	West Virginia-American Water Company	Appropriate test year, Historical vs. Future
9/15	15-1256-G-390P	WV	West Virginia Energy Users Gp.	Mountaineer Gas Co.	Rate design for Infrastructure Replacement and Expansion Program
10/15	4220-UR-121	WI	Wisconsin Industrial Energy Gp.	Northern States Power Co.	Class cost of service, cost and revenue allocation, rate design
12/15	15-1600-G-390P	WV	West Virginia Energy Users Gp.	Dominion Hope	Rate design and allocation for Pipeline Replacement & Expansion Prog.
12/15	45188	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Co.	Ring-fence protections for cost of capital

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Date	Case	Jurisdict.	Party	Utility	Subject
2/16	9406	MD	Maryland Energy Group	Baltimore Gas & Electric	Cost and revenue allocation, rate design, proposed Rider 5

Case No. 9406
Baltimore Gas and Electric Co.
Response to MEG Data Request 1
Request Received: 12/22/2015
Response Date: 01/07/2016

Item No.: MEGDR01-02

With respect to Baltimore City conduit costs, please provide the following:

a. Explain how current conduit costs are currently allocated in the Company's filed ECOSS. If more than one allocator is used, please show which allocators were used, the division of conduit costs between each allocator, and explain why each separate allocator was used.
b. Explain how conduit costs were allocated in the Company's filed ECOSS in its last rate case. If more than one allocator was used, please show which allocators were used, the division of conduit costs between each allocator, and explain why each separate allocator was used.

RESPONSE:

a. In the 2014 ECOSS, conduit use and maintenance fees included in FERC Account 594-Underground Lines are allocated using the internal allocator PLTDUGLN, which is based on demand. PLTDUGLN is based on the composite of FERC Accounts 366-Underground Conduit and 367-Underground Conductors. FERC Accounts 366 and 367 are allocated by voltage level (34 kV, 13 kV and Secondary) and then by their corresponding Non-Coincident Peak allocator (DEMDSUBT, DEMDPRI and DEMDSEC), respectively.

b. The 2013 ECOSS, in Case No. 9355, follows the same allocation methodology as described above in part a.

Case No. 9406
Baltimore Gas and Electric Co.
Response to MEG Data Request 1
Request Received: 12/22/2015
Response Date: 01/07/2016

Item No.: MEGDR01-03

On page 17 of his Direct Testimony, Mr. Vahos testified that BGE's electric assets in the conduit system include electric cables, switches, transformers, street lighting cable, and communication cable. Please provide the following:

a. The rate base amount of BGE's electric assets in the conduit system shown by FERC Account.
b. The above amounts shown in part a. segregated by primary and secondary facilities.

RESPONSE:

BGE does not track electric cables, switches, transformers, street lighting cable, and communication cable by location in its property/plant accounting subledger system.

MARYLAND ENERGY GROUP
RECOMMENDED ALLOCATION OF PROPOSED GAS BASE RATE
REVENUE CHANGE TO CLASSES OF SERVICE
BASED ON 12 MONTHS ACTUAL ENDING NOVEMBER 2015

STEP 1 - ALLOCATION OF REVENUE INCREASE

RATE SCHEDULE	BASE RATE REVENUE AT CURRENT RATES	RELATIVE ROR	STEP 1 REVENUE ALLOCATION	BASE REVENUE AFTER STEP 1
	(1)	(2)	(3)	(4) = (1) + (3)
1. SCHEDULE D	$ 285,437,745	0.99	$ -	$ 285,437,745
2. SCHEDULE C	$ 99,377,151	1.01	$ -	$ 99,377,151
3. SCHEDULE PLG	$ 32,255	8.79	$ -	$ 32,255
4. SCHEDULE IS	$ 20,806,107	1.15	$ (312,614)	$ 20,493,493
5. SCHEDULE ISS	$ 1,080,539	0.94	$ -	$ 1,080,539
6. TOTAL	$ 406,733,797		$ (312,614)	$ 406,421,183

STEP 2 - ALLOCATION OF REMAINING REVENUE INCREASE TO ALL RATE SCHEDULES, EXCLUDING PLG

	REVENUE INCREASE
	(6)
7. REQUIRED CHANGE IN BASE RATE REVENUE TO BE ALLOCATED	$ 79,494,000

RATE SCHEDULE	BASE REVENUE AFTER STEP 1	PERCENT OF TOTAL (a)	STEP 2 REVENUE ALLOCATION	TOTAL BASE REVENUE ALLOCATION
	(7) = (4)	(8)	(9) = ((6) - (3)) * (8)	(10) = (3) + (9)
8. SCHEDULE D	$ 285,437,745	70.24%	$ 56,054,234	$ 56,054,234
9. SCHEDULE C	$ 99,377,151	24.45%	$ 19,515,674	$ 19,515,674
10. SCHEDULE PLG	$ 32,255	0.00%	$ -	$ -
11. SCHEDULE IS	$ 20,493,493	5.04%	$ 4,024,510	$ 3,711,896
12. SCHEDULE ISS	$ 1,080,539	0.27%	$ 212,196	$ 212,196
13. TOTAL	$ 406,421,183	100%	$ 79,806,614	$ 79,494,000
14. TOTAL REVENUE INCREASE				$ 79,494,000

