STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE JACOB S. GERTSMAN

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF (2017)	)))))))))))	**BPU DOCKET No. ER17030308** **OAL DOCKET No. PUC 04989-17**

DIRECT TESTIMONY OF MATTHEW I. KAHAL
ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. I am employed as an independent consultant retained in this matter by the Division of Rate Counsel ("Rate Counsel"). My business address is 1108 Pheasant Xing, Charlottesville, Virginia 22901.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration included industrial organization, economic development and econometrics.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have been employed in the area of energy, utility and telecommunications consulting for the past 35 years working on a wide range of topics. Most of my work has focused on electric utility integrated planning, plant licensing, environmental issues, mergers and financial issues. I was a co-founder of Exeter Associates, and from 1981 to 2001, I was employed at Exeter Associates as a Senior Economist and Principal. During that time, I took the lead role at Exeter in performing cost of capital and financial studies. In recent years, the focus of much of my professional work has shifted to electric utility markets, power procurement and industry restructuring.

Prior to entering consulting, I served on the Economics Department faculties at the University of Maryland (College Park) and Montgomery College teaching courses on economic principles, development economics and business.

A complete description of my professional background is provided in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified before approximately two-dozen state and federal utility commissions, federal courts and the U.S. Congress in more than 380 separate regulatory cases. My testimony has addressed a variety of subjects including fair rate of return, resource planning, financial assessments, load forecasting, competitive restructuring, rate design, purchased power contracts, merger economics and other regulatory policy issues. These cases have involved electric, gas, water and telephone utilities. A list of these cases is set forth in Appendix A, with my statement of qualifications.

Q. WHAT PROFESSIONAL ACTIVITIES HAVE YOU ENGAGED IN SINCE LEAVING EXETER AS A PRINCIPAL IN 2001?

A. Since 2001, I have worked on a variety of consulting assignments pertaining to electric restructuring, purchase power contracts, environmental controls, cost of capital and other regulatory issues. Current and recent clients include the U.S. Department of Justice, U.S. Air Force, U.S. Department of Energy, the Federal Energy Regulatory Commission, Connecticut Attorney General, Pennsylvania Office of Consumer Advocate, the New Hampshire Consumer Advocate, New Jersey Division of Rate Counsel, Rhode Island Division of Public Utilities, Louisiana Public Service Commission, the Ohio Consumers Counsel, Arkansas Public Service Commission, the Maryland Public Service Commission, the Maine Public Advocate, Maryland Department of Natural Resources, and the Maryland Energy Administration.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES?

A. Yes. I have testified on cost of capital and other matters before the Board of Public Utilities (Board or BPU) in gas, water and electric cases during the past 25 years. A listing of those cases is provided in my attached Statement of Qualifications. This includes the submission of testimony on rate of return issues in the recent electric and gas service rate cases of New Jersey Natural Gas Company (BPU Docket No. GR07110889), Elizabethtown Gas (BPU Docket No. GR09030195) and Public Service Electric and Gas Company (BPU Docket Nos. GR05100845 and GR09050422), and United Water New Jersey, Inc. (BPU Docket No. WR09120987). I participated in the previous Atlantic City Electric Company ("ACE" or "the Company") rate cases on a rate of return issues, including submitting testimony in BPU Docket Nos. ER09080664 and ER11080469. In all of these cases, my testimony and other work was on behalf of Rate Counsel.

II. OVERVIEW

A. Summary of Recommendation

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by Rate Counsel in this case to develop a recommendation concerning the fair rate of return on the jurisdictional electric distribution utility rate base of ACE. This includes both a review of the Company's proposal concerning rate of return and the preparation of an independent study of the cost of common equity. I am providing my recommendation to Rate Counsel's revenue requirement consultant, Ms. Andrea Crane, for use in calculating the Company's annual revenue requirement in this case. In addition, my testimony briefly addresses the Company's proposal in this case for approval of a System Renewal Recovery Charge ("SRRC"), a proposal discussed in more detail in the testimony of Rate Counsel accounting witness Crane and engineering panel Chang and Salmone.

Q. WHAT IS THE COMPANY'S RATE OF RETURN PROPOSAL IN THIS CASE?

A. As presented in the Company's Petition, the Company requests an authorized overall rate of return of 7.83 percent. The proposed capital structure is indicated as being the Company's adjusted actual capital structure at December 31, 2016, which includes 50.14 percent common equity and 49.86 percent long-term debt. This capital structure is generally similar to or slightly more equity rich than the industry proxy group that I have used, as discussed later in my testimony. This proposed capital structure excludes any recognition of short-term debt. The Company requests a return on the common equity component of 10.1 percent. The overall rate of return, capital structure and cost of debt recommendations are sponsored by Company witness Mr. Kevin M. McGowan, and the cost of equity recommendation is sponsored by the Company's consultant, Mr. Robert B. Hevert. Mr. Hevert's 10.1 percent return on equity ("ROE") recommendation is based on the results of his various studies. Specifically, he identifies a cost of equity range for ACE of 10.0 to 10.75 percent, with his ultimate ROE recommendation being toward the lower end of his range.

Q. WHAT IS ACE'S CORPORATE STRUCTURE?

A. ACE is a wholly owned subsidiary of PEPCO Holdings, Inc. ("PHI"), which is a corporate holding company that owns two other electric utility operating companies. PHI also has a very limited amount of non-utility operations (Pepco Energy Services), and it has sold off most of its unregulated generation assets. ACE is the smallest of the three PHI utility subsidiaries, with the sister utilities being Potomac Electric Power Company ("PEPCO") and Delmarva Power & Light Company ("DP&L"), which operate in Maryland, Delaware, and the District of Columbia. PHI, in turn, was recently acquired by Exelon Corp., one of the nation's largest electric utility corporations and the nation's largest nuclear generation company.

Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME ON RATE OF RETURN?

A. As summarized on Schedule MIK-1, page 1 of 1, I am recommending at this time a return on ACE's jurisdictional electric distribution rate base of 7.28 percent. This includes a return on common equity of 9.00 percent and a capital structure and cost of debt identical to Mr. McGowan's recommendation. This capital structure is very similar to those approved for ACE by the Board in previous rate cases. It adopts the Company's proposal to remove securitization debt and the associated equity. In addition, I concur with the Company's decision to exclude short-term debt from capital structure and instead directly assign it to the financing of Construction Work in Progress ("CWIP"). This recommendation is conditioned on a commitment by ACE to continue this accounting practice (sometimes referred to as "the FERC method"). The Company reports that it has used no short-term debt during the test year, but in my opinion it is likely to do so in the future.

Q. WHAT IS YOUR COST OF DEBT RECOMMENDATION?

A. I am using at this time a long-term cost of debt of 5.56 percent, which is identical to that sponsored by witness McGowan on behalf of the Company in its filed case. This cost of debt figure is the actual cost rate at year-end 2016, inclusive of appropriate recognition of debt-related expenses, including reacquisition costs. This is a reduction from the cost of debt used in past cases. As discussed later in my testimony, I anticipate that ACE's embedded cost rate for long-term debt will fall sharply in late 2018 when a very expensive (7.9 percent) $250 million debt issue matures and presumably will be refinanced by lower cost debt. Due to the timing of this maturity, after the conclusion of the test year and this case, I have excluded this savings from my rate of return recommendation.

Q. HOW DOES MR. HEVERT DEVELOP HIS 10.00 TO 10.75 PERCENT ROE RESULTS?

A. Mr. Hevert utilizes three cost of equity methods: (1) Discounted Cash Flow (DCF); (2) the Risk Premium; and (3) Capital Asset Pricing Model (CAPM), with each methodology applied to a proxy group of 22 publicly traded electric companies. Mr. Hevert's testimony is rather complex, and he develops ranges and multiple estimates using each cost of equity methodology. Focusing on his mean or midpoint results, he obtains estimates of about 8.9 percent using the standard DCF model, 9.1 to 10.2 percent using the multi-stage DCF, 10.48 percent for the CAPM approach (i.e., the average of his twelve CAPM calculations), and 10.00 to 10.30 percent for the Risk Premium study. He also calculates a flotation expense adder of 0.12 percent, but he does not include this adjustment in his cost of equity results. Based on these results he identifies a range of 10.0 to 10.75 percent, and he recommends an ROE of 10.1 percent which is near the low end of this range.

Q. HOW HAVE YOU DEVELOPED YOUR 9.00 PERCENT ROE RECOMMENDATION?

A. I rely primarily on the use of the standard DCF model as applied to a proxy group of 22 electric utility companies. This produces a range of about 8.3 to 8.8 percent, with a midpoint of 8.6 percent. This is the same electric proxy group as used by Mr. Hevert. I have used the same proxy group to facilitate a direct comparison of our respective cost of equity studies and to eliminate controversy over proxy group selection. Unfortunately, Mr. Hevert's proxy group, while not unreasonable, is an imperfect risk proxy for ACE because it measures (to some degree) the risks incurred by many companies of the proxy group associated with generation assets and supply, whereas this case sets rates only for ACE's distribution service. ACE ratepayers already pay for the risks associated with generation supply in the Basic Generation Service ("BGS") charges or in competitive service rates and should not have to pay twice for that generation supply risk.

I also have conducted a cost of equity study using the CAPM method, which produces even lower results – a cost of equity range of about 7 to 9 percent. However, I place much less weight on the CAPM results.

In my opinion, these cost of equity study results, taking into account the recent conditions of extremely low capital costs in financial markets, support the reasonableness of my 9.00 percent return on equity recommendation for ACE at this time, a reduction of 0.75 percent from the 9.75 percent granted by settlement in ACE's last rate case.

Q. YOUR ROE RECOMMENDATION DIFFERS GREATLY FROM THAT OF MR. HEVERT. HOW DO YOU ACCOUNT FOR THE LARGE DIFFERENCE?

A. At the outset, please note that our respective "standard" DCF studies are somewhat similar, both producing estimates of about 9 percent. Moreover, the cost of capital has declined slightly since the time period of Mr. Hevert's studies which explains a small portion of the difference.

The major difference, however, is attributable to Mr. Hevert's other studies—multi-stage DCF, CAPM, and Risk Premium. In those studies he uses inappropriate and unrealistic data assumptions that unrealistically "drive" the results far above a realistic estimate of the market cost of equity for ACE. In particular, he assumes and incorporates a substantial increase in long-term interest rates, from actual levels, whereas those interest rates have remained stable or even fallen slightly from the time he prepared his testimony. My testimony identifies and corrects his unreasonable data assumptions.

Q. MR. HEVERT CALCULATES A FLOTATION ADJUSTMENT OF 0.12 PERCENT. DO YOU INCLUDE A FLOTATION ADJUSTMENT?

A. No, I do not. Since PHI no longer is publicly traded, ultimate parent Exelon would be the source of any flotation expenses relevant to ACE. However, Exelon's only recent flotation expenses are those associated with its acquisition of PHI completed last year. Those expenses are not eligible for cost recovery from ACE customers. Consequently, consistent with Witness Hevert, I do not include an adjustment for flotation expense in the recommended cost of equity and allowed ROE.

Q. DO YOU CONSIDER ACE TO BE A LOW-RISK UTILITY COMPANY?

A. Yes, very much so. ACE provides monopoly electric utility delivery service in its New Jersey service territory, subject to the regulatory oversight of the Board. There is no indication of any material increase in business or financial risk relative to other electric utilities in recent years. In Section III of my testimony I briefly discuss the business risk attributes for the Company, including the views of credit rating agencies.

Q. YOU RECOMMEND AN ROE OF 9.0 PERCENT, AND MR. HEVERT RECOMMENDS 10.1 PERCENT. HOW DOES THIS RANGE COMPARE TO ROES GRANTED TO ACE'S PHI UTILITY AFFILIATES?

A. The Company's response to RCR-ROR-10 provides the PEPCO and Delmarva Power most recent electric rate case ROE rulings, which I list below:

Delaware	9.70%	DP&L
Maryland	9.55%	PEPCO
Washington, D.C.	9.40%	PEPCO
Maryland	9.61%	DP&L
Average	**9.56%**	

In addition, the authorized ROEs for Exelon subsidiaries Baltimore Gas and Electric Company ("BG&E") and Illinois-based Commonwealth Edison Company ("ComEd") are 9.75 percent and 8.59 percent, respectively. These authorized ROEs for other PHI and Exelon utilities are well below Mr. Hevert's cost of equity findings, and are closer to my recommendation in this case. Moreover, while the average of 9.56 percent (for the PHI companies) is somewhat higher than my recommendation, the cost of capital may have declined slightly since these rate cases took place.

Q. HOW DOES ACE'S ROE REQUEST COMPARE WITH ELECTRIC UTILITY AWARDS GENERALLY?

A. The requested 10.1 percent ROE is significantly higher than state commission award trends. Note that the 10.1 percent request in this case is higher than the 9.75 percent authorized for ACE in the last base rate case.

The ROE awards trends are provided quarterly by Regulatory Research Associates ("RRA") surveys a source relied upon by ACE witness Hevert for his Risk Premium study. The RRA survey data (discussed in more detail later in my testimony) show a generally declining trend in electric utility ROEs in recent years (particularly for delivery service electrics) to well below 10.0 percent—to the mid-9s. As I demonstrate later in my testimony, electric utility company stocks have thrived under this declining capital cost and declining ROE award environment as equity investors find such stocks to be very attractive.

I believe that the Board should recognize these market and state regulatory trends and reduce ACE's 9.75 percent current ROE. Clearly, it would be unreasonable to raise the authorized ROE.

Q. WHAT IS YOUR POSITION CONCERNING THE PROPOSED SRRC?

A. The SRRC is intended to provide ACE with a "tracker" mechanism to recover from customers the majority of its capital expenditures (and as a practical matter virtually its entire increase in distribution rate base) over the next four years outside of traditional base rate cases. Moreover, there is no commitment by ACE to refrain from filing new base rate cases over this time period along with the tracker filings. The SRRC is structured in a manner that would greatly reduce ACE's business risk as compared to standard regulation. However, ACE witnesses in their testimony in this case seem to ignore this fact in setting forth the 10.1 percent ROE request. In particular, there is no mention of the SRRC and its risk reducing attributes in Witness Hevert's testimony. Importantly, ACE witnesses have not shown that this tracker mechanism is needed to protect the Company's credit ratings or assure ACE has access to capital on reasonable terms, one of the stated rationales for this proposal.

I recommend rejection of the proposed tracker as the tracker is not needed by ACE to attract capital. In addition the proposed tracker shifts risk from the Company (where it properly belongs) to ACE customers. However, if such a proposal is adopted, I recommend that the Board recognize this reduction in business risk and appropriately decrement ACE's ROE award, both in this rate case and in the SRRC tracker mechanism itself.

B. Capital Cost Trends in Recent Years

Q. HAVE YOU EXAMINED GENERAL TRENDS IN CAPITAL COSTS IN RECENT YEARS?

A. Yes. I show the capital cost trends since 2001, through calendar year 2016, on page 1 of Schedule MIK-2. Pages 2, 3, 4, 5, 6 and 7 of that Schedule show monthly data for January 2007 through June 2017. The indicators provided include the annualized inflation rate (as measured by the Consumer Price Index), 10-year Treasury yields, 3-month Treasury bill yields and Moody's single A and triple B yields on long-term utility bonds. While there is some fluctuation, these data series show a general declining trend in capital costs. For example, in the very early part of this time period, utility bond yields averaged about 7 to 8 percent, with 10-year Treasury yields of 4 to 5 percent. By 2016, single A utility bond yields had fallen to an average of 3.9 percent, with 10-year Treasury yields declining to an average of 1.8 percent. Within the past year (i.e., calendar 2016 into mid 2017), Treasury and utility long-term bond rates have remained very close to these historically low levels.

