STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC & GAS COMPANY FOR APPROVAL OF THE ENERGY STRONG PROGRAM	))))	**BPU Docket Nos. EO13020155 and GO13020156**

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

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TABLE OF CONTENTS

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

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

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

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

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

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

A. Since 2001,1 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 Maryland Public Service Commission, the Maine Public Advocate, Maryland Department of Natural Resources, the Maryland 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. GR07110889), Elizabethtown Gas (BPU Docket No. GR09030195) and Public Service Electric and Gas Company (BPU Docket Nos. GR05100845 and GR09050422), and United Water New Jersey, Inc. (BPU Docket No. WR09120987). I participated in the previous Atlantic City Electric Company rate cases on a rate of return issues, including submitting testimony in BPU Docket Nos. ER09080664 and ER11080469. In all of these cases, my testimony and other work was on behalf of the Division of Rate Counsel ("Rate Counsel").

Q. ARE YOU FAMILIAR WITH PUBLIC SERVICE ELECTRIC AND GAS COMPANY ("PSE&G" OR "THE COMPANY")?

A. Yes. I testified in PSE&G's last base rate case in 2009, which was resolved in a Board-approved settlement in 2010. (BPU Docket No. GR09050422.) Earlier this year, I submitted surrebuttal testimony in the Company's solar program "tracker" cases. (BPU Docket Nos. E012080721 and E012080726.) In addition, I have assisted Rate Counsel in several of PSE&G's debt issuance petition dockets.

II. OVERVIEW

A. Summary of Recommendations

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

A. PSE&G filed a Petition with the Board for approval of its Energy Strong Program ("ES" or "the Program") which is intended to harden its electric and gas distribution infrastructure. This Petition covers a five-year plan to invest $1.7 billion in electric distribution and $0.9 billion in gas distribution, along with associated operation and maintenance ("O&M") expense. The Company proposes to recover the program costs, dollar for dollar, through tracker mechanisms referred to as the Energy Strong Adjustment Mechanism ("ESAM").

An important element associated with the tracker cost recovery mechanism is the rate of return on invested capital. As discussed in detail in the Direct Testimony of witness Andrea Crane, Rate Counsel opposes the use of the ESAM for cost recovery and instead recommends the use of conventional base rate cases. However, in the event that the Board permits the use of the ESAM for cost recovery, I have been asked by Rate Counsel to develop a recommendation concerning fair rate of return for both the gas and electric trackers. This includes both a review of the Company's proposal and independent study of the cost of common equity.

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

A. As shown on Schedule SS-ES-2, sponsored by witness Swetz, the Company requests an overall rate of return of 8.21 percent, or 11.85 percent with an income tax gross up. This includes a 6.02 cost rate for long-term debt, a capital structure of 51.2 percent common equity and 48.8 percent debt and a return on common equity ("ROE") of 10.3 percent. The 8.21 percent overall rate of return (including each of the components mentioned above) is derived from the Board-approved settlement in the Company's last rate case (i.e., BPU Docket No. GR09050422, June 7, 2010). The Petition and accompanying testimony include no evidence concerning the Company's cost of capital as of 2013 or the cost of capital implications of complete, dollar-for-dollar cost recovery through a tracker mechanism.

Q. HAS THE COMPANY PROVIDED IN DISCOVERY ANY INFORMATION THAT WOULD SUPPORT THE 2010 SETTLEMENT RATE OF RETURN AS BEING APPROPRIATE AT THIS TIME FOR THE ES PROGRAM?

A. Yes. The Company states that it believes that the 10.3 percent rate case ROE continues to be reasonable at this time. It bases this on the Rebuttal Testimony of Mr. Paul Moul, dated February 4, 2013 submitted in the Solar dockets, Docket No. EO12080721. (Response to RCR-ROR-9). The Company continues to support use of the Board-approved capital structure of 51.2 percent equity/48.8 percent debt as reasonable and consistent with its financial targets. Although it acknowledges that its current actual capital structure is slightly more leveraged, it expects to move close to its target capital structure by year end. (Response to RCR-ROR-1).

Finally, the Company proposes to utilize its 2010 settlement cost of long-term debt of 6.14 percent, even though its current embedded cost of debt is much lower. The Company argues that the 2010 settlement cost of debt is appropriate for the ESAM because its current relatively low cost of debt could increase over time. (Response to RCR-ROR-24(b)) I calculate that the use of the settlement embedded cost of debt in the two ESAMs (in place of the current cost of debt) will have the effect of increasing the proposed 10.3 percent ROE to a realized ROE of about 11 percent.

Q. DOES THE COMPANY PROPOSE ANY MECHANISM FOR UPDATING OR REVISING THE RATE OF RETURN TO BE EMPLOYED IN THE ESAMS?

A. Yes. The response to RCR-ROR-28 states that the rate of return elements may be revised based on Board-approved base rate case orders. The Company, however, provides no indication concerning when it would file its next base rate case.

Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME ON RATE OF RETURN, ASSUMING THE ESAM IS APPROVED?

A. Assuming the Board permits the use of the ESAM, it is highly improper to employ a stale rate of return approved in the 2009 rate case for cost recovery to begin in 2014 and extending for several years. The Company's cost of capital has declined significantly since then, and the ESAM is much less risky for the Company than conventional base rate recovery, which was the context for the Company's currently authorized 10.3 percent ROE.

As shown on Schedule MIK-1, page 1 of 1, I am recommending an overall rate of return of 6.97 percent. This is based on the 2010 settlement capital structure, the current (i.e., June 30, 2013) embedded cost of debt of 4.93 percent, customer deposits (about 1 percent of capital structure) at a cost rate of 0.11 percent and a cost of equity of 9.00 percent. My cost of equity recommendation is supported by DCF studies of both electric utility and gas distribution utility proxy groups. I have identified at this time a reasonable cost of equity range of about 9.0 to 9.5 percent, with the lower end of this range (i.e., 9.0 percent) appropriate for the ESAM.

Q. DOES YOUR RECOMMENDED CAPITAL STRUCTURE INCLUDE SHORT-TERM DEBT?

A. No, it does not, nor does the Company’s proposal. The Company allocates short-term debt to construction work in progress (“CWIP”) for purposes of calculating its Allowance for Funds Used During Construction (“AFUDC”) rate. This is sometimes referred to as the "FERC Formula", and it helps to ensure that ratepayers receive the full benefit of the very low-cost short-term debt financing. (Response to RCR-ROR-13.)

Q. THE COMPANY PROPOSES THAT THE RATE OF RETURN FOR THE ESAM BE UPDATED WHEN THE BOARD CHANGES THE AUTHORIZED RETURN IN BASE RATE CASES. DO YOU AGREE?

I do not object to updating the ROE and capital structure for the ESAM based on future Board rate case orders. However, the calculation of the Company's embedded cost of debt is neither difficult nor controversial, and as the Company has noted, it can change over time. Consequently, it would be a simple matter to update the embedded cost of debt component annually in order to improve the accuracy of the ESAM cost recovery. Moreover, annual updating would remove the Company's objection to using in this docket an updated cost of debt (i.e., the 4.93 percent) in place of the unrealistic and out-of-date cost of debt of 6.14 percent from the 2009 rate case. As I previously noted, failing to update the cost of debt at this time would effectively award PSE&G an 11 percent ROE for its ESAM, not its requested 10.3 percent.

Q. HOW DID YOU DEVELOP YOUR 9.00 PERCENT RECOMMENDATION?

A. I am relying primarily on the standard Discount Cash Flow ("DCF") model applied to two utility proxy groups. The first group, an electric utility East Region Group (selected by PSE&G's consultant, Mr. Moul) produces a range of 8.6 to 9.1 percent, with a midpoint of 8.9 percent. My second study employs a gas distribution proxy group (again, a group identical to the group selected by Mr. Moul in recent gas rate cases) produces a DCF range of 8.7 to 10.2 percent, with a midpoint of 9.5 percent. In addition, I have conducted a CAPM Study, which produces a range of 7.0 to 9.1 percent, with a midpoint of 8.1 percent. I use the CAPM study only as a check on my DCF studies.

Based on these results, I conclude that a reasonable range at this time and for this proposed ESAM program is 9.0 to 9.5 percent, with a midpoint of 9.25 percent. While the midpoint would be appropriate in a standard rate case, the lower end is appropriate for the ESAM.

Q. HAVE YOU CONSIDERED PSE&G'S OVERALL RISK AND THE ES PROGRAM'S RISK IN DEVELOPING YOUR RECOMMENDATION?

A. Yes. I conclude that PSE&G is inherently a very low-risk utility company. This is confirmed by reference to the various credit rating reports of Standard & Poors ("S&P"), Moody's Investor Service ("Moody's") and Fitch Ratings. (Response to RCR-ROR-4.) S&P rates PSE&G BBB+ based on the consolidated credit profile of its parent, Public Service Enterprise Group ("PSEG"). (April 26, 2013 report.) S&P also assigns PSE&G a business risk profile of "Excellent." Moody's and FitchRatings assign PSE&G an issuer rating of low single A (see the May 6, 2013 and July 26, 2013 reports). These are very strong credit ratings and would support the notion that PSE&G is no riskier or even less risky than the proxy groups.

In addition, the intrinsic risk attributes of the ES Program and the proposed ESAM should be considered. The Company's ratemaking proposal would provide it with both contemporaneous and dollar-for-dollar cost recovery of all prudently-incurred program costs, with the program elements themselves pre-approved by the Board.

Q. DO YOU CONSIDER THE ES PROGRAM AND ASSOCIATED ESAM TO BE RISK FREE?

A. No, and I agree with the Company that it still must execute successfully on its approved program and that it should be subject to prudence reviews and potential disallowances for poor cost control performance. That, however, is the only significant risk identified by PSE&G in connection with this program. (Response to RCR-ROR-10). Moreover, the

Company has extensive experience with infrastructure, energy efficiency and renewable resource programs and trackers over a period of several years. The Company concedes that none of these programs has resulted in an adverse prudence finding or disallowance. (Response to RCR-ROR-26.)

While I do not assert the Program is risk free for PSE&G, it is unmistakably very low risk due to its dollar-for-dollar cost recovery, particularly as compared with "standard regulation." I recommend the Board consider this very low risk cost recovery arrangement in determining the fair return on equity to be included in any approved ESAM. PSE&G's total company risk profile also compares favorably with the overall business risks of the companies comprising the two DCF proxy groups.

Q. PSE&G APPEARS TO INSIST ON USING IN ITS ESAM AN OUT-OF-DATE AND THEREFORE OVERSTATED RATE OF RETURN. WHY IS THIS IMPROPER?

A. It is quite clear that the cost of capital has declined materially since the Company's 2009 base rate case, and therefore the settlement rate of return overstates significantly today's cost of capital. The purpose of the ESAM, as I understand it, is to permit PSE&G to fully recover all (prudently-incurred) Program costs – no more, no less. Failure to update a rate case rate of return award several years old is inconsistent with that objective, and in this case will systematically overcharge electric and gas customers. This would not produce just and reasonable rates and is inconsistent with the asserted intent of the ESAM, which is exact cost recovery.

Q. HAVE YOU QUANTIFIED A SPECIFIC RISK REDUCTION ADJUSTMENT TO ARRIVE AT THE 9.00 PERCENT ROE?

A. I have not employed a specific quantitative analysis to calculate a risk-reduction adjustment for the ROE. This is because there is no available market risk proxy (e.g., a proxy group) that reflects the ESAM risk profile. For that reason, I recommend use of the lower end of my cost of equity rate (i.e., 9.0 percent) rather than the 9.25 percent midpoint, which would be the more appropriate ROE award if a conventional rate case were to be held for PSE&G at this time. I do not mean to suggest, however, that the risk reduction effect of the ESAM is only 0.25 percent. It may be much more than that, but it would be difficult to objectively quantify that effect.

B. <u>Capital Cost Trends in Recent Years</u>

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

A. Yes. I show the capital cost trends since 2002, through calendar year 2012, on page 1 of Schedule MIK-1. Pages 2, 3 and 4 of that Schedule show monthly data for January 2007 through September 2013. The indicators provided include the annualized inflation rate (as measured by the Consumer Price Index), 10-year Treasury yields, 3-month Treasury bill yields and Moody's single A and triple B yields on long-term utility bonds. While there is some fluctuation, these data series show a general declining trend in capital costs. For example, in the very early part of this 10-year period, utility bond yields averaged about 7 to 8 percent, with 10-year Treasury yields of 4 to 5 percent. By 2011, single A utility bond yields had fallen to an average of 5.1 percent, with 10-year Treasury yields declining to an average of 2.8 percent. Within the past year (i.e., late 2012 to late 2013), Treasury and utility long-term bond rates have declined even further to near or below the lowest levels in many decades but in recent months have moved up.

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.[1] The Fed has also sought to exert downward pressure on long-term interest rates through its policy of "quantitative easing." Quantitative easing is a policy whereby the Fed engages on an ongoing basis in the purchase of financial assets (such as Treasury bonds or agency mortgage-backed debt), both to support the market prices of financial assets and to increase the U.S. money supply. The intent of quantitative easing is to keep the cost of capital low (which increases the value of financial assets such as utility stocks) and make credit both cheaper and more abundant. Although that program ended in the summer of 2012, the Fed announced in September 2012 a continuation of its near zero short-term interest rate policy at least through 2015, and an indefinite continuation of quantitative easing. In its December 12, 2012 meeting, the Fed stated that its low interest rate and accommodative policies would continue at least until a much lower U.S. unemployment rate is achieved (i.e., a target of 6.5 percent), an endeavor which is expected to take several years. As a result, interest rates have remained relatively low.

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

A. Yes. Information on Fed policy is from its press release issued on January 30, 2013 following a meeting of the Federal Open Market Committee ("FOMC," the monetary policy decision-making forum for the Fed). That statement affirmed that for the foreseeable future its "highly accommodative" policy will continue until progress toward "maximum employment" is achieved. Specifically, the Fed will continue its near zero short-term interest rate policy and will foster lower long-term interest rates by asset purchases, namely $85 billion per month of incremental purchases of mortgage-backed

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

securities and long-term Treasury bonds. The FOMC further stated that an accommodative monetary policy "will remain appropriate for a considerable time after the asset purchase program ends and the economic recovery strengthens." In addition, the FOMC observes that inflation trends have been running below its 2 percent per year target level and that "long-term inflation expectations remain stable." The FOMC's policy outlook, as described above, was broadly confirmed in a press release following its May 1, 2013 meeting, noting that the Fed will carefully monitor economic conditions and labor markets.

The FOMC's most recent formal meeting took place in late September 2013. Despite the contrary expectation of many analysis, the FOMC elected to continue its highly accommodative, quantitative easing policy at its current level ($85 billion of bond purchases per month) until U.S. economic conditions (and particularly conditioned in labor markets) exhibited sustained, stronger performance. While noting that some improvement in the U.S. economy had become evident, the FOMC determined that this was not sufficient progress to warrant a policy change.

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, along with the Fed's asset purchase program. 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. The relatively sluggish economy (that we have at this time) exerts downward pressure on interest rates and capital costs generally because the demand for capital spending 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, as the FOMC has noted.

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

A. In a very general sense and over time, that is normally the case, although the utility cost of equity and cost of debt need not move together precisely in lock step or necessarily in the short run. The economic forces mentioned above (and Fed policy) that lead to lower interest rates also tend to exert downward pressure on the utility cost of equity. After all, many investors tend to view utility stocks and bonds as alternative investment vehicles for portfolio allocation purposes, and in that sense utility stocks and long-term bonds are 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), October 2013 edition, which is a survey compilation of approximately 40 major forecast organizations. The "consensus" calls for real GDP growth of 1.6 percent in 2013 and 2.6 percent in 2014 and inflation (GDP deflator) of 1.4 percent and 1.8 percent in 2013 and 2014, respectively. The October 2013 edition of Blue Chip publishes a consensus 10-year inflation forecast of 2.1 percent per year, only slightly higher than the near term. Thus, both the near- and long-term economic outlooks are indicative of modest economic growth and low inflation, implying low market capital costs.

Q. HAS THE PATTERN BEEN SIMILAR FOR EQUITY MARKETS?

A. As one would expect, equity markets exhibit more volatility than bond markets. Following the onset of the financial crisis about four years ago, stock market indices plunged, reaching a bottom in March 2009. Since then, stock prices recovered impressively and the major indices have largely recovered to or above 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 with the debt ceiling crisis. 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 the latter part of 2011. Since 2011, i.e., during most of 2012 and year-to-date 2013, U.S. equity markets in general have done quite well. This very noticeable improvement is clearly due to the very low and declining capital market environment (both in the U.S. and globally), relative economic stability (albeit with very tepid economic growth), and the tendency for investors to view the U.S. securities market as a "safe haven" for investing. In particular, the U.S. provides a very favorable capital cost environment for good quality utilities, such as PSE&G.

Q. HASN'T THERE BEEN A MAJOR CHANGE IN THE INTEREST RATE ENVIRONMENT?

A. Yes, there has been a noticeable change in the long-term bond market behavior in the last two months. This appears to be based on the perceptions of some investors that Fed policy within the next year may become less "accommodative," (i.e., a reduction in the size of the Fed's quantitative easing program) and U.S. economic growth may accelerate. This has resulted, for example, in yields on ten-year Treasuries increasing from slightly less than 2 percent earlier this year to about 2.6 percent as of this writing in early October 2013. Of course, neither the less aggressive Fed accommodation nor accelerating U.S. economic growth has yet to take place. Although the upward interest rate move is significant, long-term rates remain at historically very low levels. More importantly for this case, equity markets have continued to do quite well even with the recent upward interest rate movement.

The market cost of capital, both for PSE&G and in general, remains extremely low by historical standards and even low compared to 2009 when PSE&G's last base rate case took place. That was a time period of higher interest rates and capital market turmoil, i.e., the year following the great financial crisis of 2008/2009.

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

A. Yes. Specifically, I present DCF evidence that relies on utility stock market data from the six months ending June 2013. Such market data directly incorporate the economic forces, monetary policy choices, and market behavior described above. The use of a recent six months of market data is reasonable for assessing PSE&G's current cost of capital as it reflects recent market and economic trends.

III. <u>COST OF COMMON EQUITY</u>

A. <u>Using the DCF Model</u>

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 PSE&G's authorized equity return above the Company's currently authorized cost of equity. As noted earlier, that return award in the 2009 rate case was in the context of a conventional base rate case.

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

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

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

A. No, certainly not directly. However, he does cite to Mr. Moul's February 2013 rebuttal testimony in the Solar Program docket as supporting the notion that 10.3 percent is reasonably representative of investor requirements for PSE&G common equity at this time. In that same docket, I submitted a surrebuttal testimony on behalf of Rate Counsel demonstrating that Mr. Moul's analysis was incorrect and greatly overstated the PSE&G cost of equity, both in general and in the context of a cost tracker mechanism.

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 and gas distribution utilities. However, for reasons discussed in my testimony, I emphasize the DCF model results (as applied to both utility proxy groups) in formulating my recommendation. Please note that this consolidated docket covers PSE&G's electric and gas ES Programs. 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 past studies submitted by PSE&G), I also perform a CAPM study which also is based on the electric distribution utility proxy group companies used in my testimony. The gas utility CAPM study would produce a similar but slightly lower estimate.

Q. PLEASE DESCRIBE THE DCF MODEL.

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

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

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

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

K_e = cost of equity;

Do = the current annualized dividend;

Po = stock price at the current time; and

g = the long-term annualized dividend growth rate.

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

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly traded companies, i.e., companies whose market prices (and therefore market valuations) are transparently revealed. Consequently, the model cannot be applied to PSE&G, which is a wholly-owned subsidiary of PSEG parent, and therefore, a market proxy is needed. In theory, PSEG parent, could serve as that market proxy, but I have not included it as a member of my electric distribution utility proxy group. However, this would be inappropriate due to PSEG's extensive unregulated operations. Moreover, in order to be responsive to PSE&G's point of view on cost of equity, I am accepting Mr. Moul's electric utility proxy group from the recent solar case. This is a group of ten electric utility companies located in the East region of the U.S.

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

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

Q. DO YOU HAVE ANY MAJOR CONCERNS REGARDING MR. MOUL'S ELECTRIC PROXY GROUP?

A. Yes, I would question his decision to include FirstEnergy in the proxy group due to its large investment in merchant plant operations and its unregulated energy marketing. Excluding FirstEnergy would slightly increase my DCF proxy group average, and this exclusion would be reasonable. However, the overall effect of removing FirstEnergy would be small, and it would not alter my recommended cost of equity range of 9.0 to 9.5 percent. For reasons of consistency with Mr. Moul, I am retaining FirstEnergy in the electric proxy group at this time.

Q. DOES MR. MOUL'S PROXY GROUP INCLUDE COMPANIES THAT YOU WOULD CONSIDER TO BE PRIMARILY ELECTRIC DELIVERY SERVICE UTILITIES?

A. Yes. I would consider four of the ten companies to be primarily electric delivery service utilities which is similar to PSE&G's business model.

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

A. Yes, there are some, but in most cases they are relatively modest, with FirstEnergy being the exception. For example, with the recent sale of its merchant generation assets, Pepco Holdings has reduced non-regulated operations to a very small percentage of the total consolidated corporation. These non-regulated operations tend to increase the cost of equity relative to being a pure delivery service utility, but only slightly. On the whole, Mr. Moul's proxy group is an acceptable risk proxy for PSE&G's electric operations despite the minor presence of non-regulated operations and a large amount of regulated generation.

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

Q. PLEASE IDENTIFY THE TEN COMPANIES INCLUDED IN THE ELECTRIC UTILITY PROXY GROUP.

A. These ten proxy companies are listed on Schedule MIK-3, page 1 of 2, along with several risk indicators.

Q. HAVE YOU PROPOSED A SPECIFIC BUSINESS RISK ADJUSTMENT TO THE DCF COST OF EQUITY BETWEEN THE PROXY COMPANY AVERAGE AND PSE&G?

A. I have not reflected an explicit adjustment for risk since I believe that there is no basis for asserting that PSE&G is riskier than the average company. As noted earlier, PSE&G has a very favorable business and financial risk profile, even in the context of a conventional base rate cost recovery.

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 September 2013, the most recent data available to me as of this writing.[2] This covers the second and third calendar quarters of 2013. As a general matter, this six months has been a time period of an improving stock market, although less so for utilities than the broader markets.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, April – September 2013. Over this six-month period the proxy group average dividend yields indicate a slightly increasing trend from a high of 4.75 percent in September 2013 to a low of 4.09 percent in April 2013, averaging 4.52 percent for the full six months.

For DCF purposes and at this time, I am using a proxy group dividend yield of 4.52 percent.

Q. IS 4.52 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 4.6 percent. This is based on assuming that half of a year growth is 2.25 percent (i.e., a full year growth is about 4.5 percent).

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

[2] For September, I have used the September 30, 2013 dividend yields obtained from YahooFinance.com since the October 2013 S&P *Stock Guide* is not yet available.

earnings growth as a proxy for (long-term) dividend growth. This is because in the long-run earnings are the ultimate source of dividend payments to shareholders, and this is likely to be particularly true for a large group of utility companies.

One possible approach is to examine historical growth as a guide to investor expected future growth, for example the recent five-year or ten-year growth in earnings, dividends and book value per share. However, my experience with utilities in recent years is that these historic measures have been somewhat volatile and are not necessarily reliable as prospective measures. The DCF growth rate should be prospective, and one useful source of information on prospective growth is the projections of earnings per share growth rates (typically five years) prepared by securities analysts and reported in public surveys. It appears that in his February 2013 testimony, Mr. Moul placed exclusive weight on this growth rate information for his DCF studies, and while I agree that it warrants substantial emphasis, it should not be relied upon exclusively.