(a) Excludes Schedule PLG

Source: Company Exhibit JCF-4 Actual, Supplement 412, Sheet G-2

STATE OF VERMONT
PUBLIC SERVICE BOARD

Petition of Vermont Gas Systems, Inc. for change in rates, and for use of the System Reliability and Expansion Fund in connection therewith	)))	Docket No. 8710

SURREBUTTAL TESTIMONY

AND EXHIBITS

OF

RICHARD A. BAUDINO

ON BEHALF OF THE
VERMONT DEPARTMENT OF PUBLIC SERVICE

J. Kennedy and Associates, Inc.
570 Colonial Park Drive, Suite 305
Roswell, GA 30075

OCTOBER 31, 2016

Summary: Mr. Baudino responds to the Rebuttal Testimony of Mr. James Coyne and Ms. Eileen Simollardes, witnesses for Vermont Gas Systems. Mr. Baudino also provides an update to the return on equity analyses filed in his Direct Testimony.

Exhibit List

EXHIBIT DPS-RAB-10	Gas Distribution Company Group - Dividend Yields
EXHIBIT DPS-RAB-11	Gas Distribution Company Group - Growth Rate Analysis and DCF Return on Equity Calculation
EXHIBIT DPS-RAB-12	Gas Distribution Company Group - Capital Asset Pricing Model (CAPM) Analysis
EXHIBIT DPS-RAB-13	CAPM Analysis - Historic Market Premium
EXHIBIT DPS-RAB-14	Coyne Gas Distribution Company Group - Dividend Yields
EXHIBIT DPS-RAB-15	Coyne Gas Distribution Company Group - Growth Rate Analysis and DCF Return on Equity Calculation

STATE OF VERMONT
PUBLIC SERVICE BOARD

Petition of Vermont Gas Systems, Inc. for change in rates, and for use of the System Reliability and Expansion Fund in connection therewith	)))	Docket No. 8710

SURREBUTTAL TESTIMONY OF RICHARD A. BAUDINO

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Did you submit Direct Testimony in this proceeding?

A. Yes. I submitted Direct Testimony on behalf of the Vermont Department of Public Service ("DPS").

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimony of Mr. James Coyne and Ms. Eileen Simollardes, witnesses for Vermont Gas Systems ("VGS" or "Company"). I will also provide an update to my return on equity analyses that I filed in my Direct Testimony.

<u>Update to ROE Analyses</u>

Q. Did you perform an update to the ROE analyses that you presented to the Board in your Direct Testimony?

A. Yes. Exhibits DPS-RAB-10 through DPS-RAB-13 provide updates to my Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses that I presented in my Direct Testimony. Surrebuttal Table 1 presents a summary of the results.

SURREBUTTAL TABLE 1

VERMONT GAS SYSTEMS
ROE RESULTS SUMMARY

<u>DCF Results:</u>	
Average Growth Rates, Gas Group	
- High	9.30%
- Low	7.38%
- Average	8.37%
- Average, Earnings Growth	8.70%
Median Growth Rates, Gas Group	
- High	9.70%
- Low	6.56%
- Average	8.36%
- Average, Earnings Growth	8.96%
CAPM:	
- 5-Year Treasury Bond	7.90%
- 20-Year Treasury Bond	8.10%
- Historical Returns	5.90% - 7.43%

The results of my updated analyses continue to support my recommended 9.0% ROE for VGS. If earnings growth rates only are considered, then 9.0% is consistent with the top end of my DCF results.

I also updated the DCF results for Mr. Coyne's gas utility group, the results of which are shown in Exhibits DPS-RAB-14 and DPS-RAB-15. The DCF results range from 8.70% - 9.26%. My recommended 9.0% ROE falls in the middle of that range.

Q. On pages 30 and 31 of your Direct Testimony, you discussed the possibility of the Federal Reserve increasing interest rates later this year. Please discuss your current view of this possibility.

A. In a press release dated September 21, 2016 the Fed announced that it decided to hold interest rates steady and maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The following excerpts from this press release discuss the reasoning behind this decision.

> Information received since the Federal Open Market Committee met in July indicates that the labor market has continued to strengthen and growth of economic activity has picked up from the modest pace seen in the first half of this year. Although the unemployment rate is little changed in recent months, job gains have been solid, on average. Household spending has been growing strongly but business fixed investment has remained soft. Inflation has continued to run below the Committee's 2 percent longer-run objective, partly reflecting earlier declines in energy prices and in prices of non-energy imports. Market-based measures of inflation compensation remain low; most survey-based measures of longer-term inflation expectations are little changed, on balance, in recent months.
>
> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace and labor market conditions will strengthen somewhat further. Inflation is expected to remain low in the near term, in part because of earlier declines in energy prices, but to rise to 2 percent over the medium term as the transitory effects of past declines in energy and import prices dissipate and the labor market strengthens further. Near-term risks to the economic outlook appear roughly balanced.
>
> * * *
>
> In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. *The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run.* However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data. (Italics added)

My reading of the Fed's press release suggests that it will take a careful, considered approach with respect to monetary policy and gradually implement future interest rate increases. It is not clear whether the Fed will implement any increase in interest rates this year. The Fed also stated that the current federal funds rate is below the rate that would prevail in the longer run, which indicates future increases in interest rates.