For the past six years, short-term Treasury rates have been close to zero, with three-month Treasury bills averaging about 0.1 percent. These extraordinarily low rates (which are also reflected in non-Treasury debt instruments) were the result of an intentional policy of the Federal Reserve Board of Governors (the "Fed") to make credit and liquidity available to the U.S. economy at low cost in order to promote economic activity.[1] The Fed has also sought to exert downward pressure on long-term interest rates through its policy of "quantitative easing." Quantitative easing is a policy whereby the Fed engages on an ongoing basis in the purchase of financial assets (such as Treasury bonds or agency mortgage backed debt), both to support the market prices of financial assets and to increase the U.S. money supply. The intent of quantitative easing is to keep the cost of capital low (which increases the value of financial assets such as utility stocks) and makes credit both cheaper and more abundant. Although that program ended in the summer of 2012, the Fed announced in September 2012 a continuation of its near zero short-term interest rate policy at least through 2015, and an indefinite continuation of quantitative easing. In its December 12, 2012 meeting, the Fed stated that its low interest rate and accommodative policies would continue at least until a much lower U.S. unemployment rate is achieved, an endeavor expected by the Fed to take several years. As a result, interest rates have remained low and trended down and, for at least an extended period of time, this very low short- and long-term interest rate and cost of capital environment is expected to continue. In October 2014, the Fed announced the phase out of its aggressive quantitative easing program due to progress with the U.S. economic recovery.

[1] By law, the Fed has a "dual mandate" to pursue policies both to ensure price stability (i.e., low inflation) and to promote maximum employment.

Q. HAS THE FED ISSUED ANY MORE RECENT INFORMATION ON ITS POLICY INTENT?

A. Due to positive progress in lowering unemployment and expectations of higher inflation (from extraordinary low levels) the Federal Open Market Committee ("FOMC," the monetary policy decision-making forum for the Fed) in 2015 indicated an intention to gradually pursue monetary policy "normalization". This meant a policy of gradually increasing short-term interest rates from the near zero level, depending on further strengthening of U.S. labor markets. The FOMC began to implement this policy after its December 2015 meeting resulting in short-term rates increasing from close to zero to about 0.3 percent—an extremely modest increase. The FOMC at the time implied that further increases in 2016 were likely to occur.

Due to weaker than expected conditions in the U.S. economy and globally during most of 2016, the FOMC was unwilling to follow through and further increase interest rates. With economic improvement in late 2016, the FOMC at its December 2016 meeting increased the federal funds rate by 0.25 percent to a range of 0.50 to 0.75 percent. In 2017, the FOMC has voted to increase the federal funds rate further to its current range of 1.00 to 1.25 percent, most recently at its June 14, 2017 meeting. In its policy statement following that meeting, the FOMC noted that "monetary policy remains accommodative" and inflation remains below the Fed's 2 percent target level.[2] The Fed has emphasized that its policy changes will be quite gradual.

Q. ARE THERE FORCES CONTRIBUTING TO LOW INTEREST RATES OTHER THAN FED POLICY?

A. Yes. While the very low short-term rates are largely attributable to Fed policy decisions, the behavior of long-term rates also reflects more fundamental economic

[2] See www.federalreserve.gov/newsevents/press/monetary/20170614a.htm.

forces. Factors that drive down long-term bond interest rates include the ongoing modest growth of the U.S. and global macro economy, the inflation outlook and even international events. A relatively weakly growing economy (as we have at this time) exerts downward pressure on interest rates and capital costs generally because the demand for capital is low and inflationary pressures are contained. While inflation measures can fluctuate from month to month, long-term inflation rate expectations presently remain quite low, as the FOMC has noted. Europe's Euro-zone continuing sovereign debt and banking issues (along with "Brexit") likely contributes somewhat to lower U.S. interest rates, as U.S. securities are valued as a relative "safe haven" for global capital. Other major industrial nations are experiencing near zero or very low interest rates on their sovereign debt. This "safe haven" benefit for U.S. assets clearly has benefitted utility stocks making them more attractive for investors.

Q. DO LOW LONG-TERM INTEREST RATES IMPLY A LOW COST OF EQUITY FOR UTILITIES?

A. In a very general sense and over time, that is normally the case, although the utility cost of equity and cost of debt need not move together precisely in lock step or necessarily in the short run. The economic forces mentioned above (and Fed policy) that lead to lower interest rates also tend to exert downward pressure on the utility cost of equity. After all, many investors tend to view utility stocks and bonds as alternative investment vehicles for portfolio allocation purposes, and in that sense utility stocks and long-term bonds are closely related by market forces.

Q. ARE RELATIVE ECONOMIC WEAKNESS AND LOW INFLATION EXPECTED TO CONTINUE?

A. Yes, that appears to be the case. I have consulted the latest "consensus" forecasts published by *Blue Chip Economic Indicators* ("Blue Chip"), June 10, 2017 edition, which is a survey compilation of approximately 40 major forecast organizations. The "consensus" calls for real GDP growth of 2.2 percent in 2017 and 2.4 percent in 2018 and inflation (GDP deflator) of 1.9 percent and 2.1 percent in 2017 and 2018, respectively. The March 2017 edition of Blue Chip publishes a consensus 10-year inflation forecast of 2.1 percent per year, approximately the same as the near term. Thus, both the near- and long-term economic outlooks are for modest economic growth and low inflation, implying low market capital costs. There has been a considerable slowing of economic growth globally and a glut of savings and liquidity seeking a return. In that regard, the U.S. provides a very favorable capital cost environment for good quality utilities, such as ACE.

Q. HAVE YOU BEEN ABLE TO INCORPORATE THESE RECENT CHANGES IN FINANCIAL MARKETS INTO YOUR COST OF CAPITAL ANALYSIS IN THIS CASE?

A. Yes, to a large extent I have done so. As a general matter, electric utility stocks have performed quite well during the first half of 2017 in response to declining capital costs. Specifically, I present DCF evidence that relies on utility stock market data from this recent time period (i.e., January-June 2017). Such market data directly incorporate the economic forces and monetary policy choices described above. The use of a recent six months of market data is reasonable for assessing ACE's current cost of capital as it reflects recent market and economic trends.

C. <u>Overview of Testimony</u>

Q. HOW HAVE YOU ORGANIZED THE REMAINDER OF YOUR TESTIMONY?

A. Section III of my testimony briefly discusses the capital structure and cost of debt recommended in this case by the Company. This section also discusses ACE's business risk profile. In Section III, I also briefly comment on the cost of capital aspects of the SRRC proposal. Section IV presents my cost of equity studies which are based on the DCF method, with the application of the CAPM providing a comparison and corroboration. Section V is my review of Mr. Hevert's cost of equity studies, risk adjustments and his 10.1 percent ROE recommendation. Finally, Section VI provides a summary of major findings and conclusions. In particular, that section explains why it is appropriate to lower at this time the currently authorized 9.75 percent in light of market, regulatory, and industry trends.

III. CAPITAL STRUCTURE AND ACE'S INVESTMENT RISK

A. Capital Structure

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY USING IN THIS CASE?

A. The requested capital structure of 50.14 percent common equity and 49.86 percent long-term debt is the Company's adjusted actual December 31, 2016 capital structure, as sponsored by Mr. McGowen (Schedule (KMM-1)). In developing this capital structure, the Company makes certain adjustments to the actual year-end debt and equity balances and excludes short-term debt.

Q. IS THE PROPOSED CAPITAL STRUCTURE CONSISTENT WITH THE ELECTRIC UTILITY PROXY GROUP COMPANIES?

A. Generally, yes, as I show on Schedule MIK-3 for the two proxy groups. ACE's proposed 50 percent equity ratio compares with an average 48 percent for the electric proxy group, with about half of the companies having equity rates above 50 percent. Please note that these are the projected equity ratios for year-end 2017, as reported by Value Line. Based on these data, I conclude that ACE's balance sheet strength is similar to that or slightly stronger than the electric proxy group.

Q. WHAT ADJUSTMENTS DOES ACE PROPOSE?

A. As shown on Schedule (KMM-1), page 2 of 4, ACE has excluded transition bonds, along with the common equity ($2.96 million) of its transition bond special purpose entity (ACE Transition Funding LLC). For ratemaking capital structure purposes, the Company removes about $12 million for unamortized debt-related expenses, principally the unamortized balance of debt reacquisition costs, from its actual balance of long-term debt outstanding. This adjustment reduces long-term debt for ratemaking purposes from $1,037 million to $1,025 million, about a 1 percent reduction. Finally, ACE includes no short-term debt in capital structure.

Q. DO YOU AGREE WITH THESE ADJUSTMENTS?

A. Not entirely. I agree with the removal from capital structure of transition debt and equity, as this has been standard practice. This capital is not directly related to ACE's distribution utility service. However, I do not necessarily support the $12 million debt balance reduction for the unamortized debt expense. However, this adjustment has been employed and accepted in past settlements of ACE cases, and in any event is a minor adjustment. Finally, I can accept the Company's exclusion of short-term debt from capital structure as long as the Company continues to directly assign it to CWIP, which is a non-rate base item. While, ACE normally makes extensive use of short-term debt, in this case the Company reports that there is no short-term debt during the test year.

As this is ACE's actual capital structure (subject to removing securitization capital) and roughly consistent with what has been approved in past ACE cases, I find this capital structure to be acceptable for rate of return purposes.

Q. WHY IS IT ACCEPTABLE IN THIS CASE TO EXCLUDE SHORT-TERM DEBT FROM CAPITAL STRUCTURE?

A. It is acceptable in this particular case to do so because the Company directly assigns its actual short-term debt to CWIP for purposes of calculating the Allowance for Funds Used During Construction ("AFUDC") rate. ACE normally does make use of short-term debt, and this practice ensures that ratepayers will receive the cost of capital savings that short-term debt provides. Given that excluding short-term debt has been accepted in past cases, the Company should commit to continue its normal practice of assigning short-term debt to CWIP for AFUDC accrual purposes.

Q. WHAT IS ACE'S CLAIMED COST RATE FOR LONG-TERM DEBT?

A. ACE claimed its embedded cost of long-term debt to be 5.56 percent, which is the calculated embedded cost at December 31, 2016 (Schedule (KMM-1), page 3 of 4). As noted above, this cost rate provides for full cost recovery of all debt expenses, discounts/premiums and reacquisition costs. The 5.56 percent is lower than the cost rate used in previous ACE rate cases, but it is well above ACE's cost rate for new debt, which is at least a full percentage point lower. The relatively high cost rate of 5.56 percent is partially attributable to the fact that in late 2008 ACE issued $250 million of long-term debt at a 7.9 percent cost rate. This debt was issued at the height of the financial crisis of 2008. This very large and expensive debt issue is scheduled to mature in late 2018, which should provide a large cost of capital savings at that time. I estimate this interest expense savings to be on the order of about $10 million per year total Company.

B. Discussion of Credit Ratings and Risk

Q. HAVE COMPANY WITNESSES IN THIS CASE THOROUGHLY EXPLORED BUSINESS RISKS FACED BY ACE?

A. In my opinion, they have not. Mr. Hevert has very little discussion of ACE's risks, and Mr. McGowan provides overview testimony concerning ACE's operations and financial needs, as well as the service area economy. Mr. Hevert's discussion is even more limited as he cites to capital structure and credit ratings as his only mention of risks.

A vital consideration of ACE's business risk is how it compares to that of other electric utilities, particularly those in Mr. Hevert's proxy group. Neither witness sheds any light on that question. While I agree with Mr. McGowan that ACE needs to access capital markets, has substantial capital requirements and can experience regulatory lag, Company witnesses provide no comparison of these and other factors to the risks faced by Mr. Hevert's proxy companies. For example, is New Jersey regulatory lag more problematic than other states? These witnesses do not at any time suggest that New Jersey regulation poses greater risks, on average, than regulation in other jurisdictions.

Moreover, Mr. Hevert does not acknowledge in his testimony that distribution (or delivery service) electric utilities are exposed to less risk than the vertically-integrated electric utilities that must cope with generation-related risks. In response to RCR-ROR-24, Mr. Hevert appears to recognize that vertically-integrated electric utilities (the majority of his proxy group) face greater business risks (in an "all else equal" context) than delivery service electric utilities. The lower risk of delivery service certainly is understood by investors and credit rating agencies.

As I discuss further in Section V of my testimony, recent experience indicates that state Commissions recently have been granting lower equity returns for delivery service electric utilities than for vertically-integrated electrics.

Q. DO YOU REGARD ACE AS BEING A LOW-RISK UTILITY COMPANY?

A. Yes, very much so. ACE does, of course, face business risks and has an ongoing need to access capital markets. However, it operates in its service territory as a monopoly provider of a vital service – electric distribution. It is spared the risks associated with investing in and operating generation assets and the burdens of directly providing generation service. ACE receives dollar-for-dollar recovery of its Basic Generation Service costs. While regulatory lag does exist, in general New Jersey's regulatory climate is reasonable and fair to the utilities in the state.

Q. WHAT IS THE ASSESSMENT OF CREDIT RATING AGENCIES?

A. The Company has provided credit rating reports for ACE and its parent in response to RCR-ROR-5. Moody's assigns ACE an issuer rating of Baa2 and rates its secured bonds as A3 (i.e., low single A). Standard & Poor's ("S&P") assigns ratings to ACE based on its assessment of the consolidated parent, PHI, which it rates BBB+, and it assigns ACE's secured debt an A rating. FitchRatings assigns ACE a corporate rating of triple B and its secured bonds a rating of A-. All three agencies rate ACE (and its parent) as having a "stable" outlook. The single A rating on secured debt is particularly important since the vast majority of ACE's long-term debt is secured. It should be noted that these ratings are the same as the ratings at the time of ACE's last several rate cases.

The credit rating reports provide an assessment of Company business risks and financial metrics. Both credit rating agencies find that ACE's regulated distribution service to be very low risk and New Jersey regulation to be reasonable and supportive.

Q. HAVE CREDIT RATING AGENCIES RECOGNIZED THE BUSINESS RISK DIFFERENCES BETWEEN DISTRIBUTION AND GENERATION UTILITY SERVICE?

A. Yes, they have. They generally view distribution operations as inherently less risky than generation. Moreover, unregulated operations (particularly generation) are regarded as generally being riskier than either distribution or regulated generation. S&P has placed electric distribution utility service in the same general business risk profile category as water and gas distribution. S&P explicitly acknowledges ACE's absence of generating assets and operations as a positive factor for its risk profile and credit quality.

