STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE IRENE JONES

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	)	**BPU DOCKET No. ER11080469** **OAL DOCKET No. PUCRL 09929-2011**

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 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044.

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 30 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 restructuring and competition.

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 and federal court in more than 350 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. In 1989, I testified before the U. S. House of Representatives, Committee on Ways and Means, on proposed federal tax legislation affecting utilities. A list of these cases may be found 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 2001,1 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, New Jersey Division of Rate Counsel, Rhode Island Division of Public Utilities, Louisiana Public Service Commission, Arkansas Public Service Commission, the Maine Public Advocate, Maryland Department of Natural Resources and Energy Administration, and MCI.

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 20 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. GR070110889), 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. WR0912087). I participated in the previous Atlantic City Electric Company ("ACE" or "the Company") on a rate of return issues (BPU Docket No ER09080664). 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.

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

A. As presented in the Company's 12 + 0 Update, the Company requests an authorized overall rate of return of 8.56 percent. The proposed capital structure is indicated as being the Company's adjusted actual capital structure at December 31, 2011, which includes 48.86 percent common equity and 51.14 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 10.75 percent. The overall rate of return, capital structure and cost of debt recommendations are sponsored by witness Kevin M. McGowan, and the cost of equity recommendation is sponsored by the Company's consultant on Mr. Robert B. Hevert. Mr. Hevert's 10.75 percent return on equity ("ROE") is based on the results of his various studies. The 10.75 percent recommendation appears to be based on judgment after consideration of his study results. Mr. Hevert estimates a cost of equity range of 10.5 to 11.25 percent and recommends "at least" 10.75 percent for ACE.

Q. WHAT IS ACE'S CORPORATE STRUCTURE?

A. ACE is a wholly-owned subsidiary of PEPCO Holdings, Inc. ("PEPCO"), which is a corporate holding company that owns two other electric utility operating companies. PEPCO also has non-utility operations (Pepco Energy Services), and it recently sold off most of its unregulated generation assets. ACE is the smallest of the three PEPCO utility subsidiaries.

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

A. As summarized on Schedule MIK-1, page 1 of 2, I am recommending at this time a return on ACE's jurisdictional electric distribution rate base of 7.88 percent. This includes a return on common equity of 9.5 percent and a capital structure of 52 percent long-term plus short-term debt and 48 percent common equity. This capital structure recommendation includes a slightly higher debt ratio than that proposed by the Company but is provisional and may change with updating. It includes the Company's proposal to remove securitization debt, but I have reversed the Company's proposal to subtract unamortized debt-related expenses (about $18 million) from the balance of debt outstanding, and I have included a small amount of short-term debt (about $12 million). Please note that my preference would be to exclude short-term debt from capital structure and instead directly assign it to the financing of Construction Work in Progress ("CWIP"). Unfortunately, this is not ACE's current practice, but I recommend that the Board direct ACE to do so.

Q. WHAT IS YOUR COST OF DEBT RECOMMENDATION?

A. I am using at this time a long-term cost of debt of 6.47 percent, which is identical to that sponsored by witness McGowan on behalf of the Company in its 12 + 0 Update. This cost of debt figure is the actual cost rate at year-end 2011, inclusive of debt-related expenses.

Q. HOW DOES MR. HEVERT DEVELOP HIS 10.75 PERCENT ROE RECOMMENDATION?

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 ten publically-traded electric companies. Mr. Hevert's testimony is rather complex, and he develops ranges for each cost of equity methodology. Focusing on his mean or midpoint results, he obtains estimates of about 10.85 percent for the DCF, 10.3 percent for the CAPM approach (i.e., the average of his eight CAPM calculations) and 10.76 percent for the Risk Premium study. He also calculates a flotation expense adder of 0.16 percent but does not directly include it in his results. Based on these results he obtains a range of 10.5 to 11.25 percent and recommends a point value of 10.75 percent.

Q. HOW HAVE YOU DEVELOPED YOUR 9.5 PERCENT ROE RECOMMENDATION?

A. I rely primarily on the use of the DCF model as applied to a proxy group of electric distribution utility companies. This produces a range of 8.5 to 9.5 percent, with a midpoint of 9.0 percent. As a secondary analysis, I have applied the DCF model to Mr. Hevert's proxy group of vertically-integrated electric utility companies (removing one company as discussed later in my testimony). This proxy group study results in a DCF return range estimate of 8.9 to 9.9 percent, with a 9.4 percent midpoint. Mr. Hevert's proxy group is less appropriate in this case because it measures (to some degree) the risks associated with generation assets and supply, whereas this case sets rates for ACE's distribution service. ACE ratepayers already pay for the risks associated with generation supply in the Basic Generation Service ("BGS") charges or competitive service.

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 little weight on the CAPM results.

In my opinion, these cost of equity study results, taking into account the recent conditions in financial markets, support the reasonableness of my 9.5 percent return on equity recommendation for ACE at this time.

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

A. There are several differences including the timing of when our studies were undertaken. Mr. Hevert relies on a proxy group of integrated electrics, reflecting generation risk, whereas I primarily use a proxy group of distribution electrics. In addition, Mr. Hevert uses overstated interest rates in his CAPM and risk premium studies.

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 discuss the business risk attributes for the Company (i.e., along with its parent) including the views of credit rating agencies.

Q. YOU RECOMMEND AN ROE OF 9.5 PERCENT AND MR. HEVERT RECOMMENDS 10.75 PERCENT. HOW DOES THIS RANGE COMPARE TO ROES GRANTED TO ACE'S UTILITY AFFILIATES?

A. Rate Counsel requested such information for 2010 and 2011 in RCR-ROR-15. The response indicates the following recent ROE awards by jurisdiction:

Delaware	10.0%	(August 2011)
Maryland	10.0%	(July 2011)
Washington, D.C.	9.625%	(March 2010)
Maryland	9.83%	(August 2010)
Average	**9.8%**	

These awards for other PEPCO utilities are far below Mr. Hevert's recommendation, and are far more consistent with my position in this case. Moreover, while the average of 9.8 percent is modestly higher than my recommendation, the cost of capital has declined over the past two years as discussed in the next subsection of my testimony.

Q. WHAT IS ACE'S CURRENTLY AUTHORIZED RETURN ON EQUITY?

A. My understanding is that a return on equity of 10.3 percent was established for ACE by settlement in the last rate case (2009/2010). This figure is higher than my current recommendation though lower than the Company's current request. As discussed below, capital costs have declined and capital markets have improved since 2010. As shown on page 1 of Schedule MIK-2, Single A utility bond yields were 5.5 to 6.0 percent in 2009 and 2010, and in recent months have been well below 5 percent. Prior to the 10.3 percent award, ACE was authorized 9.75 percent.

B. Capital Cost Trends

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 2011, on page 1 of Schedule MIK-2. Pages 2, 3 and 4 of that schedule show monthly data for January 2007 through February 2012. The indicators provided include the annualized inflation rate (as measured by the Consumer Price Index), ten-year Treasury yields, 3-month Treasury bill yields and Moody's Single A yields on long-term utility bonds. While there is some fluctuation, these data series show a generally declining trend in capital costs. For example, in the early part of this ten-year period utility bond yields averaged about 8 percent, with 10-year Treasury yields of 5 percent. By 2011, Single A utility bond yields had fallen to 5.1 percent, with ten-year Treasury yields declining to 2.8 percent. Within the past six months, Treasury and utility long-term bond rates have declined even further to near or below the lowest levels in decades.

For the past three 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) are the result of an intentional policy of the Federal Reserve Board of Governors (the Fed) to make liquidity available to the U.S. economy and to promote economic activity. The Fed has also sought to exert downward pressure on long-term interest rates through its policy of "quantitative easing." Although that program ended this past summer, the Fed announced a continuation of its near-zero short-term interest rate policy at least through 2013 and possibly 2014. As a result, interest rates have remained low and have trended down and, for at least the near term, this is expected to continue.

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

A. Yes. While the decline in short-term rates is largely attributable to Fed policy decisions, the behavior of long-term rates reflects more fundamental economic forces. Factors that drive down long-term bond interest rates include the ongoing weakness of the U.S. and global macro economy, the inflation outlook and even international events. A weak 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 lacking. While inflation measures can fluctuate from month to month, long-term inflation rate expectations presently remain quite low. Europe's Euro-zone continuing sovereign debt crisis may contribute to lower U.S. interest rates, as U.S. securities are valued as a relative "safe haven" for global capital.

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 in lock step or in the short run. The economic forces mentioned above 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 investment vehicles that compete with each other, and in that sense utility stocks and long-term bonds are 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), March 10, 2012 edition, a survey compilation of approximately 40 major forecast organizations. The "consensus" calls for real GDP growth of 2.3 percent in 2012 and 2.6 percent in 2013 and inflation (GDP deflator) of 1.8 percent in 2012 and 1.9 percent in 2013. The March 2012 edition of Blue Chip also publishes a consensus ten-year inflation forecast of 2.1 to 2.2 percent per year, which is very similar to the near term outlook.