Q. Has the general level of interest rates increased since you filed your Direct Testimony?

A. No. As of October 21, 2016 the yield on the 20-year Treasury bond was 2.15%. This is not significantly different from the Treasury yields over the last 6 months as shown on Exhibit DPS-RAB-12, which range from 1.82% to 2.21%. Likewise, Moody's Credit Trends showed that the yield on average public utility bonds was 3.89% for October 24, 2016. This current yield represents a significant decline from the beginning of 2016, in which the Mergent average public utility bond yield was 4.62%.

Q. Does your recommended ROE of 9.0% properly account for both current and future expectations for capital costs?

A. Yes. None of the economic conditions I described in my Direct Testimony have changed significantly. Although I still expect the Fed to raise the federal funds rate at some point in the future, the timing is uncertain. Nevertheless, the Fed signaled that any increases in the federal funds rate would likely be gradual. Since my recommended ROE of 9.0% is already at the top of my DCF range, no further adjustments to this recommendation are warranted at this time.

Q. On page 13 of his Rebuttal Testimony, Mr. Coyne discussed interest rate forecasts from Blue Chip Financial Forecasts. On page 13, line 13 through page 14, line 2 Mr. Coyne concluded that your DCF results were understated "because the current dividend yield component does not adequately reflect the higher interest rate environment that both the financial market and Mr. Baudino expect." Please respond to Mr. Coyne's conclusion.

A. Mr. Coyne is incorrect. As I stated in my Direct Testimony current interest rates embody investor expectations based on their assessments of all available market information. This includes interest rate forecasts cited by Mr. Coyne as well as statements from the Federal Reserve. The Board should not invest in the interest rate forecasts cited by Mr. Coyne in determining a fair rate of return for VGS. We really don't know and should not trust the accuracy of these forecasts in setting rates for VGS' Vermont ratepayers.

Recently, there has been evidence that economists have systematically overestimated interest rates in recent years. Jared Bernstein wrote the following in a recent article in the New York Times[1]:

> In the early 1980s, forecasters did a good job of predicting the path of bond rates, though their job was a bit easier than usual because rates were so highly elevated that it was a pretty sure bet they'd be headed back down. ("Regression to the mean," for all you statistics fans.)
>
> But since the mid-1990s, government forecasters have consistently overestimated this critical variable.
>
> This "consistently" point is essential. Most economic forecasts are off one way or the other — too high or too low, but they tend to be pretty much balanced in either direction. But on the 10-year bond rate, the errors are systemic.
>
> Forecasters are regularly overestimating and thus regularly overstating, all else being equal, future interest payments on the debt.

Another article by Akin Oyedele entitled "Interest Rate Forecasters Are Shockingly Wrong Almost All Of The Time"[2] showed that from June 2010 through June 2015 interest rate forecasts were wrong most of the time. Mr. Oyedele noted that 2014 "was particularly bad, when strategists became too optimistic that the Federal Reserve would hike rates." These articles highlight the consistent upward bias that is likely embodied in the forecasts presented by Mr. Coyne.

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[1] "We Keep Flunking Forecasts on Interest Rates, Distorting the Budget Outlook", Jared Bernstein, *New York Times*, Feb. 23, 2015.

[2] Akin Oyedele, "Interest Rate Forecasters Are Shockingly Wrong Almost All of the Time", *Business Insider*, July 18, 2015.

Q. Did the Value Line Investment Survey opine on the attractiveness of recent dividend yields of gas distribution companies?

A. Yes. Value Line noted the following in its September 2, 2016 summary of the Natural Gas Utility Industry:

> The main feature of utility equities is their dividend income, which is well covered by corporate profits. (It's important to mention that the Financial Strength ratings for the 11 companies in our universe are no lower than B+.) At the time of this report, the average yield for the group was about 2.7%, significantly above the Value Line median of 2.2%. Standouts include South Jersey Industries, Northwest Natural Gas, Spire Inc., and WGL Holdings. When the financial markets face heightened volatility, which seems to be more the case these days, solid dividend yields tend to act like an anchor, so to speak.

Value Line's comments with respect to the current dividend yields of gas utilities stand in stark contrast to Mr. Coyne's assertion. Indeed, my gas group's dividend yield of 2.76% is very attractive compared to current long-term Treasury bond yields. Further, Mr. Coyne overlooked the fact that investors can expect growth in dividends, a factor which increases the total returns on gas utility stocks relative to bonds.