C. <u>The SRRC Proposal</u>

Q. WHAT IS THE COMPANY'S SRRC PROPOSAL**?**

A. As described in Witness McGowan's testimony, the Company is proposing a "tracker" cost recovery mechanism that would begin in 2018 and extend for four years. This proposed mechanism would provide contemporaneous cost recovery for most of the Company's planned distribution investment over this time period and would be in addition to this rate case request and other rate case requests that the Company chooses to file. The SRRC rate increases would be implemented annually, based on projected capital spending, and would include a "true up" feature to correct for forecast error. The rate increases would reflect the Board's rate case authorized rate of return and depreciation expense.

Witness McGowan testifies that this tracker mechanism is needed to protect the Company from earnings erosion associated with regulatory lag and thereby enhance ACE's access to capital to fund capital spending. He further asserts that the SRRC is designed to include certain customer safe guards such as a cap on annual SRRC rate increases and the possibility of refunds in the event that ACE actual realized earnings exceed its authorized ROE plus 50 basis points over the life of the SRRC.

Q. WHAT IS YOUR ASSESSMENT OF THIS PROPOSAL FROM A COST OF CAPITAL AND RATE OF RETURN PERSPECTIVE?

A. At the outset, I note that a more comprehensive assessment of this proposal is provided in the testimony of Rate Counsel accounting witness Crane, and engineering panel Chang and Salomone. While I limit my comments to cost of capital/rate of return issues, I share their concerns.

The Company's proposal unquestionably is a major change to the current base rate recovery method of regulation, and it will materially change (lower) the Company's business risk profile. The SRRC tracker, with its contemporaneous rate recovery of forecasted capital investment plus true-up feature, is very low risk – far lower in risk than conventional rate cases, which is precisely why it is being proposed. Moreover, this tracker proposal would not simply cover a certain set of discrete investments serving a special purpose, but rather it will cover the vast majority of ACE's total distribution investment spending. It is important to note that ACE witnesses, including Witness Hevert, provide no discussion of the ACE capital cost implications of this proposal, nor do they recognize that any adjustment to the ACE ROE request in this case (a request for an increased ROE) is needed or appropriate for either the rate case or the tracker mechanism itself. In my opinion, ignoring the cost of capital reduction is one sided and a fatal flaw in the proposal.

Q. IN THE EVENT THE SRRC PROCEEDS, SHOULD THERE BE AN ADJUSTMENT TO THE ACE AUTHORIZED RATE OF RETURN?

A. Yes. In the event the SRRC is approved, the authorized ROE should be lowered both for this rate case and the annual SRRC filings to recognize this lowered risk. ACE's business risk is not, of course, totally eliminated because ACE would still be subject to prudence reviews and has "execution risk". Nonetheless, the tracker cost recovery features and the sheer size of the program (covering most of the capital investment in distribution) greatly mitigate normal and traditional business risk as compared with current and standard regulation.

While there is no way to accurately and reliably quantify this cost of capital reduction risk, I believe that the ROE should be decremented by the Board by a substantial amount. In addition, since the SRRC initial rate change is not expected to be implemented until sometime in 2018, I further recommend that the 7.9 percent $250 million debt issue that will mature in late 2018 be excluded from the SRRC tracker cost of debt.

Q. CAN ACE ACCESS CAPITAL ON REASONABLE TERMS ABSENT APPROVAL OF THE SRRC?

A. Yes, it can. ACE's credit ratings for the past several years have been stable and solidly investment grade, medium to high triple B on an issuer basis and single A for secured debt, which is the vast majority of its outstanding debt. According to Schedule (KMM-1), page 3 of 4, in December 2015 ACE issued $150 million in long-term debt at a cost rate (inclusive of issuance expense) of 3.6 percent. This demonstrates that under the current regulatory paradigm, based on base rate case recovery of distribution investments, ACE has access to capital on reasonable terms, as needed.

IV. COST OF COMMON EQUITY

A. Using the DCF Model

Q. WHAT STANDARD ARE YOU USING TO DEVELOP YOUR RETURN ON EQUITY RECOMMENDATION?

A. As a general matter, the ratemaking process is designed to provide the utility an opportunity to recover its prudently-incurred costs of providing utility service to its customers, including the reasonable costs of financing its used and useful investment. Consistent with this "cost-based" approach, the fair and appropriate return on equity award for a utility is its cost of equity. The utility's cost of equity is the return required by investors (i.e., the "market return") to acquire or hold that company's common stock. A return award greater than the market return would be excessive and would overcharge customers for utility service. Similarly, an insufficient return could unduly weaken the utility and impair incentives to invest.

Although the *concept* of the cost of equity may be precisely stated, its quantification poses challenges to regulators. The market cost of equity, unlike most other utility costs, cannot be directly observed (i.e., investors do not directly, unambiguously state their return requirements), and it therefore must be estimated using analytic techniques. The DCF model is one such prominent technique familiar to analysts, this Board and other utility regulators.

Q. IS THE COST OF EQUITY A FAIR RETURN AWARD FOR THE UTILITY AND ITS CUSTOMERS?

A. Generally speaking, I believe it is. A return award commensurate with the cost of equity generally provides fair and reasonable compensation to utility equity investors and normally should allow efficient utility management to successfully finance utility operations on reasonable terms. Setting the authorized return on equity equal to a reasonable estimate of the cost of equity also is generally fair to ratepayers.

I recognize that there can be exceptions to this general rule. For example, in some instances, utilities have obtained rate of return adders as a reward for asserted good management performance or lowered returns where performance is subpar. In this case, the Company is making no explicit request to raise ACE's authorized equity return above Mr. Hevert's cost of equity range of results.

Q. WHAT DETERMINES A COMPANY'S COST OF EQUITY?

A. It should be understood that the cost of equity is essentially a market price, and as such, it is ultimately determined by the forces of supply and demand operating in financial markets. In that regard, there are two key factors that determine this price. First, a company's cost of equity is determined by the fundamental conditions in capital markets (e.g., outlook for inflation, monetary policy, changes in investor behavior, investor asset preferences, the general business environment, etc.). The second factor (or set of factors) is the business and financial risks of the company (the utility in this case) in question. For example, the fact that a utility company operates as a regulated monopoly, dedicated to providing an essential service (in this case electric utility distribution service), typically would imply very low business risk and therefore a relatively low cost of equity. ACE's balance sheet strength and the favorable (i.e., "excellent") business risk profile, as assessed by credit rating agencies (i.e., Moody's, FitchRatings and S&P), also contribute to its relatively low cost of equity.

Q. DOES MR. HEVERT INCORPORATE THESE PRINCIPLES IN HIS TESTIMONY?

A. By and large, Mr. Hevert does attempt to incorporate these principles. His studies purport to estimate the market-based cost of capital. However, I disagree with certain of his data inputs, as well as his risk premium study. While his proxy group, taken as a whole, seems reasonable, it does likely overstate the cost of equity of ACE due to ACE's status as a pure delivery service utility.

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

A. I employ both the DCF and CAPM models, applied to a proxy group of electric utility companies. This proxy group is the same as that used by Witness Hevert. However, for reasons discussed in my testimony, I emphasize the DCF model results (as applied to my electric utility proxy group) in formulating my recommendation. It has been my experience that most utility regulatory commissions (federal and state), including New Jersey, heavily emphasize the use of the DCF model to determine the cost of equity and setting the fair return. As a check (and partly to respond to Mr. Hevert), I also perform a CAPM study which also is based on the electric utility proxy group companies used in my testimony.

Q. PLEASE DESCRIBE THE DCF MODEL.

A. As mentioned, this model has been widely relied upon by the regulatory community, including this Board. Its widespread acceptance among regulators is due to the fact that the model is market-based and is derived from standard economic/financial theory. The model, as typically used, is also transparent and generally understandable. I do not believe that an obscure or highly arcane model would receive the same degree of regulatory acceptance.

The theory begins by recognizing that any publicly-traded common stock (utility or otherwise) will sell at a price reflecting the discounted stream of cash flows *expected by investors*. The objective is to estimate that investor discount rate.

Using certain simplifying assumptions that I believe are generally reasonable for stable utility companies, the DCF model for dividend paying stocks can be distilled down as follows:

K_e = (Do/Po) (1 + 0.5g) + g, where:

K_e = cost of equity;

Do = the current annualized dividend;

Po = stock price at the current time; and

g = the long-term annualized dividend growth rate.

This is referred to as the constant growth DCF model, because for mathematical simplicity it is assumed that the growth rate is constant for an indefinitely long time period. While this assumption may be unrealistic in many cases, for traditional utilities (which tend to be more stable than most unregulated companies) the assumption generally is reasonable, particularly when applied to a group of companies.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly-traded companies, i.e., companies whose market prices (and therefore market valuations) are transparently revealed. Consequently, the model cannot be applied to ACE, which is a wholly-owned subsidiary of PHI parent and ultimately Exelon, and therefore, a market proxy is needed. In theory, Exelon parent could serve as that market proxy. I have not done so consistent with Witness Hevert's exclusion. More importantly, I am reluctant to rely upon a single-company DCF study (nor does Mr. Hevert), although in theory that approach could be used. Moreover, Exelon would be a poor risk proxy for ACE due to its extensive unregulated nuclear operations.

In any case, I believe that an appropriately selected proxy group is likely to be far more reliable than a single company study. This is because there is "noise" or fluctuations in stock price or other data that cannot always be readily accounted for in a simple DCF study. The use of an appropriate and robust proxy group helps to allow such "data anomalies" to cancel out in the averaging process.

For the same reason, I prefer to use market data that are relatively current but averaged over a period of six months rather than purely relying upon "spot" market data. It is important to recall that this is not an academic exercise but involves the setting of "permanent" utility rates that are likely to be in effect for several years. The practice of averaging market data over a period of several months also can add stability to the results.

Q. IN EMPLOYING THE DCF MODEL, HOW DID YOU SELECT YOUR PROXY GROUP?

A. I began by reviewing the electric utility proxy group selected by Mr. Hevert, a group of 22 companies. His selection criteria requires that companies pay quarterly cash dividends; are covered by at least two equity analysis; have investment grade credit ratings by S&P; have regulated (i.e., utility) income that is at least 60 percent of total income; have electric income that is at least 60 percent of regulated income; and not be involved in a merger or similar transaction. While his criteria and resulting proxy group certainly are not perfect, I find his selections to be acceptable given the data limitations.

One of my concerns is that Mr. Hevert's criteria permit inclusion of companies that could have up to 40 percent of their income from unregulated operations. As non-regulated operations are far riskier than regulated utility operations, this could result in an overstatement of ACE's cost of equity. While the vast majority of his proxy companies are predominantly utility, some do have significant non-utility operations (e.g., American Electric Power, PNM Resources, etc.). I also note that all but three of his proxy companies can be described as vertically-integrated, which I believe Mr. Hevert concedes is probably riskier than distribution utility operations, as a broad generalization. (See his response to RCR-ROR-24.) Thus, while his proxy group is acceptable, it is not a perfect risk proxy in this case for ACE.

Q. DID YOU ACCEPT MR. HEVERT'S PROXY GROUP IN ITS ENTIRETY?

A. Yes. Despite the limitations of the proxy group discussed above, I have accepted his proxy group without modification. Doing so eliminates proxy group selection as a potential issue of dispute in this case.

Q. DID YOU CONSIDER EMPLOYING A PROXY GROUP OF DELIVERY SERVICE ELECTRIC UTILITIES?

A. Yes, that would be preferable to Mr. Hevert's primarily vertically-integrated proxy group, if it were feasible to do so. Unfortunately, it is not. While there are numerous delivery service electric utilities, the vast majority are subsidiaries of companies with vertically-integrated operations and/or significant merchant generation. While it was feasible to use a delivery service proxy group in the past, due to merger and acquisition activity there are simply too few such publicly-traded companies today to constitute a robust group. For example, Mr. Hevert's relatively comprehensive group includes only three companies that could be described as being mainly delivery service.

B. <u>DCF Study Using the Electric Utility Proxy Group</u>

Q. PLEASE IDENTIFY THE 22 COMPANIES INCLUDED IN YOUR ELECTRIC DISTRIBUTION UTILITY PROXY GROUP.

A. These 22 proxy companies are listed on Schedule MIK-3, page 1 of 1, along with several Value Line risk indicators. Please note that ACE's ultimate parent, Exelon, is not included in this group in all likelihood due to its extensive unregulated nuclear generation activity.

Q. HAVE EITHER YOU OR MR. HEVERT PROPOSED A SPECIFIC BUSINESS RISK ADJUSTMENT TO THE DCF COST OF EQUITY BETWEEN THE PROXY COMPANY AVERAGE COST OF EQUITY AND ACE?

A. No. Mr. Hevert does not include a specific risk adjustment in the development of his final ROE for ACE. In past rate cases, he has included a consideration of "size" as a negative factor for setting the recommended ROE. In addition, Witness Hevert compares the capital structure of ACE with that of his proxy group. But he proposes no specific adjustment factor between the proxy group and ACE.

I also have not incorporated a specific risk adjustment or "adder" or decrement to reflect risk differences between ACE and the proxy group results.

Q. HOW HAVE YOU APPLIED THE DCF MODEL TO THIS GROUP?

A. I have elected to use a six-month time period to measure the dividend yield component (Do/Po) of the DCF formula. Using the Standard & Poor's *Stock Guide*, I compiled the month-ending dividend yields for the six months ending June 2017, the most recent data available to me as of this writing. (Please note that due to publication lags I employed the month ending dividend yields reported by YahooFinance! for my reported June dividend yields.) As a general matter, this six months has been a time period of a moderately improving stock market, both for utilities as well as the broader markets. I believe this is due to both the relatively stable or declining long-term interest rates and investor "flight to quality" (i.e., risk avoidance) behavior.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, January through June 2017. Over this six-month period the proxy group average dividend yields indicate a steady but declining trend from a high of 3.35 percent in January 2017 to a low of 3.08 percent in May (and 3.09 percent in June), averaging 3.19 percent for the full six months. This is a modest decline of about 0.25 percent during 2017 year to date, demonstrating that there has been a small cost of equity reduction since the time period of Mr. Hevert's study (i.e., late 2016 and early 2017).

For DCF purposes and at this time, I am using a proxy group dividend yield of 3.19 percent.

Q. IS 3.19 PERCENT YOUR FINAL DIVIDEND YIELD?

A. Not quite. Strictly speaking, the dividend yield used in the model should be the value the investor expects to receive over the next 12 months. Using the standard "half-year" growth rate adjustment technique, the DCF adjusted yield becomes 3.3 percent. This is based on assuming that half of a year growth is 2.75 percent (i.e., assuming a full year growth is 5.5 percent, i.e., the upper end of the DCF growth rate range).

Q. DOES MR. HEVERT EMPLOY THE SAME GROWTH RATE ADJUSTMENT?

A. I understand that Mr. Hevert also employs this standard half-year growth adjustment to the measured dividend yield. Mr. Hevert also employs three different time periods for measuring the dividend yield (and share prices), 30, 90 and 180 days, as compared with my six-month period. His market data therefore reflect conditions prevailing in very late 2016 and early 2017 i.e., roughly six months ago when capital costs were slightly higher than currently.

Q. HOW HAVE YOU DEVELOPED YOUR GROWTH RATE COMPONENT?

A. Unlike the dividend yield, the investor growth rate cannot be directly observed but instead must be inferred through a review of available evidence. The growth rate in question is the *long-run* dividend per share growth rate, but analysts frequently use earnings growth as a proxy for (long-term) dividend growth. This is because in the long-run earnings are the ultimate source of dividend payments to shareholders, and this is likely to be particularly true for a large group of utility companies.