Q. PLEASE DESCRIBE THE ANALYST EARNINGS GROWTH RATE EVIDENCE.

A. Schedule MIK-4, page 3 presents five available and well-known public sources of analyst earnings growth rate projections. Four of these five sources – YahooFinance, 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 2010-2012 compared to the annual average for the forecast period of 2016-2018.

As this schedule shows, the growth rates for individual companies vary only slightly among the five sources. These proxy group averages are 4.6 percent for CNNfn, 4.5 percent for YahooFinance, 4.7 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 a narrow 4.2 to 4.7 percent. The average of these five sources is 4.5 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 4.5 percent. Please note that absent FirstEnergy, the securities analyst growth rate 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 five proxy companies tend to be somewhat less (on average) than analyst growth projections. For the five companies, projected dividend growth averages 2.6 percent, book value growth averages 3.6 percent, and earnings retention growth averages 3.2 percent. While this provides a useful comparison, I have not relied on these published growth rates in developing my DCF growth rate range.

Some analysts and regulators favor the use of earnings retention growth (often referred to as “sustainable growth”), which Value Line indicates to be 3.2 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 ten companies of the growth rate (through 2016-2018) 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 ten companies, the external growth rate calculated in this manner averages about 0.2 percent. (Note that two of the five proxy companies are not expected to issue any new stock in the near term.) The sum of "internal" or earnings retention growth (i.e., 3.2 percent) and the "external" growth rate (i.e., 0.8 percent) is 4.0 percent.

Given this estimate of 4.0 percent for the sustainable growth rate and 4.5 percent for analyst earnings projections, a reasonable DCF growth rate range is approximately 4.0 to 4.5 percent.

Q. ARE THERE ANY OTHER FACTORS TO CONSIDER?

A. Some analysts include an adder for floatation expense to cover utility (or parent) costs incurred in issuing new common stock. This adder does not appear to be needed in this case since PSEG has not conducted a public issuance in recent years, nor is such an issuance expected for the foreseeable future. (Response to RCR-ROR-17 and 18.)

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 September 2013 is 4.6 percent for this group. Available evidence would support a long-run growth rate in the range of approximately 4.0 to 4.5 percent, as explained above. Summing the adjusted yield and growth rate range, with no flotation adjustment, produces a total return of 8.6 to 9.1 percent, and a midpoint result of 8.9 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. Moreover, excluding FirstEnergy from the proxy group would slightly increase the DCF results, supporting an estimate toward the upper end of this range.

C. DCF Study Using the Gas Utility Proxy Companies

Q. HOW HAVE YOU SELECTED YOUR DCF STUDY USING THE GAS UTILITY PROXY COMPANIES?

A. The gas distribution proxy group consists of nine companies identified by the Value Line Investment Survey as being in the gas utility industry, with two exceptions – UGI Corp. and NiSource. UGI has extensive unregulated propane operations, and NiSource is a combination of vertically-integrated electric utility, gas pipeline, and gas utility distribution company. It would be appropriate to exclude both companies from the proxy group.

In his recent gas utility rate cases, Mr. Moul has employed these same nine companies as his gas utility proxy group (for example, see his Columbia Gas of Pennsylvania testimony submitted in late 2012, PaPUC Docket No. R-2012-2321748).

Schedule MIK-5, page 1 of 1, provides a listing of my nine gas distribution utility proxy companies along with their risk attributes.

Q. WHAT IS THE DIVIDEND YIELD FOR THIS GROUP?

A. As shown on Schedule MIK-6, page 2 of 5, the proxy group average dividend yield for the six months ended September 2013 is 3.60 percent. The adjusted dividend yield for this proxy group is 3.7 percent.

Q. WHAT IS THE GROWTH RATE EVIDENCE?

A. I show the analyst projections of earnings growth for these nine companies on Schedule MIK-6, page 3 of 5, employing the same five public sources as I used for the electric utility proxy group. The group averages are 5.8 percent for Value Line, 4.7 percent for Reuters, 4.7 percent for YahooFinance, 4.2 percent for CNNfn and 4.6 percent for MSNMoney. The five sources average to 4.8 percent.

A second set of growth rates for the nine-company gas 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 or lower than the securities analyst projections, averaging 4.1 percent for dividends, 3.9 percent for book value and 5.0 percent for earnings retention growth. Again, these growth rates are used for comparative purposes and are not the basis for my recommended growth rate range.

Q. DID YOU CONDUCT A SUSTAINABLE GROWTH RATE ANALYSIS FOR THE PROXY GROUP?

A. Yes. 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 5.0 percent, as shown on page 4 of Schedule MIK 5. I calculated an "external" or "s x v" component for each of the nine gas proxy companies in the same manner as described for the electric utility companies, producing an "external" growth component of 1.5 percent. Thus, the total sustainable growth rate is 5.0 percent plus 1.5 percent, or 6.5 percent. This is shown on page 5 of Schedule MIK-5.

I have used the securities analyst earnings projections (4.8 percent) and the sustainable growth rate (6.5 percent) to develop a reasonable but conservatively high range for DCF purposes of 5.0 to 6.5 percent.

Q. PLEASE EXPLAIN WHY YOUR SUSTAINABLE GROWTH RATE IS SO MUCH HIGHER THAN THE SECURITIES ANALYST GROWTH RATES.

A. Part of the explanation is that my sustainable growth rate calculation is based entirely on Value Line projections, and, as shown on page 3 of Schedule MIK-6, Value Line is far more optimistic concerning growth than four other sources. In addition, there is a data anomaly with one gas company, LaClede Group. As shown on page 5 of Schedule MIK-6, over the period 2012 to 2017, LaClede is projected to increase its common shares outstanding by nearly 8 percent per year. This highly unusual projection in shares outstanding produces a sustainable growth rate for LaClede of 9.7 percent, a figure clearly out of line.

Upon closer inspection, this massive increase in shares outstanding, which pertains to a large acquisition by LaClede, already has taken place in mid-2013. Going forward, LaClede's stock issuance over the next five years is expected to be close to zero, and therefore its true sustainable growth rate is 4.5 percent, not 9.7 percent. This change would be automatically picked up when updating the sustainable growth rate calculation for LaClede. When the "corrected" growth rate value for LaClede is used, the proxy group average declines from 6.5 to 5.9 percent. Nonetheless, for DCF presentation purposes, I continue to employ a gas utility growth range at this time of 5.0 to 6.5 percent, even though a growth range of 5.0 to 6.0 percent would be more realistic.

Q. WHAT DCF MARKET RETURN DOES THIS PRODUCE?

A. As shown on Schedule MIK-6, page 1 of 5, I obtain a DCF return range of 8.7 to 10.2 percent, with a midpoint of 9.5 percent. This is based on an adjusted dividend yield of 3.7 percent plus a 5.0 to 6.5 percent growth range, with no adjustment for flotation expense. With a more realistic 5.0 to 6.0 percent growth rate range, my DCF range for the gas utility proxy group would be 8.7 to 9.7 percent, with a midpoint of 9.2 percent.

D. The CAPM Analysis

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. Moul's cost of equity methods.

According to this model, the cost of equity (Ke) 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. The greatest difficulty, however, is in the measurement of the expected stock market return (and therefore the equity risk premium), since that variable cannot be directly observed.

While the beta itself also is “observable,” different investor services provide differing calculations of betas depending on the specific procedures and methods that they use. These differences can potentially have large impacts on the CAPM results. I note that Mr. Moul has also employed Value Line as a source of betas.

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 electric utility proxy group average beta is slightly higher than the gas utility company group beta shown on Schedule MIK-5 (i.e., 0.70 versus 0.68). In the last six months, long-term (i.e., 30-year) Treasury yields have averaged approximately 3.5 percent, and as of this writing, is about 3.7 percent. 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-7. My low-end cost of equity estimate uses a risk-free rate of 3.5 percent, a proxy group beta of 0.70 and an equity risk premium of 5 percent.

$$Ke = 3.5\% + 0.70\ (5.0\%) = 7.0\%$$

The upper-end estimate uses a risk-free rate of 3.5 percent, a proxy group beta of 0.70 and an equity risk premium of 8.0 percent.

$$Ke = 3.5\% + 0.70\ (8.0\%) = 9.1\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 7.0 to 9.1 percent, with a midpoint of 8.1 percent. The CAPM analysis produces a midpoint result significantly lower than the range of results obtained for my two utility proxy 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. These market conditions make it difficult to assess equity risk premiums at this time.

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 10.0 to 11.0 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 9 to 12 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.)

My "midpoint" risk premium of roughly 6.5 percent falls well within that range.

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

IV. CONCLUSION

Q. WHAT ARE YOUR RECOMMENDATIONS CONCERNING FAIR RATE OF RETURN?

A. As discussed in detail in the Direct Testimony of witness Andrea Crane, Rate Counsel opposes the use of the ESAM for cost recovery and instead recommends the use of conventional base rate cases. However, in the event that the Board permits the use of the ESAM for cost recovery, I recommend and current evidence supports an overall rate of return of 6.97 percent compared to the Company's request of 8.21 percent. This consists of the Company's requested capital structure (i.e., 51.2 percent common equity and 48.8 percent debt); a return on common equity of 9.00 percent; an embedded cost of debt of 4.93 percent, and customer deposits (1 percent of capitalization) at 0.11 percent.

In addition to these numerical results, I recommend that the cost of debt used in the ESAM be updated annually. Capital structure and cost of equity used in the ESAM may be updated with base rate case decisions.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED 9.00 PERCENT ROE?

A. I have conducted DCF studies using both electric and gas utility proxy groups, with the proxy groups consistent with those previously selected by the Company's rate of return consultant in the solar docket, Mr. Moul. The electric DCF study ranges from 8.6 to 9.1 percent, with a midpoint of 8.9 percent. The gas utility DCF study produces a range of 8.7 to 10.2 percent, with a midpoint of 9.5 percent. I conclude that a reasonable range would be 9.0 to 9.5 percent, with 9.25 percent being the midpoint. For the ESAM, it is more appropriate to employ the lower end of the range in recognition of the very low risks PSE&G will incur under this program.

Q. THE COMPANY RELIES ON THE RATE OF RETURN DECISION FROM ITS LAST RATE CASE. WHY IS IT IMPORTANT TO UPDATE THE FAIR RATE OF RETURN?

A. The Company's ESAM proposal is intended to permit the Company to recover its prudent and reasonable Program costs, including its cost of capital. Capital costs have undoubtedly declined since the 2009 rate case. Failure to recognize and incorporate this cost of capital reduction would systematically ensure that customers are overcharged under this program, i.e., paying PSE&G more than its actual program costs incurred. As a simple example, failure to update the cost of debt will result in the Company actually earning about 11 percent on its ES equity investment, not its claimed 10.3 percent. In addition, it seems clear that the proposed ESAM cost recovery provides PSE&G with an exceptionally low risk investment.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION	)	
OF PUBLIC SERVICE ELECTRIC AND	)	**BPU DOCKET NOS. EO13020155 and**
GAS COMPANY FOR APPROVAL OF	)	**GO13020156**
THE ENERGY STRONG PROGRAM	)	

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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Filed: October 18, 2013

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Rate of Return Summary

Capital Type	% of Total[1]	Cost Rate	Weighted Cost
Long-Term Debt	47.79%	4.93%[2]	2.36%
Customer Deposits	1.01	0.11	0.00
Common Equity	51.2	9.00	4.61
Total	**100%**	**--**	**6.97%**

(1) PSE&G Schedule SS-ES-2 and responses to RCR-ROR-3 and 23.
(2) Response to RCR-ROR-3 (June 30, 2013 cost of debt)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Trends in Capital Costs

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield	Baa Utility Yield
2002	1.6%	4.6%	1.6%	7.4%	8.0%
2003	1.9	4.1	1.0	6.6	6.8
2004	2.7	4.3	1.4	6.2	6.4
2005	3.4	4.3	3.0	5.6	5.9
2006	2.5	4.8	4.8	6.1	6.3
2007	2.8	4.6	4.5	6.1	6.3
2008	3.8	3.4	1.6	6.5	7.2
2009	(0.4)	3.2	0.2	6.0	7.1
2010	1.6	3.2	0.1	5.5	6.0
2011	3.1	2.8	0.0	5.0	5.6
2012	2.1	1.8	0.1	4.1	4.9

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield	Baa Utility Yield
2007					
January	2.1%	4.8%	5.1%	6.0%	6.2%
February	2.4	4.7	5.2	5.9	6.1
March	2.8	4.6	5.1	5.9	6.1
April	2.6	4.7	5.0	6.0	6.2
May	2.7	4.8	5.0	6.0	6.2
June	2.7	5.1	5.0	6.3	6.5
July	2.4	5.0	5.0	6.3	6.5
August	2.0	4.7	4.3	6.2	6.5
September	2.8	4.5	4.0	6.2	6.5
October	3.5	4.5	4.0	6.1	6.4
November	4.3	4.2	3.4	6.0	6.3
December	4.1	4.1	3.1	6.2	6.5
2008					
January	4.3%	3.7%	2.8%	6.0%	6.4
February	4.0	3.7	2.2	6.2	6.6
March	4.0	3.5	1.3	6.2	6.7
April	3.9	3.7	1.3	6.3	6.8
May	4.2	3.9	1.8	6.3	6.8
June	5.0	4.1	1.9	6.4	6.9
July	5.6	4.0	1.7	6.4	7.0
August	5.4	3.9	1.8	6.4	7.0
September	4.9	3.7	1.2	6.5	7.2
October	3.7	3.8	0.7	7.6	8.6
November	1.1	3.5	0.2	7.6	9.0
December	0.1	2.4	0.0	6.5	8.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield	Baa Utility Yield
2009					
January	0.0%	2.5%	0.1%	6.4%	7.9%
February	0.2	2.9	0.3	6.3	7.7
March	(0.4)	2.8	0.2	6.4	8.0
April	(0.7)	2.9	0.2	6.5	8.0
May	(1.3)	2.9	0.2	6.5	7.8
June	(1.4)	3.7	0.2	6.2	7.3
July	(2.1)	3.6	0.2	6.0	6.9
August	(1.5)	3.6	0.2	5.7	6.4
September	(1.3)	3.4	0.1	5.5	6.1
October	(0.2)	3.4	0.1	5.6	6.1
November	1.8	3.4	0.1	5.6	6.2
December	2.5	3.6	0.1	5.8	6.3
2010					
January	2.6%	3.7%	0.1%	5.8%	6.2%
February	2.1	3.7	0.1	5.9	6.3
March	2.3	3.7	0.2	5.8	6.2
April	2.2	3.9	0.2	5.8	6.2
May	2.0	3.4	0.2	5.5	6.0
June	1.1	3.2	0.1	5.5	6.0
July	1.2	3.0	0.2	5.3	6.0
August	1.1	2.7	0.2	5.0	5.6
September	1.1	2.7	0.2	5.0	5.5
October	1.2	2.5	0.1	5.1	5.6
November	1.1	2.8	0.1	5.4	5.9
December	1.2	3.3	0.1	5.6	6.0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield	Baa Utility Yield
2011					
January	1.6%	3.4%	0.1%	5.6%	6.1%
February	2.1	3.6	0.1	5.7	6.1
March	2.7	3.4	0.1	5.6	6.0
April	2.2	3.5	0.1	5.6	6.0
May	3.6	3.2	0.0	5.3	5.7
June	3.6	3.0	0.0	5.3	5.7
July	3.6	3.0	0.0	5.3	5.7
August	3.8	2.3	0.0	4.7	5.2
September	3.9	2.0	0.0	4.5	5.1
October	3.5	2.2	0.0	4.5	5.2
November	3.0	2.0	0.0	4.3	4.9
December	3.0	2.0	0.0	4.3	5.1
2012					
January	2.9	2.0	0.0	4.3	5.1
February	2.9	2.0	0.0	4.4	5.0
March	2.7	2.2	0.1	4.5	5.1
April	2.3	2.1	0.1	4.4	5.1
May	1.7	1.8	0.1	4.2	5.0
June	1.7	1.6	0.1	4.1	4.9
July	1.4	1.5	0.1	3.9	4.9
August	1.7	1.7	0.1	4.0	4.9
September	2.0	1.7	0.1	4.0	4.8
October	2.2	1.8	0.1	3.9	4.5
November	1.8	1.7	0.1	3.8	4.4
December	1.7	1.7	0.1	4.0	4.6
2013					
January	1.6	1.9	0.1	4.2	4.7
February	2.0	2.0	0.1	4.2	4.7
March	1.5	2.0	0.1	4.2	4.7
April	1.1	1.8	0.7	4.0	4.5
May	1.4	1.9	0.0	4.2	4.7
June	1.8	2.3	0.1	4.5	5.1
July	2.0	2.6	0.0	4.7	5.2
August	1.5	2.7	0.0	4.7	5.3
September	--	2.8	0.0	4.8 (p)	5.4 (p)

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Listing of Companies in the Electric Utility Proxy Group

Company	Safety Rating	Financial Strength	Beta	2012 Common Equity Ratio*
Con. Edison	1	A+	0.60	54.1%
Dominion Resources	2	B++	0.70	38.2
Duke Energy	2	A	0.60	52.9
FirstEnergy	3	B+	0.80	46.3
Northeast Utilities	2	B++	0.75	55.4
Pepco Holdings	3	B	0.75	52.7
Scana Corp.	2	B++	0.65	45.6
Southern Company	1	A	0.55	47.3
TECO Energy	2	B++	0.85	43.5
UIL Holdings	2	B++	0.75	41.1
Average	**2.0**	**--**	**0.70**	**47.7%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2012 equity ratio including short-term debt and current maturities averages 43.5 percent.

Source: *Value Line Investment Survey,* August 23, 2013

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DCF Summary for the
Electric Utility Proxy Group

1. Dividend Yield (April – September 2013)[1]	4.52%
2. Adjusted Yield ((1) x 1.0225)	4.6%
3. Long-Term Growth Rate[2]	4.0% - 4.5%
4. Total Return ((2) + (3))	8.6% - 9.1%
5. Flotation Expense	0.0%
6. Cost of Equity ((4) + (5))	8.6% - 9.1%
7. Midpoint	8.9%
Recommendation	**9.00%**

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Dividend Yields for the Electric Utility Proxy Group
(April 2013 – September 2013)

	Company	April	May	June	July	August	September	Average
1.	Con. Edison	3.9%	4.3%	4.2%	4.1%	4.4%	4.5%	4.23%
2.	Dominion Resources	3.6	3.9	4.1	3.8	3.9	3.6	3.82
3.	Duke Energy	4.1	4.5	4.6	4.4	4.8	4.7	4.52
4.	FirstEnergy	4.7	5.6	5.9	5.8	5.9	6.0	5.65
5.	Northeast Utilities	3.2	3.5	3.5	3.3	3.6	3.5	3.43
6.	Pepco Holdings	4.8	5.1	5.3	5.3	5.7	5.9	5.35
7.	Scana Corp.	3.7	4.0	4.2	3.9	4.2	4.4	4.07
8.	Southern Company	4.2	4.6	4.7	4.5	4.9	4.9	4.63
9.	TECO Energy	4.6	5.0	5.2	5.0	5.3	5.3	5.07
10.	UIL Holdings	4.1	4.4	4.5	4.2	4.6	4.7	4.42
	Average	**4.09%**	**4.49%**	**4.62%**	**4.43%**	**4.73%**	**4.75%**	**4.52%**

Source: S&P *Stock Guide,* May 2013 - September 2013. The September figure is the September 30, 2013 yield obtained from YahooFinance.com.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Company	Value Line	Yahoo	MSN	Reuters	CNN	Average
1.	Con. Edison	2.5%	1.78%	3.0%	1.78%	2.30%	2.27%
2.	Dominion Resources	5.0	6.88	5.8	6.66	6.74	6.22
3.	Duke Energy	4.0	3.66	3.7	3.85	3.00	3.64
4.	FirstEnergy	0.5	1.94	0.0	2.12	0.00	0.91
5.	Northeast Utilities	8.0	7.62	7.8	7.19	8.00	7.72
6.	Pepco Holdings	6.0	4.77	5.0	3.82	5.00	4.92
7.	Scana Corp.	4.5	3.81	4.7	4.83	4.25	4.42
8.	Southern Company	4.5	4.28	4.4	4.54	3.92	4.33
9.	TECO Energy	3.0	2.83	5.0	2.83	5.00	3.73
10.	UIL Holdings	4.0	7.79	8.0	7.03	8.00	6.96
	Average	**4.20%**	**4.54%**	**4.74%**	**4.47%**	**4.62%**	**4.51%**

Sources: *Value Line Investment Survey*, August 23, 2013. YahooFinance.com, MSNMoney.com, CNNMoney.com, Reuters.com, public websites, September 2013.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Other Value Line Measure of Growth for the
Electric Utility Proxy Group

	Company	Dividend Per Share	Book Value Per Share	Earnings Retention
1.	Con. Edison	1.5%	3.5%	3.5%
2.	Dominion Resources	5.5	4.5	4.0
3.	Duke Energy	2.0	3.0	2.5
4.	FirstEnergy	0.0	1.5	1.0
5.	Northeast Utilities	8.0	6.0	4.5
6.	Pepco Holdings	1.0	2.0	2.5
7.	Scana Corp.	2.5	5.0	4.0
8.	Southern Company	3.5	4.0	3.5
9.	TECO Energy	2.0	2.0	3.5
10.	UIL Holdings	0.0	4.5	3.0
	Average	**2.60%**	**3.60%**	**3.20%**

Source: *Value Line Investment Survey*, August 23, 2013. The earnings retention figures are projections for 2016-2018.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Fundamental Growth Rate Analysis
for the Electric Utility Proxy Group

	Company	Shares 2012-2017[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	Con. Edison	0.01%	46.3%	0.0%	3.5%	3.5%
2.	Dominion Resources	1.48	227.4	3.4	4.0	7.4
3.	Duke Energy	0.17	21.9	0.0	2.5	2.5
4.	FirstEnergy	0.51	19.3	0.1	1.0	1.1
5.	Northeast Utilities	0.31	47.9	0.1	4.5	4.6
6.	Pepco Holdings	2.08	4.5	0.1	2.5	2.6
7.	Scana Corp.	3.92	62.6	2.5	4.0	6.5
8.	Southern Company	1.39	106.5	1.5	3.5	5.0
9.	TECO Energy	0.13	65.8	0.1	3.5	3.6
10.	UIL Holdings	0.05	82.4	0.0	3.0	3.0
	Average			**0.8%**	**3.2%**	**4.0%**

(1) Projected growth rate in shares outstanding, 2012-2017.

(2) % Premium of share price ("Recent Price") over 2012 Book Value per share.

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

(4) br is Value Line's projection as of 2016-2018.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Listing of the Gas Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2012 Common Equity Ratio*
1.	AGL Resources	1	A	0.75	50.5%
2.	Atmos Energy	2	B++	0.70	54.7
3.	LaClede Group	2	B++	0.60	64.0
4.	New Jersey Resources	1	A	0.70	60.8
5.	NW Natural Gas	1	A	0.60	51.5
6.	Piedmont Natural	2	B++	0.70	51.3
7.	South Jersey Ind.	2	B++	0.65	55.0
8.	Southwest Gas	3	B+	0.75	50.8
9.	WGL Corporation	1	A	0.65	67.5
	Average	**1.7**	**--**	**0.68**	**56.2%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2012 equity ratio including short-term debt and current maturities averages 48.8 percent.

Source: *Value Line Investment Survey*, September 6, 2013.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DCF Summary for
Gas Distribution Proxy Group

1. Dividend Yield (April – September 2013)[1]	3.60%
2. Adjusted Yield ((1) x 1.0275)	3.7%
3. Long-Term Growth Rate[2]	5.0% - 6.5%
4. Total Return ((2) + (3))	8.7% - 10.2%
5. Flotation Expense	0.0%
6. Cost of Equity ((4) + (5))	8.7% - 10.2%
7. Midpoint	9.5%
Recommendation	**9.00%**

[1] Schedule MIK-6, page 2 of 5.