Q. If interest rates increase significantly over the next few years, couldn't VGS file a rate case and seek a higher cost of equity?

A. Yes. The Company could file a rate case and ask the Board to adjust its cost of equity upward in response to higher interest rates. This is an important point. In her testimony at page 8, lines 5 through 10, Ms. Simollardes indicates that if the Company's proposed alternative regulation plan is not approved, it will likely file a new rate case very soon. This means that the rates at issue in this case will only be in effect in the near term. The Board should therefore weight current and near term financial conditions more heavily than long-term conditions, which are speculative at best. This approach will track the financial environment during the period that rates will be in effect. This point is equally appropriate even were the Board to approve the Company's proposed alternative regulation plan, as that plan includes an adjustment mechanism to change the Company's ROE to account for broader market conditions.

Q. In your Direct Testimony, you adjusted the Company's requested cost of short-term debt to 0.50% plus a 1.0% basis point differential. Has the 30-day LIBOR increased since you filed your Direct Testimony?

A. Yes. The 30-day LIBOR increased slightly to about 0.53% since my Direct Testimony was filed. Given the possibility of higher interest rates later this year, it is reasonable to update my recommended cost of short-term debt to 0.55% plus a 1.0% adder for a total short-term debt rate of 1.55%. Surrebuttal Table 2 presents my recommended weighted cost of capital for VGS. This revision has no noticeable impact of my recommended cost of capital of 6.84%.

SURREBUTTAL TABLE 2

VERMONT GAS SYSTEMS
WEIGHTED COST OF CAPITAL

	Percentage	Cost	Wtd. Cost
Long-term Debt	42.13%	5.27%	2.22%
Short-term Debt	7.87%	1.55%	0.12%
Common Equity	50.00%	9.00%	4.50%
Total	100.00%		6.84%

<u>**VGS ROE Recommendation Based on Stale Data**</u>

Q. Did Mr. Coyne provide an update to the return on equity ("ROE") analyses he provided in his Direct Testimony?

A. No. In his Rebuttal Testimony Mr. Coyne continued to base his recommended 9.70% ROE on the analysis he provided in his Direct Testimony.

Q. In your Direct Testimony, page 34, you addressed the issue of stale data in Mr. Coyne's DCF analyses. Please address this issue in regard to Mr. Coyne's Rebuttal Testimony.

A. This issue of stale data still persists, and in fact is exacerbated, with respect to Mr. Coyne's DCF analyses as well as the other ROE methods he relied upon in his Direct Testimony.

As I stated in my Direct Testimony, the Board simply cannot rely on ROE analyses that employ stock prices ending December 31, 2015. This data is over 10 months out of date as of the filing of my Surrebuttal Testimony. In no way can it provide accurate, up to date guidance for the Board's consideration of a fair return for VGS.

Q. On page 9, lines 3 through 5 of his Rebuttal Testimony, Mr. Coyne testified that the ROE results he presented in his Direct Testimony "take into consideration both current and forward-looking conditions in capital markets". Please respond to Mr. Coyne's testimony on this point.

A. The staleness of the data relied upon by Mr. Coyne does not support his conclusion. In fact, Mr. Coyne's ROE results are even further removed from current and forward looking conditions in capital markets than they were when he filed his Direct Testimony.

In conclusion, Mr. Coyne's ROE analyses provide the Board very little useful information in setting the allowed rate of return on equity for VGS in this proceeding.

<u>**Current Economic Conditions Are Not Anomalous**</u>

Q. On pages 17 through 19 of his Rebuttal Testimony, Mr. Coyne cited FERC Orders that expressed concerns with respect to the current level of interest rates, its effect on the DCF model, and to "anomalous" conditions in current capital markets. Please respond to this portion of Mr. Coyne's testimony.

A. Current financial market conditions are not "anomalous". As I stated in my Direct Testimony, the Federal Reserve has been pursuing an accommodative monetary policy since the severe recession of 2008 - 2009. All indications suggest that, although the Fed will increase interest rates at some point in the future, such increases will be gradual. Low interest rates have been the norm for several years and, if anything, rates have declined since the beginning of 2016. Required ROEs have declined since 2008 and are reflective of this low interest rate environment, which is completely expected and rational.