Q. HAS THE PATTERN BEEN SIMILAR FOR EQUITY MARKETS?

A. As one would expect, equity markets have exhibited far more volatility than bond markets. Following the onset of the financial crisis about three years ago, stock market prices plunged, reaching a bottom in March 2009. Since then, stock prices recovered impressively and the major indexes have largely recovered to pre-crisis levels. The market recovery continued through most of the first half of 2011, but it then began to deteriorate in late July 2011. The second half of 2011 was characterized by significant stock market losses, some recovery and high volatility. The federal debt ceiling debate issue and the subsequent Standard & Poors (S&P) downgrade of Treasury securities may have been initial triggering events for the equity market turmoil during August and September 2011. The larger fundamental concerns of investors, based on reporting by the financial press, include the unraveling of the Euro-zone sovereign debt crisis (and its potential adverse impact on the European banking system) and the expectations by investors of the potential for further weakening in the U.S. economy (and to a lesser extent, the global economy). In the fourth quarter 2011, the stock market recovered, and for 2011 overall the broad market was flat or provided only very modest returns for investors. The first quarter of 2012 has been very positive for equities.

The effects of these economic events on U.S. utilities (such as ACE), however, are difficult to interpret. It would seem that the Euro-zone and global economic issues would have little to do directly with U.S. electric distribution utilities such as ACE. However, the 2011 behavior of markets may, in a general sense, reflect heightened equity risk premiums. At the same time, the continuing economic weakness tends to exert downward pressure on capital costs, interest rates and inflation. Thus, despite the turmoil in financial markets, we remain in a generally low 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 large extent I have done so. As a general matter, utility stocks have been reasonably stable in late 2011, and into the first two months of 2012, as my testimony demonstrates. The observed 2011 overall stock market volatility was quite significant, but it may turn out to be transitory. While these market events are notable, there is no clear evidence that this 2011 European and U.S. equity market volatility has adversely affected the utility cost of capital. Indeed, equity markets have stabilized and moved upward during the first quarter of 2012. Dividend yields for utility companies (such as low-risk electric utility companies) have been reasonably stable, and the utility long-term cost of debt is at a historic low. At this point, I believe it is reasonable to rely on a most recent six-month average of market data, which has been my past practice. This use of market data over a several month period fully accounts for market volatility as well as recent market recovery.

C. **Overview of Testimony**

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

A. Section III of my testimony presents my discussion of the capital structure and cost of debt recommended in this case by the Company. This section also discusses ACE's business risk profile. 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. Finally, Section V is my review of Mr. Hevert's cost of equity studies, risk adjustments and his 10.75 percent ROE recommendation. In this section, I also comment on ACE witness Cannell's discussion of the risk environment and ACE's financial need. Finally, Section VI provides a summary of major findings and conclusions.

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 48.86 common equity and 51.14 percent long-term debt is the Company's adjusted actual December 31, 2011 capital structure provided with the recently submitted 12 + 0 Update. 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 49 percent equity ratio compares with 48.0 percent for the electric distribution group (excluding Central Vermont) and 50.6 percent for the riskier integrated electric group. These equity ratios, however, should be viewed with some caution. They are reported by Value Line, which in calculating the ratios excludes short-term debt and current maturities of long-term debt. As a result, Value Line is reflecting in its reported equity ratios only about 90 percent of total debt (on average), and for that reason the Value Line equity ratios are somewhat overstated. Thus, ACE's proposed equity ratio of 49 percent is similar to or somewhat higher than the proxy group averages when total debt is considered. By this standard, I conclude that ACE has a reasonably strong balance sheet.

Q. WHAT ADJUSTMENTS DOES ACE PROPOSE?

A. As shown in the response to RCR-ROR-36, ACE has excluded transition bonds, along with the common equity ($2.9 million) of its transition bond special purpose entity (ACE Transition Funding LLC). For capital structure purposes, the Company removes about $18 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 $856 million to $838 million. Finally, ACE has chosen to exclude short-term debt from 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. I do not favor the $18 million debt reduction for the unamortized debt expense. I believe this adjustment is non-standard and contrary to typical practice in New Jersey for setting capital structure. Finally, I have concerns regarding the Company's exclusion of short-term debt from capital structure.

Q. HAS THE COMPANY CITED ANY AUTHORITY FOR THE $18 MILLION DEDUCTION TO THE DEBT BALANCE?

A. Rate Counsel requested in RCR-ROR-19 a cite to Board authority for this adjustment. The Company responded as follows:

> The Company is unaware if this treatment of debt financing costs (i.e., with the above subtractions) has been previously accepted by the Board for ratemaking capital structure purposes.

The response goes on to indicate that the District of Columbia and Maryland apparently have accepted this treatment (obviously for ACE's utility affiliate, PEPCO).

At this time, I believe that it is reasonable to use the balance of debt outstanding absent the $18 million adjustment. Please note that the debt-related expenses in question will be recovered by the Company in two ways. First, an annual amortization of these expenses is reflected (added to interest expense) for cost of debt purposes. Second, in computing the embedded cost of debt the $18 million of the unamortized balance of debt expense is removed. That is, ACE computes its cost of debt by taking annualized interest expense (which includes these annual expenses) divided by the lower figure of $838 million, not the higher $856 million (debt outstanding). Thus, the Company's proposed 6.47 percent cost rate for long-term debt provides full recovery of these debt-related expenses, including a return. It is simply not necessary (and costly to ratepayers) to take the further step of artificially reducing the debt balance for computing capital structure ratios.

I have reversed this $18 million adjustment and am using the actual balance of debt outstanding (excluding securitization debt) for capital structure purposes.

Q. WHY HAS THE COMPANY EXCLUDED SHORT-TERM DEBT FROM CAPITAL STRUCTURE?

A. Rate Counsel sought an explanation in RCR-ROR-21. The Company's response indicated that short-term debt should be viewed as funding CWIP, a non-rate base item that must be financed. The response goes on to reference the Federal Energy Regulatory Commission ("FERC") formula in which "short term debt is assumed to fund CWIP."

The Company's response suggests that it is proper to exclude short-term debt from the ratemaking capital structure because it is already fully accounted for in the financing of CWIP, i.e., the Allowance for Funds Used during Construction ("AFUDC") rate. The problem is that ACE's other data responses do not seem to confirm that treatment. For example, the Company's response to RCR-ROR-6 states that the current AFUDC rate being used is 8.25 percent which seems out of line with current short-term debt rates of less than 1 percent. In response to RCR-ROR-33, ACE states that it "does not directly assign short-term debt to construction work in progress (CWIP) for AFUDC accrual purposes."

In light of these data responses and ACE's decision not to directly assign short-term debt to CWIP, it is necessary to include short-term debt in capital structure.

Q. IS IT YOUR PREFERENCE TO INCLUDE SHORT-TERM DEBT IN CAPITAL STRUCTURE?

A. This depends partly on past regulatory practice and whether the Company has a large construction program. Given ACE's circumstances and construction program, I would prefer excluding it from capital structure and instead directly assigning it to CWIP. Since short-term debt usage tends to fluctuate, this would provide a more accurate matching or assigning of short-term debt. Unfortunately, ACE's current AFUDC practice necessitates including short-term debt in capital structure in this case, unless ACE agrees or is directed by the Board to change its AFUDC methodology. I recommend that the Board do so.

Q. HOW MUCH SHORT-TERM DEBT ARE YOU INCLUDING IN CAPITAL STRUCTURE?

A. I am including $11.8 million. This is the average reported balance for the period May through December 2011. Normally, I would use a 12-month average, i.e., the 2011 calendar year average. However, in this case the Company issued $200 million of long-term debt in April 2011, and it appears that one of the uses of the proceeds was to pay down short-term debt balances. Thus, the inclusion of the much higher balances prior to May 2011 would not necessarily be appropriate. I intend to update short-term debt through April 2012 later in this case so that a full 12-month average can be used.

Q. WITH YOUR CHANGES, WHAT CAPITAL STRUCTURE ARE YOU RECOMMENDING?

A. As shown on page 1 of Schedule MIK-1, I recommend a common equity ratio of 47.98 percent, a short-term debt ratio of 0.71 percent and a long-term debt ratio of 51.31 percent. This capital structure is consistent with (or stronger than) the proxy group average and the Company's own target range. For example, the response to RCR-ROR-13 states: "ACE's capital structure target for equity is in the high 40 percent range."

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

A. ACE proposes in its 12 + 0 Update a 6.47 percent, which is the calculated embedded cost at December 31, 2011 (S-AROR-5 Update). As noted above, this cost rate provides for full cost recovery of all debt expenses, discounts/premiums and reacquisition costs. The 6.47 percent is well above ACE's cost rate for new debt. For example in April 2011, the Company issued new long-term debt (ten-year term) at an interest rate of 4.35 percent. The relatively high cost rate of 6.47 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, and the Company reports that it has no opportunity to economically refinance this expensive debt. (See Company's response to SROR-2.) Absent this one debt issue, the ACE cost of debt would be 5.86 percent.

B. <u>Discussion of Credit Ratings and Risk</u>

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

A. In my opinion, they have not. The Company has sponsored two outside witnesses, Ms. Cannell and Mr. Hevert on cost of capital and business risk issues. The analyses regarding ACE's business risk provided by these witnesses is very limited and not particularly balanced. Mr. Hevert cites to credit ratings and ACE's allegedly small size, but little more. Ms. Cannell discusses ACE's construction plan, the need to access capital markets and regulatory lag as risks specific to ACE. As a result, Ms. Cannell seems to suggest that the rate of return award should reflect the upper end of the range, a suggestion that Mr. Hevert apparently does not adopt.

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 Ms. Cannell that ACE needs to access capital markets, has substantial capital requirements and can experience regulatory lag, she makes 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 than regulation in other jurisdictions.

What is even more disturbing is that these two witnesses do not acknowledge in testimony that distribution (or delivery service) electric utilities are exposed to far less risk than vertically-integrated electric utilities that must cope with generation-related risks. In response to RCR-ROR-24, Mr. Hevert appears to grudgingly concede that greater risks are associated with generation than delivery service.