[2] Schedule MIK-6, pages 3 of 5, 4 of 5, and 5 of 5.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Dividend Yields for Gas Distribution Proxy Group
(April 2013 – September 2013)

	Company	April	May	June	July	August	September*	Average
1.	AGL Resources	4.3%	4.4%	4.4%	4.1%	4.3%	4.1%	4.27%
2.	Atmos Energy	3.2	3.3	3.4	3.2	3.5	3.3	3.32
3.	LaClede Group	3.6	3.6	3.7	3.7	3.8	3.8	3.70
4.	New Jersey Resources	3.4	3.5	3.9	3.6	3.7	3.8	3.65
5.	Northwest Natural Gas	4.1	4.2	4.3	4.1	4.4	4.3	4.23
6.	Piedmont Natural	3.6	3.6	3.7	3.6	3.8	3.8	3.68
7.	South Jersey Ind.	2.9	3.0	3.1	2.9	3.1	3.1	3.02
8.	Southwest Gas	2.6	2.8	2.8	2.7	2.8	2.6	2.72
9.	WGL Corporation	3.6	3.9	3.9	3.7	4.0	3.9	3.83
	Average	**3.48%**	**3.59%**	**3.69%**	**3.51%**	**3.71%**	**3.63%**	**3.60%**

Source: S&P *Stock Guide,* May 2013 – September 2013. The September figure is as of September 30, 2013 per YahooFinance.com.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Projection of Earnings per Share
Five-Year Growth Rates for the
Gas Distribution Proxy Group

	Company	Value Line	Yahoo	MSN	Reuters	CNN	Average
1.	AGL Resources	9.0%	N/A	4.0%	5.00%	4.05%	5.51%
2.	Atmos Energy	5.5	6.20	6.1	6.20	6.20	6.04
3.	LaClede Group	6.0	4.70	4.1	4.70	4.71	4.84
4.	New Jersey Resources	4.0	2.50	4.0	2.50	2.50	3.10
5.	Northwest Natural Gas	4.5	4.00	4.3	4.00	4.00	4.16
6.	Piedmont Natural	4.0	5.00	4.3	5.00	5.00	4.66
7.	South Jersey Ind.	7.5	6.00	6.0	6.0	6.00	6.30
8.	Southwest Gas	8.0	3.53	3.5	3.53	4.00	4.51
9.	WGL Corporation	3.5	5.25	5.3	5.25	0.90	4.04
	Average	**5.78%**	**4.65%**	**4.62%**	**4.69%**	**4.15%**	**4.80%**

Sources: *Value Line Investment Survey*, September 6, 2013. YahooFinance.com, MSNMoney.com, CNNFox.com, Reuters.com, public websites, September 2013

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Other Value Line Measure of Growth for the
Gas Distribution Proxy Group

	Company	Dividend Per Share	Book Value Per Share	Earnings Retention
1.	AGL Resources	4.5%	5.0%	5.0%
2.	Atmos Energy	1.5	5.5	4.5
3.	LaClede Group	3.5	-3.0	4.5
4.	New Jersey Resources	3.0	5.0	6.5
5.	Northwest Natural Gas	2.5	3.0	4.0
6.	Piedmont Natural	3.0	4.5	3.5
7.	South Jersey Ind.	8.5	6.5	6.5
8.	Southwest Gas	7.0	5.0	6.5
9.	WGL Corporation	3.0	4.0	4.0
	Average	**4.06%**	**3.94%**	**5.00%**

Source: *Value Line Investment Survey*, September 6, 2013. The earnings retention figures are projections for 2016-2018.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Fundamental Growth Rate Analysis for the
Gas Distribution Proxy Group

	Company	Shares 2012-2017[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	AGL Resources	Negative	N/A	0.0%	5.0%	5.0%
2.	Atmos Energy	2.68%	58.8%	1.6	4.5	6.1
3.	LaClede Group	7.85	66.4	5.2	4.5	9.7
4.	New Jersey Resources	Negative	N/A	0.0	6.5	6.5
5.	Northwest Natural Gas	0.79	53.3	0.4	4.0	4.4
6.	Piedmont Natural	1.02	128.7	1.3	3.5	4.8
7.	South Jersey Ind.	2.61	149.3	3.9	6.5	10.4
8.	Southwest Gas	1.62	66.9	1.1	6.5	7.6
9.	WGL Corporation	0.19	72.4	0.1	4.0	4.1
	Average			**1.5%**	**5.0%**	**6.5%**

(1) Projected growth rate in shares outstanding, 2012-2017.

(2) % Premium of share price ("Recent Price") over 2012 Book Value per share.

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

(4) br is Value Line's projection as of 2016-2018.

Source: *Value Line Investment Survey*, September 6, 2013.

PUBLIC SERVICE ELECTRIC AND GAS 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 = 3.5% (Long-term treasury bond yield for the most recent six months, see page 2 of 2)

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

Beta = 0.70 (See Schedule MIK-3)

C. **Model Calculations**

Low end: K_e = 3.5% + 0.70 (5.0) = 7.0%

Midpoint: K_e = 3.5% + 0.70 (6.5) = 8.1%

Upper End: K_e = 3.5% + 0.70 (8.0) = 9.1%

High Sensitivity: K_e = 3.5% + 0.70 (9.0) = 9.8%

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Long-Term Treasury Yields
(April – September 2013)

Month	30-Year	20-Year	10-Year
April	2.93%	2.55%	1.76%
May	3.11	2.73	1.93
June	3.40	3.07	2.30
July	3.61	3.31	2.58
August	3.76	3.49	2.74
September	3.79	3.53	2.81
Average	**3.43%**	**3.11%**	**2.35%**

Source: Federal Reserve, "Statistical Release," publication H.15, May 2012 – October 2013.

APPENDIX A

STATEMENT OF QUALIFICATIONS

MATTHEW I. KAHAL

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

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

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 of the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted by both Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring, and utility purchase power contracts.

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

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

Publications and Consulting Reports

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

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

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

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

Conference and Workshop Presentations

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

	Docket Number	Utility	Jurisdiction	Client	Subject
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

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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)

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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
365.	2010-2213369 April 2011	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues

Expert Testimony
of Matthew I. Kahal

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

Expert Testimony
of Matthew I. Kahal

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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
396.	U-32628 April 2013	Entergy Louisiana and Gulf States Louisiana	Louisiana	Staff	Avoided cost methodology
397.	U-32675 June 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	RTO Integration Issues
398.	ER12111052 June 2013	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Cost of capital
399.	PUE-2013-00020 July 2013	Dominion Virginia Power	Virginia	Apartment & Office Building Assoc. of Met. Washington	Cost of capital
400.	U-32766 August 2013	Cleco Power	Louisiana	Staff	Power plant acquisition
401.	U-32764 September 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	Storm Damage Cost Allocation
402.	P-2013-237-1666 September 2013	Pike County Light and Power Co.	Pennsylvania	Office of Consumer Advocate	Default Generation Service

APPENDIX B

RESPONSES OF PSE&G
TO RATE COUNSEL DATA REQUESTS

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
REGULATORY EQUITY TO TOTAL CAPITALIZATION RATIO

QUESTION:
Please provide the Public Service Electric and Gas Company ("PSE&G" or "the Company") actual regulatory capital structure as of June 30, 2013, both in percentages and in dollar balances. The term "regulatory capital structure" in this context is intended to mean employing the same capital structure elements and definitions as used in the last rate case (e.g., no short-term debt, including current maturities of long-term debt, and no securitization debt, including customer deposits, etc.).

ANSWER:
As of June 30, 2013, our regulatory equity to total capitalization ratio was 49.7%. The components include equity of $5,574M, long-term debt of $5,540M and customer deposits of $95M

PSE&G targets a capital structure consistent with the BPU approved regulatory equity ratio of 51.2%. On December 31, 2012, PSE&G had an equity ratio of 51.5%. On March 31, 2013 PSE&G had an equity ratio of 51.5%. The June 30, 2013 equity ratio was influenced by a $500M long-term debt issuance in May 2013.

The Company anticipates the equity to total capitalization ratio returing near 51.2% by the end of the year.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

FINANCIAL STATEMENTS

QUESTION:
Please provide the Company's financial statements (i.e., income statement, balance sheet, and cash flow statement) at June 30, 2013 when available.

ANSWER:
The requested information will be available in the FERC Form 3Q for 2013/2Q, which will be submitted in mid-August. An updated response with the FERC Form 3Q attached will be submitted at that time.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMBEDDED COST

QUESTION:
Please provide the Company's embedded cost rates of (a) long-term debt; (b) short-term debt; (c) preferred stock (if any); and (d) customer deposits at June 30, 2013. In the case of long-term debt, please include a schedule showing the calculation of the embedded cost rate.

ANSWER:
As of June 30, 2013, PSE&G's embedded cost of long term debt was 4.93%; PSE&G's cost for short term debt (commercial paper) on June 30, 2013 was 0.24%. PSE&G does not have any preferred stock outstanding. The cost rate for customer deposits, as established by the BPU for 2013, is 0.11%.

Please see attachment for embedded cost rate.

June 30, 2013

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
EMBEDDED COST OF LONG TERM DEBT AS OF JUNE 30, 2013
INCLUDING NET UNAMORTIZED PREMIUM

	PSE&G LONG TERM DEBT	COST OF BOND YIELD BASIS	PRINCIPAL AMOUNT OUTSTANDING	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT)	PLUS NET UNAMORTIZED SELLING EXPENSE	PLUS NET UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE	PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	WEIGHT IN % OF PRINCIPAL AMOUNT AND UNAMORTIZED PREMIUM/ (DISCOUNT) & SELLING EXPENSE- NET	COST IN PERCENT
6.750%	SERIES VV DUE 1/1/16	7.199%	$171,245,000.00	($332,691.37)	($4,200.00)	($336,891.37)	$170,908,108.63	3.1006%	0.2232%
9.250%	SERIES CC DUE 6/1/21	9.602%	$134,380,000.00	($102,028.58)	($4,560.00)	($106,588.58)	$134,273,411.42	2.4360%	0.2339%
8.000%	SERIES DUE 6/1/37	8.260%	$7,462,900.00	$0.00	$0.00	$0.00	$7,462,900.00	0.1354%	0.0112%
5.000%	SERIES DUE 7/1/37	5.163%	$7,537,800.00	$0.00	$0.00	$0.00	$7,537,800.00	0.1368%	0.0071%
0.350%	PC SERIES Z (2003 B1) DUE 11/1/33	0.543%	$50,000,000.00	$0.00	($326,568.14)	($326,568.14)	$49,673,431.86	0.9012%	0.0049%
0.370%	PC SERIES AG (2012A) DUE 4/1/46	0.493%	$50,000,000.00	$0.00	($324,646.59)	($324,646.59)	$49,675,353.41	0.9012%	0.0044%
5.000%	SERIES D DUE 8/15/14 *	5.557%	$250,000,000.00	($111,925.00)	($185,801.73)	($297,726.73)	$249,702,273.27	4.5301%	0.2518%
7.040%	SERIES A DUE 11/06/20 *	7.473%	$9,000,000.00	($21,519.57)	($24,816.00)	($46,335.57)	$8,953,664.43	0.1624%	0.0121%
5.375%	SERIES C DUE 9/1/13 *	5.898%	$300,000,000.00	($5,311.37)	($32,490.05)	($37,801.42)	$299,962,198.58	5.4419%	0.3210%
5.250%	SERIES D DUE 7/1/35 *	5.547%	$250,000,000.00	($577,500.00)	($1,573,549.68)	($2,151,049.68)	$247,848,950.32	4.4965%	0.2494%
5.700%	SERIES D DUE 12/1/36 *	6.022%	$250,000,000.00	($828,693.04)	($1,700,385.00)	($2,529,078.04)	$247,470,921.96	4.4896%	0.2703%
5.800%	SERIES E DUE 5/1/37 *	6.106%	$350,000,000.00	($542,861.64)	($2,366,320.44)	($2,909,182.08)	$347,090,817.92	6.2969%	0.3845%
5.300%	SERIES E DUE 5/1/18 *	5.820%	$400,000,000.00	($154,067.30)	($1,324,017.80)	($1,478,085.10)	$398,521,914.90	7.2300%	0.4208%
6.330%	SERIES F DUE 11/1/2013 *	7.265%	$275,000,000.00	($5,783.04)	($118,711.36)	($124,494.40)	$274,875,505.60	4.9868%	0.3623%
5.375%	SERIES G DUE 11/1/2039 *	5.678%	$250,000,000.00	($705,920.19)	($1,913,241.19)	($2,619,161.38)	$247,380,838.62	4.4880%	0.2548%
5.500%	SERIES G DUE 3/1/2040 *	5.818%	$300,000,000.00	($1,278,161.60)	($2,294,820.90)	($3,572,982.50)	$296,427,017.50	5.3778%	0.3129%
2.700%	SERIES G DUE 5/1/2015 *	3.575%	$300,000,000.00	($197,888.70)	($678,158.30)	($876,047.00)	$299,123,953.00	5.4267%	0.1940%
3.500%	SERIES G DUE 8/15/2020 *	4.007%	$250,000,000.00	($447,580.97)	($1,333,862.44)	($1,781,443.41)	$248,218,556.59	4.5032%	0.1804%
0.850%	SERIES G DUE 8/15/2014 *	2.124%	$250,000,000.00	($55,227.05)	($445,102.07)	($500,329.12)	$249,499,670.88	4.5264%	0.0962%
3.950%	SERIES H DUE 5/1/2042 *	4.225%	$450,000,000.00	($2,782,520.82)	($3,757,655.14)	($6,540,175.96)	$443,459,824.04	8.0453%	0.3399%
3.650%	SERIES H DUE 9/1/2042 *	3.909%	$350,000,000.00	($1,658,534.90)	($3,097,514.61)	($4,756,049.51)	$345,243,950.49	6.2634%	0.2448%
3.800%	SERIES H DUE 1/1/2043 *	4.071%	$400,000,000.00	($2,507,855.41)	($3,462,139.66)	($5,969,995.07)	$394,030,004.93	7.1485%	0.2910%
2.375%	SERIES I DUE 5/15/2023 *	2.86%	$500,000,000.00	($1,572,435.51)	($3,713,905.36)	($5,286,340.87)	$494,713,659.13	8.9751%	0.2569%
	TOTAL PSE&G LONG TERM DEBT		**$5,554,625,700.00**	**($13,888,506.06)**	**($28,682,466.46)**	**($42,570,972.52)**	**$5,512,054,727.48**	**100.000%**	**4.9279%**

*MTN

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CREDIT RATING REPORTS

QUESTION:
Please provide copies of all credit rating reports for PSE&G and Public Service Enterprise Group (PEG) issued since January 1, 2013. Please update for new reports issued during the pendency of this case.

ANSWER:
Attached are PSE&G & Public Service Enterprise Group credit rating reports since January 2013.

Public Service Electric & Gas Co.

Subsidiary of Public Service Enterprise Group Incorporated
Full Rating Report

Ratings

Long-Term IDR	A–
Senior Unsecured	A+
Short-Term IDR	F2
Commercial Paper	F2

IDR – Issuer Default Rating.

Rating Outlook

Stable

Financial Data

Public Service Electric & Gas Co.

($ Mil.)	LTM 9/30/12	2011
Revenue	6,365	7,049
Operating EBITDA	1,604	1,593
FFO	1,162	1,282
Capex	(1,732)	(1,302)
Total Debt	4,744	4,270
EBITDA Interest Coverage (x)	6.57	6.56
FFO Interest Coverage (x)	5.76	6.28
Debt/EBITDA (x)	2.96	2.68
FFO/Debt (%)	24.49	30.02
Total Debt/Total Capitalization (%)	48.19	47.89

Related Research

PSEG Power LLC (Subsidiary of Public Service Enterprise Group Inc.)' (January 2013)

Public Service Enterprise Group Incorporated (January 2013)

Fitch Upgrades PSEG&G to 'A–'; Affirms PSEG & PSEG Power at 'BBB+'; Outlook Stable (July 2012)

Power Down: Slow U.S. Electricity Sales Growth Ahead (January 2012)

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Key Rating Drivers

Ratings Upgrade: Fitch Ratings upgraded the long term Issuer Default Rating (IDR) of Public Service Electric & Gas Company (PSE&G) to 'A–' from 'BBB+' on July 27, 2012. The upgrade reflects PSEG's strong credit metrics derived from recent capital investments combined with a constructive regulatory environment. Maturation of planned infrastructure investments should provide further momentum to earnings and cash flows over the next few years.

Strong Credit Metrics: Fitch expects PSE&G's FFO-to-debt ratio to average more than 20% and its EBITDA-to-interest coverage ratio to remain greater than 6.0x over 2012–2014. While cash flows are reduced from the absence of bonus depreciation, the quality of cash flow improves from the earnings from new infrastructure investments placed into service and into rate base over forecast period. Fitch does not expect a significant financial impact from Hurricane Sandy.

Large Capex Program: PSE&G is in the midst of a large capital spending program that is largely centered on transmission projects. PSE&G receives timely recovery of costs on such transmission infrastructure investments and receives an authorized return on equity (ROE) of 11.68% on Federal Energy Regulatory Commission (FERC)-regulated transmission projects. Transmission investments are expected to average slightly above $1 billion per annum over the next three years.

Constructive Regulatory Environment: PSE&G operates in a balanced regulatory environment, with oversight from the New Jersey Board of Public Utilities (BPU). The BPU permits PSE&G to use several regulatory mechanisms to recover costs in a timely manner, and has also implemented a weather normalization clause at the natural gas utility. These regulatory mechanisms enhance the predictability of utility cash flows by mitigating the effect of exogenous factors.

Hurricane Sandy Costs: PSE&G estimates the cost associated with the restoration of its distribution and transmission system at approximately $250 million–$300 million. PSE&G estimates that at least 85% of these costs will be deferred or capitalized for future regulatory recovery. Fitch expects PSE&G to receive an accounting order from the BPU to establish the regulatory asset. Fitch does not expect the need for PSE&G to file another rate case during the next couple of years given the likelihood of the utility being able to continue to earn its authorized 10.3% ROE.

Credit Concerns Limited: The primary credit concern is the financial stress of the company's sizable construction program. Failure to fund the expenditures with a balanced mix of debt and equity or earn an adequate return on investment could pressure credit protection measures.

What Could Trigger a Rating Action

Positive: A positive rating action is not considered likely at this time.

Negative: A negative rating action could occur if PSE&G failed to maintain its existing capital structure or earn an adequate return on investment during this period of elevated capex. EBITDA to interest coverage below 5.5x could result in a downgrade.

Key Rating Issues

Regulatory Overview

Fitch considers PSE&G's regulatory environment to be constructive. The most recent BPU-approved electric rate case was approved on June 7, 2010, and most recent natural gas rate case was approved on July 9, 2010. The authorized ROE for both electric and natural gas is 10.3%, based on a 51.2% equity-to-capital ratio, slightly above the nationwide averages for these sectors.

For PSE&G's FERC-regulated transmission projects, the utility receives an authorized ROE of 11.68%. Critical congestion-relieving projects Susequehana-Roseland Transmission Project and Northeast Grid Transmission Project receive a 125-bps and 25-bps, respectively, adder above the base authorized ROE. PSE&G is also allowed to recover 100% of construction work in progress (CWIP) in rate base and is authorized to recover 100% of all prudently development and construction costs if projects are abandoned or cancelled for reasons beyond PSE&G's control.

Retail Market Structure

All electric and gas customers in New Jersey have the option to choose their electric and natural gas supplier. PSE&G is required, under New Jersey law, to serve as the supplier of last resort. All commodity purchases under basic generation service (BGS) and basic gas supply service (BGSS) are recoverable from customers. PSE&G does not earn a return on the commodity procurement costs.

Basic Generation Service

The energy supply for electric customers that do not chose a third-party supplier is obtained through a statewide BGS auction. For residential and small industrial and commercial customers (C&I), electricity is obtained at a fixed price; for the large C&I customers, energy is priced at hourly real-time market price.

The fixed-price energy for residential and small C&I customer is contracted for 36-month periods. The supply contracts are staggered so that one-third of the load requirement is repriced annually with each 12-month period beginning June 1 and ending May 31. Staggering the power supply contracts over a three-year period reduces price volatility.

Customer migration to third-party suppliers was 34% at year-end 2011, and was expected to climb to 40% by year-end 2012.

Basic Gas Supply Service

Charges for BGSS for residential and small C&I that do not choose a third-party provider are set annually on Oct. 1 of each year. PSE&G can adjust the BGSS tariffs, with a 30-day notice to the BPU, twice a year by 5% on Dec. 1 and Feb. 1. Large C&I customers taking BGSS are subject to monthly price changes.

Related Criteria

2013 Outlook: Utilities, Power, and Gas (December 2012)

Recovery Ratings and Notching Criteria for Utilities (November 2012)

Corporate Rating Methodology (August 2012)

Parent and Subsidiary Rating Linkage (August 2012)

Rating North American Utilities, Power, Gas, and Water Companies (May 2011)

Financial Overview

Liquidity and Debt Structure

Liquidity is considered adequate and supported by operating cash flows, bank credit availability, market access through a commercial paper program, and manageable debt maturities. PSE&G has a $600 million five-year bank facility that matures April 15, 2016. Approximately $599 million was available under the facility as of Sept. 30, 2012. PSE&G also has an active commercial paper program backstopped by the bank facility.

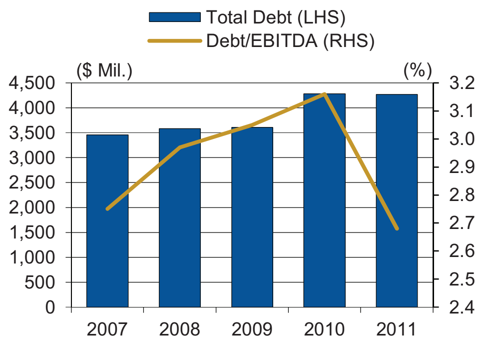
Debt Maturities and Liquidity

(At Sept. 30, 2012)

Debt Maturities	($ Mil.)
2012	0
2013	725
2014	500
2015	300
2016	171
Cash and Cash Equivalents	71
Undrawn Committed Facilities	599

Note: Excludes securitization debt.
Source: Company reports, Fitch.

Total Debt and Leverage



Source: Company reports, Fitch.

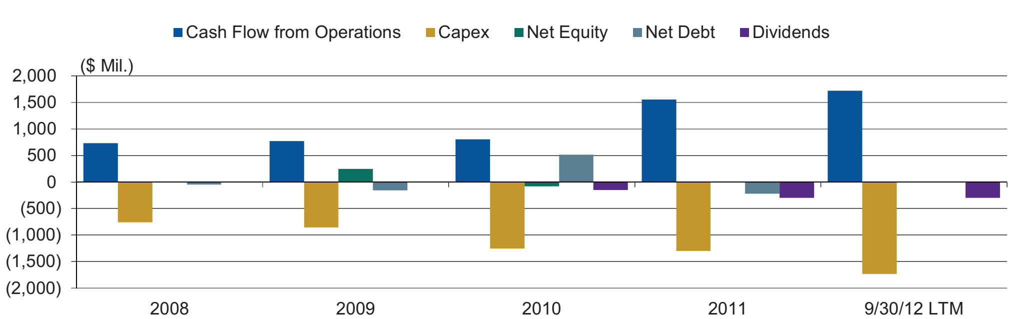
Fitch expects PSE&G to have strong access to the capital markets to roll over upcoming debt maturities and fund new capital investments.

Cash Flow Analysis

PSE&G delivers consistent cash flow derived from strong earnings and regulatory mechanisms that permit timely recovery of power and commodity pass-through collections from customers and capital investments. Under the BGS and BGSS, commodity price risk is essentially passed on to customers.