Q. Is there support for the position that today's currently low interest rates is part of a long-term trend?

A. Yes. In a weekly blog at the Brookings Institution, former Fed Chairman Ben Bernanke wrote the following:[3]

> Interest rates around the world, both short-term and long-term, are exceptionally low these days. The U.S. government can borrow for ten years at a rate of about 1.9 percent, and for thirty years at about 2.5 percent. Rates in other industrial countries are even lower: For example, the yield on ten-year government bonds is now around 0.2 percent in Germany, 0.3 percent in Japan, and 1.6 percent in the United Kingdom. In Switzerland, the ten-year yield is currently slightly negative, meaning that lenders must pay the Swiss government to hold their money! The interest rates paid by businesses and households are relatively higher, primarily because of credit risk, but are still very low on an historical basis.
>
> Low interest rates are not a short-term aberration, but part of a long-term trend. As the figure below shows, ten-year government bond yields in the United States were relatively low in the 1960s, rose to a peak above 15 percent in 1981, and have been declining ever since. That pattern is partly explained by the rise and fall of inflation, also shown in the figure. All else equal, investors demand higher yields when inflation is high to compensate them for the declining purchasing power of the dollars with which they expect to be repaid. But yields on inflation-protected bonds are also very low today; the real or inflation-adjusted return on lending to the U.S. government for five years is currently about *minus* 0.1 percent.
>
> Why are interest rates so low? Will they remain low? What are the implications for the economy of low interest rates?
>
> If you asked the person in the street, “Why are interest rates so low?”, he or she would likely answer that the Fed is keeping them low. That’s true only in a very narrow sense. The Fed does, of course, set the benchmark nominal short-term interest rate. The Fed’s policies are also the primary determinant of inflation and inflation expectations over the longer term, and inflation trends affect interest rates, as the figure above shows. But what matters most for the economy is the real, or inflation-adjusted, interest rate (the market, or nominal, interest rate minus the inflation rate). The real interest rate is most relevant for capital investment decisions, for example. The Fed’s ability to affect real rates of return, especially longer-term real rates, is transitory and limited. Except in the short run, real interest rates are determined by a wide range of economic factors, including prospects for

[3] Ben S. Bernanke, "Why Are Interest Rates So Low", Weekly Blog, Brookings, March 30, 2015. https://www.brookings.edu/blog/ben-bernanke/2015/03/30/why-are-interest-rates-so-low/

economic growth—not by the Fed.

Q. Would it make sense for an investor in bonds or utility stocks to be buying these securities at their current prices if that investor expected a significant increase in interest rates in the near term?

A. No, it would make no sense whatsoever. A significant increase in current interest rates would cause investors to suffer losses in their investments, as the prices of utility stocks and government bonds move inversely to interest rates. Therefore, the Board can rely on current stock prices and bond yields as accurate barometers of investors' expectations with regards to future movements in interest rates.

Comparisons with Recent Authorized Returns

Q. Beginning on page 5 of his Rebuttal Testimony, Mr. Coyne criticized your recommended 9.0% ROE as being inconsistent with authorized returns in other jurisdictions. Please address this criticism.

A. I recommend the Board base its ROE decision on the evidence presented in this proceeding, not on the ROE awards in other state jurisdictions. My DCF and CAPM results effectively demonstrate that Mr. Coyne's recommended ROE of 9.70% is not supported by current market evidence. Furthermore, Mr. Coyne's analyses and conclusions rely on market data that is out of date and that cannot be relied upon by the Board.

Furthermore, Mr. Coyne failed to point out that Green Mountain Power's ("GMP") ROE was recently adjusted to 9.02% in connection with its alternative regulation plan.[4] Although GMP is an electric distribution company, its ROE should be relatively comparable to Vermont Gas. Thus, if state-allowed ROE awards are to be considered in this docket, GMP's Vermont approved ROE of 9.02% should also be considered.

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[4] See GMP tariff filing dated August 1, 2016, Schedule 3. See also the Order Approving Tariff Filing by the Board entered September 26, 2016.

<u>Response to Coyne Criticism of Constant Growth Method</u>

Q. On pages 24 and 25 of his Rebuttal Testimony, Mr. Coyne used the FERC's methodology in Opinion No. 531 to obtain a ROE result of 10.19% from your originally filed DCF analysis. Is it appropriate to use the FERC's ROE method in Opinion No. 531 for Vermont Gas?

A. Definitely not. Mr. Coyne did not use this approach himself in his originally filed Direct Testimony and I find it inappropriate for him to use it now in an effort to inflate my DCF results.

It should be noted that FERC's Opinion No. 531 set what it considered to be an appropriate ROE for transmission companies. As a gas distribution company, Vermont Gas does not face the many risks outlined by the FERC with respect to companies whose focus is electric transmission infrastructure. Therefore, using this approach for Vermont Gas would severely overstate the investor required return for a lower risk gas distribution company.

<u>Variability of Returns for Smaller Companies</u>

Q. On page 39 of his Rebuttal Testimony, Mr. Coyne presented Figure 5, which shows higher standard deviations of returns for smaller companies. Mr. Coyne concluded from this that smaller sized companies should have higher expected returns from investors. Please address this portion of Mr. Coyne's Rebuttal Testimony.

A. I agree that smaller sized companies tend to have more variable returns and higher required ROEs. However, the Morningstar data presented by Mr. Coyne includes all companies, most of which are unregulated. There is no evidence that smaller regulated utility companies have higher variability of returns than larger ones or that they have higher required returns. Regulation tends to eliminate many of the risks that smaller unregulated companies face, particularly with respect to having a service territory that is protected from competitors. Smaller regulated utilities may also file for higher rates to cover increased costs, something that smaller unregulated companies cannot do. In conclusion, Mr. Coyne's Figure 5 does not provide any basis for increasing Vermont Gas' ROE based on its size.