> All else being equal, Mr. Hevert believes that vertically integrated electric utilities are subject to operating risks to which transmission and distribution electric utilities may not be exposed.

This data response admission brings into question Mr. Hevert's decision to omit distribution electrics from his proxy group.

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, as Ms. Cannell states. 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 generation assets and the burdens of providing generation service. 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-9. Moody's assigns ACE an issuer rating of Baa2 and rates its secured bonds A3 (low single A). Standard & Poors ("S&P") assigns ACE ratings based on its assessment of the consolidated parent, PEPCO Holdings, which it rates BBB+. FitchRatings assigns ACE a corporate rating of triple B. All three agencies rate ACE (and its parent) as having a "stable" outlook.

The credit rating reports provide an assessment of Company business risks and financial metrics. Moody's refers to ACE's "relatively low risk transmission and distribution (T&D) operations and the relatively supportive regulatory environment in New Jersey". The report goes on to list the favorable attributes of New Jersey regulation, while also acknowledging the relatively weak financial metrics, regulatory lag and capital needs. (Report dated December 7, 2011)

S&P provided a similar assessment, although focusing more on the parent. It assigns ACE a rating of “excellent” for its business risk profile and “significant” for its financial risk profile. Referring to the PEPCO distribution utilities, S&P states:

> The utilities’ strengths include the lack of competition, increasing energy use by residential and commercial customers, and the absence of generation-related operating risk. Also, the utilities’ ability to pass through power costs to ratepayers without a rate case provides additional credit support.
> (Report of January 27, 2012.)

S&P makes note of PEPCO’s reduction in the relative size of its non-regulated operations as being positive for risk and credit quality.

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 regulate generation. S&P has placed distribution utility service in the same general business risk profile category as water and gas.

Q. MS. CANNELL AND OTHER WITNESSES EMPHASIZE ACE’S NEED TO ACCESS CAPITAL MARKETS. IS THERE ANY RECENT EVIDENCE ON THAT ISSUE?

A. Yes. In April 2011, ACE was able to issue $200 million of new long-term debt at a cost rate of 4.35 percent. This is a very low interest rate, with $200 million being more than ten percent of ACE’s total capitalization. This is a strong indication that ACE can access capital markets on very favorable terms and is evidence of ACE’s very low cost of capital. Moreover, if anything, capital markets have improved from a year ago when this debt was issued.

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 (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 business risk profile, as assessed by credit rating agencies (i.e., Moody's 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. I also take issue with his selection of companies asserted to be good risk proxies for ACE.

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

A. I employ both the DCF and CAPM models, applied to two proxy groups of electric utility companies. However, for reasons discussed in my testimony, I emphasize the DCF model results (as applied to the electric distribution utility 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 distribution 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 discount rate.

Using certain simplifying assumptions that I believe are generally reasonable for utilities, 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 PEPCO Holdings parent and therefore a market proxy is needed. In theory, PEPCO parent could serve as that market proxy, and I have included it as a member of my electric distribution utility proxy group. 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.

In any case, I believe that an appropriately selected proxy group is likely to be 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 can add stability to the results.

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

A. I am using a proxy group that consists of the seven companies included in the Value Line East Electric Industry Group that are predominantly in the delivery service utility business. That is, all seven companies are mostly or entirely electric (and in some cases combination electric/gas) distribution and transmission ("T&D") utilities. None is considered "vertically integrated" or has substantial unregulated generation. Also, all seven are located in the mid-Atlantic or northeast, operate in Regional Transmission Organizations ("RTOs") and provide for retail access (with one exception).

As a second study, I use Mr. Hevert's proxy group of vertically-integrated electrics. However, this group of companies is much less appropriate as a risk proxy for ACE.

Q. SOME OF YOUR PROXY COMPANIES HAVE BEEN TAKEOVER TARGETS. DOES THIS DISTORT YOUR DCF RESULTS?

A. Such activity arguably has the potential to distort the DCF results since the acquisition often raises the stock price of the to-be-acquired company (and correspondingly can sometimes lower that of the acquiring company). There are three of my proxy companies that potentially could be affected in this manner -- C. H. Energy, Central Vermont and NSTAR.

Central Vermont has been the subject of an acquisition since the middle of last year, and this transaction is expected to be completed soon. This clearly has altered its stock price (and therefore lowered its dividend yield) by a material amount. For that reason, I present my DCF results both with and without Central Vermont, and I emphasize use of the "without" results.

A second takeover target is NSTAR, although that transaction has not yet been approved. In the case of NSTAR, the acquisition was done without an acquisition premium, indicating that the stock price is probably not distorted. As Value Line reports in its February 24, 2012 discussion on NSTAR:

> Even if the merger fails to win regulatory approval, however, this would likely not have a big effect on NSTAR stock [price]. When the transaction was struck, there was no merger premium for NSTAR shareholders.

For this reason, it is reasonable to continue to use NSTAR at this time as a proxy company for ACE.

C. H. Energy is the third affected company, with its merger transaction announced only a few weeks ago on February 23, 2012. This clearly caused a "bump" in its share price, thereby reducing the dividend yield. (As noted below, following S&P, I use published month-ending dividend yields for DCF purposes.) This is a very minor problem and easily correctable. To avoid the inclusion of an acquisition premium in the dividend yield data, I substituted C. H. Energy's February 17, 2012 dividend yield (the closing price just before merger announcement) in place of the February 2012 month-ending dividend yield.

Q. DO THE PROXY COMPANIES HAVE ANY RELATIVELY RISKY NON-REGULATED OPERATIONS?

A. Yes, there are some but they are relatively modest. For example, with the recent sale of its merchant generation assets, PEPCO has reduced non-regulated operations to less than ten percent of the total consolidated corporation. These non-regulated operations tend to increase the cost of equity relative to pure delivery service utility, but only slightly. On the whole, my proxy group is an appropriate risk proxy for ACE despite the minor presence of non-regulated operations.

B. DCF Study Using the Electric Distribution Utility Proxy Group

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

A. These seven proxy companies are listed on Schedule MIK-3, page 1 of 2, along with several risk indicators. Notably, the group includes ACE's parent, PEPCO Holdings.

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

No. Mr. Hevert does not include a specific adjustment, but he does suggest that ACE is riskier than his proxy group due to its smaller than average size. That is, he views size as a risk factor that should be considered by the Board in setting the authorized equity return.

As I discuss later in my testimony, there is no basis for adjusting ACE's authorized return based on its purported smaller size.

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 February 2012, the most recent data available to me as of this writing.[1] This covers the last four months of 2011 and the beginning of 2012. During September-October 2011, equity markets experienced significant volatility and some episodes of distress, and those conditions, to the extent they affect the proxy electric companies, are reflected in my DCF studies. Recently, this severe volatility has diminished.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, September 2011 through February 2012. Over this six-month period the proxy group average dividend yields were relatively stable, ranging from a low of 4.08 percent in December 2011 to a high of 4.42 percent in September 2011, averaging 4.26 percent for the full six months. The dividend yields that I cite exclude Central Vermont whose stock price and resulting dividend yield were altered by its pending merger.

For DCF purposes and at this time, I am using a proxy group dividend yield of 4.26 percent.

Q. IS 4.26 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

[1] As noted earlier, for C.H. Energy the February 17, 2012 share price ($58.77) and the prevailing quarterly dividend (multiplied by 4) were used to calculate a dividend yield of 3.8 percent in place of the month-end share price and yield.

4.4 percent. This is based on assuming that half of a year growth is 2.5 percent (i.e., a full year growth is 5.0 percent).

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 the first half of 2011, i.e., about a year ago.

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 very volatile and are not necessarily reliable as prospective measures. This is due in part to extensive corporate or financial restructuring, particularly in the electric industry. 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. It appears that Mr. Hevert places exclusive weight on this information for his DCF studies, and I agree that it warrants substantial emphasis but not the exclusive emphasis that he gives it.

Q. PLEASE DESCRIBE THE ANALYST EARNINGS GROWTH RATE EVIDENCE.

A. Schedule MIK-4, page 3 presents five available and well-known public sources of projected earnings growth rates. Four of these five sources -- YahooFinance, MSNMoney, 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 publically on a subscription basis. Value Line publishes its own projections using annual average earnings per share for a base period of 2008-2010 compared to the annual average for the forecast period of 2015-2017.

As this schedule shows, the growth rates for individual companies vary somewhat among the five sources. These proxy group averages are 5.0 percent for CNNfn, 4.5 percent for YahooFinance, 4.9 percent for MSNMoney, 4.5 percent for Reuters and 4.2 percent for Value Line. Thus, the range of growth rates among the five sources is 4.2 to 5.0 percent. The average of these five sources is 4.6 percent, and I have used these results (along with other evidence) in obtaining a reasonable range growth range for the group of 4.0 to 5.0 percent. These averages exclude Central Vermont, and with that company, the group average would be 4.9 percent.

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 six large companies (i.e., excluding Central Vermont) tend to be somewhat less than analyst growth projections. For the six companies, projected dividend growth averages 2.6 percent, book value growth averages 3.8 percent, and earnings retention growth averages 3.6 percent.

Some analysts and regulators favor the use of earnings retention growth (often referred to as "sustainable growth"), which Value Line indicates to be 3.6 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 six companies of the growth rate (through 2015-2017) 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 six companies (again, excluding Central Vermont), the external growth rate calculated in this manner averages about 0.2 percent. (Note that three of the six proxy companies are not expected to issue any new stock in the near term.) The sum of "internal" or earnings retention growth (i.e., 3.6 percent) and the "external" growth rate (i.e., 0.2 percent) is 3.8 percent.