One possible approach is to examine historical growth as a guide to investor expected future growth, for example the recent five-year or ten-year growth in earnings, dividends and book value per share. However, my experience with utilities in recent years is that these historic measures have been somewhat volatile and are not necessarily reliable as prospective measures. I note that Mr. Hevert does not rely upon historical growth rates as an indicator of long-term growth for his proxy companies for DCF purposes. The DCF growth rate should be prospective, and one useful source of information on prospective growth is the projections of earnings per share growth rates (typically five years) prepared by securities analysts and reported in public surveys. It appears that Mr. Hevert places exclusive weight on this information for his standard DCF studies, and while I agree that it warrants substantial emphasis, it should not be relied upon exclusively.

Q. PLEASE DESCRIBE THE ANALYST EARNINGS GROWTH RATE EVIDENCE.

A. Schedule MIK-4, page 3 presents five available and well-known public sources of analyst earnings growth rate projections. Four of these five sources—YahooFinance, Zacks, Reuters and CNNfn—provide averages from securities analyst surveys conducted by or for these organizations (typically they report the mean or median value). The fifth, Value Line, is that organization's own estimates and is available publicly on a subscription basis. Value Line publishes its own projections using annual average earnings per share for a base period of 2014-2016 compared to the annual average for the forecast period of 2020-2022. These are very similar to the sources used by Mr. Hevert for securities analyst growth rates in his DCF studies, as he also uses Zacks, Yahoo, and Value Line.

As this schedule shows, the growth rates for individual companies vary somewhat among the five sources. These proxy group averages are 5.2 percent for CNNfn, 5.3 percent for YahooFinance, 5.4 percent for Zacks, 5.4 percent for Reuters and 5.0 percent for Value Line. Thus, the range of growth rates among the five sources is 5.0 to 5.4 percent. The average of these five sources is 5.3 percent, and I have used these results (along with other evidence) in obtaining a reasonable growth rate range for the group of 5.0 to 5.5 percent. I note that Witness Hevert (using the same proxy group) employs a mean growth rate figure of 5.4 percent, nearly identical to my projected earnings growth rate results.

Q. IS THERE ANY OTHER EVIDENCE THAT SHOULD BE CONSIDERED?

A. Yes. There are a number of reasons why investor expectations of long-run growth could differ from the limited, five-year earnings growth rate projections prepared by securities analysts. Consequently, while securities analyst estimates should be considered and given significant weight, these growth rates should be subject to a reasonableness test and corroboration, to the extent feasible.

On Schedule MIK-4, page 4 of 5, I have compiled three other measures of growth published by Value Line, i.e., growth rates of dividends and book value per share and the long-run retained earnings growth. (Retained earnings growth reflects the growth over time one would expect from the reinvestment of retained earnings, i.e., earnings not paid out as dividends.) As shown on this schedule, these growth measures for the 22 proxy companies tend to be somewhat less (on average) than analyst growth projections. For the 22 proxy companies, projected dividend growth averages 5.5 percent, book value growth averages 4.1 percent, and earnings retention growth averages 4.0 percent.

Some analysts and regulators favor the use of earnings retention growth (often referred to as "sustainable growth"), which Value Line indicates to be 4.0 percent. However, at least in theory, the sustainable growth rate also should include "an adder" to reflect potential future earnings growth from issuing new common stock at prices above book value (referred to as "external growth" or the "s x v" factor). In practice, this is difficult to estimate since future stock issuances of companies over the long-term are an unknown and rarely discussed by analysts. Nonetheless, I have estimated this "external growth" factor using Value Line projections for these 22 companies of the growth rate (through 2020-2022) in shares outstanding, along with the current stock price premium over book value. This is a common method for calculating the external growth factor. For these 22 companies, the external growth rate calculated in this manner averages about 0.6 percent. (Note that two of the 22 proxy companies are not expected to issue any new stock in the near term.) The sum of "internal" or earnings retention growth (i.e., 4.0 percent) and the "external" growth rate (i.e., 0.6 percent) is 4.6 percent.

Given this estimate of 4.6 percent for the sustainable growth rate and 5.3 percent for analyst earnings projections, a reasonable though conservatively high DCF growth rate range is approximately 5.0 to 5.5 percent. I tend to place more weight on the analyst projected growth rates as it is derived from five sources, whereas the sustainable growth rate analysis relies entirely only on one source, i.e., Value Line. I further note that Value Line projections appear to be slightly less optimistic than the other four sources that I use, which is an additional reason to emphasize the analyst published earnings growth rates.

Q. ARE THERE ANY OTHER FACTORS TO CONSIDER?

A. Yes. Witness Hevert estimates a flotation expense adder for ACE of 0.12 percent, but he has decided not to include this adder in his ROE results. He develops this adjustment based on the historic flotation expenses shown on his Schedule RBH-7.

Mr. Hevert's data indicate that PHI parent has incurred stock flotation expenses of about $10 million and $12 million in 2008 and 2012, respectively. PHI will not be issuing stock to the public in the future as it is now wholly-owned by Exelon Corp.

Q. HAVE YOU INCLUDED A FLOTATION ADJUSTMENT FOR ACE?

A. No, I have not. PHI's last public issuance was five years ago in 2012, and no longer will incur flotation expense in the future due to its acquisition by Exelon. According to the response to RCR-ROR-17, Exelon has incurred flotation expense since the PHI merger, but those expenses were associated with the financing of the merger and therefore not recoverable from ACE customers under the Board's approval order. For that reason, I concur with Witness Hevert that a flotation adder need not be included in the reported cost of equity and authorized ROE in this case.

Q. WHAT IS YOUR DCF CONCLUSION?

A. I summarize my DCF analysis on page 1 of Schedule MIK-4. The adjusted dividend yield for the six months ending June 2017 is 3.3 percent for this group. Available evidence would support a long-run growth rate in the range of approximately 5.0 to

5.5 percent, as explained above. Summing the adjusted yield, growth rate range and with no flotation adjustment produces a total cost of equity of 8.3 to 8.8 percent, and a midpoint result of 8.6 percent. Reliance on analyst earnings projections would tend to support a result toward the upper end of that range, while the sustainable growth rate produces a lower end DCF result. Emphasizing the upper end results, I recommend an ROE award of 9.0 percent which is somewhat above the DCF upper end, as I place greater weight on security analyst projections.

Q. HOW DOES YOUR 8.6 PERCENT DCF MIDPOINT COMPARE TO MR. HEVERT'S DCF ESTIMATE FOR HIS PROXY GROUP?

A. Mr. Hevert reports a series of standard DCF estimates of about 8.9 percent using his midpoint growth rates (i.e., the average of his three growth rate sources). His slightly higher results, based entirely on security analyst earnings growth rates, reflect the slightly higher market cost of equity that was prevailing roughly six months ago.

C. <u>The CAPM Analysis</u>

Q. PLEASE DESCRIBE THE CAPM MODEL.

A. The CAPM is a form of the "risk premium" approach and is based on modern portfolio theory. Based on my experience, the CAPM is the cost of equity method most often used in rate cases after the DCF method, and it is one of Mr. Hevert's three cost of equity methods.

According to this model, the cost of equity (K_e) is equal to the yield on a risk-free asset plus an equity risk premium multiplied by a firm's "beta" statistic. "Beta" is a firm-specific risk measure which is computed as the movements in a company's stock price (or market return) relative to contemporaneous movements in the broadly defined stock market (e.g., the S&P 500 or the New York Stock Exchange Composite). This measures the investment risk that cannot be reduced or eliminated through asset diversification (i.e., holding a broad portfolio of assets). The overall market, by definition, has a beta of 1.0, and a company with lower than average investment risk (e.g., a utility company) would have a beta below 1.0. The "risk premium" is defined as the expected return on the overall stock market minus the yield or return on a risk-free asset.

The CAPM formula is:

K_e = $R_f + \beta\ (R_m - R_f)$, where:

K_e = the firm's cost of equity

R_m = the expected return on the overall market

R_f = the yield on the risk free asset

β = the firm (or group of firms) risk measure.

Two of the three principal variables in the model are directly observable – the yield on a risk-free asset (e.g., a Treasury security yield) and the beta. For example, Value Line publishes estimated betas for each of the companies that it covers, and Mr. Hevert uses those betas along with betas published by Bloomberg, with the latter betas being somewhat lower. The greatest difficulty, however, is in the measurement of the expected stock market return (and therefore the equity risk premium), since that variable cannot be directly observed.

While the beta itself also is "observable," different investor services provide differing calculations of betas depending on the specific procedures and methods that they use. These differences can potentially have large impacts on the CAPM results. In this case, the betas that Mr. Hevert and I use are similar, with Mr. Hevert's ranging from 0.62 to 0.71, or a midpoint of 0.67. (See Mr. Hevert's Schedule (RBH)-4.)

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. For purposes of my CAPM analysis, I have used a long-term (i.e., 30-year) Treasury yield as the risk-free return (as has Witness Hevert) along with the average beta for the electric utility proxy group. (See Schedule MIK-3 for the company-by-company betas.) In the last six months, long-term (i.e., 30-year) Treasury yields have averaged approximately 3.0 percent, and the recent Value Line betas for my distribution utility proxy group average 0.71. As of this writing in late July 2017, the 30-year Treasury rate is a slightly lower figure of 2.9 percent. I note that Mr. Hevert has elected to use a risk-free rate in his studies that range from 3.03 to 4.35 percent, which is includes figures higher than recent actual Treasury bond yields. Finally, and as explained below, I am using an equity risk premium range of 5 to 8 percent, although I also provide calculations using a higher risk premium as a sensitivity test.

Using these data inputs, the CAPM calculation results are shown on page 1 of Schedule MIK-5. My low-end cost of equity estimate uses a risk-free rate of 3.0 percent, a proxy group beta of 0.71 and an equity risk premium of 5 percent.

K_e = 3.0% + 0.71 (5.0%) = 6.6%

The upper-end estimate uses a risk-free rate of 3.0 percent, a proxy group beta of 0.71 and an equity risk premium of 8.0 percent.

K_e = 3.0% + 0.71 (8.0%) = 8.7%

Thus, with these inputs the CAPM provides a cost of equity range of 6.6 to 8.7 percent, with a midpoint of 7.6 percent. The CAPM analysis produces a midpoint result significantly lower than the range of results obtained for my electric utility group DCF analysis, but I have not placed reliance on the CAPM returns in formulating my ROE recommendation in this case. In my opinion, this is due in large part to the difficulty in measuring the market risk premium and the fact that the DCF is a more reliable methodology for relatively stable utility companies.

Q. WHAT RESULT WOULD YOU OBTAIN USING MR. HEVERT'S MARKET RISK PREMIUM?

A. For his CAPM study, Mr. Hevert has selected a market risk premium range of 9.75 to 10.90 (average of about 10.33 percent) percent. In conjunction with his two sources of proxy group betas (which average to 0.67) and a 3.0 percent Treasury bond yield, the CAPM using his market risk premium estimate produces:

$$K_e = 3.0\% + 0.67\ (10.33\%) = 9.91\%$$

The 9.91 percent CAPM result, based on the recent six-month average Treasury yield, is slightly below Mr. Hevert's 10.1 percent ROE recommendation, but it is much higher than my CAPM range of results. I attribute this result to his unrealistically high 10.33 percent market risk premium estimate, a figure that is unsupportable as a long-run sustainable market return expected by investors. I discuss this further in Section V of my testimony.

Q. IT APPEARS THAT A KEY ELEMENT IN YOUR CAPM STUDY IS YOUR EQUITY MARKET RETURN RISK PREMIUM OF 5 TO 8 PERCENT. HOW DID YOU DERIVE THAT RANGE?

A. There is a great deal of disagreement among analysts regarding the reasonably expected market return on the stock market as a whole and therefore the risk premium. In my opinion, a reasonable overall stock market risk premium to use would be about 6 to 7 percent, which today would imply a stock market return of about 9 to 10 percent. Due to uncertainty concerning the true market return value, I am employing a broad range of 5 to 8 percent as the overall market rate of return, which would imply a market equity return of roughly 8 to 11 percent for the overall stock market.

Q. DO YOU HAVE A SOURCE FOR THAT RANGE?

A. Yes. The well-known finance textbook by Brealey, Myers and Allen (*Principles of Corporate Finance*) reviews a broad range of evidence on the equity risk premium. The authors of the risk premium literature conclude:

> Brealey, Myers and Allen have no official position on the issue, but we believe that a range of 5 to 8 percent is reasonable for the risk premium in the United States. (Page 154)

I would note that Mr. Hevert's 10.33 percent risk premium midpoint greatly exceeds the upper end of that plausible range. My "midpoint" risk premium of roughly 6.5 percent falls well within that range.

There is one important caveat to consider here regarding the 5 to 8 percent range that the authors believe is supported by the literature. It appears that the 5 to 8 percent range is specified relative to short-term Treasury yields, not relative to long-term (i.e., 30-year) Treasury yields. At this time, the application of the CAPM using short-term Treasury yields would not be meaningful because those yields within the past year have approximated zero. It therefore could be argued that the 5 to 8 percent range of Brealey *et al*. is overstated if a long-term Treasury yield (i.e., the 30-year Treasury) is used as the risk-free rate, i.e., the practice followed by both Mr. Hevert and me.

V. REPLY TO WITNESS HEVERT

A. Overview of Mr. Hevert's Recommendation

Q. MR. HEVERT IDENTIFIES A COST OF EQUITY RANGE OF 10.00 TO 10.75 PERCENT AND AN ROE AWARD OF 10.1 PERCENT. HOW DID HE DEVELOP THAT RECOMMENDATION FOR ACE?

A. Mr. Hevert employs three cost of equity estimation methodologies, DCF, CAPM and Risk Premium, although he is not clear about the weight he attaches to each method in developing his recommendation.

He presents a number of different cost of equity estimation calculations using each method. He presents three proxy group "mean" DCF calculations averaging about 8.9 percent based on differing time periods for measuring share prices (i.e., the averages for 30, 90 or 180 days). Mr. Hevert also employs two sets of "multi-stage" DCF studies the first of which produces estimates of about 9.1 percent and the second which produces estimates averaging about 10.2 percent (based on mean growth rate figures). He presents twelve CAPM calculations using differing risk-free rates (30-year Treasury bond yields), betas and market risk premium values, with his cost of equity estimates ranging from 9.08 to 12.10 percent. The higher end of this range is due to Witness Hevert's erroneous use of higher projected instead of actual long-term interest rates. Finally, he presents his three Risk Premium cost of equity calculations which range from 10.00 to 10.30 percent, based on three different interest rate assumptions (again, one being actual and two being projected).

As noted earlier, Mr. Hevert's final stated cost of equity range does not include either a stock flotation adjustment or a risk adjustment.

B. <u>Mr. Hevert's DCF Results</u>

Q. DO YOU HAVE ANY OBJECTIONS TO MR. HEVERT'S "STANDARD" DCF STUDY?

A. No, I do not. He obtains 8.9 percent, and it would decline slightly upon updating with 2017 market data, producing a result consistent with my ROE recommendation. Other than a need for updating (which is a minor issue), I have no further comments on that study.