With an elevated capital investment program over the next few years, Fitch expects PSE&G to remain FCF negative over the near term. PSE&G will be dependent on external financing to manage its capital investment program and maintain its capital structure. Dividend payments to the parent were approximately 60% of new income in 2011.

CFO and Cash Use



Source: Company reports, Fitch.

PSE&G Planned Capex

	2012	2013	2014
Transmission			
Reliability Enhancements	870	1,165	1,015
Facility Replacement	115	140	175
Support Facilities	10	15	10
Distribution			
Reliability Enhancements	200	75	80
Facility Replacement	265	135	135
Support Facilities	45	40	60
New Business	120	130	130
Environmental/Regulatory	30	30	30
Renewables/EMP	250	60	25
Total Planned Capex	1,905	1,790	1,660

Source: Company reports, Fitch.

Fitch does not see any undue risk with the large capital program. PSE&G receives timely returns on its investments, and capitals market access is strong and interest costs are low.

Key drivers of the capital spending program are FERC-regulated or BPU-authorized transmission projects. Fitch expects transmission spending to remain elevated for the next three to five years. In June 2012, the BPU approved the siting of the North Central Reliability Transmission Project, which is estimated to cost $390 million with an in-service date of June 2014.

The Susquehana-Roseland Transmission project received a final Environmental Impact Statement from the National Park Service on Oct. 1, 2012. The project also received environmental permits from the New Jersey Department of Environmental Protection. The expected in-service date for the eastern segment of the project is June 2014, and 2015 for the western segment.

Gas Infrastructure

Like many other natural gas distribution utilities, PSE&G faces large capex spending for aging cast iron or bare steel gas mains, as well as bare steel customer connections. PSE&G is evaluating the potential for increased gas infrastructure replacement estimated at between $250 million and $300 million per year. PSE&G will likely seek a gas infrastructure clause from the BPU to allow timely recovery of this capital spend.

Peer and Sector Analysis

Peer Group

Issuer	Country
A–	
KeySpan Corp.	U.S.
MidAmerican Energy Company	U.S.
Mississippi Power Company	U.S.
Northern States Power Co. — Minnesota	U.S.

Source: Fitch.

Issuer Rating History

Date	LT IDR (FC)	Outlook/ Watch
July 27, 2012	A–	Stable
Aug. 1, 2011	BBB+	Stable
Aug. 2, 2010	BBB+	Stable
June 11, 2009	BBB+	Stable
Nov. 20, 2007	BBB+	Stable
Dec. 6, 2005	BBB+	Stable
Dec. 20, 2004	A–	Stable
Sept. 10, 2004	A–	Stable
June 14, 2002	A–	Negative
Dec. 5, 2000	A–	Negative

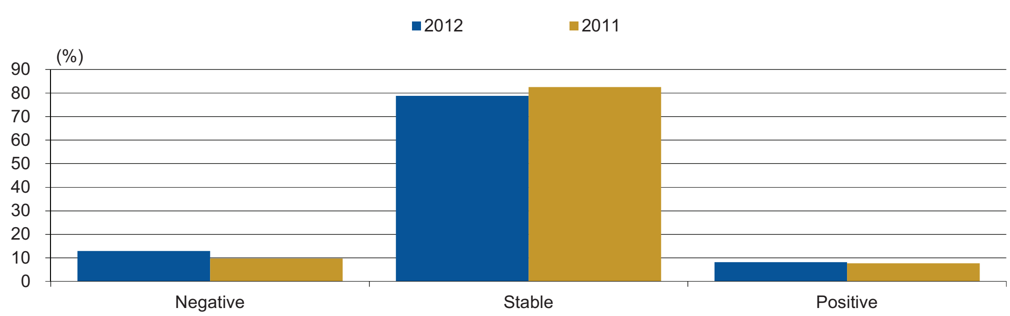
LT IDR – Long-term Issuer Default Rating.
Source: Fitch.

Peer Group Analysis

	Public Service Electric & Gas Co.	MidAmerican Energy Company	Mississippi Power Company
LTM as of	9/30/12	9/30/12	9/30/12
Long-Term IDR	A–	A–	A–
Outlook	Rating Outlook Stable	Rating Outlook Stable	Rating Outlook Negative
Financial Statistics ($ Mil.)			
Revenue	6,365	3,260	1,038
YoY Revenue Growth (%)	(13)	(8)	(8)
EBITDA	1,604	807	242
EBITDA Margin (%)	25.2	24.75	23.31
Total Adjusted Debt	4,744	3,368	1,934.50
Funds Flow from Operations	1,162	1,101	188
Capex	(1,732)	(613)	(1,613)
Credit Metrics (x)			
EBITDA/Gross Interest Coverage	6.57	5.04	2.78
Debt/FFO	4.08	3.06	10.29
Debt/EBITDA	2.96	4.17	7.99
FFO Interest Coverage	5.76	7.88	3.16

YoY – Year over year.
Source: Company reports, Fitch.

Sector Outlook Distribution



Source: Company reports, Fitch.

Organizational Structure

Organizational Chart — Public Service Enterprise Group Inc.
($ Mil., As of Sept. 30, 2012)

Public Service Enterprise Group, Inc.
IDR: BBB+

PSEG Power, LLC
IDR: BBB+

2.500% Sr. Unsecured Notes due 4/15/13	300
5.000% Sr. Unsecured Notes due 4/1/14	250
5.500% Sr. Unsecured Notes due 12/1/15	300
2.750% Sr. Unsecured Notes due 9/15/16	250
5.320% Sr. Unsecured Notes due 9/15/16	303
5.125% Sr. Unsecured Notes due 4/15/20	406
4.150% Sr. Unsecured Notes due 9/15/21	250
8.625% Sr. Unsecured Notes due 4/15/31	500
5.500% Pollution Control Notes due 9/1/20	14
5.850% Pollution Control Notes due 6/1/27	19
5.750% Pollution Control Notes due 4/1/31	25
5.750% Pollution Control Notes due 11/1/37	40
Variable-Rate Pollution Control Notes due 2014	45

Other Subsidiaries

PSEG Fossil LLC	NR
PSEG Nuclear LLC	NR
PSEG Energy Resources & Trade LLC	NR

Public Service Electric and Gas Company
IDR: A–

6.750% First Mortgage Bonds due 1/1/16	171
9.250% First Mortgage Bonds due 6/1/21	134
8.000% First Mortgage Bonds due 6/1/37	7
5.000% First Mortgage Bonds due 7/1/37	8
5.000% Medium-Term Notes due 1/1/13	150
5.375% Medium-Term Notes due 9/1/13	300
6.330% Medium-Term Notes due 11/1/13	275
0.850% Medium-Term Notes due 8/15/14	250
5.000% Medium-Term Notes due 8/15/14	250
2.700% Medium-Term Notes due 5/1/15	300
5.300% Medium-Term Notes due 5/1/18	400
7.040% Medium-Term Notes due 11/6/20	9
3.500% Medium-Term Notes due 8/15/20	250
5.250% Medium-Term Notes due 7/1/35	250
5.700% Medium-Term Notes due 12/1/36	250
5.800% Medium-Term Notes due 5/1/37	350
5.375% Medium-Term Notes due 11/1/39	250
5.500% Medium-Term Notes due 3/1/40	300
3.950% Medium-Term Notes due 5/1/42	450
3.650% Medium-Term Notes due 9/1/42	350
5.200% and 5.450% Sr. Unsecured Pollution Control Bonds due 2025 and 2032	73
Transition Funding and Transition Funding II Debt (Securitization Debt)	785

Other Subsidiaries

PSEG Energy Holdings LLC	NR
PSEG Global LLC	NR
PSEG Resources LLC	NR

IDR – Issuer Default Rating. NR – Not rated.
Source: Company filings, Bloomberg, and Fitch Ratings.

Definitions

Leverage: Gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock divided by FFO plus gross interest paid plus preferred dividends plus rental expense.

Interest Cover: FFO plus gross interest paid plus preferred dividends divided by gross interest paid plus preferred dividends.

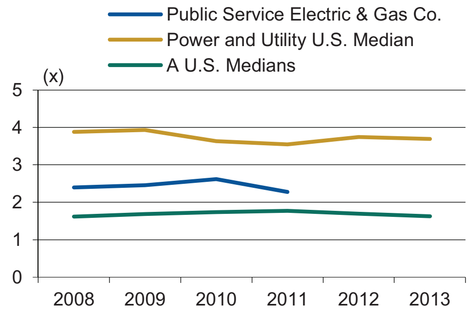
FFO/Debt: FFO divided by gross debt plus lease adjustment minus equity credit for hybrid instruments plus preferred stock.

Fitch's expectations are based on the agency's internally produced, conservative rating case forecasts. They do not represent the forecasts of rated issuers individually or in aggregate. Key Fitch forecasts assumptions include:

- No general rate case filings during the forecast period;
- Capex maintained at $1.7 billion–$1.8 billion during forecast period.

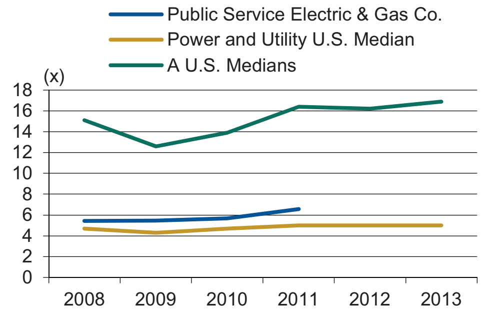
Key Metrics

Leverage: Total Adj. Debt/Op. EBITDAR



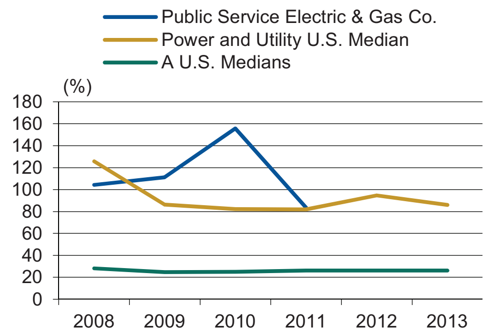
Source: Company reports, Fitch.

Int. Coverage: Op EBITDA/Gross Int. Exp.



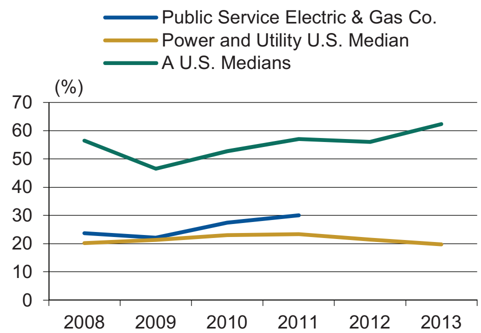
Source: Company reports, Fitch.

Capex/CFO



Source: Company reports, Fitch.

FFO/Debt



Source: Company reports, Fitch.

Company Profile

PSE&G is the largest utility in New Jersey, supplying electricity to 2.2 million customer and natural gas to 1.8 million customers. The service area is largely urban or suburban. Annual distribution load growth over 2007–2011 was negative 0.5% for electric and 2.3% for natural gas.

PSE&G continues to benefit from residential and commercial heating oil conversion to natural gas, reflecting environmental concerns and the substantial pricing advantage natural gas has over heating oil on a British thermal unit (BTU) equivalent basis. Fitch expects electricity sales trends for PSE&G and the electric industry to generally be under pressure from efficiency gains and enactment of federal lighting standards, which will eliminate the traditional incandescent bulb.

The electric sales mix is 33% residential, 57% commercial, and 10% industrial.

The natural gas sales mix is 60% residential, 36% commercial, and 4% industrial.

PSEG's customer mix is favorable, with a low percentage of economically sensitive industrial usage that is volume sensitive and generally lower margined.

Financial Summary — Public Service Electric & Gas Co.

	2008	2009	2010	2011	LTM Ended 9/30/12
Fundamental Ratios (x)					
FFO/Interest Expense	5	5	6	6	6
CFO/Interest Expense	4	5	4	7	8
FFO/Debt (%)	24	22	27	30	25
Operating EBIT/Interest Expense	4	4	3	4	4
Operating EBITDA/Interest Expense	5	5	6	7	7
Operating EBITDAR/(Interest Expense + Rent)	5	5	6	7	7
Debt/Operating EBITDA	3	3	3	3	3
Common Dividend Payout (%)	—	—	42	58	54
Internal Cash/Capital Expenditures (%)	96	90	52	98	83
Capital Expenditures/Depreciation (%)	188	203	227	254	312
Profitability					
Adjusted Revenues	8,752	7,960	7,588	7,049	6,365
Net Revenues	2,680	2,790	2,933	3,098	3,158
Operating and Maintenance Expense	1,338	1,474	1,442	1,372	1,450
Operating EBITDA	1,206	1,183	1,355	1,593	1,604
Depreciation and Amortization Expense	404	421	553	513	555
Operating EBIT	802	762	802	1,080	1,049
Gross Interest Expense	222	217	239	243	244
Net Income for Common	360	321	358	521	552
Operating and Maintenance Expense % of Net Revenues	50	53	49	44	46
Operating EBIT % of Net Revenues	30	27	27	35	33
Cash Flow					
Cash Flow from Operations	730	769	807	1,557	1,719
Change in Working Capital	(122)	(31)	(365)	275	557
Funds from Operations	852	800	1,172	1,282	1,162
Dividends	(4)	(4)	(151)	(300)	(300)
Capital Expenditures	(761)	(855)	(1,257)	(1,302)	(1,732)
FCF	**(35)**	**(90)**	**(601)**	**(45)**	**(313)**
Net Other Investment Cash Flow	3	(37)	(16)	(39)	(56)
Net Change in Debt	(51)	(159)	517	(220)	—
Net Equity Proceeds	—	250	(80)	—	—
Capital Structure					
Short-Term Debt	19	—	—	—	—
Long-Term Debt	3,564	3,612	4,283	4,270	4,744
Total Debt	**3,583**	**3,612**	**4,283**	**4,270**	**4,744**
Total Hybrid Equity and Minority Interest	40	40	—	—	—
Common Equity	3,647	4,221	4,424	4,647	5,100
Total Capital	**7,270**	**7,873**	**8,707**	**8,917**	**9,844**
Total Debt/Total Capital (%)	49	*46*	49	48	48
Total Hybrid Equity and Minority Interest/Total Capital (%)	1	1	—	—	—
Common Equity/Total Capital (%)	50	54	51	52	52

Source: Company reports.

The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

Public Service Enterprise Group Incorporated

Full Rating Report

Ratings

Long-Term IDR	BBB+
Senior Unsecured	BBB+
Short-Term IDR	F2
Commercial Paper	F2

IDR – Issuer Default Rating.

Rating Outlooks

Stable

Financial Data

Public Service Enterprise Group Incorporated

	LTM 9/30/12	2011
Revenue	9,739	10,802
Operating EBITDA	3,281	3,441
FFO	2,409	2,502
Capex	2,573	2,040
Total Debt	7,480	7,111
EBITDA Interest Coverage (x)	7.98	7.75
FFO Interest Coverage (x)	6.86	6.64
Debt/EBITDA (x)	2.28	2.07
FFO/Debt (%)	32.2	35.2
Total Debt/Total Capitalization (%)	40.9	40.9

Related Research

PSEG Power LLC (Subsidiary of Public Service Enterprise Group Inc.) (January 2013)

Public Service Electric & Gas Co. (Subsidiary of Public Service Enterprise Group Inc.) (January 2013)

Fitch Upgrades PSE&G to ‘A–’; Affirms PSEG & PSEG Power at ‘BBB+’; Outlook Stable (July 2012)

Power Down: Slow U.S. Electricity Sales Growth Ahead (January 2012)

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Key Rating Drivers

Ratings Supported by Strong Subsidiaries: The ratings on Public Service Enterprise Group (PSEG) are supported by the strong credit profile of PSEG’s two principal subsidiaries: Public Service Electric and Gas Company (PSE&G), the largest regulated electric and natural gas distribution utility in New Jersey, and PSEG Power LLC (Power), a merchant energy company. In addition, PSEG does not have any long-term parent-level debt.

Constructive Regulatory Environment: PSE&G operates in a balanced regulatory environment, with oversight from the New Jersey Board of Public Utilities (BPU). The BPU permits PSE&G to use several regulatory mechanisms to recover costs in a timely manner, and has also implemented a weather normalization clause at the natural gas utility. These regulatory mechanisms enhance the predictability of utility cash flows by mitigating the effect of exogenous factors.

Volatility of Power Prices: The primary credit concern for Power is the company’s exposure to price volatility in the merchant power market. Power only contracts its power sales out a few years, and it will generally have up to a quarter of its expected annual power generation unhedged at the beginning of each year. Due to Power’s merchant exposure, it is important that management continues to keep leverage at a modest level to enable the company to absorb periods of weak cash flows without too much strain on the balance sheet.

Multiyear Contract Profile: Power’s ratings benefit from the company’s pro rata multiyear hedging program. The company locks in prices three years in advance, primarily through participation in the Basic Generation Services (BGS) auction in New Jersey and in capacity auctions held by the PJM Regional Transmission Organization (PJM).

Fuel Diversification: Power has a relatively diverse source of fuel for its generating plants, which limits the impact associated with any negative shock to a particular fuel source. In 2011, 56% of Power’s generation was from its interest in five nuclear plants, with 28% from natural gas and 15% from coal.

Strong Financial Metrics: The ratings on PSEG, Power, and PSE&G are bolstered by strong financial metrics, aided by management’s relatively conservative use of debt. Over the 2012–2014 forecast period, Fitch Ratings expects PSEG’s FFO-to-debt ratio to average more than 25% and its EBITDA-to-interest coverage ratio to remain greater than 6.0x.

Rating Outlook: The Stable Rating Outlook reflects the solid and predictable performance from the regulated utility operations at PSE&G combined with the financially conservative management of the riskier merchant energy operations at Power.

What Could Trigger a Rating Action

Negative Rating Action: A negative rating action on PSEG could occur if the company’s consolidated FFO-to-debt ratio was to drop below 24% over a multiyear period. A negative rating action could also be triggered by a one- or two-notch downgrade on both Power and PSE&G.

Positive Rating Action: A positive rating action on PSEG is unlikely due to the company’s strong existing ratings and exposure to the merchant generation business.

Key Rating Issues

Regulatory Overview

Fitch considers PSE&G's regulatory environment to be constructive. The BPU permits PSE&G to use several regulatory mechanisms to recover costs in a timely manner, and it has also implemented a weather normalization clause at the natural gas utility. These regulatory mechanisms enhance the predictability of utility cash flows by mitigating the effect of exogenous factors.

The latest authorized return on equity (ROE) of 10.3% for both the electric and natural gas utility operations is roughly the nationwide average for the sector.

For PSE&G's Federal Energy Regulatory Commission (FERC)-regulated transmission projects, the utility receives an authorized ROE of 11.68%. Critical congestion-relieving projects, the Susquehana-Roseland Transmission Project and the Northeast Grid Project, receive a 125-bps and 25-bps, respectively, adder above the base authorized ROE. PSE&G is also allowed to recover 100% of construction work in progress (CWIP) in rate base and is authorized to recover 100% of all prudently incurred development and construction costs if projects are abandoned or cancelled for reasons beyond PSE&G's control.

Power's Hedging Overview

Power uses a multiyear hedging strategy to mitigate commodity price risk exposure. The company's primary means of hedging include sales at PJM West and New Jersey's BGS contracts.

Power engages in block energy sales at the PJM Western Hub.

The BGS sales are full requirements contracts that include energy and capacity, ancillary, and other services that are awarded for three-year periods through an auction process managed by the BPU. The volume of BGS contracts account for roughly 40%–50% of Power's baseload power on any given year.

As of Sept. 30, 2012, Power's nuclear and baseload coal generation, which accounted for 71% of the company's total generation in 2011, was fully hedged for the remainder of 2012 at $54/MWh, 90%–95% hedged for 2013 at $51/MWh, and 50%–55% hedged for 2014 at $49/MWh. Power's intermediate coal, combined cycle, and peaking facilities were 35%–40% hedged for the remainder of 2012 at $54/MWh and unhedged in the outer years.

Financial Overview

Liquidity and Debt Structure

PSEG, Power, and PSE&G all have good liquidity. PSEG and PSE&G each have their own commercial paper program to meet short-term liquidity requirements, with PSEG using its program to also meet the short-term liquidity needs of Power.

The companies have an aggregate $4.3 billion in bank credit facilities. This includes a total of $2.1 billion of five-year revolving credit facilities that were renewed earlier this year and mature in March 2017. Another $2.1 billion of five-year revolving credit facilities matures in April 2016.

Related Criteria

Recovery Ratings and Notching Criteria for Utilities (November 2012)

Corporate Rating Methodology (August 2012)

Parent and Subsidiary Rating Linkage (August 2012)

Rating North American Utilities, Power, Gas, and Water Companies (May 2011)

PSEG's share of the revolving credit facilities totals $1 billion, with Power's totaling $2.7 billion and PSE&G's totaling $600 million.

Debt maturities are manageable, and Fitch expects PSEG and its subsidiaries to maintain good access to the capital markets relative to their peer companies.

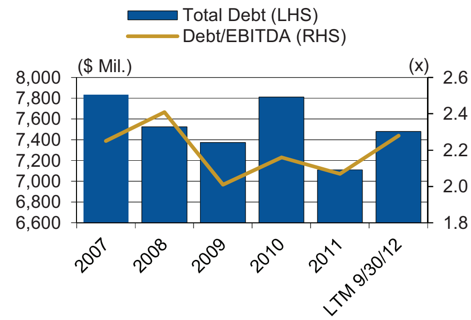
Liquidity and Debt Structure

($ Mil., As of Sept. 30, 2012)

Debt Maturities	
2012	0
2013	1,025
2014	750
2015	600
2016	725
Cash and Cash Equivalents	780
Undrawn Committed Facilities	4,076

Source: Company reports, Fitch analysis.

Total Debt and Leverage

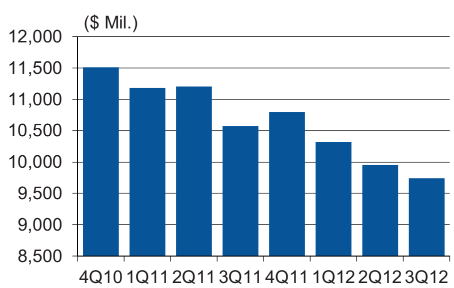


Source: Company reports, Fitch analysis.

Cash Flow Analysis

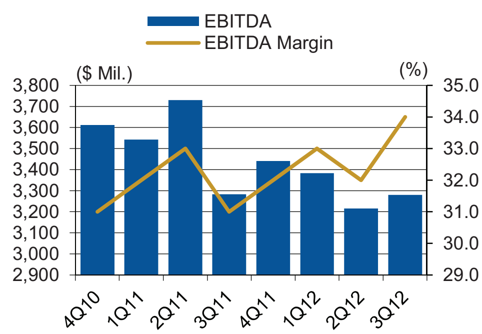
Power's EBITDA will likely continue to trend downward through 2014, due to higher priced electricity hedges rolling off and continued pressure on power prices as a result of weak demand and low natural gas prices.

Revenue Dynamics



Source: Company reports, Fitch analysis.

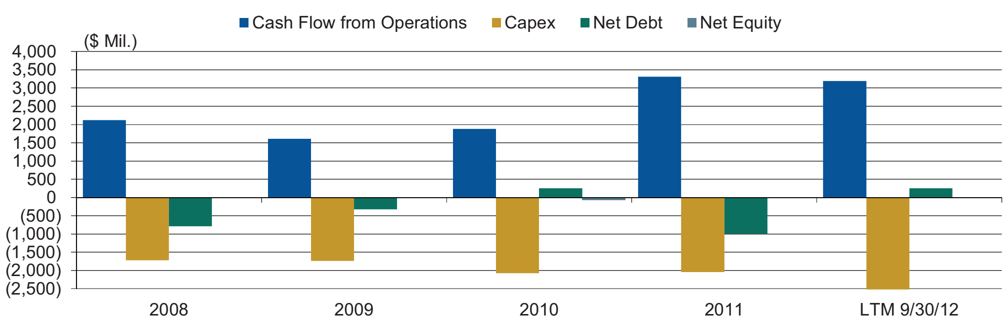
EBITDA Dynamics



Source: Company reports, Fitch analysis.