Given this estimate of 3.8 percent for the sustainable growth rate and 4.6 percent for analyst earnings projections, a reasonable DCF growth rate range is approximately 4.0 to 5.0 percent.

Q. ARE THERE ANY OTHER FACTORS TO CONSIDER?

A. Yes. Mr. Hevert estimates a flotation expense adder of 0.16 percent, although he does not actually directly employ it in his cost of equity estimates. He develops this adjustment based on historic flotation expenses shown on his Exhibit RBH-7.

Mr. Hevert's data indicate that PEPCO Holdings has incurred stock flotation expenses of about $10 million each in 2004 and 2008. There is no indication of when the next PEPCO public stock issuance can be expected.

This information suggests that $10 million in flotation expense may be incurred by PEPCO (on behalf of its subsidiaries) roughly once every four years, or a cost of $2.5 million per year. Since PEPCO Holding's equity balance is approximately $4 billon, this suggests that a flotation adjustment of about 0.1 percent would be appropriate ($2.5 million/$4 billion). I have incorporated this cost figure in my cost of equity calculation.

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 February 2012 is 4.4 percent for this group. Available evidence would support a long-run growth rate in the range of approximately 4.0 to 5.0 percent, as explained above. Summing the adjusted yield, growth rate range and including a 0.1 percent flotation adjustment produces a total return of 8.5 to 9.5 percent, and a midpoint result of 9.0 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.

Q. HOW DOES YOUR 9.0 PERCENT DCF MIDPOINT COMPARE TO MR. HEVERT'S DCF ESTIMATE FOR ELECTRIC DISTRIBUTION UTILITIES?

A. Mr. Hevert reports a series of DCF estimates of about 10.8 percent using his midpoint growth rates. I explain in Section V why I believe his results are overstated.

C. <u>DCF Study Using Mr. Hevert's Proxy Companies</u>

Q. HOW HAVE YOU CONDUCTED YOUR DCF STUDY USING MR. HEVERT'S PROXY COMPANIES?

A. As an important check on my electric distribution utility DCF study, I have conducted an additional DCF study using all but one of Mr. Hevert's ten company group. I excluded one of his companies, Empire District, because that company suspended its dividend payments to shareholders during the last half of 2011, including the time period of my market data. I retained all other nine companies which I list along with their risk indicators on page 2 of Schedule MIK-3. I have conducted this DCF study using essentially the same analytic procedures as I used in my distribution electric utility study.

Q. PLEASE DESCRIBE THESE COMPANIES.

A. All of Mr. Hevert's proxy companies are predominantly electric utilities, but in all cases they are vertically-integrated electric utilities. This means they have regulated generation supply operations. One utility, Southern Company, is located in the East region, and all others are in the Midwest or West Region. They therefore operate in business environments and have functions quite different from ACE. Most of these companies have extensive coal-fired power plants and therefore face difficult issues of compliance with emerging environmental rules which will require financial and operational challenges. Southern Company is presently embarking on a massive and potentially risky nuclear generation expansion plan. While this group on the whole can be considered to be predominantly regulated, some have important non-regulated operations. For these reasons, I consider this group, on average, to have much greater business risk than ACE.

Q. WHAT IS THE DIVIDEND YIELD FOR THIS GROUP?

A. As shown on Schedule MIK-5, page 2 of 5, the group average dividend yield for the six months ending February 2012 is 4.21 percent. The adjusted dividend yield for this proxy group is 4.3 percent. The supporting detail is listed on page 3 of Schedule MIK-5.

Q. WHAT IS THE GROWTH RATE EVIDENCE?

A. I show the analyst projections of earnings growth for these nine companies on Schedule MIK-5, page 3 of 5, employing the same five public sources as used for the distribution electric utility proxy group. The group averages are 6.5 percent for Value Line, 5.2 percent for Reuters, 5.3 percent for YahooFinance, 5.0 percent for CNNfn and 5.5 percent for MSNMoney. The five sources average to 5.5 percent.

A second set of growth rates for the nine-company integrated utility group is shown on page 4 of Schedule MIK-5. This schedule provides Value Line's projections of dividends, book value and growth from earnings retention. These growth rates are generally similar to the securities analyst projections, averaging 3.9 percent for dividends, 3.9 percent for book value and 3.8 percent for earnings retention growth.

As mentioned earlier, an important alternative to analyst projections is earnings retention or the "sustainable" measure of long-term growth. The internal component for this proxy group is 3.8 percent, as shown on page 4 of Schedule MIK-5. I calculated an "external" or "s x v" component for each of the nine integrated electric companies in the same manner as described for the distribution electric companies, producing an "external" growth component of 0.6 percent. Thus, the total sustainable growth rate is 3.8 percent plus 0.6 percent, or 4.5 percent. This is shown on page 5 of Schedule MIK-5.

I have used the securities analyst earnings projections (5.5 percent) and the sustainable growth rate (4.5 percent) to develop a reasonable range for DCF purposes of 4.5 to 5.5 percent.

Q. WHAT DCF MARKET RETURN DOES THIS PRODUCE?

A. As shown on Schedule MIK-5, page 1 of 5, I obtain a DCF return range of 8.9 to 9.9 percent, with a midpoint of 9.4 percent. This is based on an adjusted dividend yield of 4.3 percent plus a 4.5 to 5.5 percent growth range plus 0.1 percent for flotation expense.

I believe that the integrated utility DCF midpoint estimate of 9.4 percent helps support the reasonableness of my 9.5 percent recommendation for ACE. The upper end of this range, 9.9 percent, reflects the use of the security analysts projections, which is the same method used by Mr. Hevert.

Q. ARE YOU SPECIFICALLY REFLECTING A RISK ADJUSTMENT FOR ACE AS COMPARED TO YOUR TWO UTILITY PROXY GROUP BASELINES?

A. No, I am not, and it is not clear that Mr. Hevert has done so either. I believe that ACE's business and investment risk profiles are generally in line with the distribution utility proxy group and much lower than the vertically-integrated proxy group. I believe my 9.5 percent recommendation is reasonable in light of my DCF range of results.

D. <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 and his own beta calculation. 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 have large impacts on the CAPM results. In this case, the betas that Mr. Hevert and I use are similar, with Mr. Hevert's (on average) being slightly higher.

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 along with the average beta for the electric utility proxy group. (See Schedule MIK-3 for the company-by-company betas.) It should be noted that the distribution utility proxy group beta is slightly lower than the integrated utility company group beta. In last six months, long-term (i.e., 30-year) Treasury yields have averaged approximately 3.1 percent, and the recent Value Line betas for my distribution utility proxy group average 0.69. Since Treasury rates have drifted upwards in recent weeks, I am using 3.25 percent instead of the pure six-month average of 3.1 percent. I note that Mr. Hevert has elected to use betas for his group that range from 0.69 to 0.74. 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-6. My low-end cost of equity estimate uses a risk-free rate of 3.25 percent, a proxy group beta of 0.69 and an equity risk premium of 5 percent.

$$K_e = 3.25\% + 0.69\ (5.0\%) = 6.7\%$$

The upper end estimate uses a risk-free rate of 3.25 percent, a proxy group beta of 0.69 and an equity risk premium of 8.0 percent.

$$K_e = 3.25\% + 0.69\ (8.0\%) = 8.8\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 6.7 to 8.8 percent, with a midpoint of 7.7 percent. The CAPM analysis produces a midpoint result significantly lower than the range of results obtained for my two electric utility group DCF analyses, but I have not placed reliance on the CAPM returns in formulating my return on equity recommendation in this case. This is due to the unusual behavior of Treasury bond markets (the recent “flight to quality problem”), and the current actions by the Fed to hold down interest rates. This makes it difficult to assess equity risk premiums at this time.

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

A. For his CAPM study, Mr. Hevert has selected a high end market risk premium of 8.5 percent. In conjunction with the Value Line utility beta of 0.69 (based on Value Line data for the distribution utility group) and a 3.25 percent Treasury bond yield, the CAPM using his market risk premium estimate produces:

$$K_e = 3.25\% + 0.69\ (8.5\%) = 9.1\%$$

While I view Mr Hevert's high-end 8.5 percent market risk premium estimate as excessive, given current data on long-term Treasury yields and electric utility betas (from Value Line), the CAPM using this very high risk premium value produces a cost of equity of 9.1 percent. This is well below my recommendation for ACE of 9.5 percent.

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. Hervet's 8.5 percent exceeds the upper end of that range. My "midpoint" risk premium of roughly 6.5 percent falls well within that range.[2]

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 Brealy *et al*. is overstated if a long-term Treasury yield is used as the risk-free rate, i.e., the practice followed by both Mr. Hevert and me.

[2] Please note that Mr. Hevert also reports a 7.4 percent risk premium when using the Sharpe ratio method. This figure is within my assumed risk premium range.

V. REPLY TO WITNESSES HEVERT AND CANNELL

A. Overview of Mr. Hevert's Recommendation

Q. MR. HEVERT IDENTIFIES A COST OF EQUITY RANGE OF 10.5 TO 11.25 PERCENT AND AN AWARD OF 10.75 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. His results are difficult to summarize because he presents so many different calculations. He presents nine DCF calculations ranging from 9.81 to 11.97 percent based on differing time periods for measuring share prices (i.e., average for 30, 60 or 90 days) and based on using low, average (mean) or high earnings growth rates. He presents eight CAPM calculations using differing risk-free rates (30-year Treasury bond yields), betas and market risk premium values. Finally, he presents his three Risk Premium calculations which range from 10.5 to 11.06 percent, based on three different interest rate assumptions.