Q. Does this complete your Surrebuttal Testimony?

A. Yes

VERMONT GAS SYSTEMS
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-16	Aug-16	Jul-16	Jun-16	May-16	Apr-16
Atmos Energy	High Price ($)	77.720	80.180	81.970	81.350	75.100	74.860
	Low Price ($)	71.610	73.250	78.390	72.420	70.840	70.410
	Avg. Price ($)	74.665	76.715	80.180	76.885	72.970	72.635
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.420
	Mo. Avg. Div.	2.25%	2.19%	2.10%	2.19%	2.30%	2.31%
	6 mos. Avg.	2.22%					
New Jersey Resources	High Price ($)	35.590	37.290	38.920	38.560	37.170	36.880
	Low Price ($)	32.270	33.280	36.270	35.140	33.910	34.550
	Avg. Price ($)	33.930	35.285	37.595	36.850	35.540	35.715
	Dividend ($)	0.255	0.240	0.240	0.240	0.240	0.240
	Mo. Avg. Div.	3.01%	2.72%	2.55%	2.61%	2.70%	2.69%
	6 mos. Avg.	2.71%					
Northwest Natural Gas	High Price ($)	63.250	65.530	66.170	64.840	57.950	54.290
	Low Price ($)	57.960	59.470	63.260	55.060	51.120	49.460
	Avg. Price ($)	60.605	62.500	64.715	59.950	54.535	51.875
	Dividend ($)	0.468	0.468	0.468	0.468	0.468	0.468
	Mo. Avg. Div.	3.09%	3.00%	2.89%	3.12%	3.43%	3.61%
	6 mos. Avg.	3.19%					
South Jersey Industries	High Price ($)	31.050	32.030	32.000	31.640	28.970	28.550
	Low Price ($)	28.170	29.390	30.870	28.520	26.290	27.170
	Avg. Price ($)	29.610	30.710	31.435	30.080	27.630	27.860
	Dividend ($)	0.264	0.264	0.264	0.264	0.264	0.264
	Mo. Avg. Div.	3.57%	3.44%	3.36%	3.51%	3.82%	3.79%
	6 mos. Avg.	3.58%					
Southwest Gas	High Price ($)	74.030	77.460	79.580	79.430	70.510	66.600
	Low Price ($)	67.970	69.690	75.500	69.180	64.390	62.750
	Avg. Price ($)	71.000	73.575	77.540	74.305	67.450	64.675
	Dividend ($)	0.450	0.450	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	2.54%	2.45%	2.09%	2.18%	2.40%	2.50%
	6 mos. Avg.	2.36%					
Spire Inc.	High Price ($)	66.520	69.850	71.210	70.870	66.200	68.400
	Low Price ($)	61.960	64.400	67.670	63.150	61.000	62.650
	Avg. Price ($)	64.240	67.125	69.440	67.010	63.600	65.525
	Dividend ($)	0.490	0.490	0.490	0.490	0.490	0.490
	Mo. Avg. Div.	3.05%	2.92%	2.82%	2.92%	3.08%	2.99%
	6 mos. Avg.	2.97%					

VERMONT GAS SYSTEMS
GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-16	Aug-16	Jul-16	Jun-16	May-16	Apr-16
UGI Corp.	High Price ($)	48.130	46.540	45.650	45.250	43.720	41.430
	Low Price ($)	44.630	43.830	44.190	42.750	39.440	39.200
	Avg. Price ($)	46.380	45.185	44.920	44.000	41.580	40.315
	Dividend ($)	0.238	0.238	0.238	0.238	0.238	0.238
	Mo. Avg. Div.	2.05%	2.11%	2.12%	2.16%	2.29%	2.36%
	6 mos. Avg.	2.18%					
WGL Holdings	High Price ($)	66.000	70.990	72.180	70.810	70.090	72.840
	Low Price ($)	60.270	62.500	69.310	65.100	63.060	65.000
	Avg. Price ($)	63.135	66.745	70.745	67.955	66.575	68.920
	Dividend ($)	0.488	0.488	0.488	0.463	0.463	0.463
	Mo. Avg. Div.	3.09%	2.92%	2.76%	2.73%	2.78%	2.69%
	6 mos. Avg.	2.83%					
6-month Average Dividend Yield		2.76%					

Source: Yahoo! Finance

VERMONT GAS SYSTEMS
GAS DISTRIBUTION COMPANY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson/ IBES
Atmos Energy	6.50%	6.50%	5.50%	7.20%	7.30%
New Jersey Resources	3.00%	1.00%	5.00%	6.50%	6.50%
Northwest Natural Gas	2.00%	7.00%	3.50%	4.00%	4.00%
South Jersey Industries	6.50%	3.00%	1.50%	10.00%	6.00%
Southwest Gas	8.50%	7.00%	6.00%	4.50%	4.00%
Spire Inc.	3.50%	9.00%	5.00%	4.60%	4.52%
UGI Corp.	4.00%	4.00%	7.50%	7.60%	7.60%
WGL Holdings	2.50%	3.50%	3.50%	7.30%	8.00%
Average Growth Rates	4.56%	5.13%	4.69%	6.46%	5.99%
Median Growth Rates	3.75%	5.25%	5.00%	6.85%	6.25%