However, Power's financial metrics are expected to continue to have sufficient cushion for the ratings, and Fitch anticipates cash flows remaining robust enough to retire debt as needed to

CFO and Cash Use



Source: Company data, Fitch.

maintain appropriate strength. Fitch expects Power's FFO-to-debt ratio to average more than 35% over the 2012–2014 period, and its EBITDA-to-interest coverage ratio to remain greater than 6.0x.

PSE&G will undergo a relatively large capital spending program over the next few years, but this concern is mitigated by the quality and solid returns of the projects. The spending is primarily on BPU-authorized infrastructure projects and FERC-regulated transmission projects, both of which include timely recovery of costs and attractive returns.

These infrastructure projects should provide significant growth to EBITDA through the forecast period. Fitch expects PSE&G's FFO-to-debt ratio to average more than 20% and its EBITDA-to-interest coverage ratio to remain greater than 6.0x over the 2012–2014 period.

Fitch's expectations for continued strong financial performance at Power and PSE&G should provide similarly strong consolidated financial metrics at PSEG. Over the 2012–2014 forecast period, Fitch expects PSEG's FFO-to-debt ratio to average more than 25% and its EBITDA-to-interest coverage ratio to remain greater than 6.0x.

Peer and Sector Analysis

Peer Group

Issuer	Country
BBB+	
Consolidated Edison, Inc. (Con Ed)	United States
Exelon Corp.	United States
BBB	
FirstEnergy Corp.	United States

Source: Fitch Ratings.

Issuer Rating History

Date	LT IDR	Outlook
July 27, 2012	BBB+	Stable
Aug. 1, 2011	BBB+	Stable
Aug. 2, 2010	BBB+	Stable
June 11, 2009	BBB+	Stable
Nov. 20, 2007	BBB+	Stable

Source: Fitch Ratings.

Peer Group Analysis

	Public Service Enterprise Group Incorporated	Consolidated Edison, Inc. (Con Ed)	Exelon Corp.	FirstEnergy Corp.
LTM as of	9/30/12	9/30/12	9/30/12	9/30/12
Long-Term IDR	BBB+	BBB+	BBB+	BBB
Outlook	Stable	Stable	Stable	Negative
Financial Statistics ($ Mil.)				
Revenue	9,739	12,938	21,123	16,116
EBITDA	3,281	3,123	4,459	4,076
Total Adjusted Debt	7,480	10,782	18,752	19,698
Funds Flow from Operations	2,409	2,703	5,734	2,340
Capex	(2,573)	(1,887)	(5,395)	(2,676)
Credit Metrics (x)				
EBITDA/Gross Interest Coverage	7.98	5.21	4.87	3.43
Debt/FFO	3.11	3.99	3.27	8.42
Debt/EBITDA	2.28	3.45	4.21	4.83
FFO Interest Coverage	6.86	5.51	7.27	2.97

YoY – Year over year.
Source: Fitch Ratings, company reports.

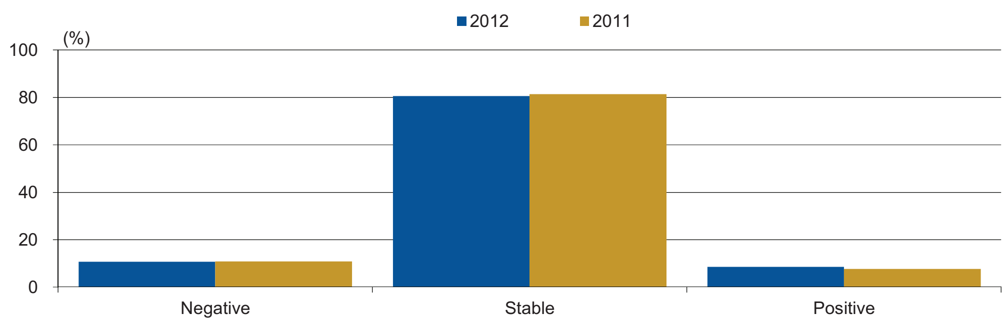
PSEG generally has much stronger financial metrics than its peer companies, reflecting the company's relatively conservative financial management and strong operational performance. Power strives to maintain a ratio of FFO/debt greater than 35%, and has reduced its amount of outstanding debt during the decline in power prices over the past couple years to maintain the strength of its balance sheet. PSE&G's focus on FERC-regulated transmission and BPU-authorized infrastructure projects has provided strong growth and stable returns, further boosting cash flows.

Fitch's outlook for utility parent companies (UPCs) and investor-owned electric and gas utilities (IOUs) remains Stable, while the outlook for competitive generators (gencos) remains Negative (*see the Sector Outlook Distribution chart below*). UPCs with competitive generation subsidiaries and regulated utilities with whole power sales continue to face a challenging environment, with most regional power markets suffering from weak power prices. Managing through an extended period of high capital investment is the other principle risk to bondholders should adequate and timely returns on investment not be authorized.

Integrated electric utilities have riskier business profiles than transmission and distribution electric and gas utilities, reflecting their exposure to new power-generation builds or environmental upgrades of existing facilities. UPCs with diversified activities also exhibit a riskier business profile than those with a pure regulated model.

Competitive generation companies face a challenging operating environment given the slow recovery in power prices, tightening environmental regulations, and choppy capital markets. Unlike the pure play generation companies, affiliated gencos may benefit from strong parent or affiliate linkages. Fitch expects power market recovery to gradually accelerate as coal-fired generation retirements bring supply more in line with demand, although timing varies by market.

Sector Outlook Distribution



Source: Company data, Fitch.

In Fitch's opinion, there is growing evidence that technological and manufacturing improvements have the potential to reduce electricity consumption growth to flat to +1% over the next two to five years. See Fitch's special report, "Power Down: Slow U.S. Electricity Sales Growth Ahead" published on Jan. 11, 2012.

Company Profile

PSEG is a holding company that conducts its business primarily through its two largest subsidiaries: PSE&G and Power.

PSE&G is a regulated transmission and distribution company that supplies electricity to 2.2 million customers and natural gas to 1.8 million customers in the state of New Jersey. The utility accounts for nearly half of consolidated EBITDA.

Power is a merchant energy company that owns more than 13,000 MW of electric generation capacity in the Mid-Atlantic region of PJM, New York, and Connecticut.

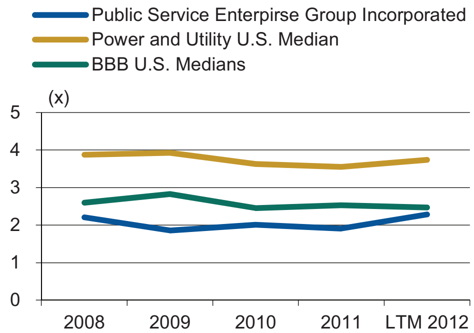
Management's strategy is centered on growth at the regulated utility through FERC-regulated transmission projects and BPU-authorized infrastructure projects, which provide strong and stable cash flows. At Power, the company is focused on maintaining appropriately strong leverage metrics to weather periods of low power prices and providing some level of near-term cash flow predictability through capacity and energy auctions, primarily in New Jersey and PJM.

Key Metrics

Definitions

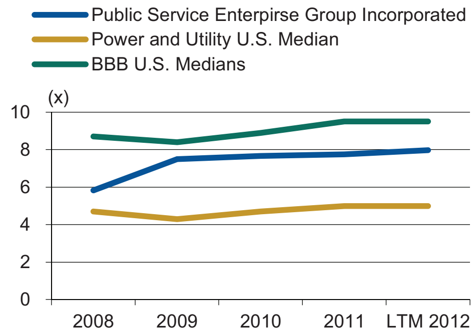
Debt/EBITDA: Debt plus lease adjustment divided by EBITDA plus rental expense.
EBITDA Interest Coverage: EBITDA divided by gross interest paid.
FFO/Debt: FFO divided by debt plus lease adjustment.

Debt/EBITDA



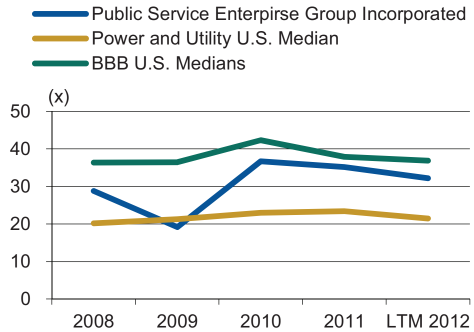
Source: Company data, Fitch.

EBITDA Interest Coverage



Source: Company data, Fitch.

FFO/Debt



Source: Company data, Fitch.

Organizational Structure

Organizational Chart — Public Service Enterprise Group Inc.
($ Mil., As of Sept. 30, 2012)

Public Service Enterprise Group, Inc.
IDR: BBB+

PSEG Power, LLC
IDR: BBB+

2.500% Sr. Unsecured Notes due 4/15/13	300
5.000% Sr. Unsecured Notes due 4/1/14	250
5.500% Sr. Unsecured Notes due 12/1/15	300
2.750% Sr. Unsecured Notes due 9/15/16	250
5.320% Sr. Unsecured Notes due 9/15/16	303
5.125% Sr. Unsecured Notes due 4/15/20	406
4.150% Sr. Unsecured Notes due 9/15/21	250
8.625% Sr. Unsecured Notes due 4/15/31	500
5.500% Pollution Control Notes due 9/1/20	14
5.850% Pollution Control Notes due 6/1/27	19
5.750% Pollution Control Notes due 4/1/31	25
5.750% Pollution Control Notes due 11/1/37	40
Variable-Rate Pollution Control Notes due 2014	45

Other Subsidiaries

PSEG Fossil LLC	NR
PSEG Nuclear LLC	NR
PSEG Energy Resources & Trade LLC	NR

Public Service Electric and Gas Company
IDR: A–

6.750% First Mortgage Bonds due 1/1/16	171
9.250% First Mortgage Bonds due 6/1/21	134
8.000% First Mortgage Bonds due 6/1/37	7
5.000% First Mortgage Bonds due 7/1/37	8
5.000% Medium-Term Notes due 1/1/13	150
5.375% Medium-Term Notes due 9/1/13	300
6.330% Medium-Term Notes due 11/1/13	275
0.850% Medium-Term Notes due 8/15/14	250
5.000% Medium-Term Notes due 8/15/14	250
2.700% Medium-Term Notes due 5/1/15	300
5.300% Medium-Term Notes due 5/1/18	400
7.040% Medium-Term Notes due 11/6/20	9
3.500% Medium-Term Notes due 8/15/20	250
5.250% Medium-Term Notes due 7/1/35	250
5.700% Medium-Term Notes due 12/1/36	250
5.800% Medium-Term Notes due 5/1/37	350
5.375% Medium-Term Notes due 11/1/39	250
5.500% Medium-Term Notes due 3/1/40	300
3.950% Medium-Term Notes due 5/1/42	450
3.650% Medium-Term Notes due 9/1/42	350
5.200% and 5.450% Sr. Unsecured Pollution Control Bonds due 2025 and 2032	73
Transition Funding and Transition Funding II Debt (Securitization Debt)	785

Other Subsidiaries

PSEG Energy Holdings LLC	NR
PSEG Global LLC	NR
PSEG Resources LLC	NR

IDR – Issuer Default Rating. NR – Not rated.
Source: Company filings, Bloomberg, and Fitch Ratings.

Financial Summary — Public Service Enterprise Group Incorporated

($ Mil., Fiscal Years Ended Dec. 31)	2008	2009	2010	2011	LTM Ended 9/30/12
Fundamental Ratios (x)					
FFO/Interest Expense	5.05	3.89	7.09	6.64	6.86
CFO/Interest Expense	4.97	4.28	5.00	8.45	8.78
FFO/Debt (%)	28.78	19.20	36.7	35.18	32.21
Operating EBIT/Interest Expense	4.68	6.17	6.06	6.02	5.98
Operating EBITDA/Interest Expense	5.83	7.50	7.67	7.75	7.98
Operating EBITDAR/(Interest Expense + Rent)	5.83	7.50	7.67	7.75	7.98
Debt/Operating EBITDA	2.41	2.01	2.16	2.07	2.28
Common Dividend Payout (%)	55.13	42.27	44.31	46.11	50.39
Internal Cash/Capital Expenditures (%)	84.91	53.95	57.3	128.19	98.61
Capital Expenditures/Depreciation (%)	288.91	275.58	284.96	270.52	312.26
Profitability					
Adjusted Revenues	13,036	12,123	11,512	10,802	9,739
Net Revenues	5,741	6,412	6,251	6,055	5,913
Operating and Maintenance Expense	2,486	2,603	2,504	2,481	2,528
Operating EBITDA	3,119	3,676	3,611	3,441	3,281
Depreciation and Amortization Expense	613	651	758	770	824
Operating EBIT	2,506	3,025	2,853	2,671	2,457
Gross Interest Expense	535	490	471	444	411
Net Income for Common	1,188	1,592	1,564	1,503	1,411
Operating and Maintenance Expense % of Net Revenues	43.3	40.6	40.06	40.97	42.75
Operating EBIT % of Net Revenues	43.65	47.18	45.64	44.11	41.55
Cash Flow					
Cash Flow from Operations	2122	1609	1882	3308	3197
Change in Working Capital	(44)	193	(985)	806	788
Funds from Operations	2166	1416	2867	2502	2409
Dividends	(659)	(673)	(693)	(693)	(711)
Capital Expenditures	(1771)	(1794)	(2160)	(2083)	(2573)
FCF	(308)	(858)	(971)	532	(87)
Net Other Investment Cash Flow	33	179	80	(9)	(47)
Net Change in Debt	(788)	(323)	258	(991)	(667)
Net Equity Proceeds	(92)	—	(80)	—	—
Capital Structure					
Short-Term Debt	19	530	64	—	—
Long-Term Debt	7,507	6,845	7,749	7,111	7,480
Total Debt	7,526	7,375	7,813	7,111	7,480
Total Hybrid Equity and Minority Interest	40	50	8	2	2
Common Equity	7,771	8,788	9,633	10,270	10,806
Total Capital	15,337	16,213	17,454	17,383	18,288
Total Debt/Total Capital (%)	49.07	45.49	44.76	40.91	40.9
Total Hybrid Equity and Minority Interest/Total Capital (%)	0.26	0.31	0.05	0.01	0.01
Common Equity/Total Capital (%)	50.67	54.2	55.19	59.08	59.09

Source: Company reports, Fitch ratings.

The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

FitchRatings

FITCH AFFIRMS PUBLIC SERVICE ENTERPRISE GROUP & SUBSIDIARIES RATINGS; OUTLOOK STABLE

Fitch Ratings-New York-26 July 2013: Fitch Ratings has affirmed the 'BBB+' long-term Issuer Default Rating (IDR) for Public Service Enterprise Group Incorporated (PSEG) and its competitive generation subsidiary PSEG Power LLC (Power). Fitch has also affirmed the 'A-' long-term IDRs of Public Service Electric & Gas Company (PSE&G), its regulated electric and gas distribution utility in New Jersey.

The 'F2' short-term IDR and commercial paper rating on PSEG and PSE&G were also affirmed. A detailed list of rating actions follows at the end of this release.

The Rating Outlook for PSEG, Power, and PSE&G is Stable.

These rating actions affect approximately $7.5 billion of long- term debt.

KEY RATING DRIVERS

--Low consolidated leverage and conservative capitalization at PSE&G and Power;
--Growing earnings and cash flow contribution from PSE&G;
--A constructive regulatory environment in New Jersey;
--Fuel diversification, good operating performance, and multi-year hedging program at Power;
--Extended period of weak power prices to pressure Power's earnings and cash flows throughout the three-year forecast period.

Conservative Leverage

The ratings for PSEG, Power, and PSE&G are supported by strong financial metrics, in part, reflecting management's conservative use of leverage. There is no long-term debt at PSEG and Power and PSE&G are conservatively capitalized with debt to capital measures of 30% and 49%, respectively. Concomitant with lower earnings at Power, cash flows have been applied to long-term debt reduction. Long term debt as of March 31, 2013 has been reduced to $2.3 billion from $3.4 billion at Dec. 31, 2010.

Robust Utility Financial Metrics

PSE&G's recent infrastructure projects and expected strong EBITDA growth from transmission projects in progress will propel earnings and cash flow measures throughout Fitch's 2013 - 2015 forecast period. The New Jersey Board of Public Utilities (BPU) approved an authorized Return on Equity (ROE) of 10.3% in 2010 for both the electric and gas distribution segments and new PJM transmission investments that earn a Federal Energy Regulatory Commission (FERC) formula rate return will significantly diversify the utility's future cash flows. These transmission projects provide increased cash flow predictability at a strong return on equity, with timely recovery of capital deployed.

PSE&G is in the midst of a large capital spending program that is largely centered on transmission projects. PSE&G receives timely recovery of costs and invested capital on such transmission infrastructure investments and in some cases receives an authorized ROE of up to 11.68% on FERC regulated projects. Transmission investments are expected to average slightly above $1 billion per annum over the next three years.

Fitch expects PSE&G to maintain its capital structure during this period of elevated capex. PSE&G did not pay any dividends to its parent in 2012 Retained earnings and modest incremental debt issuances are expected to fund the capex budget and preserve the authorized equity base at 51.2%

of total capital.

PSE&G incurred approximately $40 million of expenses related to Hurricane Sandy in the fourth quarter of 2012. A regulatory asset of $242 million was recorded to reflect other storm costs from which the utility can seek recovery as part of the next general rate case

Fitch does not expect PSE&G will have the need to file another rate case over the 2013 - 2015 forecast period given the likelihood of the utility being able to continue to earn its authorized 10.3% return on equity. Over this time period, Fitch expects EBITDA to Interest to average over 7.0x and FFO to Debt to average over 22%. Both measures compare favorably to rating category peers.

Power

Power continues to be plagued by weak power prices in its core mid-Atlantic and New England markets. Despite the weakness in earnings, management has used cash flows to substantially reduce long-term debt and thus, key credit performance metric have been maintained in recent reporting periods.

Power's ratings benefit from the company's pro-rata multi-year hedging program. The company locks in prices three years in advance through participation in the Basic Generation Services (BGS) auction in New Jersey and in capacity auctions held by the PJM Regional Transmission Organization (PJM) and the Independent System Operator New England (ISO-NE).

As of March 31, 2013, Power's nuclear and baseload coal generation, which accounted for 68% of the company's total generation in 2012, was fully hedged for the balance of 2013, 80 to 85% hedged in 2014, and 40 to 45% hedged in 2015. Power will realized approximately $50 megawatt hour (MWh) on these hedges. Power's intermediate load and peaking facilities generally have a lower percentage of their expected volumes hedged in the current year and are unhedged in the outer years. This merchant portfolio provides exposure to possible higher sustained or seasonal power prices, as just experienced during the recent heat wave in the end of June and July 2013 but also carries sensitivity to short-term swings in power prices.

Power has a relatively diverse source of fuel for its generating plants, which limits the impact associated with any negative shock to a particular fuel source. In 2012, 57% of Power's generation was from its interest in five nuclear plants, with 32% from natural gas and 11% from coal.

Power's coal-fired generating fleet already has the bulk of its necessary environmental control equipment in place. This mitigates the need for future expenditures or the shutdown of plants in order to comply with environmental regulations.

The company's diverse fuel sources result in Power's assets being placed all along the dispatch curve, enabling the company to benefit from different electric generation market conditions. Power's baseload units have had a solid operating record, with its nuclear plants having achieved an aggregate capacity utilization factor of greater than 90% in each of the past five years. The strong performance of these baseload units gives Power a favorable competitive position in its wholesale markets.

The primary credit concern for Power is the company's exposure to price volatility in the merchant power market. Due to Power's merchant exposure, it is important that management continue to keep leverage at a modest level to enable the company to absorb periods of weak cash flows without too much strain on the balance sheet.

Fitch expects Power's earnings and cash flows to weaken over the forecast period. Under Fitch financial models, EBITDA to Interest is expected to average approximately 6.0x and FFO to Debt is expected to remain above 40%, moderately below 2012 levels of 8.5x and 58%, respectively. Lower debt levels are offsetting some of the earnings and cash flow pressures. Leverage, as measured by Debt to EBITDA is expected to average 2.3x.

PSEG

Over 95% of earnings are derived from PSE&G and Power, while a small subsidiary, PSEG Energy Holdings accounts for most of the remainder. There is no debt at PSEG and its financial and credit profile mirrors that of its key subsidiaries Power and PSE&G.

Adequate Liquidity

PSEG, Power, and PSE&G all have good liquidity. PSEG and PSE&G each has its own commercial paper program to meet short-term liquidity requirements, with PSEG using its program to also meet the short-term liquidity needs of Power.

The companies have an aggregate $4.3 billion in bank credit facilities. PSEG's share of the revolving credit facilities totals $1 billion, with Power's totaling $2.7 billion and PSE&G's totaling $600 million.

Storm Hardening

PSE&G has proposed a nearly $4 billion ten-year infrastructure investment in the aftermath of Hurricane Sandy. Any such investment would require BPU regulatory approvals and be subject to contemporaneous returns on such investment. Fitch has not included any such investment in its forecasts, although given the conservative capital structure of the utility and PSEG, the incremental investment could be financed within rating category leverage bands.

RATING SENSITIVITIES

A negative rating action on Power could occur if Fitch's forecasted FFO to debt ratio were to drop below 35% over a multi-year period. A positive rating action on Power is remote, due to the company's presence in the merchant power sector.

A negative rating action on PSE&G could occur if Fitch were to expect an increase in leverage that reduces PSE&G's FFO to debt ratio to below 20% over a multi-year period. A positive rating action on PSE&G is unlikely.

A negative rating action on PSEG could occur if the company issued enough debt at the parent level to fund acquisitions or higher risk investments so as to reduce PSEG's FFO to debt ratio to below 24% over a multi-year period. A negative rating action could also be triggered by a one-notch downgrade on both Power and PSE&G or a two-notch downgrade on either Power or PSE&G. A positive rating action on PSEG is unlikely.

Fitch has affirmed the following ratings with a Stable Outlook:

PSE&G
--Long-term IDR at 'A-';
--Senior secured debt at 'A+';
--Pollution control revenue bonds at 'A+'.

PSEG
--Long-term IDR at 'BBB+';
--Senior unsecured debt at 'BBB+';
--Short-term IDR at 'F2';
--Commercial paper at 'F2'.

Power
--Long-term IDR at 'BBB+';
--Senior unsecured debt at 'BBB+'.

PSE&G
--Short-term IDR at 'F2';
--Commercial paper at 'F2'.

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Additional information is available at 'www.fitchratings.com'.

Applicable Criteria and Related Research:

--'Corporate Rating Methodology' (Aug. 8, 2012);
--'Recovery Ratings and Notching Criteria for Utilities' (Nov. 12, 2012);
--'Rating North American Utilities, Power, Gas, and Water Companies' (May 16, 2011).
--'Parent and Subsidiary Linkage' (Aug. 8. 2012).