Mr. Hevert discusses two other factors that appear to play some role in the development of the 10.75 percent recommendation. As noted earlier, he estimates a cost of stock flotation as adding 0.16 percent to the cost of equity. He also undertakes a size analysis claiming that ACE is smaller than his average proxy company. Since he suggests that size is a risk factor, this further contributes to ACE's investment risk as compared to his proxy group average.

Q. CAN YOU SUMMARIZE HIS QUANTITATIVE RESULTS?

A. Yes. Focusing on his assumed mean earnings growth rates (and ignoring the high and low extremes), his DCF studies average 10.86 percent. His eight CAPM calculations average 10.2 percent, and his three Risk Premium cost of equity calculations average

10.76 percent. If the three methodologies were given equal weight, the cost of equity would be 10.6 percent based on his studies.

Q. HAS MR. HEVERT PROVIDED AN UPDATE?

A. No, he has not. The Company's recently filed 12+0 update continues to use the same 10.75 percent. The Company's response to RCR-ROR-43 (dated 3/14/12) states that ACE "has confirmed with Company witness Hevert that a further update of ACE's cost of common equity would not alter his general conclusions or recommendation as originally filed."

The data response provides no further information concerning how Mr. Hevert reached that conclusion that ACE's cost of equity is unchanged from mid 2011. This is a puzzling assertion given that long-term Treasury rates (the driver in two of his three methods) have *declined* by a full percentage point since prepared his testimony in mid 2011. At that time, Mr. Hevert assumed that capital costs would increase over time, and he built that assumed increase into his cost of equity findings. Since then, the opposite has happened, and capital costs have fallen, yet Mr. Hevert and ACE have chosen not to update.

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

Q. MR. HEVERT OBTAINS A SET OF DCF ESTIMATES THAT ARE HIGHER THAN THOSE THAT YOU OBTAINED. WHAT ACCOUNTS FOR THE DIFFERENCES?

A. To begin with, Mr. Hevert simply used the wrong proxy group, with all companies in the group being vertically integrated and therefore embodying the risks associated with generation supply. This overstates ACE's cost of equity, as one would expect and as I show on my Schedules MIK-4 and 5.

A second and smaller problem is that Mr. Hevert includes Empire District, a company that suspended its dividend in the latter half of 2011 and may be perceived as riskier than the other companies. Removing Empire District from his proxy group reduces the DCF cost of equity by about 0.2 percent.

A third difference is that with the passage of time the adjusted dividend yield for his proxy group has declined. In his studies, the dividend yield is about 4.7 to 4.8 percent (or slightly less than that if Empire District is removed). Using more recent market data, the proxy group adjusted dividend yield declines to 4.3 percent, a reduction of about 0.2 to 0.4 percent. (See Schedule MIK-5, page 2)

The largest difference is due to the assumed earnings growth rates. I use a range of growth rates with the "fundamental" or earnings retention being the lower end and published securities analyst growth rates being the higher end. Unfortunately, Mr. Hevert chooses to utilize only securities analyst estimates, which I am sure he is aware has sometimes been heavily criticized as being excessively optimistic. For his proxy group, these growth rates average 6.1 percent. On Schedule MIK-5, page 3 of 5, I cite to five readily-available public sources which average to about 5.5 percent, or 0.6 percent lower than Mr. Hevert's 6.1 percent. This reduction may also reflect effects of simply using more recently published information.

Q. DO YOU HAVE ANY OTHER REASONS FOR BELIEVING HIS 6.1 PERCENT GROWTH RATE IS OVERSTATED.

A. Yes. The growth rate used in the DCF model should reflect prospects for long-range sustained growth, not either the very rapid or unusually slow growth that might be expected to occur over the next few years as a company returns to its "normal" growth path. Indeed, that is a reason for using a fundamental growth rate as an additional measure to complement the use of securities analyst growth rates which in some cases may be reflecting short-term trends or excessive optimism.

As a type of "reality check," I have compared the earnings growth rates that Mr. Hevert and I have used with currently-available long-term projections of nominal U.S. GDP growth. In fact, in the past, Mr. Hevert has used nominal GDP growth for essentially the same vertically-integrated proxy group in a multi-stage DCF study. *Blue Chip Economic Indicators* published its compilation of long-term economic forecasts in its March 2012 edition. The "consensus" (or average of the survey participants) indicates long-term growth in nominal GDP of 5.1 percent per year through 2018 and 4.7 percent per year thereafter through 2023. While the expected growth in the U.S. economy is only a rough guide, it tends to support my range for Mr. Hevert's proxy group of 4.5 to 5.5 percent. It also strongly suggests that Mr. Hevert's 6.1 percent is probably too high. His growth rate figures are either out of date or more reflective of short-term trends.

Q. WHAT DO YOU CONCLUDE?

A. This information strongly indicates that a more up-to-date and reasonable DCF study would lower Mr. Hevert's estimate from his 10.8 percent to a figure well below 10 percent. A more basic problem is that Mr. Hevert's proxy group overstates ACE's investment risk and would force ACE customers to pay for generation-related risks in their distribution rates. This is improper since ACE customers already pay for generation-related risks in their payments for BGS or competitive retail supply.

C. **The CAPM Results**

Q. MR. HEVERT OBTAINED CAPM RESULTS RANGING FROM 9.31 TO 11.12 PERCENT, AVERAGING ABOUT 10.2 PERCENT. HOW DID HE OBTAIN THESE RESULTS?

A. Mr. Hevert used three sources of beta for his proxy group (12-month values that he calculated, Value Line betas and Bloomberg betas); two market-risk premium estimates (7.4 and 8.5 percent); and two risk-free interest rates (4.24 and 4.78 percent). The market risk premium is often the most controversial component of the CAPM studies. The 7.4 percent figure is based on the "Sharpe ratio," i.e., the historically-measured market risk premium of 6.7 percent *increased* to 7.4 percent to account for today's market volatility (as compared to the historic norm). The higher figure of 8.5 percent is based on Mr. Hevert's DCF analysis of the overall stock market. This DCF study finds a total annualized return for the broad overall stock market of 12.8 percent.

Q. WHY ARE MR. HEVERT'S CAPM ESTIMATES HIGHER THAN YOURS?

A. There are several reasons, but the most important appears to be that he has used a much higher risk-free rate, even though both of us rely on the same definition, i.e., the prevailing yield on 30-year Treasury bonds. I have used 3.25 percent, which approximates the actual six-month average ending February 2012. Mr. Hevert uses 4.24 percent, which he characterizes as the then "current" Treasury yield and 4.78 percent which is a year-ahead forecasted yield. Specifically, Mr. Hevert assumes that in the year or so following his mid 2011 analysis Treasury yields would move sharply upwards from the "current" level. In fact, at least through today, the very opposite has happened, and yields have fallen sharply, by about a full percentage point. Yet, Mr. Hevert sees no reason to submit an updated study.

Q. WHAT SHOULD MR. HEVERT HAVE DONE CONCERNING THE RISK-FREE RATE?

A. I have no objection to Mr. Hevert using the then "current" 4.24 percent as the risk-free rate at the time he prepared his testimony in mid 2011. Had he done only that, his CAPM cost of equity results would average about 9.9 percent. However, it was totally improper for Mr. Hevert to increase the "current" Treasury yield by about 0.5 percent under the assumption that the cost of capital would increase significantly. There is no valid basis for speculating what the cost of capital might be in the future when applying the CAPM. Moreover, once he could observe that his assumed yield increase was wrong and that capital costs instead had fallen, he made no attempt to correct the error.

If Mr. Hevert would simply update his CAPM cost of capital estimate for the reduction in the 30-year Treasury yield since mid 2011, his estimate would likely approximate my 9.5 percent recommendation for ACE.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH MR. HEVERT'S CAPM?

A. Yes, to repeat my earlier discussion, Mr. Hevert erred in applying the CAPM to his proxy group of vertically-integrated electrics rather than to the distribution electrics. This poor choice of risk proxies causes an overstatement of ACE's cost of equity by some unknown amount.

I also must question Mr. Hevert's risk premium estimates of 7.4 percent and 8.5 percent used in his CAPM application, although they do approximate the upper end of the range that I have used. The 7.4 percent is the long-term historical risk premium that Mr. Hevert obtained from a Morningstar publication (i.e., 6.7 percent), adjusted upward for increases in forward market volatility measures (e.g., the "VIX") relative to actual historic volatility. In other words, at the time of his testimony in mid 2011, the market volatility outlook was somewhat greater than the long-term historic average, so he increased the 6.7 historic market risk premium to 7.4 percent. He refers to this method as the "Sharpe ratio."

Mr. Hevert's two methods would indicate that investors expect long-run annual stock market returns averaging about 12 to 13 percent. But there is reason to believe this is unrealistically high as a representation of investor expectations.

A recent article in the respected publication *The Economist*, in commenting on corporate estimates of pension fund returns, questioned whether even 10 percent is too optimistic a long-run return expectation for stocks.

> That [a 10% return on stocks after expenses] is quite an extraordinary expectation, given current market conditions. Over the long run equity returns comprise the current dividend yield plus dividend growth. Since the dividend yield on the S&P 500 is just 2.5%, that requires dividends to grow at 7.5% a year, faster than any plausible forecast for economic growth. A rapid increase in profits might be possible if the starting point was sufficiently low, but American profit margins are at their highest level since the mid-1960s.
>
> The evidence suggests that companies themselves don't really believe such rosy forecasts. A Duke University poll of chief financial officers shows they have an average forecast for equity returns over the next ten years of 6.3 percent. (*The Economist*, January 21, 2012, page 82)

At best, the 7.4 to 8.5 percent should be considered upper bound estimates of the market risk premium.