Sources: Zack's and Thomson Earnings Reports, retrieved September 30, 2016
Value Line Investment Survey,September 2, 2016

VERMONT GAS SYSTEMS
GAS DISTRIBUTION COMPANY GROUP
DCF RETURN ON EQUITY CALCULATION

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) IBES Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	2.76%	2.76%	2.76%	2.76%	2.76%
Average Growth Rate	4.56%	5.13%	6.46%	5.99%	5.54%
Expected Div. Yield	2.82%	2.83%	2.84%	2.84%	2.83%
DCF Return on Equity	***7.38%***	***7.96%***	***9.30%***	***8.83%***	***8.37%***
DCF Return on Equity, Earnings Growth		***7.96%***	***9.30%***	***8.83%***	***8.70%***
Method 2:					
Dividend Yield	2.76%	2.76%	2.76%	2.76%	2.76%
Median Growth Rate	3.75%	5.25%	6.85%	6.25%	5.53%
Expected Div. Yield	2.81%	2.83%	2.85%	2.84%	2.83%
DCF Return on Equity	***6.56%***	***8.08%***	***9.70%***	***9.09%***	***8.36%***
DCF Return on Equity, Earnings Growth		***8.08%***	***9.70%***	***9.09%***	***8.96%***

GAS DISTRIBUTION COMPANY GROUP
Capital Asset Pricing Model Analysis

20-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.92%
2	Risk-free Rate of Return, 20-Year Treasury Bond	
3	Average of Last Six Months	2.03%
4	Risk Premium	
5	(Line 1 minus Line 3)	7.89%
6	Comparison Group Beta	0.77
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.07%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	8.10%

5-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	9.92%
2	Risk-free Rate of Return, 5-Year Treasury Bond	
3	Average of Last Six Months	1.19%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.74%
6	Comparison Group Beta	0.77
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	6.72%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.90%

GAS DISTRIBUTION COMPANY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

20 Year Treasury Bond Data

	Avg. Yield
April-16	2.21%
May-16	2.22%
June-16	2.02%
July-16	1.82%
August-16	1.89%
September-16	2.02%
6 month average	2.03%

5 Year Treasury Bond Data

	Avg. Yield
April-16	1.26%
May-16	1.30%
June-16	1.17%
July-16	1.07%
August-16	1.13%
September-16	1.18%
6 month average	1.19%

Source: www.federalreserve.gov, Selected Interest Rates (Daily) - H.15

Value Line Market Return Data:

Forecasted Data:

Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	7.00%
Average	9.00%
Average Dividend Yield	0.81%
Estimated Market Return	9.85%
Value Line Projected 3-5 Yr. Median Annual Total Return	10.00%
Average of Projected Mkt. Returns	9.92%

Source: Value Line Investment Survey
for Windows retreived September 30, 2016

Comparison Group Betas:

Atmos Energy	0.75
New Jersey Resources	0.80
Northwest Natural Gas	0.65
South Jersey Industries	0.80
Southwest Gas	0.75
Spire, Inc.	0.70
UGI Corp.	0.95
WGL Holdings	0.75
Average	0.77

Source: Value Line Investment Survey,
September 2, 2016

CAPITAL ASSET PRICING MODEL ANALYSIS
Historic Market Premium

	Geometric Mean	Arithmetic Mean	Adjusted Arithmetic Mean
Long-Term Annual Return on Stocks	10.10%	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.07%	5.07%	
Historical Market Risk Premium	5.03%	7.03%	6.19%
Gas Distribution Group Beta, Value Line	0.77	0.77	0.77
Beta * Market Premium	3.87%	5.40%	4.76%
Current 20-Year Treasury Bond Yield	2.03%	2.03%	2.03%
CAPM Cost of Equity, Value Line Beta	**5.90%**	**7.43%**	**6.79%**

Source: *Ibbotson SBBI 2015 Classic Yearbook,* Morningstar, pp. 39, 40, 152, 157 - 158