Applicable Criteria and Related Research:
Recovery Ratings and Notching Criteria for Equity REITs
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=693751
Rating North American Utilities, Power, Gas, and Water Companies
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=625129
Parent and Subsidiary Rating Linkage
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=685552
Corporate Rating Methodology
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=684460

MOODY'S
INVESTORS SERVICE

Credit Opinion: Public Service Electric and Gas Company

Global Credit Research - 06 May 2013

New Jersey, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured	A1
Senior Unsecured Shelf	(P)A3
Pref. Stock	Baa2
Commercial Paper	P-2
Parent: Public Service Enterprise Group Incorporated	
Outlook	Stable
Senior Unsecured Shelf	(P)Baa2
Subordinate Shelf	(P)Baa3
Pref. Shelf	(P)Ba1
Commercial Paper	P-2

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Key Indicators

[1]**Public Service Electric and Gas Company**

	2012	2011	2010	2009
(CFO Pre-W/C + Interest) / Interest Expense	**5.1x**	**5.6x**	**4.6x**	**4.1x**
(CFO Pre-W/C) / Debt	**22%**	**28%**	**21%**	**20%**
(CFO Pre-W/C - Dividends) / Debt	**22%**	**22%**	**19%**	**20%**
Debt / Book Capitalization	**40%**	**40%**	**44%**	**45%**

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Low-risk rate-regulated transmission and distribution (T&D) utility

Regulatory environment appears supportive

Already large capital expenditure program could increase further, subject to approvals

Strengthened financial profile over the past several years

Service territory slowly stabilizing after recession and Superstorm Sandy

Adequate liquidity when parent is taken into consideration

Corporate Profile

Public Service Electric and Gas Company (PSE&G) is the largest regulated T&D utility in the state of New Jersey, serving a territory encompassing about 70% of the state's population, with about 2.2 million electric customers and 1.8 million gas customers. Per its last approved rate case, PSE&G's rate base broke down as 62% electric and 38% gas. The sales breakdown for PSE&G's electric business is 33% residential, 57% commercial and 10% industrial, while gas sales break down as 60% residential, 36% commercial and 4% industrial. PSE&G is a 100% owned subsidiary of Public Service Enterprise Group Incorporated (PSEG) and an affiliate of PSEG Power LLC (PEG Power). In 2012, PSE&G represented about 41% of PSEG's consolidated pre-tax income, 68% of total assets and 47% of cash flow before changes in working capital items (CFO Pre-WC).

SUMMARY RATING RATIONALE

PSE&G's A3 senior unsecured rating is supported by a low risk T&D business model, a constructive relationship with its principal regulator, the steady improvement in the company's financial profile in recent years (including a reduction in pension under-funding), and a balanced financial policy. These positive rating considerations are balanced against the risks associated with PSE&G's elevated capital spending plans, which are heavily weighted toward large, complex transmission projects that are FERC-regulated, with certain incentive returns but continuing local licensing and approval hurdles despite their approval by PJM. Our expectation is that PSE&G will continue to generate financial metrics appropriate for its rating category and that its major projects will be financed conservatively and constructed without significant un-recoverable cost over-runs.

DETAILED RATING CONSIDERATIONS

LOW RISK REGULATED T&D BUSINESS MODEL

We consider PSE&G's business and operating risk to be relatively low because it is almost exclusively a regulated T&D utility. T&D utilities generally have lower business and operating risk than integrated utilities with generating assets. PSE&G retains provider of last resort obligations, but contractually transfers that risk through auctions to Basic Generation Service (BGS) providers for electric supply and to PEG Power for gas supply. The BGS providers assume the power supply volumetric risks, including the risk of customer migration to competitive suppliers. PSE&G retains replacement risk (if a BGS provider were to default on its obligation), but since electricity and gas costs are a full pass through to the consumer, this potential cost would also be recoverable in rates. PSE&G's unregulated activities are limited in scope and strategically aligned with the regulated T&D operations. PSE&G's transmission business, which is regulated by the FERC, has no volume risk. Similar to most T&D utilities, the electric distribution business retains substantial intra-rate case volume exposure, as most delivery charges are on a per KWh basis. Thus, cash flow is affected by customer usage (and weather, conservation, self-generation, etc.) PSE&G's exposure to gas distribution volume risk is more limited, due to the existence of a weather normalization clause.

REGULATORY ENVIRONMENT APPEARS SUPPORTIVE

PSE&G's electricity and gas distribution activities are regulated at the state level by the New Jersey Board of Public Utilities (BPU), and its electricity transmission activities are regulated by the Federal Energy Regulatory Commission (FERC). In our opinion, the relationship between PSE&G and the BPU has primarily been constructive in nature, and PSE&G's ability to earn authorized returns has improved in recent years. However, the BPU has required other utilities in New Jersey to make substantial refunds based on multi-year retrospective excess earnings tests, which is incorporated in our scoring for the regulatory environment (Baa). Our scoring for the ability to recover costs and earn a reasonable return (A) considers the 2010 negotiated settlement of PSE&G's combined electricity and gas base rate application (with an allowed ROE of 10.3% on 51.2% common equity), the company's ability to securitize and recover substantial stranded costs related to New Jersey's transition to competitive energy markets, as well as recent earned returns that indicate a relatively small amount of regulatory lag. Moody's calculates 2012 ROE (GAAP-based, with Moody's standard adjustments) as 10.2% in 2012, down from 11.2 % in 2011. PSE&G has sought to align itself with state initiatives, and we believe its storm response and outage rates are generally perceived as comparing favorably to in-state peers.

PSE&G PLAN TO ACCELERATE T&D INVESTMENT IS GENERALLY POSITIVE

Superstorm Sandy caused devastation in many areas of the NY, NJ, and CT tri-state area in 2012. PSE&G had less damage than some tri-state utilities serving beach-front communities. Nonetheless, 2.1 million PSE&G customers (about 95%) lost power, and storm costs totaled $295 million, primarily caused by high winds and flooding related to the storm surge. In response, PSE&G announced a major two-part investment program. The program totals $5.4 billion over 10 years and is designed to protect and strengthen its electric and natural gas transmission and distribution (T&D) networks. On 20 February 2013, PSE&G filed with the NJBPU a plan called Energy Strong, under which the utility proposes to invest $3.9 billion in its electric and gas distribution networks over 10 years, of which about $2.2 billion in 2013-2017 . These investments include $1.7 billion to raise, relocate or protect electric switching and substations, and about $1.1 billion to replace and modernize 750 miles of cast iron gas mains in flood-prone areas. The following day, PSE&G announced the second part of the program - a plan to invest $1.5 billion over 10 years (of which about $600 million in 2013-2017)to harden its high voltage electric transmission lines. These transmission investments are subject to a no-harm review by PJM, after which they will be filed under existing formula rates set by the US Federal Energy Regulatory Commission (FERC) . Of the $5.4 billion total program amount, PSE&G expects to spend about $2.8 billion in 2013-2017.

The new investments are incremental to existing, approved investment plans, primarily to upgrade T&D, totaling about $6.9 billion in 2013-2017 . PSE&G expects to be able to spend the incremental capital with limited effect on customer rates, in part because of the expiration of stranded cost transition charges in 2015 (an adder to rates that has been in place since 2000, when New Jersey transitioned to competitive electric generation). In addition, lower natural gas prices are expected to keep the the power portion of electric bills well below levels experienced in 2008-2010. We expect PSE&G to recover the additional infrastructure investments in rates on a reasonably contemporaneous basis through a capital rider clause or FERC formula rates. Perhaps more important, the program demonstrates that the utility's relationship with New Jersey regulators did not suffer after Superstorm Sandy. If state regulators approve the program, PSE&G will have the opportunity to make investments and expand its rate base to harden its system against future storms and flooding.

ADDITIONAL T&D CAPEX IS AGGRESSIVE BUT MANAGEABLE

PSE&G's current Capex budget for 2013-2017 is $6.9 billion, or $1.4 billion on average per year, on par with the $1.4 billion of incurred annual average expenditures in 2010-2012 . Including recent proposed filings for Energy Strong as well as solar and energy efficiency investments, the proposed 2013-2017 budget is 50% higher at about $10.6 billion, or $2.1 billion on an average annual basis. The expanded investment plan increases execution risk, but the financial impact of construction is mitigated by the expectation of reasonably contemporaneous return on investment in rates, and an expectation that parent PSEG will contribute capital necessary to maintain PSE&G's regulatory capital ratio. Approved transmission, at about $4.4 billion, represents the largest component of the both the existing (64%) and proposed (42%) budgets. Of this amount, five major projects represent about $2.9 billion. These projects were approved by PJM and have certain incentives from FERC, including ROEs ranging from 11.68-12.93%, inclusion of construction work-in-progress in rate base, and 100% recovery of costs if abandonment is required. With the receipt of National Park Service approval in October 2012 for the Susquehanna-Roseland transmission line, PSE&G has obtained all required major approvals for all of these projects, and construction is underway. The other major components of the proposed budget are approved distribution investment of $2.3 billion, proposed Energy Strong investments of $2.2 billion, and proposed solar and efficiency investments of about $900 million. Our current view is that PSE&G will receive approval for a substantial portion of the proposed investments.

TREND OF STRENGTHENED FINANCIAL METRICS EXPECTED TO CONTINUE AFTER 2012

PSE&G's financial metrics were lower in 2012 when compared to 2011 driven primarily by $295 million of costs incurred due to Hurricane Sandy, of which $40 million were expensed in the fourth quarter of 2012 and the remainder deferred for future collections, as well as reduced benefits associated with bonus depreciation and higher pension and benefit expenses . As a result, CFO Pre-WC decreased to $1.4 billion in 2012 from $1.6 billion in 2011. Debt increased by about $700 million, primarily to fund capex. CFO Pre-WC + Interest/Interest and CFO Pre-WC to Debt were 5.1x and 22.1%, respectively, in 2012, compared to 5.6x and 27.8%, respectively, in 2011. Going forward, CFO Pre-WC is expected to increase, based on the absence of Sandy costs and a steady growth of rate base from planned capital expenditures. Metrics are expected to be somewhat higher than in 2012 and to remain appropriate for the rating category.

SERVICE TERRITORY STABILIZING BUT HEADWINDS REMAIN

PSE&G's service territory is one of the most densely populated areas of the United States, providing limited potential for meaningful population growth. Moody's Economy.com projects a slow recovery for the state of New Jersey, as total employment is not expected to attain its 2007 level until 2015, while its unemployment rate could remain above 9% until 2014. Strengths of the state economy include its diversity, very high education levels, high per capita income, strong links to international trade and a large contingent of high-tech and research operations, balanced against high costs, persistent state budget problems, high personal bankruptcy rates related to the housing bubble and a slow mortgage foreclosure process. New Jersey benefitted from a brief uplift in jobs at the end of 2012 due to increased construction spending after Superstorm Sandy. The state Department of Labor recently reported the addition of 10,400 jobs in March 2013, and 44,600 over the past year. PSE&G has an outsized exposure to commercial customers and low exposure to industrial customers. In many other areas of the country, industrial customers have led the recovery from the recession as well as electricity sales.

Liquidity Profile

We consider that PSE&G's liquidity is adequate, based on its strong access to capital markets, and when parent liquidity is taken into account. However, Moody's grid scoring for PSE&G is currently Ba. This scoring is based on our projection, assuming no access to the public debt or equity markets, that PSE&G would not be able to fund its maturing obligations (which are relatively heavy over the next twelve months) and to maintain its current capex plans and dividend levels for at least four quarters without fully exhausting its own committed credit facilities.

PSE&G has a $600 million 5 year syndicated revolving credit facility that matures in March, 2018, except for $29 million that matures in April 2016. As of 12/31/12, $324 million was available . The facility has a same day borrowing option, does not require the absence of a material adverse change as a condition precedent to borrowing, but does contain a maximum debt to capitalization covenant of 65%. PSE&G states it is in compliance with the covenant as of 12/31/12, and we believe there is an ample cushion. The credit agreement contains cross defaults to certain indebtedness of PSE&G or its major subsidiaries (as defined), but there is no cross default to indebtedness of PSEG, PEG Power or other affiliates.

For LTM 12/31/12, PSE&G generated roughly $1.3 billion in Cash from Operations (CFO), incurred roughly $1.7 billion in capital expenditures and made no dividend payments.. As a result, PSE&G generated roughly $400 million in negative free cash flow (FCF), which was primarily funded with debt. Given the size of the company's planned capital expenditure program, we expect PSE&G will have negative free cash flow over the next several years. Based on PSEG's most recent guidance for 2013-2015 earnings and spending including Energy Strong, as well as certain assumptions by Moody's, including an absence of major storm expenses, we estimate that CFO will average about $1.5-1.7 billion per year and capital expenditures about $2 billion per year, with only a very small amount of dividends paid if any (net of any capital increase), as PSEG has stated it will maintain the regulatory capital ratio at PSE&G. Resultant negative FCF of about $300-500 million per year will be financed with increases in debt and some capital contribution from the parent.

For additional information on the liquidity profile of PSEG, please refer to its Credit Opinion, which can be found on www.moodys.com.

Rating Outlook

PSE&G's stable rating outlook reflects our expectation that the company's financial profile will continue to be appropriate for its rating category. It also reflects our expectation that the company will continue to successfully manage its large capital spending program, and that the BPU will continue to provide timely recovery of investment expenditures, including any Energy Strong investments it approves.

What Could Change the Rating - Up

PSE&G's ratings could be upgraded if there were a positive change in our view of the regulatory framework (which could include more lag-reducing mechanisms) or if there were a sustainable improvement in credit metrics such that (CFO pre-WC + Interest) / Interest were in excess of 6x, CFO pre-WC / Debt were in excess of 26%, (CFO pre-WC - Dividends) / Debt were greater than 21% and Debt / Capitalization were below 40%.

What Could Change the Rating - Down

PSE&G's ratings could be downgraded if there were a negative change in our view of the regulatory framework (which could include disallowances or instances of increasing regulatory lag) or if there were a deterioration in

PSE&G's financial metrics, for instance CFO pre-WC/Interest below 4.4x, CFO pre-WC/Debt below 22% or CFO Pre-WC- Dividends/Debt below 17%. In addition, the incurrence of material holding company debt, particularly in conjunction with a shareholder oriented financial strategy, would also place downward pressure on the rating.

PSE&G is rated in accordance with Moody's August 2009 Regulated Electric and Gas Utility Rating Methodology.

Rating Factors

Public Service Electric and Gas Company

Regulated Electric and Gas Utilities Industry [1][2]	**Current 12/31/2012**		**Moody's 12-18 month Forward View* As of May 2013**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (10%)		Baa		Baa
b) Generation and Fuel Diversity (0%)				
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Ba
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	5.1x	A	5.7 - 6.2x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	23.6%	A	22 - 28%	A
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	21.1%	A	20 - 27%	A
e) Debt/Capitalization (3 Year Avg) (7.5%)	41.2%	A	35 - 38%	A
Rating:				
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		A3		A3

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2012(L); Source: Moody's Financial Metrics

Moody's
INVESTORS SERVICE

Credit Opinion: Public Service Enterprise Group Incorporated

Global Credit Research - 06 May 2013

Newark, New Jersey, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured Shelf	(P)Baa2
Subordinate Shelf	(P)Baa3
Pref. Shelf	(P)Ba1
Commercial Paper	P-2
Public Service Electric and Gas Company	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured	A1
Senior Unsecured Shelf	(P)A3
Pref. Stock	Baa2
Commercial Paper	P-2
PSEG Power LLC	
Outlook	Stable
Senior Unsecured	Baa1

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Key Indicators

[1]**Public Service Enterprise Group Incorporated**

	2012	2011	2010	2009
(CFO Pre-W/C + Interest) / Interest Expense	6.7x	6.2x	6.1x	4.9x
(CFO Pre-W/C) / Debt	32%	33%	32%	26%
RCF/Debt	26%	26%	26%	23%
FCF/Debt	-4%	13%	-6%	4%

[1] All ratios calculated in accordance with the Unregulated Utility and Power Rating Methodology using Moody's standard adjustments.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Shifting business mix, with larger rate-regulated component

The Energy Strong plan could increase the already robust capex at the utility

Reasonably supportive regulatory environment for rate-regulated operations

Locational and cost advantages in merchant power operations

Good liquidity resources

PSEG debt structurally subordinate to operating company debt

Corporate Profile

Headquartered in Newark, New Jersey, Public Service Enterprise Group Incorporated (PSEG) is the parent holding company of PSEG Power LLC (PEG Power), New Jersey's largest wholesale merchant generator with approximately 13.1 GW of capacity; Public Service Electric and Gas Company (PSE&G), New Jersey's largest regulated electric and gas transmission and distribution (T&D) utility; and PSEG Energy Holdings L.L.C. (Holdings), which owns a portfolio of leveraged leases and is also pursuing investments in renewable generation. On average for 2010-2012, PEG Power and PSE&G represented 66% and 32%, respectively, of PSEG's consolidated net income, 48% and 47%, respectively, of PSEG's consolidated cash flow from operations before changes in working capital (CFO Pre-W/C), 31% and 64%, respectively, of its consolidated capex and 33% and 63%, respectively, of PSEG's consolidated debt. Holdings holds equity lessor interests in leveraged and other leases totaling about $1 billion (excluding deferred taxes) , as well owned capacity of about 174 MW in a portfolio of small fossil and renewable power projects in the US. Holdings' total investments were about $1.2 billion at 12/31/12 .

SUMMARY RATING RATIONALE

PSEG's Baa2 senior unsecured rating reflects the increasing contribution of rate-regulated businesses to consolidated cash flows, a reasonably supportive regulatory environment in New Jersey for PSE&G, merchant power operations that have historically benefitted from their low cost, fuel diversity and proximity to major load centers of New Jersey, and a generally lower risk profile at Holdings, which has settled significant tax issues . These positive factors are balanced against the execution and financing risks associated with a major transmission investment program at PSE&G, the inherent merchant risks associated with an unregulated generation business, and the structural subordination of PSEG's creditors to the creditors of its principal operating companies. At December 31, 2012, there was no long term debt outstanding at the parent, with Power and PSE&G accounting for virtually all of PSEG's unadjusted consolidated debt.

DETAILED RATING CONSIDERATIONS

BUSINESS RISK PROFILE WILL BENEFIT FROM SHIFT TO MORE REGULATED CASH FLOWS

On a consolidated basis, PSEG is considered to have a medium risk business profile, reflecting its three major subsidiaries - Power, PSE&G, and Holdings. PSE&G's percentage contribution to cash flow as measured by CFO Pre-WC has increased steadily in the past three years from 39% in 2010 to 47% in 2012, and that trend is expected to increase with continued investment at PSE&G, particularly in major transmission projects.

Power's business risk profile is viewed as moderately-high risk. Like all merchant generators, Power is exposed to significant operating risks and volatile power prices. The performance of Power's nuclear plants is an important driver of its operational and financial performance. High nuclear capacity factors for the past four years have been a strong contributor to results. Power's hedging strategy is viewed as credit supportive.

We consider PSE&G's business and operating risk to be relatively low because it is almost exclusively a regulated T&D utility. PSE&G is expected to represent over 77% of PSEG's consolidated capex over the next several years, with a majority being allocated to transmission and distribution. In addition, to already approved projects, PSE&G announced a major two-part investment program, including $3.9 billion for Energy Strong (designed to protect and strengthen the distribution system) and $1.5 billion in additional transmission upgrades. The proposed program, which is subject to certain approvals and no-harm reviews, totals $5.4 billion over 10 years, of which $2.2 billion would be spent in 2012-2017.

Holdings has reduced its business risk materially by reducing its investment portfolio from $4.9 billion at 12/31/06 to about $1.2 billion at 12/31/12. PSEG reached a settlement with the IRS related to its international leveraged leases that will result in net tax refund to PSEG of about $100 million over time. Negotiations with the IRS were settled in Q1 of 2012 and the conclusion of the tax audits and settlements of the cross-border lease transactions for all tax years from 1997-2006 will result in the net return of approximately $170 million in cash. During 2012, PSEG liquidated its equity lease position in Dynegy following the company's emergence from bankruptcy in October 2012 and on a pre-tax basis, PSEG Holdings received $63 million as part of its claim. Other large exposures include about $341 million for power plants leased to GenOn REMA, LLC (B2, stable), a subsidiary of NRG Energy, Inc. (Ba3, stable) and about $218 million for plants leased to Midwest Generation Company (MWG), a subsidiary of Edison Mission Energy (EME). Both MWG and EME entered bankruptcy in December 2012, and MWG has not yet made a determination whether the lease will be rejected or upheld. The MWG lease debt holders agreed to a forbearance agreement through April 2013. If the forbearance is not renewed, the indenture trustee could accelerate the debt or exercise other remedies, which would eventually include foreclosure proceedings. We currently believe PSEG's potential tax liability in the event of an unwind of the lease will be manageable, net of its recovery on lease termination and tax indemnity claims. Growth at PSEG Holdings is expected to be modest, with a focus investments in renewable energy, especially solar.

GENERALLY SUPPORTIVE REGULATORY ENVIRONMENT

PSE&G's electricity and gas distribution activities are regulated at the state level by the New Jersey Board of Public Utilities (BPU), and its electricity transmission activities are regulated by the Federal Energy Regulatory Commission (FERC). In our opinion, the relationship between PSE&G and the BPU is generally constructive in nature, and PSE&G's ability to earn authorized returns has improved in recent years. However, the BPU has required other utilities in New Jersey to make substantial refunds based on multi-year retrospective excess earnings tests, which is incorporated in our scoring for the regulatory environment (Baa). Our scoring for the ability to recover costs and earn a reasonable return (A) considers the 2010 negotiated settlement of PSE&G's combined electricity and gas base rate application (with an allowed ROE of 10.3% on 51.2% common equity), the company's ability to securitize and recover substantial stranded costs related to New Jersey's transition to competitive energy markets, as well as recent earned returns indicates a relatively small amount of regulatory lag. Moody's calculates 2012 ROE (GAAP-based, with Moody's standard adjustments) as 10.2% in 2012, down from 11.2 % in 2011 . PSE&G has sought to align itself with state initiatives, and we believe its storm response and outage rates are generally perceived as comparing favorably to in-state peers.

ATTRACTIVE LOW COST ASSETS WITH STRONG BASE-LOAD CAPACITY

In our opinion, Power's assets are well positioned along the dispatch curve to provide load-following generation, which provides the company with an opportunity to maintain profitability under a variety of market conditions. PEG Power's approximately 3,632 MW base load nuclear fleet has a strong operating track record of high capacity factors and low cost generation. While capacity factors at coal assets have decreased substantially in the past two quarters, the company's approximately 3,176 MW of gas-fired combined cycle assets have been able to operate profitably for significantly more hours per month. Power's gas and oil-fired single cycle plants typically operate at relatively low capacity factors but generate meaningful cash flow through capacity sales and provide a hedge against forced outages at the base-load nuclear plants. Our ratings assume that Power will continue to maintain the high availability levels that its nuclear, coal and gas-fired generating plants have achieved in recent years.

STRUCTURAL SUBORDINATION AT PSEG

PSEG's principal source of cash flow is the dividends it receives from PSE&G and PEG Power, so its (currently minimal) debt is structurally subordinated to the debt at its subsidiaries. Due to heavy capex at PSE&G, which will increase if the Energy Strong plan is approved, PSEG will rely heavily on dividends from PEG Power for a multi-year period. Management has stated that PSEG will not issue equity to fund Energy Strong. If market prices were to erode PEG Power's cash generation, PSEG may need to issue debt to fund its dividend and/or for capex at PSE&G, thereby increasing structurally subordinated debt. Eventually, however, we expect that the resultant higher rate base at PSE&G will permit the utility to support a much greater share of the parent's dividend.

FINANCIAL PROFILE

PSEG's financial metrics remained strong in 2012, with net income at $1.3 billion and CFO Pre-WC remaining essentially flat at $2.9 billion, stemming from lower hedged power prices and the costs of Superstorm Sandy offset by a benefit of bonus depreciation, a reduction in O&M, and slight increase in transmission revenue. Debt increased almost $400 million due to an increase in the debt equivalent of operating lease and underfunded pension obligations. With CFO Pre-WC + Interest/Interest of 6.7x, CFO Pre-WC/Debt of 32% and Retained Cash Flow/Debt of 25.5%, PSEG's 2012 metrics were robust for the rating category. Including the recently announced Energy Strong initiative, metrics over the next three years are expected to be generally in line with the rating category, although Free Cash Flow/Debt is expected to be weak due to higher capex levels at PSE&G and a moderately increasing dividend payment. We expect free cash flow to be negative on average over the next several years.