Q. DO YOU HAVE ANY FURTHER CONCERNS REGARDING THE SHARPE RATIO METHOD?

A. Yes. Mr. Hevert's 7.4 percent estimate is based on the forward market volatility indicators as of the time that he prepared his testimony in mid 2011. However, conditions in equity markets have changed since then with forward market volatility indices declining. Updating for this reduced volatility outlook would lower his 7.4 percent risk premium to a risk premium figure well below the historic 6.7 percent average.

Finally, while the Sharpe ratio approach has considerable intuitive appeal, it is not a very practical method for use in utility rate cases. I checked on the published VIX (which is traded on the Chicago Options Exchange) on March 23, 2012. The quote that day was about 15, which is well below Mr. Hevert's stated historic average of about 20. However, as of March 23, 2012, the 52 week range for the VIX was 13.66 to 48.0. Thus, the Sharpe ratio, as used by Mr. Hevert, can produce wild swings in the utility cost of equity estimate using the CAPM depending on the point in time within the past year when the analysis is conducted.

I therefore recommend against reliance on the Sharpe ratio in this case. However, if it is to be considered at all Mr. Hevert's VIX measure and his cost free rate *must* be updated. This will result in CAPM estimates consistent with or below my 9.5 percent.

D. Mr. Hevert's Risk Premium Study

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. His estimated equation is:

$$RP = 8.85 - 0.6 \text{ x Treasury Yield} \qquad R^2 = 0.65$$

Thus, at recent Treasury yields of 3.25 percent, his model indicates a risk premium of:

$$RP = 8.8\% - 0.6\ (3.25\%) = 6.85\%$$

Adding back the 3.25 percent yield, produces a cost of equity of 10.1 percent.

Mr. Hevert, however, did not use a Treasury yield of 3.25 percent, but because of the timing of his study (about a year ago) and his propensity for assuming the cost of capital will increase over time, he uses Treasury yields of 4.24, 4.78 and 5.65 percent. Using these higher yields, he obtains Risk Premium cost of capital estimates of 10.5 percent to 11.06 percent. Had Mr. Hevert updated to recent Treasury yields, he would have obtained 10.1 percent cost of equity.

Q. IS THIS MODEL 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.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THIS METHOD?

A. Yes. The statistical or "econometric" model assumes that the measured historic risk premium is accurately measured. This assumption is unlikely to be true for a variety of reasons. The measurement is based on state commission authorized equity returns (including rate case settlements) that undoubtedly reflect rate case regulatory lag as well as numerous other practical or policy factors that can enter into return on equity awards. Mr. Hevert's model makes the unwarranted assumption that return on equity awards are precisely the same thing as the utility cost of equity at the point in time of the award.

In addition to the accuracy of the key data inputs, the model suffers from major technical shortcomings. Regression models assume causation. Mr. Hevert cannot convincingly explain why changes in Treasury yields *cause* changes in the equity risk premium. Absent a convincing and rigorously developed theory, the model is meaningless and the econometric results may be entirely spurious. It also appears that Mr. Hevert never explored whether other factors or variables also could affect the magnitude of the risk premium and therefore should be in the model, or whether alternative functional forms that could improve the model should be considered.

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

A. No. I do not regard his model as having any validity. However, if it is used, it would today produce a "generic" cost of equity estimate of about 10.1 percent. This result then must be reduced for ACE's lesser risk as a distribution utility, implying a cost of equity well below 10 percent

E. The Size Factor

Q. DOES MR. HEVERT ANALYZE ACE'S INVESTMENT RISK?

A. Yes, he does, but in a manner that is not particularly helpful in this case. His only analysis of risk pertains to his contention that size is a risk factor, and he contends that ACE is smaller than his proxy group average. However, in the end, he makes no adjustment to his cost of equity results for the alleged smaller size and greater risk.

Q. IS HIS ANALYSIS VALID?

A. No, it is not. His conclusion concerning size and risk are based on studies that focus mostly or entirely on non-regulated companies, not utilities. Thus, he has no evidence that size is an important risk factor specifically for electric utilities.

Mr. Hevert's more fundamental error is in failing to recognize that ACE is part of PEPCO Holdings and that equity investors can invest in ACE only by purchasing PEPCO stock. In other words, even if it is true that size is a risk factor, it would only be PEPCO's size that is relevant. This is because ACE (and all PEPCO subsidiaries) contribute to PEPCO's size and whatever risk benefits (if any) that PEPCO's size creates. ACE is financially integrated into PEPCO, and PEPCO serves as its source of equity capital.

Q. HOW WOULD FOCUSING ON PEPCO'S SIZE INSTEAD OF ACE'S SIZE ALTER MR. HEVERT'S CONCLUSIONS?

A. Mr. Hevert's proxy group consists of two giant companies (Southern and American Electric Power), one medium size company (Pinnacle West) and seven remaining companies that are relatively small. PEPCO is significantly larger than all seven and is close in size to Pinnacle West. Thus, if anything, PEPCO (and by implication ACE) would have a size advantage relative to Mr. Hevert's proxy group. There is no basis for claiming a risk premium for ACE.

F. Reply to Ms. Cannell

Q. WHAT ARE THE MAJOR ARGUMENTS IN MS. CANNELL'S TESTIMONY?

A. Ms. Cannell presents no quantitative cost of capital analysis, but instead presents the investment community's perspective on an appropriate return award for ACE. Her testimony is intended to support Mr. Hevert's recommendation to increase the current 10.3 percent to 10.75 percent (or even higher). Her testimony emphasizes the following factors or themes:

- ACE's risk and financial need have increased from the last rate case in 2009/2010 due to the current uncertain economic environment and the Company's large construction program.
- Regulatory lag is an important business risk for ACE and warrants a higher return award.
- It is vitally important for ACE to maintain its strong credit rating and avoid a downgrading to below investment grade.
- An increased equity return award will boost PEPCO's stock price, which will benefit ACE customers by providing the Company more equity capital.

Ms. Cannell maintains that ACE is confronted with "rising risk levels in the macroeconomic and capital market environments" as compared to conditions prevailing in the 2009/2010 case and that approving the requested 10.75 percent return would help the Company maintain access to capital. (Testimony, page 38) She concludes stating that, "Current market conditions, current trends in ROE awards, and ACE's increased risks support an increase in the last allowed ROE." (*Id.,* page 39)

Q. IS MS. CANNELL'S COMPARISON OF CONDITIONS TODAY WITH THOSE PREVAILING DURING THE LAST CASE IN 2009/2010 ACCURATE?

A. No, exactly the opposite is true. There has been a clear improvement in macroeconomic and capital market conditions since 2009/2010, both in general and for ACE. The best evidence is that in 2011, ACE was able to successfully access debt markets and issue $200 million of long-term debt at 4.35 percent. As my Schedule MIK-2 illustrates capital costs have declined significantly since 2009/2010, and beyond that, strength and stability have returned to capital markets. It is interesting to note that in the last rate case, the Company sought an authorized equity return of 11.5 percent compared with 10.75 percent in this case, or a 0.75 percent reduction. While ACE obviously does have business risks, which include the potential for regulatory lag, there is no showing in her testimony or that of any ACE witness that these risks have increased since the last rate case. The investment community and credit rating agencies certainly recognize that risks exist (as do I), but they regard New Jersey utility regulation, on the whole, as supportive and constructive. Based on the requested return on equity in this case and the previous case, ACE clearly recognizes that its cost of capital is lower today than in 2009/2010, and all objective evidence supports that finding.

Q. DO YOU AGREE WITH MS. CANNELL'S STATEMENTS CONCERNING THE NEED FOR ACE TO MAINTAIN ITS ACCESS TO CAPITAL?

A. Yes, very much so. I further agree that credit ratings are important, and the avoidance of a downgrade is a key objective. Moreover, PEPCO parent serves as ACE's source of equity capital, both directly and indirectly, and therefore it is PEPCO's financial policies that ultimately will determine ACE's access to capital and funding amounts.

Where I disagree with Ms. Cannell is that maintaining ACE's access to capital necessarily requires an increased rate of return award, particularly in an environment of declining capital costs. ACE's credit ratings are both strong and stable, as is the case for PEPCO parent and the other PEPCO utilities. As noted earlier, other retail regulators have awarded ACE's affiliate equity returns of 9.6 to 10.0 percent–well below ACE's current 10.3 percent–and this has not impaired the PEPCO affiliates' credit ratings or access to capital. It is important to note that credit rating agencies, particularly S&P, evaluate ACE as part of the consolidated PEPCO, thereby recognizing those 9.6 to 10 percent return on equity awards.

In summary, there is no evidence or analysis in Ms. Cannell's testimony supporting the notion that either the current a 10.3 percent return on equity award or the 10.75 percent request are needed to maintain ACE's access to capital. Moreover, there is abundant evidence from ACE's affiliates that a lower ROE award would not impair access to capital nor threaten investment grade credit ratings.

Q. SHOULD ACE'S AUTHORIZED RETURN ON EQUITY BE MAINTAINED OR RAISED IN ORDER TO PROP UP THE PEPCO HOLDINGS STOCK PRICE, AS MS. CANNELL SUGGESTS?