Q. DO YOU OBJECT TO HIS MULTI-STAGE DCF STUDIES?

A. I do not object to this approach conceptually as long as reasonable and supportable data inputs are used. For his testimony in this case, he employs two variants of this model with both variants using securities analyst earnings growth rates in the initial stage and the longer-term growth rate for the U.S. economy ("nominal GDP") in the third stage. For the nominal GDP growth rate, Mr. Hevert selects 5.50 percent. As I explain below, this is a key but completely unreasonable assumption which explains in part why his multi-stage DCF results are higher than his (and my) standard DCF results.

His results are presented in his Schedule RBH-2, a very complex and opaque 55-page schedule. The first variant of his multi-stage DCF study obtains cost of equity results of 9.0 to 9.1 percent for his three market data time periods (30, 60, and 90 days ending February 28, 2017). If one corrects the overstated nominal GDP growth rate to a more realistic figure and updates to mid-2017 market conditions, this multi-stage study would produce results similar to or possibly even lower than my 9.0 percent ROE recommendation.

It appears that this first multi-stage DCF variant is the same methodology used by Witness Hevert in previous ACE rate cases. (See his response to RCR-ROR-2.)

However, Mr. Hevert inexplicably leaves these 9.0 and 9.1 percent DCF results buried in the 55 page schedule <u>and never reports them in his testimony</u>. Instead, he inexplicably only reports his second variant of the multi-stage DCF which produces a much higher ROE mean estimate of averaging about 10.3 percent.

Q. WHAT IS THE CHANGE DRIVING THIS SECOND VARIANT OF THE MULTI-STAGE?

A. In this new version of the multi-stage DCF Mr. Hevert arbitrarily assumes that in the final year of his study the price/earnings ratio ("P/E") for the proxy group companies becomes the figure 24.76 in the year 2032. He has no documentation (e.g., security analyst projections or authoritative forecasts) demonstrating that this extremely high P/E ratio is what investors are expecting for the year 2032 (or any year for that matter). It is merely an assumption that appeals to him (and also benefits ACE with a higher ROE). This unsupported and speculative assumption is apparently what causes the 9.0 to 9.1 percent results to increase to about 10.2 percent, as he shows on his Table 5 in his testimony.

Q. WHY IS HIS 5.5 PERCENT LONG-TERM U.S. GDP GROWTH RATE UNREALISTIC?

A. Once again, this is merely an assumption of his liking unsupported by any investor, securities analysts or authoritative forecasts. Instead, he erroneously derives this figure from historic trend data.

Authoritative forecasts clearly contradict Mr. Hevert's 5.5 percent as being wildly optimistic. In particular, the March 10, 2017 edition of *Blue Chip Economic Indicators* publishes a long-term (10-year) forecast of nominal GDP growth rates compiled from approximately 40 authoritative forecast organizations. The average or "consensus" long-term growth rate forecast is 4.2 percent. Forecasts of nominal GDP from governmental sources (the Congressional Budget Office and the Fed) are quite similar—about 4.0 to 4.5 percent long-term annual growth.

I believe that forecasters (and investors) expect slower growth in the future than the past for fundamental and well-known economic reasons—slowing productivity gains in recent years and an observed slowing growth in the U.S. work force due to an aging population and reduced labor force participation.

I note that the Federal Energy Regulatory Commission ("FERC") also uses a multi-stage DCF method for electric utilities and has adopted a long-term nominal U.S. GDP growth rate of less than 4.5 percent.

Q. HOW WOULD CORRECTING THIS OVERSTATED GROWTH RATE ALTER MR. HEVERT'S RESULTS?

A. RCR-ROR-26 asked Witness Hevert to change the GDP growth rate in his second (i.e., new) multi-stage DCF model from 5.5 percent to 4.5 percent (a figure slightly higher than the Blue Chip consensus). The response states that this change results in the DCF model estimates declining to 9.7 to 9.9 percent. This correction is a reduction in the cost of equity from this model of about 0.5 percent.

Presumably, this correction here also would provide a similar reduction to his first multi-stage DCF study, reducing the DCF estimate to approximately 8.6 percent—slightly less than the ROE from his standard DCF study.

Q. WHEN CORRECTED, DOES THE MULTI-STAGE DCF CHALLENGE YOUR 9.0 PERCENT RECOMMENDATION?

A. No, when corrected only for the overstated nominal GDP growth rate and updated for 2017 market data, I believe it fully supports my 9.0 percent ROE recommendation. With the GDP growth rate correction, the two multistage models produce a range of about 8.6 to 9.8 percent, averaging in the low 9s. As I indicate above, the higher figure is highly suspect as it is based on the unsupported assumption that investors in the year 2032 expect a P/E ratio for all proxy group electric utilities of 24.76.

C. <u>The CAPM Results</u>

Q. WHAT ARE YOUR OBJECTIONS TO MR. HEVERT'S CAPM STUDY?

A. I have two significant difference with Mr. Hevert concerning his CAPM analyses -- the market risk premium values that he selected and his use of forecasted in place of actual Treasury yields (with the forecasted figures being higher than actual). Both he and I use similar values for the beta and adopt the 30-year Treasury as the measure of the risk-free rate, and we use essentially the same CAPM formula.

My first objection to his CAPM studies is his use of market risk premium estimates that seem excessive. Specifically, he employs risk premium figures averaging about 10.33 percent. This 10.33 percent figure is based on his two DCF studies of the S&P 500.

As noted in Section IV of my testimony, the reasonable range for the equity market risk premium would be about 5 to 8 percent. The 10.33 percent value greatly exceeds the top end of the range and is simply not reasonable. Specifically, the 10 percent risk premium means that the S&P 500 cost of equity today must be about 13 percent on a long-term basis, a figure that clearly is unreasonably and implausibly high.

Q. WHAT TREASURY BOND YIELDS DID MR. HEVERT USE?

A. He uses a relatively current value (as of the time of his testimony) of 3.03 percent, a near-term forecast of 3.40 percent and a long-term forecast of 4.35 percent.

Q. WHAT IS YOUR OBJECTION TO THESE TREASURY YIELDS?

A. Mr. Hevert's selection of 3.03 percent at the time of his testimony was reasonable, and it remains today to be a reasonable value for CAPM purposes. I do not contest at this time his "actual" 3.03 percent risk-free rate.

His near-term projection may have been his attempt to reflect cost of equity conditions as of the completion of this rate case, which is understandable. The problem is that such forecasts at best are speculative and in this case to date have proven to be wrong. While the 3.40 percent is Mr. Hevert's expectation of an interest rate increase from the actual 3.03 percent, instead 30-year Treasury yields have fallen slightly since the beginning of this year.

Finally, the 4.35 percent figure may reflect forecasters (but clearly not investors') views regarding Treasury yields at some time in the future. Consequently, this has nothing to do with the cost of equity for this rate case in 2017. Capital cost conditions in future years will be addressed in future ACE rate cases. This is projection therefore is irrelevant to investor requirements today, as well as being speculative.

Q. HAVE YOU COMPARED MR. HEVERT'S CLAIMED 13 PERCENT S&P 500 RATE OF RETURN ESTIMATE AGAINST OTHER SOURCES?

A. Yes, and other information suggests that the 13 percent investor rate of return/10.3 percent risk premium values are excessive and unrealistic. This investor return may reflect only short-term earnings growth for the S&P 500 firms, but it would not be sustainable on a long-term basis as the DCF and CAPM models require. Witness Hevert's 13 percent stock market return requires an expected 11 percent growth rate in earnings. (This is because the S&P 500 dividend yield is about 2 percent.) The 11 percent growth rate is not plausible on a long-run sustained basis since the U.S. economy is expected to grow by only about 4.2 percent (nominally) per year long term. The market return of 13 percent asserted by Witness Hevert is also inconsistent and far greater than long-term average market returns and market surveys often cited or relied upon by financial analysts.

D. <u>Mr. Hevert's Risk Premium Study</u>

Q. HOW DID MR. HEVERT ESTIMATE THE COST OF EQUITY USING THE RISK PREMIUM METHOD?

A. Mr. Hevert estimated a regression model in which the historic electric utility risk premium is "explained" by the level of 30-year U.S. Treasury yield. The risk premium data series itself is based upon 30 years of historical state commission ROE awards as reported by Regulatory Research Associates ("RRA"). His estimated equation is:

$$RP = -0.0274 \ln(x) – 0.0262$$

Thus, at Mr. Hevert's recent Treasury yield of 3.03 percent, his regression model indicates a risk premium of about 7.0 percent:

$$RP = -0.0279 \ln(0.0296) – 0.0272 = 7.0\%$$

Adding back the 3.03 percent Treasury yield, produces a cost of equity of 10.0 percent.

Mr. Hevert, however, did not only use the actual Treasury yield of 3.03 percent, but he also assumed Treasury bond yields would increase to 3.40 percent near term and spike to 4.35 percent long term. Using his assumption of sharply higher capital costs in the future, he obtains an alternative risk premium cost of equity estimates of 10.1 and 10.3 percent. I explained in the last section why such assumptions about rising interest rates are both factually incorrect and/or irrelevant to this rate case.

Q. IS THIS MODEL SPECIFICALLY APPLICABLE TO ACE?

A. No, it is not. Even if this model is completely valid and accurate (which it is not), at best, it measures a kind of "generic" or industry-wide cost of capital. The industry, however, is largely or mostly made up of vertically-integrated utilities, such as Mr. Hevert's proxy companies. ACE is a much less risky distribution utility, and it therefore follows that its equity risk premium would be less than the industry average.

I have reviewed the historic return on equity awards for electric utilities as published in the July 2016 RRA rate case activity survey as well as data employed by Witness Hevert supplied in response to RCR-ROR-23. That survey and Mr. Hevert's data for the year 2016 indicate that, on average, the delivery service utility awards (and hence the measured equity award premium over contemporaneous Treasury yields) are significantly lower than for vertically-integrated electrics. I show this below. Mr. Hevert failed to take this distinction into account by using his inappropriate "one size fits all" regression model.

The RRA data provides annual ROE awards in base rate cases for all electrics, vertically-integrated electrics and delivery service electrics for the time period 2006-2016 summarized as follows.

Year	All Electrics	Vertically-Integrated	Delivery Service
2006	10.34%	10.63%	9.91%
2007	10.31	10.50	9.86
2008	10.37	10.48	10.04
2009	10.52	10.66	10.15
2010	10.29	10.42	9.98
2011	10.19	10.33	9.85
2012	10.01	10.10	9.73
2013	9.81	9.95	9.41
2014	9.75	9.94	9.50
2015	9.60	9.75	9.23
2016	9.60	9.77	9.31
Average	**10.07%**	**10.23%**	**9.72%**

Please note that during this time period single A utility bond yields averaged about 5.1 percent (as calculated from my Schedule MIK-2, page 1 of 7), implying an average ROE award premium of about 5.1 percent for vertically-integrated utilities and 4.6 percent for delivery service utilities. Given the currently prevailing single A utility bond yield of about 4.1 percent this implies a Risk Premium-derived cost of equity of 8.6 percent for delivery service electrics (i.e., 4.1% yield + 4.5% RP). If we assume that a 1.0 percent in interest rates causes the risk premium to increase by 0.5 percent, then the delivery service cost of equity under this methodology rises to about 9.1 percent.

I believe that the RRA survey data tends to support the reasonableness of my 9.0 percent recommendation, or at a minimum implies that a significant reduction from the current 9.75 percent ROE would be appropriate.

Q. SHOULD ANY WEIGHT BE GIVEN TO MR. HEVERT'S RISK PREMIUM COST OF EQUITY MODEL IN THIS CASE?

A. No. The model is actually designed to "explain" or predict state utility commission behavior rather than estimating today's cost of equity. A major problem is that the data base in his analysis extends back 30 years, i.e., to the 1980s and 1990s, time periods when capital cost conditions were far different than today. If state commission ROE awards are to be used in a risk premium study, it makes far more sense to focus on the past ten years, as I have done. Moreover, the assumed 4.35 percent Treasury bond yield employed in his application of the model is not in any way reflective of current capital market conditions. Witness Hevert's other major mistake is in failing to take into account the lower ROEs awarded to delivery service utilities as compared to all electric utilities.

VI. CONCLUSIONS

Q. WHAT ARE YOUR MAJOR FINDINGS AND CONCLUSIONS?

A. Based on my review of the testimony, discovery responses and market information, I find that ACE is a financially sound and low-risk electric distribution utility company presently operating in a very low capital cost environment. In this case, the Company is proposing to increase its currently authorized return on equity from 9.75 to 10.6 percent despite the clear evidence of stable or declining capital costs during the past year. The current 9.75 percent ROE should be reduced, not increased, based on today's historically low capital costs and investor requirements.

Q. WOULD A REDUCTION TO THE CURRENT 9.75 PERCENT BE UNREASONABLE OR PUNITIVE TO SHAREHOLDERS?

A. No, not at all. As I have just shown in the last section, there has been a declining trend in state commission ROE awards in recent years, albeit a gradual trend. For the electric industry as a whole, in state-level base rate cases the average award was 9.60 percent in 2015 and 2016. The ROE awards for delivery service electrics are even lower, averaging 9.23 percent in 2015 and 9.31 percent in 2016.

A legitimate question is how have utility stocks performed in this environment of declining ROE awards. Do investors find these lowered ROE awards to be acceptable? The answer is the stocks have performed extremely well. On page 5 of Schedule MIK-4, I show the stock price premiums over book value per share. Those premiums range from a low of 52 percent to a high of nearly 243 percent, averaging about 100 percent for the 22 proxy companies. This indicates that electric utility valuations are very strong, and investors find electric utility stocks with the sub 10 percent (or sub 9.75 percent) ROE awards to be very attractive.

On Schedule MIK-6 I have compiled the annualized market returns (dividends plus price appreciation) for the one-year, three years and five years ending May 31, 2017, as reported by S&P. For the 22 proxy companies, these market rates of return average 20 percent for the most recent one-year period, 16 percent per year for the most recent three years and 16 percent per year for the most recent five years.

Investors clearly find electric utility stocks to be very attractive and are bidding up share prices notwithstanding declining trend for ROE awards. This undoubtedly is because the cost of capital has been declining by even more than the ROE awards. The message from capital markets is clear: the reduction in ROEs to the low- to mid-9s has not harmed the attractiveness of utility stocks to investors, nor has it impaired the ability of utilities to attract needed capital. External capital is abundantly available on favorable terms to utilities.

Q. HOW DID YOU ARRIVE AT YOUR RATE OF RETURN RECOMMENDATION?

A. I am recommending at this time a 7.28 percent return on ACE's distribution rate base, including a 9.00 percent return on common equity. This is supported by current market conditions and the following studies:

(1) DCF Study of Electric Proxy Companies

8.3 to 8.8 percent, with an 8.6 percent midpoint

(2) CAPM Calculations

6.6 to 8.7 percent, with a 7.6 percent midpoint. My "high sensitivity" case is 9.4 percent.

Thus, my recommendation for ACE is consistent with my range of cost of equity evidence and is conservative.