Liquidity Profile

PSEG's liquidity is considered adequate.

PSEG has two syndicated revolving credit facilities with an aggregate total of $1 billion - $500 million matures in March, 2017 and $500 million matures in March, 2018. There was $4 million of usage at 12/31/12. The facilities have a same day borrowing option, do not require the absence of a material adverse change as a condition precedent to borrowing, but do contain a maximum debt to capitalization covenant of 70%. PSEG states it is in compliance with the covenant as of 12/31/12, and we believe there is an ample cushion. The credit agreement contains cross defaults to certain indebtedness of its major subsidiaries (as defined and including PSE&G and PEG Power).

For 2012 on a consolidated basis, PSEG generated roughly $2.8 billion in Cash from Operations (CFO), incurred roughly $2.5 billion in capital expenditures and made dividend payments of approximately $718 million. As a result, PSEG generated roughly $400 million in negative FCF, which was financed with debt. Given the size of the planned capital expenditure program at PSE&G, combined with PSEG's announced resumption of increases in dividends to shareholders, we expect that PSEG will have negative free cash flow on a consolidated basis over the next several years. Based on PSEG's most recent guidance regarding 2013-2015 earnings, and certain assumptions by Moody's, we estimate that CFO will average about $2.7-2.9 billion per year, capital expenditures about $2.7 billion per year, dividends about $740 million per year, and that negative FCF of about $400-600 million per year will be financed with increases in debt.

For additional information on the liquidity profile of subsidiaries, PSE&G and PEG Power, please refer to their respective Credit Opinions, which can be found on www.moodys.com.

Rating Outlook

PSEG's stable rating outlook reflects our expectation that PSEG's financial profile will remain consistent with the rating category, with greater contributions from PSE&G somewhat offsetting expected reductions in cash flow at PEG Power, and that management will continue to maintain a balanced financial profile on a consolidated basis.

What Could Change the Rating - Up

Ratings upgrades are unlikely for PSEG in the near term, due to its continuing dependence on merchant cash flows combined with expectations of negative consolidated free cash flow due to the large capex investment program at PSE&G over the next several years. Nonetheless, if there were a sustainable improvement in PSEG's financial profile, such that CFO pre-WC/Interest were above 6x, CFO pre-WC/Debt above 31% and Free Cash Flow/Debt above 20%, ratings could be upgraded. Moreover, upon completion of the transmission capex and Energy Strong programs, PSEG's ratings could be upgraded if we conclude that the regulated business will represent the majority of the company's consolidated operations on an sustained basis.

What Could Change the Rating - Down

PSEG's ratings could be downgraded if in the near-term there were deterioration in PSEG's financial metrics, for instance CFO pre-WC/Interest below 4.7x, CFO pre-WC/Debt below 25% or CFO Pre-WC- Dividends/Debt below 19%. In addition, the incurrence of material holding company debt, particularly in conjunction with a shareholder oriented financial strategy, would also place downward pressure on the rating.

The principal methodology used for PSEG is the Unregulated Utilities and Power Companies Methodology dated August, 2009.

Rating Factors

Public Service Enterprise Group Incorporated

Unregulated Power Companies [1][2]	**Current (12/31/12)**	**Moody's 12-18**

				month Forward View*	
Factor 1: Market Assessment, Scale and Competitive Position (20%)	**Measure**	**Score**		**Measure**	**Score**
a) Market and Competitive Position (15%)		A			A
b) Geographic Diversity (5%)		Ba			Ba
Factor 2: Cash Flow Predictability of Business Model (20%)					
a) Hedging strategy (10%)		A			A
b) Fuel Strategy and mix (5%)		Baa			Baa
c) Capital requirements and operatinal performance (5%)		Baa			Baa
Factor 3: Financial policy (10%)		Baa			Baa
Factor 4: Financial Strength - Key Financial Metrics (50%)					
a) CFO pre-WC + Interest / Interest (15%) (3yr Avg)	6.3x	Baa		6.0x - 6.7x	Baa
b) CFO pre-WC / Debt (20%) (3yr Avg)	32.2%	Baa		24 - 29%	Baa
c) RCF / Debt (7.5%) (3yr Avg)	25.7%	A		19 - 21%	Baa
d) FCF / Debt (7.5%) (3yr Avg)	0.7%	Ba		(10) - 0%	B
Rating:					
a) Indicated Rating from Grid		Baa1			Baa2
b) Actual Rating Assigned		Baa2			Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2012; Source: Moody's Financial Metrics

STANDARD & POOR'S RATINGS SERVICES

RatingsDirect®

Summary:
Public Service Electric & Gas Co.

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Table Of Contents

Summary:

Public Service Electric & Gas Co.

Corporate Credit Rating	BBB+/Stable/A-2

Profile Assessments

BUSINESS RISK	EXCELLENT

Vulnerable Excellent

FINANCIAL RISK	SIGNIFICANT

Highly leveraged Minimal

Rationale

Business Risk: Excellent	Financial Risk: Significant
• Lower-risk, monopolistic, rate-regulated utility businesses that provide an essential service • Lower-risk transmission and distribution businesses • Effective management of regulatory risk • Capital investments that materially reduce the regulatory lag by utilizing contemporaneous returns • Business and regulatory diversity	• Public Service Electric & Gas Co. (PSE&G) financial risk profile and ratings are based on the consolidated credit profile of its parent, Public Service Enterprise Group Inc. (Enterprise) • Affiliation with Enterprise's competitive generation businesses that ultimately depend on the market price of electricity • Low power prices that will weaken the competitive businesses' cash flow. • High capital expenditures • Strong liquidity

Outlook: Stable

The stable outlook reflects our base-case scenario that Enterprise's business risk profile will continue to gradually improve, reflecting material growth at regulated PSE&G. This is partially offset by the ongoing difficulty within the merchant business primarily because of weak power prices. The Energy Strong initiative announced in February 2013 could enhance credit quality by potentially providing even greater momentum to the already utility-focused capital program. Under our base-case scenario we expect that consolidated funds from operations (FFO) to debt will approximate 26% and consolidated debt to EBITDA of about 3x.

Upside scenario

We could raise the rating if the company continues to invest disproportionately in its regulated businesses such that the regulated operations represent more than 65% of Enterprise and consolidated FFO to debt is consistently greater than 28%. This would most likely occur if the company's regulated capital program approximate $2 billion annually and current low power prices do not weaken.

Downside scenario

We could lower the ratings if FFO to debt is consistently lower than 22%, which could occur if there is a sustained decrease in natural gas prices, power prices, unfavorable developments in the capacity markets, or the company makes material investments within its regulated businesses without contemporaneous returns.

Standard & Poor's Base-Case Scenario

Assumptions

- Material incremental capital spending is predicated on the company obtaining and utilizing contemporaneous returns
- The company does not file for a base rate increase within the next three years
- The consolidated financial measures weaken primarily because of lower power prices
- Minimal economic growth within the company's service territory
- The regulated companies earn their allowed return on equity
- Long-term debt maturities are refinanced
- Net cash flow (FFO less dividends) to capital expenditures at about 90%, indicating the need for external funding
- Negative discretionary cash flow primarily due to high capital spending on the regulatory businesses
- A dividend payout ratio of about 60%

Key Metrics

	2012A	2013E	2014E
FFO/debt	30.2%	28%-32%	26%-30%
Debt/EBITDA	2.9x	2.7x – 3.2x	2.7x – 3.2x
Debt/capital	46.1%	45% - 50%	45% - 50%

Standard & Poor's adjusted consolidated financial ratios for Enterprise include debt adjustments for operating leases ($180 million) and pension-related items ($1.4 billion) that are partially offset by securitized bonds ($722 million). EBITDA adjustments include pension-related items ($133 million) offset by securitized bonds ($272 million). A--Actual. E—Estimate.

Business Risk: Excellent

PSE&G's excellent business risk profile reflects its lower-risk, monopolistic, rate-regulated utility pure transmission and distribution (T&D) businesses that provide an essential service. The company is a regulated utility in New Jersey that distributes electricity to about 2.2 million customers and gas to about 1.8 million customers. We view the T&D businesses as lower risk than the generation businesses that are included in many fully integrated electric utilities. The company's gas and electric distribution assets are regulated by the New Jersey Board of Public Utilities and the transmission assets are regulated by the Federal Energy Regulatory Commission (FERC).

Standard & Poor's views the New Jersey regulatory environment in the credit-supportive category. The transition to deregulation has been relatively uneventful, and we consider it favorable for credit quality. The existing regulatory mechanisms are also credit supportive, in our view. These include the pass-through of gas and electricity commodities, a weather normalization clause for gas, and various charges that allow for contemporaneous return. On the transmission side, FERC has approved formula rate treatment and has also approved incentive rates for certain projects, recovery of construction-work-in-progress costs, and abandonment recovery. Overall, PSE&G has consistently demonstrated effective management of regulatory risk.

In February 2013, PSE&G filed with the New Jersey Board of Public Utilities (BPU) to invest $2.6 billion over five years to reinforce its gas and electric distribution systems as part of its "Energy Strong" program. In total, the company expects that the distribution portion of its Energy Strong program will approximate $3.9 billion and the transmission portion about $1.5 billion, both over a 10-year period. Management does not intend to file for a base rate case for this program but instead will rely on contemporaneous returns. The company is in the middle of multiple large transmission projects that have a total cost of about $3 billion, which it expects to be in service by 2014/2015. These regulated investments will accelerate the shift by consolidated enterprise to a much more pronounced regulatory strategy.

Also contributing to PSE&G's excellent business risk profile is its business diversification among gas, electric distribution, and electric transmission business. Furthermore, because of the company's near-term disproportionate capital spending on electric transmission, we expect that 2013 electric transmission rate base will grow to about 35% of the total rate base compared with 28% at year-end 2012, reflecting regulatory diversification.

Reflected in the business risk profile is our assessment of the company's management and governance as "strong". This reflects management's consistent strategy that has a demonstrated track of successful execution, comprehensive enterprise wide risk management standards, and management's considerable expertise within all of its operating businesses.

Financial Risk: Significant

Standard & Poor's views PSE&G financial profile as significant based on parent Enterprise's consolidated financial risk profile. The financial risk profile reflects Standard & Poor's base-case forecast that consolidated FFO to debt will gradually weaken to approximately 26% over the next three years, reflecting the roll-off of higher hedges in place and the existing lower market prices for electricity. In additional we expect debt to EBITDA at about 3x, FFO to interest coverage at about 7x, and debt leverage of approximately 46%. For the 12-months-ended December 2012, Enterprise's adjusted FFO to total debt declined to 30.2% from 39.3% at year-end 2011, reflecting weaker power prices, higher capital spending, and storm costs.

We expect Enterprise to have negative discretionary cash flow over the near and intermediate term, primarily because of increased annual capital expenditures at regulated PSE&G and continued softness in the power markets. Partially offsetting PSE&G's large capital expenditures, of about $1.5 billion annually, is our expectation that the vast majority of growth capital spending will be recovered through contemporaneous returns, which we view as credit supportive. In addition, we expect Enterprise to meet its cash needs in a manner that minimally preserves its credit quality.

Liquidity: Strong

Enterprise has "strong" liquidity to cover its needs over the next 12 to 18 months, in our view, even if EBITDA decreases by 30%. We expect that the company's sources of liquidity will exceed its uses by more than 1.8x.

Principal Liquidity Sources	Principal Liquidity Uses
• Credit facility availability of about $3.8 billion • FFO of about $2.9 billion • Minimal working capital at about negative $100 million	• 2014 long-term debt maturities (including securitization bonds) of $782 million • Annual capital spending of about $2 billion • Dividend payment of more than $700 million

Covenant Analysis

Under PSE&G's first-mortgage bonds (FMBs), the company's FMB issuance could be limited if its coverage ratio of earnings to fixed charges were less than 2x. As of Dec. 31, 2012, the utility's coverage ratio was 3.6x and the utility could theoretically issue more than $2.5 billion of FMB without violating this financial covenant, demonstrating adequate cushion.

Recovery Analysis

- We assign recovery ratings to first-mortgage bonds (FMBs) issued by U.S. utilities, which can result in issue ratings being notched above a corporate credit rating (CCR) on a utility depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of "secured utility bond" (SUB) that qualify for a recovery rating as defined in our criteria.
- The recovery methodology is supported by the ample historical record of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhanced those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist.
- Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed a CCR on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories depending on the calculated ratio.
- PSE&G's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of about 2.5x supports a recovery rating of '1+' and an issue rating two notches above the CCR.

Related Criteria And Research

- Corporate Criteria: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Corporate Criteria: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- 2008 Corporate Ratings Criteria: Ratios And Adjustments, April 15, 2008
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008
- 2008 Corporate Criteria: Commercial Paper, April 15, 2008
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2007
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- Collateral Coverage and Issue Notching Rules for ‘1+’ and ‘1’ Recovery Ratings on Senior Bonds Secured by Utility

Real Property, Feb. 14, 2013

- Methodology And Assumptions: Standard & Poor's Revises Key Ratios Used In Global Corporate Ratings Analysis, Dec. 28, 2011

Business And Financial Risk Matrix

	Financial Risk					
Business Risk	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA/AA+	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	B- or below

Note: These rating outcomes are shown for guidance purposes only. The ratings indicated in each cell of the matrix are the midpoints of the likely rating possibilities. There can be small positives and negatives that would lead to an outcome of one notch higher or lower than the typical matrix outcome. Moreover, there will be exceptions that go beyond a one-notch divergence. For example, the matrix does not address the lowest rungs of the credit spectrum (i.e., the 'CCC' category and lower). Other rating outcomes that are more than one notch off the matrix may occur for companies that have liquidity that we judge as "less than adequate" or "weak" under our criteria, or companies with "satisfactory" or better business risk profiles that have extreme debt burdens due to leveraged buyouts or other reasons. For government-related entities (GREs), the indicated rating would apply to the standalone credit profile, before giving any credit for potential government support.

STANDARD & POOR'S
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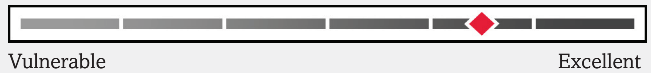
Table Of Contents

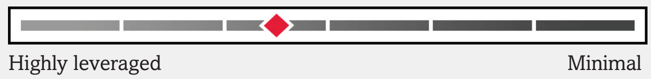
Public Service Enterprise Group Inc.

Corporate Credit Rating	BBB+/Stable/A-2

Profile Assessments

BUSINESS RISK	STRONG	
FINANCIAL RISK	SIGNIFICANT	





Rationale

Business Risk: Strong	Financial Risk: Significant
• Increasing influence of the lower-risk rate-regulated electric and gas utility subsidiary on the consolidated credit profile • Regulatory mechanisms that materially reduce lag in the recovery of and return on significant capital investment by the utility • Geographically well positioned portfolio of merchant assets with a solid performance history • Consistent hedging strategy by the merchant operations, with a significant proportion of gross margin under contract through 2014 • Lower sales and weakened margins at the merchant power business • Exposure to market price volatility as contracts expire and are renewed at prevailing market prices	• Credit measures that comfortably support the current rating • Future pressure on ratios from expected heavy capital spending by the utility • Pressure on margins at the competitive power operations resulting from depressed gas prices • Strong liquidity

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Outlook: Stable

The growing influence of the regulated business is enhancing the consolidated risk profile of Public Service Enterprise Group Inc. (PSEG) and should do so for several years. Standard & Poor's Ratings Services expects very little incremental growth at the merchant operations, where the focus will be on operational excellence and cost control. We believe that PSEG's strong operating performance, together with adjusted funds from operations (FFO) to debt of about 26% and adjusted debt to equity of about 46% for the consolidated company, supports the 'BBB+' rating. The "Energy Strong" initiative announced in February 2013 potentially enhances credit quality by providing even greater momentum to the already utility-focused capital program.

Upside scenario

We could raise the rating if the company continued to invest disproportionately in its regulated businesses such that these operations represented more than 65% of PSEG and consolidated FFO to debt were consistently greater than 28%.

Downside scenario

We could lower the ratings if FFO to debt were consistently lower than 22%, which could occur if a sustained decrease in natural gas prices, power prices, or unfavorable developments in the capacity markets occurred.

Standard & Poor's Base-Case Scenario

Assumptions

- Material capital spending by the utility, predicated on obtaining contemporaneous returns
- No base rate increase filing within the next three years
- A consistent hedging strategy, with a significant proportion of gross margin under contract through 2014
- Strong operational performance by a somewhat diversified set of generation assets
- Exposure to market price volatility as contracts expire and are renewed at lower prevailing market prices

Key Metrics

	2012A	2013E	2014E
FFO/debt	30.2%	28%-32%	26%-30%
Debt/EBITDA	2.9x	2.7x – 3.2x	2.7x – 3.2x
Debt/capital	46.1%	45% - 50%	45% - 50%

Standard & Poor's adjusted consolidated financial ratios for PSEG include additions to debt for operating leases ($180 million) and pension- and OPEB-related items ($1.4 billion), as well as the removal of securitized bonds ($722 million). EBITDA adjustments include pension- and OPEB-related items ($133 million), offset by securitized bonds ($272 million). A--Actual. E—Estimate.

Company Description

PSEG is a diversified energy company that owns Public Service Electric & Gas Co. (PSE&G), a regulated utility that serves a densely populated service territory in New Jersey; PSEG Power LLC, which owns a generation portfolio of about 13,226 megawatts (MW) mainly in the Mid-Atlantic and Northeast U.S., including ownership stakes in five nuclear units and 17 fossil generating stations; and PSEG Energy Holdings LLC, which seeks investment opportunities in the energy markets, particularly solar, in which it has about 70 MW, with an additional 19 MW under construction. Standard & Poor's analyzes these businesses and the financial ratios they generate on a consolidated basis, with the minor exception of a small subsidiary or PSEG Energy Holdings.

Business Risk: Strong

A mix of regulated and unregulated businesses

The "strong" business risk profile of PSEG reflects the growing positive influence on the company of PSE&G, whose business risk profile we view as "excellent". The regulated operations are expected to provide an increasing share of the consolidated company's cash flow as about 80% of capital expenditures over the next few years will be by the utility. While the unregulated operations are volatile, the merchant generation fleet has provided a substantial level of relatively consistent cash flow for many years, thereby supporting the group's consolidated creditworthiness. However, the depressed price of natural gas in the past few years, compounded by the impact of the recession on electric demand, has weakened the outlook for merchant power. We estimate that PSEG Power's cash flow contribution to the consolidated entity will decrease to less than 40% over the next three years. In the short term, 100% of total base load energy margins are under contract through 2013, which should provide a relatively stable source of cash flow.

In February 2013, PSE&G filed with the New Jersey Board of Public Utilities (BPU) to invest $2.6 billion over five years to reinforce its gas and electric distribution systems as part of its Energy Strong program. In total, the company has proposed a 10-year $3.9 billion spending program to reinforce its distribution network. In addition to the Energy Strong program, the utility expects to spend about $1.5 billion on its transmission system, also over a 10-year period. The utility is currently authorized to earn a return on equity (ROE) of 10.3% on its distribution business and a base ROE of 11.68% on its transmission operations, a portion of which also earns an incremental incentive return, as authorized by the Federal Energy Regulatory Commission. Management has requested contemporaneous returns for its Energy Strong investments.

For the unregulated business, margins have worsened in the past few years. Significantly lower prices for natural gas have caused a decrease in power prices and net revenues. Gas generally sets the marginal cost of power in the Eastern Mid-Atlantic Area Council region, but after collapsing in 2010, natural gas prices have strengthened, with the 2014 Henry Hub forward price currently trading at about $4.20 per million British thermal units, close to the roughly $4.00 of about a year ago, indicating perhaps some sustainability above the very low prices recently experienced. Moreover, a slow economic recovery has improved implied heat rates in the spot market, and environmental regulations are expected to cause significant retirements in the existing U.S. coal fleet.

Risks to the capacity markets include a bill passed by the New Jersey legislature to subsidize up to 2,000 MW of new power capacity. We believe the resulting out-of-market long-term capacity agreements may hurt capacity prices for PSEG Power's existing generation in the short to medium term, but may not throttle long-term capacity prices. The 2,000 MW identified by the BPU will not likely come on line before 2015, yet capacity prices still increased 8% to $136 per MW-day for the "rest of the pool", and still recognized, though less so than historically, the constrained location of PSEG Power's fleet. PSEG Power's assets received a blended $167 per MW-day in the auction.

The full-requirements contracting in the annual basic generation service (BGS) auction exposes PSEG Power's margins to market risks, including load-shaping, fuel, and volume risks. The decrease in natural gas prices has caused a significant difference between the BGS price and wholesale prices, resulting in significant customer migration, which reached about 40% in 2012. We estimate that the decreasing difference between the spot price of power and the BGS price will cause rate shopping to level off at about the current percentage.

We score PSEG's management and governance as "strong". In our opinion, management responds proactively to anticipated regulatory requirements, including environmental regulations, while remaining strongly focused on preserving balance sheet strength. The company has been transparent in the planning of its capital expenditures. It has been highly consistent in applying risk management strategies related to its merchant power operations, and management's risk tolerance around these assets has not wavered.

S&P Base-Case Operating Scenario

- Economic conditions in the utility's service territory steadily but modestly improve, increasing customers and usage.
- Base EBITDA benefits from expanding rate base as well as customer and usage growth.
- Regulatory practices continue that largely support credit quality, including cost pass-through mechanisms that help stabilize cash flows.
- The merchant fleet continues to operate well.

Peer comparison

Table 1

Public Service Enterprise Group Inc. -- Peer Comparison

Industry sector: energy

	Public Service Enterprise Group Inc.	Exelon Corp.	PPL Corp.	FirstEnergy Corp.	Dominion Resources Inc.
Rating as of May 14, 2013	BBB+/Stable/A-2	BBB/Stable/A-2	BBB/Stable/NR	BBB-/Stable/--	A-/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	10,585.2	20,214.3	11,181.3	14,893.6	14,223.0
EBITDA	3,522.9	6,179.8	3,693.2	4,214.5	4,802.2
Net income from cont. oper.	1,451.7	2,072.7	1,326.7	813.0	1,565.0
Funds from operations (FFO)	2,913.6	6,120.3	2,981.0	2,768.2	3,302.2
Capital expenditures	2,294.2	4,590.1	2,352.3	2,443.1	3,733.7
Free operating cash flow	653.6	1,421.2	522.7	413.1	(507.8)

Table 1

Public Service Enterprise Group Inc. -- Peer Comparison (cont.)					
Discretionary cash flow	(47.7)	(93.6)	(359.2)	(410.6)	(1,709.7)
Cash and short-term investments	476.8	1,381.3	1,069.0	464.3	137.3
Debt	8,870.4	20,899.7	17,497.5	20,288.0	20,583.4
Equity	10,036.0	16,844.7	11,992.7	11,635.0	12,408.4
Adjusted ratios					
EBITDA margin (%)	33.3	30.6	33.0	28.3	33.8
EBITDA interest coverage (x)	8.3	6.2	4.6	3.6	4.7
EBIT interest coverage (x)	6.7	4.7	3.5	2.5	3.7
Return on capital (%)	12.4	10.9	9.9	8.2	10.3
FFO/debt (%)	32.8	29.3	17.0	13.6	16.0
Free operating cash flow/debt (%)	7.4	6.8	3.0	2.0	(2.5)
Debt/EBITDA (x)	2.5	3.4	4.7	4.8	4.3
Total debt/debt plus equity (%)	46.9	55.4	59.3	63.6	62.4

Financial Risk: Significant

Large capital expenditure program and moderating credit measures

We view PSEG's financial risk profile as "significant," reflecting adjusted financial measures that are comfortably within guidelines for the current rating. This assessment incorporates the anticipated heavy capital spending program that the utility is undertaking. The elevated spending level, combined with dividend payments, will lead to negative discretionary cash flow in the near term, requiring external financing. However, management has stated that the spending associated with the Energy Strong program will not proceed without the BPU granting concurrent and assured cost recovery.