A. No, this is not a proper objective of regulation, nor is it any way needed to maintain ACE's access to capital. I recommend that the Board set just and reasonable rates, including a fair return on the approved rate base that reflects investor requirements. I have provided a realistic estimation of that requirement. My testimony also recommends a ratemaking capital structure that is fully consistent with the Company's stated objectives. Targeting a specific parent company stock price or setting rates to prop up the stock price is not a proper regulatory objective, nor is it particularly useful for ensuring ACE's financial soundness. The PEPCO Holdings stock price will depend on the performance of PEPCO's other utility subsidiaries (ACE being the smallest), PEPCO management decisions and performance and a host of other factors. PEPCO can provide ACE with equity capital, as needed, assuming management chooses to do so. Contrary to Ms. Cannell's assertions, there is no benefit to ACE customers from raising ACE's authorized return above the cost of capital, and there is no financial need to do so.

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 10.3 to 10.75 percent despite the clear evidence of declining capital costs. This increase request may reflect the fact that Mr. Hevert improperly uses vertically-integrated electric utilities as a risk proxy for ACE.

Witness Cannell supports the requested increase stressing the importance of ACE maintaining access to capital markets and its current credit rating. I concur that this is an important objective. However, the evidence demonstrates that an increase in the rate of return is not needed. In particular, ACE's utility affiliates in Maryland, D.C. and Delaware have received authorized returns of 10 percent or less, while maintain access to capital and solid triple B credit ratings.

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

A. I am recommending at this time a 7.88 percent return on ACE's distribution rate base, including a 9.5 percent return on common equity. This is supported by current market conditions and the following studies:

(1) DCF Study of Electric Distribution Companies

8.5 to 9.5 percent, with a 9.0 percent midpoint

(2) DCF Study of Mr. Hevert's Integrated Electrics

8.9 to 9.9 percent, with a 9.4 percent midpoint

(3) CAPM Calculations

6.7 to 9.5 percent, with an 8.2 percent midpoint.

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

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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 shifted to electric utility restructuring, mergers and various aspects of regulation.

Mr. Kahal has provided expert testimony on more than 350 occasions before state and federal regulatory commissions 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.

Education:

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.

Previous Employment:

1981-2001 - Exeter Associates, Inc. (founding Principal, Vice President and President).

1980-1981 - Member of the Economic Evaluation Directorate, The Aerospace Corporation, Washington, D.C. office.

1977-1980 - Economist, Washington, D.C. consulting firm.

1972-1977 - Research/Teaching Assistant and Instructor, Department of Economics, University of Maryland (College Park). Lecturer in Business and Economics, Montgomery College.

Professional Work Experience:

Mr. Kahal has more than thirty 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 in the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted both by 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.

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"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.

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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).

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"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.

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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, October 2, 2002. (Presentation on Performance-Based Ratemaking and panelist on RTO issues). Baton Rouge, Louisiana.

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

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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	NA	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

	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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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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	Docket Number	Utility	Jurisdiction	Client	Subject
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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	Docket Number	Utility	Jurisdiction	Client	Subject
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

	Docket Number	Utility	Jurisdiction	Client	Subject
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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	Docket Number	Utility	Jurisdiction	Client	Subject
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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	Docket Number	Utility	Jurisdiction	Client	Subject
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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	Docket Number	Utility	Jurisdiction	Client	Subject
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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	Docket Number	Utility	Jurisdiction	Client	Subject
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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	Docket Number	Utility	Jurisdiction	Client	Subject
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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	Docket Number	Utility	Jurisdiction	Client	Subject
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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	Docket Number	Utility	Jurisdiction	Client	Subject
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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	Docket Number	Utility	Jurisdiction	Client	Subject
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

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	Docket Number	Utility	Jurisdiction	Client	Subject
365.	2010-2213369 April 2011	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
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

BEFORE THE 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	)	**BPU DKT. NO. ER11080469**
INCREASE IN RATES AND CHARGES	)	**OAL DKT. NO. PUC09929-2011**
FOR ELECTRIC SERVICE PURSUANT	)	
TO N.J.S.A. 48:2-21 AND FOR OTHER	)	
APPROPRIATE RELIEF	)	

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY OF
MATTHEW I. KAHAL

ON BEHALF OF THE

DIVISION OF RATE COUNSEL

STEFANIE A. BRAND, ESQ.
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Filed: April 25, 2012

ATLANTIC CITY ELECTRIC COMPANY

Rate of Return Summary at
December 31, 2011

Capital Type	Balance[1] (Thousands $)	% of Total	Cost Rate	Weighted Cost
Long-Term Debt	$ 856,215	51.31%	6.47%[1]	3.32%
Short-Term Debt[2]	11,803	0.71	0.35	0.00
Common Equity	800,722	47.98	9.5[3]	4.56
Total	**$1,668,740**	**100.00%**	**--**	**7.88%**

[1] Source: 12+0 Update, S-AROR-5 Update. Long-term debt is the reported unadjusted balance outstanding excluding securitization debt.

[2] Response to RCR-ROR-1 and 36. Subject to update.

[3] Schedules MIK-4, 5 and 6.

ATLANTIC CITY ELECTRIC COMPANY

Short-Term Debt Rates and Balances
May – December, 2011
($000)

	Balances	Cost Rate
May	$ 51,300	0.32%
June	25,000	0.33
July	18,125	0.35
August	0	--
September	0	--
October	0	--
November	0	--
December	0	--
Average	**$ 11,803**	**0.34%**

Source: Responses to RCR-ROR-1 and 36.

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

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**
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 Yield	3-Month Treasury Yield	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 (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 Distribution Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2011 Common Equity Ratio*
1.	C.H. Energy Corporation	1	A	0.65	51.5%
2.	Central Vermont PS	3	B	0.70	58.5
3.	Consolidated Edison	1	A+	0.60	52.0
4.	Northeast Utilities	3	B+	0.70	45.0
5.	NSTAR	1	A	0.65	45.5
6.	PEPCO Holdings	3	B+	0.80	52.0
7.	UIL Holdings	2	B++	0.70	42.0
	Average	**2.0**	**--**	**0.69**	**49.5%**
	Average without Central Vermont PS	**1.8**	**--**	**0.69**	**48.0%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2011 equity ratio including short-term debt and current maturities would be somewhat lower.

Source: *Value Line Investment Survey,* February 24, 2012.

ATLANTIC CITY ELECTRIC COMPANY

Listing of the Integrated Electric Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2011 Common Equity Ratio*
1.	American Electric	3	B++	0.70	48.5%
2.	Cleco Corporation	2	B++	0.70	53.5
3.	Great Plains	3	B+	0.75	47.5
4.	Hawaiian Industries	3	B+	0.70	54.0
5.	IDACORP	3	B+	0.70	52.5
6.	Pinnacle West	2	B++	0.70	55.5
7.	Portland General	3	B+	0.75	49.5
8.	Southern Company	1	A	0.55	46.0
9.	Westar Energy	2	B++	0.75	48.0
	Average	**2.4**	--	**0.70**	**50.6%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2011 equity ratio including short-term debt and current maturities would be somewhat lower.

Source: *Value Line Investment Survey*, December 23, 2011, February 3 and 24, 2012.

ATLANTIC CITY ELECTRIC COMPANY

DCF Summary for
Electric Distribution Utility Proxy Group

1.	Dividend Yield (September 2011 – February 2012)	4.26%[1]
2.	Adjusted Yield ((1) x 1.025)	4.4%
3.	Long-Term Growth Rate	4.0 – 5.0%[2]
4.	Total Return ((2) + (3))	8.4 – 9.4%
5.	Flotation Adjustment	0.1%
6.	Cost of Equity ((4) + (5))	8.5-9.5%
7.	Midpoint	9.0%
	Recommendation	**9.5%**

[1] Schedule MIK-4, page 2 of 4.
[2] Schedule MIK-4, page 3 of 4.

ATLANTIC CITY ELECTRIC COMPANY

Dividend Yields for the Electric
Utility Distribution Group
(September 2011 – February 2012)

	Company	September	October	November	December	January	February	Average
1.	C.H. Energy	4.3%	4.0%	3.9%	3.8%	3.9%	3.8%	3.95%
2.	Central Vermont	2.6	2.6	2.6	2.6	2.6	2.6	2.60
3.	Consolidated Edison	4.2	4.1	4.0	3.9	4.1	4.2	4.09
4.	Northeast Utilities	3.3	3.2	3.2	3.0	3.2	3.3	3.20
5.	NSTAR	3.8	3.8	3.7	3.6	4.0	3.8	3.78
6.	Pepco Holdings	5.7	5.5	5.5	5.3	5.5	5.6	5.51
7.	UIL Holdings	5.2	5.1	5.0	4.9	5.0	4.9	5.02
	Average	**4.16%**	**4.04%**	**3.99%**	**3.87%**	**4.04%**	**4.03%**	**4.02%**
	Average without Central Vermont	**4.42%**	**4.28%**	**4.22%**	**4.08%**	**4.28%**	**4.27%**	**4.26%**

Note: C.H. Energy February 2012 dividend yield is based on February 17 stock price, not end of month due to merger announcement on February 21, 2012.

*Source: Standard & Poors *Stock Guide,* October 2011 – March 2012.