COYNE GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-16	Aug-16	Jul-16	Jun-16	May-16	Apr-16
Atmos Energy	High Price ($)	77.720	80.180	81.970	81.350	75.100	74.860
	Low Price ($)	71.610	73.250	78.390	72.420	70.840	70.410
	Avg. Price ($)	74.665	76.715	80.180	76.885	72.970	72.635
	Dividend ($)	0.420	0.420	0.420	0.420	0.420	0.420
	Mo. Avg. Div.	2.25%	2.19%	2.10%	2.19%	2.30%	2.31%
	6 mos. Avg.	2.22%					
New Jersey Resources	High Price ($)	35.590	37.290	38.920	38.560	37.170	36.880
	Low Price ($)	32.270	33.280	36.270	35.140	33.910	34.550
	Avg. Price ($)	33.930	35.285	37.595	36.850	35.540	35.715
	Dividend ($)	0.255	0.240	0.240	0.240	0.240	0.240
	Mo. Avg. Div.	3.01%	2.72%	2.55%	2.61%	2.70%	2.69%
	6 mos. Avg.	2.71%					
Northwest Natural Gas	High Price ($)	63.250	65.530	66.170	64.840	57.950	54.290
	Low Price ($)	57.960	59.470	63.260	55.060	51.120	49.460
	Avg. Price ($)	60.605	62.500	64.715	59.950	54.535	51.875
	Dividend ($)	0.468	0.468	0.468	0.468	0.468	0.468
	Mo. Avg. Div.	3.09%	3.00%	2.89%	3.12%	3.43%	3.61%
	6 mos. Avg.	3.19%					
South Jersey Industries	High Price ($)	31.050	32.030	32.000	31.640	28.970	28.550
	Low Price ($)	28.170	29.390	30.870	28.520	26.290	27.170
	Avg. Price ($)	29.610	30.710	31.435	30.080	27.630	27.860
	Dividend ($)	0.264	0.264	0.264	0.264	0.264	0.264
	Mo. Avg. Div.	3.57%	3.44%	3.36%	3.51%	3.82%	3.79%
	6 mos. Avg.	3.58%					
Southwest Gas	High Price ($)	74.030	77.460	79.580	79.430	70.510	66.600
	Low Price ($)	67.970	69.690	75.500	69.180	64.390	62.750
	Avg. Price ($)	71.000	73.575	77.540	74.305	67.450	64.675
	Dividend ($)	0.450	0.450	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	2.54%	2.45%	2.09%	2.18%	2.40%	2.50%
	6 mos. Avg.	2.36%					
Spire Inc.	High Price ($)	66.520	69.850	71.210	70.870	66.200	68.400
	Low Price ($)	61.960	64.400	67.670	63.150	61.000	62.650
	Avg. Price ($)	64.240	67.125	69.440	67.010	63.600	65.525
	Dividend ($)	0.490	0.490	0.490	0.490	0.490	0.490
	Mo. Avg. Div.	3.05%	2.92%	2.82%	2.92%	3.08%	2.99%
	6 mos. Avg.	2.97%					

COYNE GAS DISTRIBUTION COMPANY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Sep-16	Aug-16	Jul-16	Jun-16	May-16	Apr-16
WGL Holdings	High Price ($)	66.000	70.990	72.180	70.810	70.090	72.840
	Low Price ($)	60.270	62.500	69.310	65.100	63.060	65.000
	Avg. Price ($)	63.135	66.745	70.745	67.955	66.575	68.920
	Dividend ($)	0.488	0.488	0.488	0.463	0.463	0.463
	Mo. Avg. Div.	3.09%	2.92%	2.76%	2.73%	2.78%	2.69%
	6 mos. Avg.	2.83%					
6-month Average Dividend Yield		2.84%					

Source: Yahoo! Finance

VERMONT GAS SYSTEMS
COYNE GAS DISTRIBUTION COMPANY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Value Line B x R	(4) Zacks	(5) Thomson/ IBES
Atmos Energy	6.50%	6.50%	5.50%	7.20%	7.30%
New Jersey Resources	3.00%	1.00%	5.00%	6.50%	6.50%
Northwest Natural Gas	2.00%	7.00%	3.50%	4.00%	4.00%
South Jersey Industries	6.50%	3.00%	1.50%	10.00%	6.00%
Southwest Gas	8.50%	7.00%	6.00%	4.50%	4.00%
Spire Inc.	3.50%	9.00%	5.00%	4.60%	4.52%
WGL Holdings	2.50%	3.50%	3.50%	7.30%	8.00%
Average Growth Rates	4.64%	5.29%	4.29%	6.30%	5.76%
Median Growth Rates	3.50%	6.50%	5.00%	6.50%	6.00%

Sources: Zack's and Thomson Earnings Reports, retrieved September 30, 2016
Value Line Investment Survey,September 2, 2016

VERMONT GAS SYSTEMS
COYNE GAS DISTRIBUTION COMPANY GROUP
DCF RETURN ON EQUITY CALCULATION

	(1) Value Line Earnings Gr.	(2) Zack's Earning Gr.	(3) IBES Earning Gr.	(4) Average of All Gr. Rates
Method 1:				
Dividend Yield	2.84%	2.84%	2.84%	2.84%
Average Growth Rate	5.29%	6.30%	5.76%	5.78%
Expected Div. Yield	2.91%	2.93%	2.92%	2.92%
DCF Return on Equity	***8.20%***	***9.23%***	***8.68%***	***8.70%***
Method 2:				
Dividend Yield	2.84%	2.84%	2.84%	2.84%
Median Growth Rate	6.50%	6.50%	6.00%	6.33%
Expected Div. Yield	2.93%	2.93%	2.92%	2.93%
DCF Return on Equity	***9.43%***	***9.43%***	***8.92%***	***9.26%***