I further recommend that the Board reject the proposed SRRC tracker mechanism as it unfairly and improperly shifts risk from ACE to ratepayers, with the Company providing no recognition in its ROE request in this case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

I/M/O The Petition of Atlantic City Electric Company for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Other and for Other Appropriate Relief (2017)	)	**BPU Docket No. ER17030308** **OAL Docket No. PUC 04989-17**

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE
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Dated: August 1, 2017

ATLANTIC CITY ELECTRIC COMPANY

Cost of Capital Summary
at December 31, 2016

Capital Type	Balance[1] (million $)	% Total	Cost Rate	Weighted Cost
Long-Term Debt	$1,025	49.86%	5.56%[2]	2.77%
Common Equity[3]	$1,030	50.14	9.00[3]	4.51
Total	**$2,055**	**100.0%**	**--**	**7.28%**

(1) Schedule (KMM-1), page 2 of 4.
(2) Schedule (KMM-1), page 3 of 4.
(3) See Schedules MIK-4 and MIK-5, page 1, and Direct Testimony.

ATLANTIC CITY ELECTRIC COMPANY

Trends in Capital Costs

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2001	2.9%	5.0%	3.5%	7.8%
2002	1.6	4.6	1.6	7.4
2003	1.9	4.1	1.0	6.6
2004	2.7	4.3	1.4	6.2
2005	3.4	4.3	3.0	5.6
2006	2.5	4.8	4.8	6.1
2007	2.8	4.6	4.5	6.3
2008	3.8	3.4	1.6	6.5
2009	(0.4)	3.2	0.2	6.0
2010	1.6	3.2	0.1	5.5
2011	3.1	2.8	0.0	5.1
2012	2.1	1.8	0.1	4.1
2013	1.5	2.3	0.1	4.5
2014	1.7	2.5	0.0	4.3
2015	0.1	2.2	0.0	4.1
2016	1.3	1.8	0.0	3.9

ATLANTIC CITY ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury	3-Month Treasury	Single A Utility Yield
2007				
January	2.1%	4.8%	5.1%	6.0%
February	2.4	4.7	5.2	5.9
March	2.8	4.6	5.1	5.9
April	2.6	4.7	5.0	6.0
May	2.7	4.8	5.0	6.0
June	2.7	5.1	5.0	6.3
July	2.4	5.0	5.0	6.3
August	2.0	4.7	4.3	6.2
September	2.8	4.5	4.0	6.2
October	3.5	4.5	4.0	6.1
November	4.3	4.2	3.4	6.0
December	4.1	4.1	3.1	6.2
2008				
January	4.3%	3.7%	2.8%	6.0%
February	4.0	3.7	2.2	6.2
March	4.0	3.5	1.3	6.2
April	3.9	3.7	1.3	6.3
May	4.2	3.9	1.8	6.3
June	5.0	4.1	1.9	6.4
July	5.6	4.0	1.7	6.4
August	5.4	3.9	1.8	6.4
September	4.9	3.7	1.2	6.5
October	3.7	3.8	0.7	7.6
November	1.1	3.5	0.2	7.6
December	0.1	2.4	0.0	6.5

ATLANTIC CITY ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury	3-Month Treasury	Single A Utility Yield
2009				
January	0.0%	2.5%	0.1%	6.4%
February	0.2	2.9	0.3	6.3
March	(0.4)	2.8	0.2	6.4
April	(0.7)	2.9	0.2	6.5
May	(1.3)	2.9	0.2	6.5
June	(1.4)	3.7	0.2	6.2
July	(2.1)	3.6	0.2	6.0
August	(1.5)	3.6	0.2	5.7
September	(1.3)	3.4	0.1	5.5
October	(0.2)	3.4	0.1	5.6
November	1.8	3.4	0.1	5.6
December	2.5	3.6	0.1	5.8
2010				
January	2.6%	3.7%	0.1%	5.8%
February	2.1	3.7	0.1	5.9
March	2.3	3.7	0.2	5.8
April	2.2	3.9	0.2	5.8
May	2.0	3.4	0.2	5.5
June	1.1	3.2	0.1	5.5
July	1.2	3.0	0.2	5.3
August	1.1	2.7	0.2	5.0
September	1.1	2.7	0.2	5.0
October	1.2	2.5	0.1	5.1
November	1.1	2.8	0.1	5.4
December	1.2	3.3	0.1	5.6

ATLANTIC CITY ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2011				
January	1.6%	3.4%	0.1%	5.6%
February	2.1	3.6	0.1	5.7
March	2.7	3.4	0.1	5.6
April	2.2	3.5	0.1	5.6
May	3.6	3.2	0.0	5.3
June	3.6	3.0	0.0	5.3
July	3.6	3.0	0.0	5.3
August	3.8	2.3	0.0	4.7
September	3.9	2.0	0.0	4.5
October	3.5	2.2	0.0	4.5
November	3.0	2.0	0.0	4.3
December	3.0	2.0	0.0	4.3
2012				
January	2.9%	2.0%	0.0%	4.3%
February	2.9	2.0	0.0	4.4
March	2.7	2.2	0.1	4.5
April	2.3	2.1	0.1	4.4
May	1.7	1.8	0.1	4.2
June	1.7	1.6	0.1	4.1
July	1.4	1.5	0.1	3.9
August	1.7	1.7	0.1	4.0
September	2.0	1.7	0.1	4.0
October	2.2	1.8	0.1	3.9
November	1.8	1.7	0.1	3.8
December	1.7	1.7	0.1	4.0

ATLANTIC CITY ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury	Single A Utility Yield
2013				
January	1.6%	1.9%	0.1%	4.2%
February	2.0	2.0	0.1	4.2
March	1.5	2.0	0.1	4.2
April	1.1	1.8	0.1	4.0
May	1.4	1.9	0.0	4.2
June	1.8	2.3	0.1	4.5
July	2.0	2.6	0.0	4.7
August	1.5	2.7	0.0	4.7
September	1.2	2.8	0.0	4.8
October	1.0	2.6	0.1	4.7
November	1.2	2.7	0.1	4.8
December	1.5	2.9	0.1	4.8
2014				
January	1.6%	2.9%	0.0%	4.6%
February	1.1	2.7	0.1	4.5
March	1.5	2.7	0.1	4.5
April	2.0	2.7	0.0	4.4
May	2.1	2.6	0.0	4.3
June	2.1	2.6	0.1	4.3
July	2.0	2.5	0.0	4.2
August	1.7	2.4	0.0	4.1
September	1.7	2.5	0.0	4.2
October	1.7	2.3	0.0	4.1
November	1.3	2.3	0.0	4.1
December	0.8	2.2	0.0	4.0

ATLANTIC CITY ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury	3-Month Treasury	Single A Utility Yield
2015				
January	(0.1)%	1.9%	0.0%	3.6%
February	0.0	2.0	0.0	3.7
March	(0.1)	2.0	0.0	3.7
April	(0.2)	1.9	0.0	3.8
May	0.0	2.2	0.0	4.2
June	0.1	2.4	0.0	4.4
July	0.2	2.3	0.0	4.4
August	0.2	2.2	0.1	4.3
September	0.0	2.3	0.0	4.4
October	0.2	2.1	0.0	4.3
November	0.5	2.3	0.1	4.4
December	0.7	2.2	0.2	4.4
2016				
January	1.4%	2.1%	0.3%	4.3%
February	1.0	1.8	0.3	4.1
March	0.9	1.9	0.3	4.2
April	1.1	1.8	0.2	4.2
May	1.0	1.8	0.3	4.2
June	1.0	1.6	0.3	4.1
July	0.8	1.5	0.3	3.6
August	1.1	1.6	0.3	3.6
September	1.5	1.6	0.3	3.7
October	1.6	1.8	0.3	3.8
November	1.7	2.1	0.5	4.1
December	2.1	2.5	0.5	4.3

ATLANTIC CITY ELECTRIC COMPANY

U.S. Historic Trends in Capital Costs
(Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury	Single A Utility Yield
2017				
January	2.5%	2.4%	0.5%	4.1%
February	2.7	2.4	0.5	4.2
March	2.4	2.5	0.8	4.2
April	2.2	2.3	0.8	4.1
May	1.9	2.3	0.9	4.1
June	1.6	2.2	1.0	4.1(p)

Source: *Economic Report of the President, Mergent's Bond Record, Federal Reserve Statistical Release* (H.15), *Consumer Price Index Summary* (BLS).

ATLANTIC CITY ELECTRIC COMPANY

List of the Electric Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2017 Common Equity Ratio*
1.	American Electric Power	1	A+	0.65	48.0%
2.	Allete	2	A	0.80	59.0
3.	Alliant Energy	2	A	0.70	48.0
4.	Ameren	2	A	0.65	51.5
5.	Avista	2	A	0.70	53.0
6.	Black Hills	2	A	0.85	33.0
7.	CenterPoint Energy	3	B+	0.85	32.5
8.	CMS Energy	2	B++	0.65	33.5
9.	Con. Edison	1	A+	0.50	50.0
10.	El Paso	2	B++	0.75	48.5
11.	DTE Energy	2	B++	0.65	44.0
12.	Eversource Energy	1	A	0.65	53.5
13.	IDACORP	2	A	0.75	56.0
14.	Northwestern	3	B+	0.65	49.0
15.	OGE Energy	2	A	0.95	55.5
16.	Otter Tail	2	A	0.90	58.0
17.	Pinnacle West	1	A+	0.70	51.5
18.	PNM Resources	3	B	0.70	45.5
19.	Portland General	2	B++	0.70	48.5
20.	SCANA	2	B++	0.60	47.0
21	WEC Energy	1	A+	0.60	50.0
22.	Xcel Energy	1	A+	0.60	44.0
	Average	**1.9**	**--**	**0.71**	**48.2%**

*The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2017 equity ratio including short-term debt and current maturities averages 46.4 percent.

Source: *Value Line Investment Survey*, April 28, 2017; May 19, 2017; and June 16, 2017.

ATLANTIC CITY ELECTRIC COMPANY

DCF Summary for the
Electric Company Proxy Group

1.	Dividend Yield (January – June 2017)[(1)]	3.19%
2.	Adjusted Yield ((1) x 1.0275)	3.3%
3.	Long-Term Growth Rate[(2)]	5.0 – 5.5%
4.	Total Return ((2) + (3))	8.3 – 8.8%
5.	Flotation Expense	0.0%
6.	Cost of Equity ((4) + (5))	8.3 – 8.8%
7.	Midpoint	8.6%
	Recommendation	**9.0%**

[(1)] Schedule MIK-4, page 2 of 5.
[(2)] Schedule MIK-4, pages 3 of 5, 4 of 5 and 5 of 5.

ATLANTIC CITY ELECTRIC COMPANY

Dividend Yields for the Electric Company Proxy Group
(January 2017 – June 2017)

	Company	January	February	March	April	May	June	Average
1.	American Electric Power	3.7%	3.5%	3.5%	3.5%	3.3%	3.3%	3.54%
2.	Allete	3.3	3.2	3.2	3.0	2.9	3.0	3.10
3.	Alliant Energy	3.4	3.2	3.2	3.2	3.0	3.1	3.19
4.	Ameren	3.4	3.2	3.2	3.2	3.1	3.2	3.22
5.	Avista	3.6	3.6	3.7	3.5	3.4	3.3	3.52
6.	Black Hills	2.9	2.7	2.7	2.6	2.6	2.6	2.68
7.	CenterPoint Energy	4.1	4.0	3.9	3.7	3.8	3.8	3.88
8.	CMS Energy	3.2	3.0	3.0	2.9	2.8	2.8	2.95
9.	Con. Edison	3.8	3.6	3.6	3.5	3.4	3.3	3.53
10.	El Paso	2.8	2.5	2.5	2.4	2.5	2.6	2.55
11.	DTE Energy	3.4	3.3	3.2	3.1	3.0	3.1	3.18
12.	Eversource Energy	3.3	3.2	3.2	3.2	3.1	3.1	3.18
13.	IDACORP	2.8	2.7	2.7	2.6	2.5	2.5	2.64
14.	Northwestern	3.5	3.6	3.6	3.5	3.4	3.3	3.48
15.	OGE Energy	3.6	3.3	3.5	3.5	3.4	3.4	3.45
16.	Otter Tail	3.3	3.3	3.3	3.2	3.2	3.2	3.25
17.	Pinnacle West	3.4	3.2	3.1	3.0	3.0	3.0	3.12
18.	PNM Resources	2.9	2.7	2.6	2.6	2.5	2.5	2.63
19.	Portland General	3.0	2.9	2.9	2.9	2.9	2.9	2.92
20.	SCANA	3.4	3.6	3.7	3.6	3.6	3.6	3.58
21.	WEC Energy	3.6	3.5	3.4	3.4	3.3	3.3	3.42
22.	Xcel Energy	3.3	3.3	3.2	3.2	3.0	3.1	3.18
	Average	**3.35%**	**3.22%**	**3.22%**	**3.15%**	**3.08%**	**3.09%**	**3.19%**

Source: S& P *Stock Guide*, February 2017 – June 2017. The June dividend yields are from the YahooFinance website as of June 30, 2017.

ATLANTIC CITY ELECTRIC COMPANY

Projection of Earnings Per Share
Five-Year Growth Rates for the
Electric Company Proxy Group

	Company	Value Line	Yahoo	Zacks	Reuters	CNN	Average
1.	American Electric Power	4.00%	2.39%	5.63%	2.31%	5.30%	3.93%
2.	Allete	5.00	5.00	6.10	5.0	6.10	5.44
3.	Alliant Energy	6.00	6.35	5.50	6.35	5.65	5.97
4.	Ameren	6.00	6.25	6.50	6.05	5.80	6.12
5.	Avista	2.50	5.65	NA	NA	5.30	4.48
6.	Black Hills	7.50	12.00	5.00	12.00	5.00	8.30
7.	CenterPoint Energy	6.00	5.89	5.00	5.89	6.33	5.82
8.	CMS Energy	6.50	7.52	6.00	7.52	7.15	6.94
9.	Con. Edison	2.50	3.97	3.60	3.97	3.80	3.57
10.	El Paso	5.00	6.50	7.90	6.50	6.50	6.48
11.	DTE Energy	6.00	4.58	5.93	4.58	5.20	5.26
12.	Eversource Energy	6.50	5.99	6.33	5.99	6.00	6.16
13.	IDACORP	3.50	4.00	4.00	4.00	4.00	3.90
14.	Northwestern	4.50	3.73	3.25	3.37	2.85	3.54
15.	OGE Energy	5.50	6.30	5.33	6.30	5.70	5.83
16.	Otter Tail	6.50	5.20	NA	5.20	5.00	5.48
17.	Pinnacle West	5.50	6.05	5.07	6.05	5.20	5.57
18.	PNM Resources	9.00	7.00	6.53	7.00	6.35	7.18
19.	Portland General	6.00	5.55	5.25	5.55	4.90	5.45
20.	SCANA	4.00	5.80	5.33	5.60	6.00	5.33
21.	WEC Energy	6.00	5.61	6.00	5.61	6.00	5.84
22.	Xcel Energy	4.50	NA	5.43	5.32	5.78	5.26
	Average	**5.03%**	**5.33%**	**5.41%**	**5.39%**	**5.24%**	**5.27%**

Source: *Value Line Investment Survey*, April 28, 2017, May 19, 2017, and June 16, 2017. YahooFinance.com, Zacks.com, CNNMoney.com, Reuters.com, public websites, May 2017.