ATLANTIC CITY ELECTRIC COMPANY

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

	Company	Value Line	Yahoo	MSN	Reuters	CNN	Average
1.	C.H. Energy	4.0%	NA	4.0%	3.35%	4.0%	3.84%
2.	Central Vermont	1.5	8.9	NA	NA	9.00	6.47
3.	Consolidated Edison	3.0	3.59	3.7	3.65	4.0	3.58
4.	Northeast Utilities	6.5	6.5	7.5	6.83	8.0	7.07
5.	NSTAR	6.0	4.32	5.4	4.49	5.0	5.04
6.	Pepco Holdings	2.5	4.13	4.0	4.35	5.0	4.00
7.	UIL Holdings	3.0	4.10	5.0	4.0	4.0	4.02
	Average	**3.78%**	**5.25%**	**4.93%**	**4.45%**	**5.57%**	**4.86%**
	Average without Central Vermont	**4.17%**	**4.53%**	**4.93%**	**4.45%**	**5.00%**	**4.59%**

Source: *Value Line Investment Survey*, February 29, 2012. YahooFinance.com, MSNMoney.com, Reuters.com, CNNfn.com, public websites, March 2012.

ATLANTIC CITY ELECTRIC COMPANY

Other *Value Line* Growth Measures for the
Electric Distribution Utility Proxy Group

	Company	Dividend per Share	Book Value per Share	Earnings Retention
1.	C. H. Energy	1.0%	2.0%	3.0%
2.	Central Vermont	2.5	1.5	3.5
3.	Consolidated Edison	1.0	3.0	3.5
4.	Northeast Utilities	7.0	5.5	5.0
5.	NSTAR	5.5	5.0	5.0
6.	PEPCO Holdings	1.0	2.0	2.5
7.	UIL Holdings	0.0	5.0	2.5
	Average	**2.6%**	**3.4%**	**3.6%**
	Average without Central Vermont	**2.6%**	**3.8%**	**3.6%**

Source: *Value Line Investment Survey*, February 24, 2012.

ATLANTIC CITY ELECTRIC COMPANY

Fundamental Growth Rate Analysis for Electric Distribution Utility Proxy Group

		Shares 2011-2016[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	C. H. Energy	0.00%	--	0.0%	3.0%	3.0%
2.	Central Vermont	0.00	--	0.0	3.5	3.5
3.	Consolidated Edison	1.07	47.9%	0.5	3.5	4.0
4.	Northeast Utilities	0.67	54.4	0.4	5.0	5.4
5.	NSTAR	0.00	--	0.0	5.0	5.0
6.	PEPCO Holdings	2.44	4.26	0.1	2.5	2.6
7.	UIL Holdings	0.00	--	0.0	2.5	2.5
	Average			**0.1%**	**3.6%**	**3.7%**
	Average without Central Vermont			**0.2%**	**3.6%**	**3.8%**

[1] Projected annualized growth rate in share outstanding, 2011-2016.
[2] **%** Premium of share price ("Recent Price") over 201 Book Value per share.
[3] **sv** is growth rate in shares x % premium.
[4] **br** is Value Line's projection as of 2015-2017.

Source: *Value Line Investment Survey*, February 24, 2012.

ATLANTIC CITY ELECTRIC COMPANY

DCF Summary for Integrated Electric Utility Proxy Group

1. Dividend Yield (September 2011 – February 2012)	4.21%[(1)]
2. Adjusted Yield ((1) x 1.025)	4.3%
3. Long-Term Growth Rate	4.5 – 5.5%[(2)]
4. Total Return ((2) + (3))	8.8 – 9.8%
5. Flotation Adjustment	0.1%
6. Cost of Equity ((4) + (5))	8.9 – 9.9%
7. Midpoint	9.4%
Recommendation	**9.5%**

(1) Schedule MIK-5, page 2 of 5.

(2) Schedule MIK-5, pages 3 of 5, 4 of 5 and 5 of 5.

ATLANTIC CITY ELECTRIC COMPANY

Dividend Yields for Integrated Electric Utility Proxy Group
(September 2011 – February 2012)

	Company	September	October	November	December	January	February	Average
1.	American Electric	4.8%	4.8%	4.7%	4.6%	4.8%	5.0%	4.78%
2.	Cleco Corporation	3.3	3.4	3.5	3.3	3.1	3.2	3.30
3.	Great Plains	4.3	4.0	4.0	3.9	4.1	4.3	4.10
4.	Hawaiian Ind.	5.1	4.9	4.8	4.7	4.8	5.0	4.88
5.	IdaCorp	3.2	3.0	2.9	2.8	3.1	3.3	3.05
6.	Pinnacle West	4.9	4.6	4.4	4.4	4.4	4.5	4.53
7.	Portland General	4.5	4.3	4.2	4.2	4.3	4.3	4.30
8.	Southern Company	4.5	4.4	4.3	4.1	4.1	4.3	4.29
9.	Westar Energy	4.8	4.7	4.6	4.4	4.5	4.8	4.64
	Average	**4.38%**	**4.23%**	**4.16%**	**4.04%**	**4.13%**	**4.30%**	**4.21%**

Source: S&P *Stock Guide,* October 2011 – March 2012.

ATLANTIC CITY ELECTRIC COMPANY

Projection of Earnings per Share
Five-Year Growth Rates for the
Electric Integrated Proxy Group

	Company	Value Line	Yahoo	MSN	Reuters	CNN	Average
1.	American Electric	4.5%	4.01%	4.3%	4.23%	4.0%	4.21%
2.	Cleco Corporation	6.0	3.0	NA	3.0	3.0	3.75
3.	Great Plains	6.0	4.4	7.0	4.72	3.45	5.11
4.	Hawaiian Industries	11.0	11.37	6.5	8.42	7.5	8.95
5.	IDACORP	4.0	4.0	5.0	4.67	5.0	4.53
6.	Pinnacle West	6.0	5.59	5.3	5.51	5.5	5.58
7.	Portland GE	7.5	5.27	5.0	5.68	6.0	5.89
8.	Southern Company	5.0	5.85	5.0	5.80	5.8	5.49
9.	Westar	8.5	4.23	5.5	4.98	4.66	5.57
	Average	**6.5%**	**5.30%**	**5.45%**	**5.22%**	**4.99%**	**5.45%**

Sources: *Value Line Investment Survey*, February 3 and 24, 2012 and December 23, 2011. YahooFinance.com, MSNMoney.com, CNNFN.com, Reuters.com, public websites, March 2012.

ATLANTIC CITY ELECTRIC COMPANY

Other Value Line Measures of Growth for the
Integrated Electric Utility Proxy Group

	Company	Dividend Per Share	Book Value Per Share	Earnings Retention
1.	American Electric	4.0%	5.0%	5.0%
2.	Cleco Corporation	9.5	6.5	4.0
3.	Great Plains Energy	0.0	2.0	3.0
4.	Hawaiian Industries	1.0	3.5	4.0
5.	IDACORP	4.0	5.0	3.5
6.	Pinnacle West	2.0	2.5	3.0
7.	Portland General	3.0	3.0	4.0
8.	Southern Company	4.0	5.5	4.0
9.	Westar Energy	3.0	2.5	4.0
	Average	**3.9%**	**3.9%**	**3.8%**

Source: *Value Line Investment Survey*, December 23, 2011, February 3 and 24, 2012.
The earnings retention figures are projections for 2014 – 2016 or 2015 – 2017.

ATLANTIC CITY ELECTRIC COMPANY

Fundamental Growth Rate Analysis for
Integrated Electric Utility Proxy Group

		Shares 2011-2016[(1)]	% Premium[(2)]	sv[(3)]	br[(4)]	sv + br
1.	American Electric	0.79%	29.8%	0.2%	5.0%	5.2%
2.	Cleco Corporation	0.00	--	0.0	4.0	4.0
3.	Great Plains Energy	2.69	0.00	0.0	3.0	3.0
4.	Hawaiian Industries	3.04	58.9	1.8	4.0	5.8
5.	IDACORP	0.6	24.8	0.1	3.5	3.6
6.	Pinnacle West	2.49	36.6	0.9	3.0	3.9
7.	Portland General	0.25	12.3	0.0	4.0	4.0
8.	Southern Company	1.74	121.0	2.1	4.0	6.1
9.	Westar Energy	2.68	22.2	0.6	4.0	4.6
	Average			**0.6%**	**3.8%**	**4.5%**

(1) Projected annualized growth rate in shares outstanding, 2011-2016 (or 2010 – 2015 for Value Line reports dated December 23, 2011).

(2) % Premium of share price ("Recent Price") over 2011 Book Value per share.

(3) sv is growth rate in shares x % premium.

(4) br is Value Line's projection as of 2014-2016 or 2015-2017.

Source: *Value Line Investment Survey*, December 23, 2011, February 3 and 24, 2012.

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 = 3.25% (Treasury bond yield for the most recent six months, see page 2 of 2)

Rm = 8.25% to 11.25% (equates to equity risk premium of 5.0 - 8.0%)

Beta = 0.69

C. Model Calculations

Low end:	K_e = 3.25% + 0.69 (5.0) = 6.7%
Midpoint:	K_e = 3.25% + 0.69 (6.5) = 7.7%
Upper End:	K_e = 3.25% + 0.69 (8.0) = 8.8%
High Sensitivity:	K_e = 3.25% + 0.69 (9.0) = 9.5%

ATLANTIC CITY ELECTRIC COMPANY

Long-Term Treasury Bonds Yields
(September 2011 – February 2012)

Month	30-Year	20-Year	10-Year
September 2011	3.18	2.83	1.98
October	3.13	2.87	2.15
November	3.02	2.72	2.01
December	2.98	2.67	1.98
January 2012	3.03	2.70	1.97
February	3.11	2.75	1.97
Average	**3.08%**	**2.76%**	**2.01%**

Source: Federal Reserve, "Statistical Release," October 2011 – March 2012.