ATLANTIC CITY ELECTRIC COMPANY

Other *Value Line* Measures of Growth
for the Electric Company Proxy Group

	Company	Dividend per Share	Book Value per Share	Earnings Retention
1.	American Electric Power	5.0%	3.5%	4.5%
2.	Allete	5.0	4.5	3.5
3.	Alliant Energy	4.5	4.0	5.0
4.	Ameren	4.5	3.5	4.0
5.	Avista	4.0	2.5	2.5
6.	Black Hills	5.0	5.5	5.0
7.	CenterPoint Energy	3.5	2.0	4.0
8.	CMS Energy	6.5	6.5	5.5
9.	Con. Edison	3.0	3.5	3.0
10.	El Paso	7.0	4.0	4.5
11.	DTE Energy	7.0	4.5	4.0
12.	Eversource Energy	5.5	4.0	4.5
13.	IDACORP	7.0	4.0	3.5
14.	Northwestern	5.0	3.5	3.5
15.	OGE Energy	9.0	3.5	3.5
16.	Otter Tail	2.0	6.0	4.0
17.	Pinnacle West	5.0	4.0	4.0
18.	PNM Resources	10.0	3.5	3.5
19.	Portland General	6.0	3.5	4.0
20.	SCANA	5.0	5.0	4.5
21.	WEC Energy	6.0	5.0	3.5
22.	Xcel Energy	6.0	4.0	3.5
	Average	**5.48%**	**4.09%**	**3.95%**

Source: *Value Line Investment Survey*, April 28, 2017, May 19, 2017, and June 16, 2017. The earnings retention figures are projections for 2020-2022.

ATLANTIC CITY ELECTRIC COMPANY

Fundamental Growth Rate Analysis for
Electric Company Proxy Group

	Company	Shares 2016-2021[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	American Electric Power	0.0%	96.0%	0.0%	4.5%	4.5%
2.	Allete	1.1	83.6	1.0	3.5	4.5
3.	Alliant Energy	0.7	137.6	1.0	5.0	6.0
4.	Ameren	0.0	87.8	0.0	4.0	4.0
5.	Avista	1.2	52.4	0.6	2.5	3.1
6.	Black Hills	2.7	112.3	3.0	5.0	8.0
7.	CenterPoint Energy	0.2	243.4	0.5	4.0	4.5
8.	CMS Energy	0.7	191.2	1.3	5.5	6.8
9.	Con. Edison	0.6	61.8	0.4	3.0	3.4
10.	El Paso	0.2	86.1	0.2	4.0	4.2
11.	DTE Energy	0.8	109.4	0.9	4.0	4.9
12.	Eversource Energy	0.0	69.6	0.0	4.5	4.5
13.	IDACORP	0.1	92.0	0.1	3.5	3.6
14.	Northwestern	0.3	68.5	0.2	3.5	3.7
15.	OGE Energy	0.2	99.4	0.2	3.5	3.7
16.	Otter Tail	2.3	120.3	2.7	4.0	6.7
17.	Pinnacle West	0.5	93.0	0.4	4.0	4.4
18.	PNM Resources	0.1	61.2	0.1	3.5	3.6
19.	Portland General	0.2	69.4	0.2	4.0	4.2
20.	SCANA	0.8	57.1	0.5	4.5	5.0
21.	WEC Energy	0.0	114.5	0.0	3.5	3.5
22.	Xcel Energy	Neg	NA	0.0	3.5	3.5
	Average			**0.6%**	**4.0%**	**4.6%**

(1) Projected growth rate in shares outstanding; 2016-2021.
(2) % Premium of share price ("Recent Price") over 2016 book value per share.
(3) sv is growth rate in shares x % premium.
(4) br is Value Line projection as of 2020-2022.
Source: *Value Line Investment Survey*, April 28, 2017, May 19, 2017, and June 16, 2017.

ATLANTIC CITY ELECTRIC COMPANY

Capital Asset Pricing Model Study
Illustrative Calculations

A. Model Specification

$K_e = R_F + \beta\ (R_m - R_F)$, where

K_e = cost of equity

R_F = return on risk free asset

Rm = expected stock market return

B. Data Inputs

R_F = 3.0% (Long-term Treasury bond yield for the most recent six months)

Rm = 8.0 – 11.0% (equates to equity risk premium of 5.0 - 8.0%)

Beta = 0.71 (See Schedule MIK-3)

C. Model Calculations

Low end:	K_e = 3.0% + 0.71 (5.0) = 6.6%
Midpoint:	K_e = 3.0% + 0.71 (6.5) = 7.6%
Upper End:	K_e = 3.0% + 0.71 (8.0) = 8.7%
High Sensitivity:	K_e = 3.0% + 0.71 (9.0) = 9.4%

ATLANTIC CITY ELECTRIC COMPANY

Long-Term Treasury Yields
(January – June 2017)

Month	30-Year	20-Year	10-Year
January 2017	3.02%	2.75%	2.43%
February	3.03	2.76	2.42
March	3.08	2.83	2.48
April	2.94	2.67	2.30
May	2.96	2.70	2.30
June	2.80	2.54	2.19
Average	**2.97%**	**2.71%**	**2.35%**

Source: Federal Reserve, www.federalreserve.gov website, July 2017.

ATLANTIC CITY ELECTRIC COMPANY

Investor Market Annualized Rates of Return For The
Most Recent One, Three, and Five Years Ending May 2017

	Company	One Year	Three Year	Five Year
1.	American Electric Power	14.1%	15.5%	17.6%
2.	Allete	32.8	18.2	18.0
3.	Alliant Energy	16.2	17.1	17.3
4.	Ameren	21.5	17.6	16.6
5.	Avista	10.6	14.5	15.4
6.	Black Hills	20.3	10.3	20.8
7.	CenterPoint Energy	32.3	10.9	11.7
8.	CMS Energy	17.9	21.2	19.5
9.	Con. Edison	17.0	19.4	11.0
10.	El Paso	24.5	16.6	15.2
11.	DTE Energy	25.4	17.3	18.2
12.	Eversource Energy	16.7	14.8	15.1
13.	IDACORP	22.9	20.4	20.8
14.	Northwestern	10.8	13.3	16.0
15.	OGE Energy	19.5	2.8	9.0
16.	Otter Tail	39.8	16.7	18.2
17.	Pinnacle West	23.9	21.1	18.5
18.	PNM Resources	20.1	13.9	18.6
19.	Portland General	19.3	16.3	17.2
20.	SCANA	1.0	14.0	12.1
21.	WEC Energy	8.3	15.4	14.6
22.	Xcel Energy	19.5	20.3	15.4
	Average	**19.7%**	**15.8%**	**16.2%**

Source: Standard & Poor's *Stock Guide*, December 2016. Investor market return includes dividends plus share price appreciation.

APPENDIX A

QUALIFICATIONS OF

MATTHEW I. KAHAL

MATTHEW I. KAHAL

Since 2001, Mr. Kahal has worked as an independent consulting economist, specializing in energy economics, public utility regulation, and utility financial studies. Over the past three decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing, environmental compliance, and utility financial issues. In the financial area, he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone, and water utilities. Mr. Kahal's work in recent years has expanded to electric power markets, mergers, and various aspects of regulation.

Mr. Kahal has provided expert testimony in more than 400 cases before state and federal regulatory commissions, federal courts, and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring, and various other regulatory and public policy issues.

<u>Education</u>

B.A. (Economics) – University of Maryland, 1971

M.A. (Economics) – University of Maryland, 1974

Ph.D. candidacy – University of Maryland, completed all course work and qualifying examinations.

<u>Previous Employment</u>

1981-2001	Founding Principal, Vice President, and President Exeter Associates, Inc. Columbia, MD
1980-1981	Member of the Economic Evaluation Directorate The Aerospace Corporation Washington, D.C.
1977-1980	Consulting Economist Washington, D.C. consulting firm
1972-1977	Research/Teaching Assistant and Instructor (part time) Department of Economics, University of Maryland (College Park) Lecturer in Business and Economics Montgomery College (Rockville and Takoma Park, MD)

Professional Experience

Mr. Kahal has more than thirty-five years' experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc., and for the next 20 years he served as a Principal and corporate officer of the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted by both Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring, and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity, he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College, teaching courses on economic principles, business, and economic development.

Publications and Consulting Reports

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980 (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.

Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983 (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities" (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes (with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting" (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk" (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985 (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company – Past and Present, prepared for the Texas Public Utility Commission, December 1985 (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy – An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.), authored two chapters, November 1988, PPRP-CEIR-6.

Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum).

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994, prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.).

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).
The Economic Feasibility of Air Emissions Controls at the Brandon Shores and Morgantown Coal-fired Power Plants, February 2005 (prepared for the Chesapeake Bay Foundation).

The Economic Feasibility of Power Plant Retirements on the Entergy System, September 2005, with Phil Hayet (prepared for the Louisiana Public Service Commission).

Expert Report on Capital Structure, Equity and Debt Costs, prepared for the Edmonton Regional Water Customers Group, August 30, 2006.

Maryland's Options to Reduce and Stabilize Electric Power Prices Following Restructuring, with Steven L. Estomin, prepared for the Power Plant Research Program, Maryland Department of Natural Resources, September 2006.

Expert Report of Matthew I. Kahal, on behalf of the U. S. Department of Justice, August 2008, Civil Action No. IP-99-1693C-MIS.

Conference and Workshop Presentations

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty-Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995 (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on “Restructuring the Electric Industry,” sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen ‘97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers’ Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, Baton Rouge, Louisiana, October 2, 2002 (presentation on Performance-Based Ratemaking and panelist on RTO issues).

Virginia State Corporation Commission/Virginia State Bar, Twenty-Second National Regulatory Conference, Williamsburg, Virginia, May 10, 2004 (presentation on Electric Transmission System Planning).

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	Docket Number	Utility	Jurisdiction	Client	Subject
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic Impacts of Proposed Rate Increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load Forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test Year Sales and Revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test Year Sales, Revenues, Costs, and Load Forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-Use Pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load Forecasting, Marginal Cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for Plant, Load Forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA Standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-Use Pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-Use Rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting, Load Management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA Standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of Return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of Return, CWIP

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16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of Return, Capital Structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of Equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of Return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of Return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of Return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of Return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of Return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of Return

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31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, incentive rates, rate base
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of Return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of Return, capital Structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of Return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of Return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of Return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of Return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of Return

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46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of Return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of Return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of Return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of Return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of Return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

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61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of Return, incentive regulation
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of Return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of Return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of Return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of Return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of Return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

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75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of Return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of Return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	N/A	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of Return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of Return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of Return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of Return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power

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	Docket Number	Utility	Jurisdiction	Client	Subject
89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of Return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of Return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of Return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of Return
99.	90-256 January 1991	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
100.	U-17949A February 1991	South Central Bell Telephone Company	Louisiana	Louisiana PSC	Rate of Return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of Return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Environmental controls

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103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Company Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Company	New Jersey	Rate Counsel	Rate of Return
108.	91-5032 August 1991	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of Return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of Return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of Return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of Return
116.	P-870235, et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts

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117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of Return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of Return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of Return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of Return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of Return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of Return
128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power Supply Clause

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	Docket Number	Utility	Jurisdiction	Client	Subject
131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of Return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger Issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power Plant Certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of Return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of Return
137.	P-00930715 December 1993	Bell Telephone Company of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return, Financial Projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
139.	8583 February 1994	Conowingo Power Company	Maryland	Dept. of Natural Resources	Competitive Bidding for Power Supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Company	Minnesota	Attorney General	Rate of Return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of Return
142.	92-345, Phase II June 1994	Central Maine Power Company	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Company	Nevada	Federal Executive Agencies	Rate of Return
144.	94-0065 May 1994	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Rate of Return
145.	GR94010002J June 1994	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return

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	Docket Number	Utility	Jurisdiction	Client	Subject
146.	WR94030059 July 1994	New Jersey-American Water Company	New Jersey	Rate Counsel	Rate of Return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Company	Rate of Return
149.	R-00942986 July 1994	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, Emission Allowances
150.	94-121 August 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger Savings and Allocations
152.	IPC-E-94-5 November 1994	Idaho Power Company	Idaho	Federal Executive Agencies	Rate of Return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of Return (Rebuttal Only)
154.	90-256 December 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of Return Industrial Contracts Trust Fund Earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of Return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of Return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class Cost of Service Issues

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160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of Return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of Return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of Capital Spending Program
163.	ER95-625-000, et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of Return
164.	P-00950915, et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration Contract Amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of Equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of Return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of Return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of Return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues

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175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition

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189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459 November 1997	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015 November 1997	Allegheny Power System DQE, Inc.	Pennsylvania	Office of Consumer Advocate	Merger Issues
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return
196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan

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203.	Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204.	Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205.	Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206.	Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs
207.	Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208.	Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209.	Docket No. EC-98-40-000, et al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation
210.	Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211.	Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212.	WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213.	2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214.	DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215.	00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216.	Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations

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217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power
219.	Case No. 21453, et al. July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453, et al. February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs
223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Connectivity	Maryland	MD Energy Administration	Merger Issues

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231.	U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232.	U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233.	3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234.	99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review
235.	U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Uprates Purchase Power
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237.	U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238.	R-00016849C001, et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return
239.	U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240.	U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241.	U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract
242.	8936 October 2002	Delmarva Power & Light	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243.	U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245.	02S-315EG November 2002	Public Service Company of Colorado	Colorado	Fed. Executive Agencies	Rate of Return

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246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Administration Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery
252.	C2-99-1181 October 2003	Ohio Edison Company	U.S. District Court	U.S. Department of Justice, et al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)
255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return
259.	E-01345A-03-0437 January 2004	Arizona Public Service Company	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return

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261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Company	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant Purchase and Cost Recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings
269.	EF03070532 March 2005	Public Service Electric & Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract
273.	05-0045-EI June 2005	Florida Power & Lt.	Florida	Federal Executive Agencies	Rate of Return
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration	POLR Service
275.	U-28155 August 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Independent Coordinator of Transmission Plan

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276.	U-27866-A September 2005	Southwestern Electric Power Company	Louisiana	LPSC Staff	Purchase Power Contract
277.	U-28765 October 2005	Cleco Power LLC	Louisiana	LPSC Staff	Purchase Power Contract
278.	U-27469 October 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Avoided Cost Methodology
279.	A-313200F007 October 2005	Sprint (United of PA)	Pennsylvania	Office of Consumer Advocate	Corporate Restructuring
280.	EM05020106 November 2005	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Merger Issues
281.	U-28765 December 2005	Cleco Power LLC	Louisiana	LPSC Staff	Plant Certification, Financing, Rate Plan
282.	U-29157 February 2006	Cleco Power LLC	Louisiana	LPSC Staff	Storm Damage Financing
283.	U-29204 March 2006	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Purchase power contracts
284.	A-310325F006 March 2006	Alltel	Pennsylvania	Office of Consumer Advocate	Merger, Corporate Restructuring
285.	9056 March 2006	Generic	Maryland	Maryland Energy Administration	Standard Offer Service Structure
286.	C2-99-1182 April 2006	American Electric Power Utilities	U. S. District Court Southern District, Ohio	U. S. Department of Justice	New Source Review Enforcement (expert report)
287.	EM05121058 April 2006	Atlantic City Electric	New Jersey	Ratepayer Advocate	Power plant Sale
288.	ER05121018 June 2006	Jersey Central Power & Light Company	New Jersey	Ratepayer Advocate	NUG Contracts Cost Recovery
289.	U-21496, Subdocket C June 2006	Cleco Power LLC	Louisiana	Commission Staff	Rate Stabilization Plan
290.	GR0510085 June 2006	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Rate of Return (gas services)

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291.	R-000061366 July 2006	Metropolitan Ed. Company Penn. Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
292.	9064 September 2006	Generic	Maryland	Energy Administration	Standard Offer Service
293.	U-29599 September 2006	Cleco Power LLC	Louisiana	Commission Staff	Purchase Power Contracts
294.	WR06030257 September 2006	New Jersey American Water Company	New Jersey	Rate Counsel	Rate of Return
295.	U-27866/U-29702 October 2006	Southwestern Electric Power Company	Louisiana	Commission Staff	Purchase Power/Power Plant Certification
296.	9063 October 2006	Generic	Maryland	Energy Administration Department of Natural Resources	Generation Supply Policies
297.	EM06090638 November 2006	Atlantic City Electric	New Jersey	Rate Counsel	Power Plant Sale
298.	C-2000065942 November 2006	Pike County Light & Power	Pennsylvania	Consumer Advocate	Generation Supply Service
299.	ER06060483 November 2006	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
300.	A-110150F0035 December 2006	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
301.	U-29203, Phase II January 2007	Entergy Gulf States Entergy Louisiana	Louisiana	Commission Staff	Storm Damage Cost Allocation
302.	06-11022 February 2007	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
303.	U-29526 March 2007	Cleco Power	Louisiana	Commission Staff	Affiliate Transactions
304.	P-00072245 March 2007	Pike County Light & Power	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
305.	P-00072247 March 2007	Duquesne Light Company	Pennsylvania	Consumer Advocate	Provider of Last Resort Service

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306.	EM07010026 May 2007	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Power Plant Sale
307.	U-30050 June 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
308.	U-29956 June 2007	Entergy Louisiana	Louisiana	Commission Staff	Black Start Unit
309.	U-29702 June 2007	Southwestern Electric Power Company	Louisiana	Commission Staff	Power Plant Certification
310.	U-29955 July 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contracts
311.	2007-67 July 2007	FairPoint Communications	Maine	Office of Public Advocate	Merger Financial Issues
312.	P-00072259 July 2007	Metropolitan Edison Co.	Pennsylvania	Office of Consumer Advocate	Purchase Power Contract Restructuring
313.	EO07040278 September 2007	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Energy Program Financial Issues
314.	U-30192 September 2007	Entergy Louisiana	Louisiana	Commission Staff	Power Plant Certification Ratemaking, Financing
315.	9117 (Phase II) October 2007	Generic (Electric)	Maryland	Energy Administration	Standard Offer Service Reliability
316.	U-30050 November 2007	Entergy Gulf States	Louisiana	Commission Staff	Power Plant Acquisition
317.	IPC-E-07-8 December 2007	Idaho Power Co.	Idaho	U.S. Department of Energy	Cost of Capital
318.	U-30422 (Phase I) January 2008	Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
319.	U-29702 (Phase II) February, 2008	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Certification
320.	March 2008	Delmarva Power & Light	Delaware State Senate	Senate Committee	Wind Energy Economics

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321.	U-30192 (Phase II) March 2008	Entergy Louisiana	Louisiana	Commission Staff	Cash CWIP Policy, Credit Ratings
322.	U-30422 (Phase II) April 2008	Entergy Gulf States - LA	Louisiana	Commission Staff	Power Plant Acquisition
323.	U-29955 (Phase II) April 2008	Entergy Gulf States - LA Entergy Louisiana	Louisiana	Commission Staff	Purchase Power Contract
324.	GR-070110889 April 2008	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of Capital
325.	WR-08010020 July 2008	New Jersey American Water Company	New Jersey	Rate Counsel	Cost of Capital
326.	U-28804-A August 2008	Entergy Louisiana	Louisiana	Commission Staff	Cogeneration Contract
327.	IP-99-1693C-M/S August 2008	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/ Environmental Protection Agency	Clean Air Act Compliance (Expert Report)
328.	U-30670 September 2008	Entergy Louisiana	Louisiana	Commission Staff	Nuclear Plant Equipment Replacement
329.	9149 October 2008	Generic	Maryland	Department of Natural Resources	Capacity Adequacy/Reliability
330.	IPC-E-08-10 October 2008	Idaho Power Company	Idaho	U.S. Department of Energy	Cost of Capital
331.	U-30727 October 2008	Cleco Power LLC	Louisiana	Commission Staff	Purchased Power Contract
332.	U-30689-A December 2008	Cleco Power LLC	Louisiana	Commission Staff	Transmission Upgrade Project
333.	IP-99-1693C-M/S February 2009	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/EPA	Clean Air Act Compliance (Oral Testimony)
334.	U-30192, Phase II February 2009	Entergy Louisiana, LLC	Louisiana	Commission Staff	CWIP Rate Request Plant Allocation
335.	U-28805-B February 2009	Entergy Gulf States, LLC	Louisiana	Commission Staff	Cogeneration Contract

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336.	P-2009-2093055, et al. May 2009	Metropolitan Edison Pennsylvania Electric	Pennsylvania	Office of Consumer Advocate	Default Service
337.	U-30958 July 2009	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract
338.	EO08050326 August 2009	Jersey Central Power Light Co.	New Jersey	Rate Counsel	Demand Response Cost Recovery
339.	GR09030195 August 2009	Elizabethtown Gas	New Jersey	New Jersey Rate Counsel	Cost of Capital
340.	U-30422-A August 2009	Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase
341.	CV 1:99-01693 August 2009	Duke Energy Indiana	Federal District Court – Indiana	U. S. DOJ/EPA, et al.	Environmental Compliance Rate Impacts (Expert Report)
342.	4065 September 2009	Narragansett Electric	Rhode Island	Division Staff	Cost of Capital
343.	U-30689 September 2009	Cleco Power	Louisiana	Staff	Cost of Capital, Rate Design, Other Rate Case Issues
344.	U-31147 October 2009	Entergy Gulf States Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
345.	U-30913 November 2009	Cleco Power	Louisiana	Staff	Certification of Generating Unit
346.	M-2009-2123951 November 2009	West Penn Power	Pennsylvania	Office of Consumer Advocate	Smart Meter Cost of Capital (Surrebuttal Only)
347.	GR09050422 November 2009	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Cost of Capital
348.	D-09-49 November 2009	Narragansett Electric	Rhode Island	Division Staff	Securities Issuances
349.	U-29702, Phase II November 2009	Southwestern Electric Power Company	Louisiana	Commission Staff	Cash CWIP Recovery
350.	U-30981 December 2009	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Storm Damage Cost Allocation

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351.	U-31196 (ITA Phase) February 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
352.	ER09080668 March 2010	Rockland Electric	New Jersey	Rate Counsel	Rate of Return
353.	GR10010035 May 2010	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of Return
354.	P-2010-2157862 May 2010	Pennsylvania Power Co.	Pennsylvania	Consumer Advocate	Default Service Program
355.	10-CV-2275 June 2010	Xcel Energy	U.S. District Court Minnesota	U.S. Dept. Justice/EPA	Clean Air Act Enforcement
356.	WR09120987 June 2010	United Water New Jersey	New Jersey	Rate Counsel	Rate of Return
357.	U-30192, Phase III June 2010	Entergy Louisiana	Louisiana	Staff	Power Plant Cancellation Costs
358.	31299 July 2010	Cleco Power	Louisiana	Staff	Securities Issuances
359.	App. No. 1601162 July 2010	EPCOR Water	Alberta, Canada	Regional Customer Group	Cost of Capital
360.	U-31196 July 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
361.	2:10-CV-13101 August 2010	Detroit Edison	U.S. District Court Eastern Michigan	U.S. Dept. of Justice/EPA	Clean Air Act Enforcement
362.	U-31196 August 2010	Entergy Louisiana Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase and Cost Recovery
363.	Case No. 9233 October 2010	Potomac Edison Company	Maryland	Energy Administration	Merger Issues
364.	2010-2194652 November 2010	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default Service Plan
365.	2010-2213369 April 2011	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues

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366.	U-31841 May 2011	Entergy Gulf States	Louisiana	Staff	Purchase Power Agreement
367.	11-06006 September 2011	Nevada Power	Nevada	U. S. Department of Energy	Cost of Capital
368.	9271 September 2011	Exelon/Constellation	Maryland	MD Energy Administration	Merger Savings
369.	4255 September 2011	United Water Rhode Island	Rhode Island	Division of Public Utilities	Rate of Return
370.	P-2011-2252042 October 2011	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default service plan
371.	U-32095 November 2011	Southwestern Electric Power Company	Louisiana	Commission Staff	Wind energy contract
372.	U-32031 November 2011	Entergy Gulf States Louisiana	Louisiana	Commission Staff	Purchased Power Contract
373.	U-32088 January 2012	Entergy Louisiana	Louisiana	Commission Staff	Coal plant evaluation
374.	R-2011-2267958 February 2012	Aqua Pa.	Pennsylvania	Office of Consumer Advocate	Cost of capital
375.	P-2011-2273650 February 2012	FirstEnergy Companies	Pennsylvania	Office of Consumer Advocate	Default service plan
376.	U-32223 March 2012	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract and Rate Recovery
377.	U-32148 March 2012	Entergy Louisiana Energy Gulf States	Louisiana	Commission Staff	RTO Membership
378.	ER11080469 April 2012	Atlantic City Electric	New Jersey	Rate Counsel	Cost of capital
379.	R-2012-2285985 May 2012	Peoples Natural Gas Company	Pennsylvania	Office of Consumer Advocate	Cost of capital
380.	U-32153 July 2012	Cleco Power	Louisiana	Commission Staff	Environmental Compliance Plan

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381.	U-32435 August 2012	Entergy Gulf States Louisiana LLC	Louisiana	Commission Staff	Cost of equity (gas)
382.	ER-2012-0174 August 2012	Kansas City Power & Light Company	Missouri	U. S. Department of Energy	Rate of return
383.	U-31196 August 2012	Entergy Louisiana/ Entergy Gulf States	Louisiana	Commission Staff	Power Plant Joint Ownership
384.	ER-2012-0175 August 2012	KCP&L Greater Missouri Operations	Missouri	U.S. Department of Energy	Rate of Return
385.	4323 August 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Rate of Return (electric and gas)
386.	D-12-049 October 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Debt issue
387.	GO12070640 October 2012	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of capital
388.	GO12050363 November 2012	South Jersey Gas Company	New Jersey	Rate Counsel	Cost of capital
389.	R-2012-2321748 January 2013	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Cost of capital
390.	U-32220 February 2013	Southwestern Electric Power Co.	Louisiana	Commission Staff	Formula Rate Plan
391.	CV No. 12-1286 February 2013	PPL et al.	Federal District Court	MD Public Service Commission	PJM Market Impacts (deposition)
392.	EL13-48-000 February 2013	BGE, PHI subsidiaries	FERC	Joint Customer Group	Transmission Cost of Equity
393.	EO12080721 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
394.	EO12080726 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
395.	CV12-1286MJG March 2013	PPL, PSEG	U.S. District Court for the District of Md.	Md. Public Service Commission	Capacity Market Issues (trial testimony)

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396.	U-32628 April 2013	Entergy Louisiana and Gulf States Louisiana	Louisiana	Staff	Avoided cost methodology
397.	U-32675 June 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	RTO Integration Issues
398.	ER12111052 June 2013	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Cost of capital
399.	PUE-2013-00020 July 2013	Dominion Virginia Power	Virginia	Apartment & Office Building Assoc. of Met. Washington	Cost of capital
400.	U-32766 August 2013	Cleco Power	Louisiana	Staff	Power plant acquisition
401.	U-32764 September 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	Storm Damage Cost Allocation
402.	P-2013-237-1666 September 2013	Pike County Light and Power Co.	Pennsylvania	Office of Consumer Advocate	Default Generation Service
403.	E013020155 and G013020156 October 2013	Public Service Electric and Gas Company	New Jersey	Rate Counsel	Cost of capital
404.	U-32507 November 2013	Cleco Power	Louisiana	Staff	Environmental Compliance Plan
405.	DE11-250 December 2013	Public Service Co. New Hampshire	New Hampshire	Consumer Advocate	Power plant investment prudence
406.	4434 February 2014	United Water Rhode Island	Rhode Island	Staff	Cost of Capital
407.	U-32987 February 2014	Atmos Energy	Louisiana	Staff	Cost of Capital
408.	EL 14-28-000 February 2014	Entergy Louisiana Entergy Gulf States	FERC	LPSC	Avoided Cost Methodology (affidavit)
409.	ER13111135 May 2014	Rockland Electric	New Jersey	Rate Counsel	Cost of Capital

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410.	13-2385-SSO, et al. May 2014	AEP Ohio	Ohio	Consumers' Counsel	Default Service Issues
411.	U-32779 May 2014	Cleco Power, LLC	Louisiana	Staff	Formula Rate Plan
412.	CV-00234-SDD-SCR June 2014	Entergy Louisiana Entergy Gulf	U.S. District Court Middle District Louisiana	Louisiana Public Service Commission	Avoided Cost Determination Court Appeal
413.	U-32812 July 2014	Entergy Louisiana	Louisiana	Louisiana Public Service Commission	Nuclear Power Plant Prudence
414.	14-841-EL-SSO September 2014	Duke Energy Ohio	Ohio	Office of Consumer' Counsel	Default Service Issues
415.	EM14060581 November 2014	Atlantic City Electric Company	New Jersey	Rate Counsel	Merger Financial Issues
416.	EL15-27 December 2014	BGE, PHI Utilities	FERC	Joint Complainants	Cost of Equity
417.	14-1297-EL-SSO December 2014	First Energy Utilities	Ohio	Consumer's Counsel and NOPEC	Default Service Issues
418.	EL-13-48-001 January 2015	BGE, PHI Utilities	FERC	Joint Complainants	Cost of Equity
419.	EL13-48-001 and EL15-27-000 April 2015	BGE and PHI Utilities	FERC	Joint Complainants	Cost of Equity
420.	U- 33592 November 2015	Entergy Louisiana	Louisiana Public Service Commission	Commission Staff	PURPA PPA Contract
421.	GM15101196 April 2016	AGL Resources	New Jersey	Rate Counsel	Financial Aspects of Merger
422.	U-32814 April 2016	Southwestern Electric Power	Louisiana	Staff	Wind Energy PPAs
423.	A-2015-2517036, et.al. April 2016	Pike County	Pennsylvania	Consumer Advocate	Merger Issues

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424.	EM15060733 August 2016	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Transmission Divestiture
425.	16-395-EL-SSO November 2016	Dayton Power & Light Company	Ohio	Ohio Consumer's Counsel	Electric Security Plan
426.	PUE-2016-00001 January 2017	Washington Gas Light	Virginia	AOBA	Cost of Capital
427.	U-34200 April 2017	Southwestern Power Co.	Louisiana	Commission Staff	Design of Formula Rate Plan