PSEG's financial risk profile is characterized by credit measures that comfortably support the rating, strong liquidity under our criteria, and a management posture that demonstrates support for the creditworthiness of the company. PSEG's financial statements are relatively straightforward, with only modest adjustments required to assess financial risk. For analytical purposes, Standard & Poor's removes from the consolidated profile the debt of subsidiary PSEG Resources LLC.

Standard & Poor's expects that between 2013 and 2015, PSEG Power's adjusted FFO to debt ratio will be about 35% and debt leverage about 37%, which are comfortably within guidelines for the rating. Moreover, we consider PSEG Power's positive free cash flow position to be favorable. The parent's consolidated credit protection measures have remained relatively stable, with adjusted FFO to total debt at 26% to 30% and debt leverage of about 46%, measures that are adequate for the current rating.

S&P Base-Case Cash Flow And Capital Structure Scenario

Our base case forecast suggests steady to somewhat decreasing measures through 2015 as a result of increased debt issuance. We expect adjusted debt to EBITDA to improve modestly to 2.9x from 3.1x, and total debt to total capital of about 46%.

- Capital spending related to rate base additions drives overall company growth and will require external funding.
- Capital spending decreases significantly after 2014.
- Cash dividends grow modestly, with a target payout of about 60%.
- The company issues no equity over the forecast period.
- Capital spending on the merchant business is largely limited to maintenance requirements.

Financial summary

Table 2

Public Service Enterprise Group Inc. -- Financial Summary

Industry Sector: Energy

	--Fiscal year ended Dec. 31--				
	2012	2011	2010	2009	2008
Rating history	BBB/Positive/A-2	BBB/Positive/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2
(Mil. $)					
Revenues	9,408.5	10,954.2	11,392.8	11,922.0	12,671.7
EBITDA	3,143.2	3,691.4	3,733.9	3,770.4	3,456.6
Interest Expense	390.1	418.9	470.7	550.7	428.6
Net income from continuing operations	1,304.3	1,531.1	1,519.5	1,492.3	1,388.0
Funds from operations (FFO)	2,752.6	3,302.8	2,685.3	2,377.7	2,420.2
Capital expenditures	2,690.9	2,102.3	2,089.4	1,747.1	1,787.1
Dividends paid	718.0	693.0	693.0	673.0	655.0
Debt	9,112.4	8,413.6	9,085.2	9,075.8	8,466.3
Preferred stock	0.0	0.0	0.0	80.0	80.0
Equity	10,645.1	10,108.9	9,354.0	8,678.3	7,569.0
Debt and equity	19,757.5	18,522.4	18,439.2	17,754.0	16,035.3
Adjusted ratios					
EBITDA margin (%)	33.4	33.7	32.8	31.6	27.3
EBITDA interest coverage (x)	8.1	8.8	7.9	6.8	8.1
EBIT interest coverage (x)	6.3	7.3	6.6	5.7	6.3
FFO int. cov. (x)	8.0	8.9	6.7	5.1	6.6
FFO/debt (%)	30.2	39.3	29.6	26.2	28.6
Discretionary cash flow/debt (%)	(8.6)	9.9	(2.2)	2.6	2.7
Net Cash Flow / Capex (%)	75.6	124.1	95.4	97.6	98.8
Debt/EBITDA (x)	2.9	2.3	2.4	2.4	2.4
Debt/debt and equity (%)	46.1	45.4	49.3	51.1	52.8
Return on capital (%)	10.1	13.2	14.2	15.7	15.0
Return on common equity (%)	12.4	15.6	16.2	17.9	18.8

Table 2

Public Service Enterprise Group Inc. -- Financial Summary (cont.)					
Common dividend payout ratio (un-adj.) (%)	55.0	45.3	45.6	45.2	47.3

Liquidity: Strong

We consider liquidity "strong" given the very manageable level of expected debt maturities, available credit facilities, and EBITDA generation. We estimate that PSEG's sources of cash during the next 12 to 24 months will exceed uses by about 1.5x. We expect sources over uses to remain positive even if EBITDA decreased by 50%. Collateral requirements have meaningfully decreased as commodity prices have decreased. The company would have sufficient availability under its credit facilities even if its ratings fell to speculative grade. As of Dec. 31, 2012, if PSEG Power had lost its investment-grade rating, counterparties could have required it to post additional collateral of about $654 million.

Principal Liquidity Sources	Principal Liquidity Uses
• FFO of about $2.9 billion in 2013, in Standard & Poor's estimate • Assumed credit facility availability of about $3.9 billion	• Capital spending of about $2.5 billion in 2013 • Debt maturities of about $1.026 billion over the next 12 months • Dividends of about $729 million over the next 12 months

Debt maturities

Table 3

Long-Term Debt Maturities

Mil. $	2013	2014	2015	2016	2017	Thereafter	Total
	1,252	782	876	731	1	4,281	7,923

Recovery Analysis

- We assign recovery ratings to first-mortgage bonds (FMBs) issued by U.S. utilities, which can result in issue ratings being notched above a corporate credit rating (CCR) on a utility depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of "secured utility bond" (SUB) that qualify for a recovery rating as defined in our criteria.
- The recovery methodology is supported by the ample historical record of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhanced those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist.
- Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed a CCR on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories depending on the calculated ratio.
- PSE&G's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or

subsequently acquired. Collateral coverage of about 2.5x supports a recovery rating of '1+' and an issue rating two notches above the CCR.

Reconciliation

Table 4

Reconciliation Of Public Service Enterprise Group Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2012--									
Public Service Enterprise Group Inc. reported amounts										
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	8,157.7	10,644.1	9,679.9	3,250.7	2,210.6	420.6	2,747.9	2,747.9	718.0	2,571.0
Standard & Poor's adjustments										
Operating leases	179.8	--	--	6.0	6.0	6.0	2.0	2.0	--	138.9
Postretirement benefit obligations	1,406.0	--	--	133.0	133.0	--	146.3	146.3	--	--
Capitalized interest	--	--	--	--	--	19.0	(19.0)	(19.0)	--	(19.0)
Share-based compensation expense	--	--	--	25.0	--	--	--	--	--	--
Securitized utility cost recovery	(722.0)	--	(271.5)	(271.5)	(55.5)	(55.5)	(216.0)	(216.0)	--	--
Reclassification of nonoperating income (expenses)	--	--	--	--	173.0	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	125.5	--	--
Minority interests	--	1.0	--	--	--	--	--	--	--	--
US decommissioning fund contributions	--	--	--	--	--	--	(34.0)	(34.0)	--	--
Debt - Accrued interest not included in reported debt	91.0	--	--	--	--	--	--	--	--	--
Total adjustments	954.8	1.0	(271.5)	(107.4)	256.5	(30.4)	(120.8)	4.7	0.0	119.9
Standard & Poor's adjusted amounts										
	Debt	**Equity**	**Revenues**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	9,112.4	10,645.1	9,408.5	3,143.2	2,467.1	390.1	2,627.1	2,752.6	718.0	2,690.9

Related Criteria And Research

- Corporate Criteria: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Corporate Criteria: Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- 2008 Corporate Ratings Criteria: Ratios And Adjustments, April 15, 2008
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008
- 2008 Corporate Criteria: Commercial Paper, April 15, 2008
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2007
- Criteria: Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, published Nov. 26, 2008.
- Collateral Coverage and Issue Notching Rules for '1+' and '1' Recovery Ratings on Senior Bonds Secured by Utility Real Property, Feb. 14, 2013
- Methodology And Assumptions: Standard & Poor's Revises Key Ratios Used In Global Corporate Ratings Analysis, Dec. 28, 2011

Business And Financial Risk Matrix

	Financial Risk					
Business Risk	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA/AA+	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	B- or below

Note: These rating outcomes are shown for guidance purposes only. The ratings indicated in each cell of the matrix are the midpoints of the likely rating possibilities. There can be small positives and negatives that would lead to an outcome of one notch higher or lower than the typical matrix outcome. Moreover, there will be exceptions that go beyond a one-notch divergence. For example, the matrix does not address the lowest rungs of the credit spectrum (i.e., the 'CCC' category and lower). Other rating outcomes that are more than one notch off the matrix may occur for companies that have liquidity that we judge as "less than adequate" or "weak" under our criteria, or companies with "satisfactory" or better business risk profiles that have extreme debt burdens due to leveraged buyouts or other reasons. For government-related entities (GREs), the indicated rating would apply to the standalone credit profile, before giving any credit for potential government support.

Ratings Detail (As Of May 16, 2013)

Public Service Enterprise Group Inc.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock	BBB-
Corporate Credit Ratings History	
23-Apr-2013	BBB+/Stable/A-2
11-Apr-2011	BBB/Positive/A-2
22-Jun-2007	BBB/Stable/A-2

Ratings Detail (As Of May 16, 2013) (cont.)	
Related Entities	
PSE&G Capital Trust I	
Issuer Credit Rating	BBB/Positive/--
PSE&G Fuel Corp.	
Issuer Credit Rating	--/--/A-2
Public Service Electric & Gas Co.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock	BBB-
Senior Secured	A
Senior Secured	A/A-2
Senior Secured	A/Stable
Senior Secured	AA-/Stable

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

10.3% RETURN ON EQUITY SUPPORT

QUESTION:
Schedule SS-ES-2 specifies a 10.3 percent rate of return on equity for use in the cost recovery mechanism. Please state whether PSE&G believes that 10.3 percent is, at this time, a reasonable estimate of (a) PSE&G's cost of equity; and (b) the PSE&G Energy Strong Program cost of equity. If the Company believes that 10.3 percent is a reasonable estimate for (a) or (b) at this time, please provide the supporting documentation (including any quantitative studies) for that conclusion. If not, then please state what PSE&G believes the cost of equity is at this time for (a) and (b), and provide the supporting evidence and documentation.

ANSWER:
Yes, PSE&G believes that 10.3 percent is, at this time, a reasonable estimate of the cost of equity for both PSE&G and the PSE&G Energy Strong Program. Please see the Rebuttal Testimony of Paul R. Moul dated February 4, 2013 in BPU Docket No. EO 12080721 for the supporting documentation and quantitative studies. Mr. Moul presented his analysis that supported his conclusion that 10.3 percent is reasonable. He states on page 40 of his testimony:

> "Based upon the application of a variety of methods and models described previously, it is my opinion that the reasonable cost of common equity is 10.875% for the Company. My cost of equity recommendation is obtained from a range of results and is at the midpoint of the top half of the range in recognition of the effectiveness of the Company's management in the provision of high quality service, and the demonstrated commitment to the energetic embrace of the State's clearly-stated energy policies. This study shows that the 10.3% equity return obtained from the settlement of the Company's last base rate case is reasonable…."

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

COST RECOVERY RISK

QUESTION:
Please provide a complete description of the cost recovery risks that PSE&G is accepting under its Energy Strong Program cost recovery mechanism.

ANSWER:
Under the Energy Strong Program cost recovery mechanism PSE&G risks failing to recover its costs should any expenditures be found to be imprudent. Program costs would be subject to a focused review of all associated revenue requirement components including, but not limited to, expenses, investments, and capital costs for the approved Program. These focused reviews would be conducted on an annual basis—more frequently than typically done on the Company's other capital expenditures. PSE&G further faces the risks associated with any delay in the cost recovery.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CURRENT AFUDC CALCULATION

QUESTION:
Please provide PSE&G's current AFUDC rate and a workpaper showing its calculation. As part of the response, please verify that PSE&G employs the "FERC method," i.e., short-term debt is directly assigned to construction work in progress ("CWIP") for AFUDC rate purposes, and PSE&G's WACC is included to the extent CWIP exceeds short-term debt.

ANSWER:
The Company uses the FERC approved formula for calculating AFUDC. The current AFUDC debt rate is 2.46%, the current AFUDC equity rate is 5.16%, with the total AFUDC rate at 7.62%. Please see the following page for the detailed calculation.

PSE&G
AFUDC Rate Calculation for Electric & Gas Distribution

			Jul-2013
S	Average short-term debt	Current year -Actual data w hen available, estimates for remainder	56,429,167
s	Short-term debt interest rate	Current year -Actual data w hen available, estimates for remainder	0.26%
D	Long-term debt	Actual book balance as of the end of the prior year	4,794,386,731
d	Long-term debt interest rate	Weighted average cost (per section 35.13) as of the end of prior year	5.29%
P	Preferred stock	Actual book balance as of the end of the prior year	-
p	Preferred stock cost rate	Weighted average cost (per section 35.13)	0.00%
C	Common equity	Actual book balance as of the end of the prior year	5,181,160,173
c	Common equity cost rate	Per latest rate case ruling	10.30%
W	Average CWIP balance	Current year -Actual data w hen available, estimates for remainder	1,559,980,237

Borrowed funds:	
s (S/W) + d*[D / (D+P+C)] * (1 - S/W)	
s	0.26%
(S / W)	0.036173
s (S / W)	0.000094
d	5.29%
D / (D+P+C)	0.480614
d*[D / (D+P+C)]	0.025424
(1 - S / W)	0.963827
s (S/W) + d*[D / (D+P+C)] * (1 - S/W)	**2.4599%**
Other Funds: (Equity Portion)	
(1- S/W) * {p [P / (D+P+C)] + c [C / (D+P+C)]}	
(1- S/W)	0.963827
p	0.00%
P / (D+P+C)	0.000000
p [P / (D+P+C)]	0.000000
c	10.30%
C / (D+P+C)	0.519386
c [C / (D+P+C)]	0.053497
(1- S/W) * {p [P / (D+P+C)] + c [C / (D+P+C)]}	**5.1562%**
Gross AFUDC Calculated Rate	**7.62%**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PUBLIC ISSUANCES OF COMMON STOCK

QUESTION:
Please identify all public issuances of common stock by PSE&G during the past five years, indicating number of shares, dollar proceeds, and issuance expense. (Please exclude routine, ongoing programs such as dividend reinvestments, optional stock purchases, etc.)

ANSWER:
There have not been any public issuances of common stock by PSE&G nor PSEG during the past five years.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMMON STOCK ISSUANCE

QUESTION:
Please state PSE&G's plans for a common stock issuance during the next three years.

ANSWER:
Neither PSEG nor PSE&G have any plans on issuing common stock during the next three years.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER DEPOSITS

QUESTION:
Schedule SS-ES-2 shows that customer deposits as zero percent of total capitalization.
(a) What percent of total capitalization was accounted for by customer deposits in the Company's last rate case and approved WACC?
(b) Why is customer deposits set at zero in this case?

ANSWER:
Schedule SS-ES-2 illustrates PSE&G's capitalization structure as defined by the Stipulation and Board Orders in Docket No. GR09050422, dated June 7, 2010 for electric and dated July 9, for gas.

(a) In the Company's filing, the Company included 1.01% of Customer Deposits in its Capital Structure. The Table below illustrates the Company's filed Capital Structure from its last base rate case with the Stipulated return on equity.

	Percent		**Embedded Cost**		**Weighted Cost**
Long-Term Debt	47.79%		6.14%		2.93%
Preferred Stock	0.00%		0.00%		0.00%
Customer Deposits	1.01%		0.43%		0.00%
Common Equity	51.20%		10.30%		5.27%
Total	100.00%				8.21%

(b) Customer deposits are not set at zero and are included in the line item labeled "Other Capital" on Schedule SS-ES-2.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

OTHER CAPITAL

QUESTION:
Schedule SS-ES-2 shows the cost of "Other Capital" at 6.0172 percent.

(a) Please provide a schedule or workpaper showing how that figure was calculated, including the date that cost rate reflects.

(b) The response to RCR-ROR-3 indicates an embedded cost rate for long-term debt of 4.93 percent at June 30, 2013. Please explain the Company's position regarding why the current cost rate for long-term debt should not be used rather than the less current cost rate of 6.0172 percent for the Energy Strong WACC. If the Company opposes updating the cost rate of long-term debt in these dockets, please explain why.

ANSWER:

(a) The 6.0172% after-tax weighted cost for "Other Capital" was back-solved based on the stipulated capital structure components listed in the Stipulation and Board Orders in Docket No. GR09050422, dated June 7, 2010 for electric and dated July 9, for gas. At page 6 of the Stipulation, the Parties agreed to the following:

> The undersigned parties agree that an appropriate return on common equity for this Settlement is 10.3%. The undersigned parties agree that an appropriate overall rate of return based upon a return on common equity of 10.3% is 8.21% with a 51.2% common equity component.

Based on this agreement:

1. The "Other Capital" (non-common equity) comprises 48.80% (100.00-51.20).
2. The After-Tax Weighted Cost of the Common Equity is 5.2736% (51.2*10.3%)
3. Subtracting the After-Tax Weighted Cost of the Common Equity from the stipulated overall rate of return (8.21-5.2736) leaves the After-Tax Weighted Cost of the Other Capital of 2.9364.
4. Dividing the After-Tax Weighted Cost of the Other Capital of 2.9364 by 48.80 equals 6.0172, which is the cost of "Other Capital."

(b) The Company has filed the proposed WACC as part of a comprehensive Energy Strong proposal. Upon approval of the Energy Strong proposal, the Company will seek to issue long-term debt at various points in the construction period. The embedded cost of debt provided in response to RCR-ROR-3 reflects recent issuances with their respective rates that were at historical lows. The Company does not anticipate this trend continuing during the Energy Strong construction period and considers the comprehensive WACC that was approved in the Company's last base case and proposed for the Energy Strong Program is appropriate. In addition, as stated in the testimony of Stephen Swetz:

> Any change in the WACC ordered by the Board in a subsequent electric, gas, or combined base rate case will be reflected in subsequent monthly revenue requirement calculations following the date of the corresponding written Board Order.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PRUDENCY DISALLOWANCE FOR INFRASTRUCTURE, ENERGY EFFICIENCY AND RENEWABLE PROGRAMS

QUESTION:
The response to RCR-ROR-10 states that under the proposed Energy Strong cost recovery mechanism the Company is subject to risks associated with a prudence disallowance. Please identify any and all costs for which PSE&G has been denied recovery by the Board due to an imprudence finding associated with its tracker mechanisms for infrastructure investment, energy efficiency and renewable resources.

ANSWER:
The Company has not been denied recovery of any costs as a result of an imprudence finding associated with its tracker mechanisms for infrastructure investment, energy efficiency and renewable resources. However, the Company is always at risk for an imprudence disallowance in the future cost recovery filing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

COST RECOVERY MECHANISM

QUESTION:
The response to RCR-ROR-10 states that under the proposed Energy Strong cost recovery mechanism the Company is exposed to risk due to a possible “delay in the cost recovery”. Please explain in detail how the cost recovery mechanism proposed by the Company for its Energy Strong investments would result in denial of cost recovery or failure to recover costs due to “delay”. Also, is the referenced “delay” associated with Board action, or is there some other source? Please explain.

ANSWER:
The Energy Strong cost recovery mechanism includes a provision to true-up over/under collection of costs. A delay in commencing the true-up results in a delay in monetizing the deferred expenditures. To the extent the recoverable cost of financing the deferred expenditures is non-compensatory (e.g., the WACC set in the then latest base rate case is of itself not indicative of the company’s current cost of money) a delay in monetizing an under collection will result in the Company not fully recovering the financing costs associated with the Energy Strong expenditures during the delay.

In addition, rating agencies count on the predictability of a company’s cash flow in establishing its rating, which in turn impacts its financing costs. A delay in monetizing an over/under collection impacts the predictability of the Company’s cash flow.

The reference to delay was associated with a delay by the Board in rendering a decision to reset Energy Strong rates beyond what would be reasonably expected.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

UPDATING THE WACC

QUESTION:
Please provide the Company's position or recommendation concerning the potential updating of the WACC during the life of the Energy Strong tracker cost recovery mechanism. This would cover the debt cost rate, the return on equity and capital structure ratios. As part of the response, please state how frequently the WACC should be updated and the regulatory mechanism or procedure for implementing any updates.

ANSWER:
As described on page 3 of the Revised Direct Testimony of Stephen Swetz, the Company proposes to use its Board approved weighted average cost of capital (WACC) for the Energy Strong Program from the last base rate case. The Company proposes to change the WACC for the Energy Strong Program if the Company's WACC is changed by the Board in a subsequent corresponding electric, gas or combined rate case. Any change in the Company's WACC ordered by the Board will be reflected in the subsequent monthly revenue requirement calculations following the date of the corresponding written Board Order.

APARTMENT AND OFFICE BUILDING
ASSOCIATION OF
METROPOLITAN WASHINGTON

July 31, 2013

By Federal Express and Electronic Filing

Joel H. Peck, Clerk
Virginia State Corporation Commission
Document Control Center
Tyler Building-First Floor
1300 E. Main Street
Richmond, VA 23219

Re: **Application of Virginia Electric and Power Company**
For a 2013 biennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to §56-585.1 A of the Code of Virginia
Case No. PUE–2013-00020

Dear Mr. Peck:

Enclosed is the Direct Testimony of Matthew I. Kahal on behalf of the Apartment and Office Building Association of Metropolitan Washington.

An extra copy of the Direct Testimony of Matthew I. Kahal and a self addressed stamped envelope are also enclosed. Please stamp the extra copy and return it to me.

Thank you for your attention in this matter.

Sincerely,

Frann G. Francis

Frann G. Francis
Senior Vice President & General Counsel

cc: All Parties of Record

1050 17th Street, NW, Washington, DC 20036
Phone: 202-296-3390 • Fax: 202-296-3399 • Email: webmaster@aoba-metro.org
URL: http://www.aoba-metro.org

CERTIFICATE OF SERVICE
Case No. PUE–2013-00020

I hereby certify on this 31st day of July, 2013, that true copies of the foregoing Direct Testimony of Matthew I. Kahal on behalf of the Apartment and Office Building Association of Metropolitan Washington were sent by United States First Class Mail, postage prepaid or hand-delivered to all parties on the Service List for this proceeding listed below:

Clerk of the Commission; **William H. Baxter, II, Esquire, Lisa S. Booth, Esquire, Charlotte P. McAfee, Esquire** and **Mark O. Webb,** Dominion Resources Services, 120 Tredegar Street, Law Dept., Richmond, Virginia 23219; **Joseph K. Reid, III, Esquire, Kristian Dahl, Esquire** and **Elaine S. Ryan, Esquire,** McGuire Woods LLP, One James Center, 901 East Cary Street, Richmond, Virginia 23219; **C. Meade Browder, Jr.,** Office of the Attorney General, Division of Consumer Counsel, 900 East Main Street, Second Floor, Richmond, Virginia 23219; **Louis R. Monacell, Esquire, Edward L. Petrini, Esquire and James G. Ritter, Esquire,** Christian & Barton LLP, 909 E Main Street, Suite 1200, Richmond, Virginia 23219; **Ellen M. Evans, Esquire and Stephen D. Tobin, Esquire**, Office of General Counsel, Department of Navy, 720 Kennon Street, SE, Bldg 36, Room 233, Washington Navy Yard, DC 20374; **Carrie M. Harris, Esquire,** Spilman Thomas & Battle, PLLC, 310 First Street, Suite 1100, Roanoke, Virginia 24002; **Derrick P. Williamson, Esquire,** Spilman Thomas & Battle, PPLC, 1100 Bent Creek Blvd, Suite 101, Mechanicsburg, PA 17050; **R. B. Ball, Esquire and Robert F. Riley, Esquire,** Williams Mullen, 200 S 10th Street, Suite 1600, Richmond, Virginia 23219; **Donald J. Sipe, Esquire and Peter W. Brown, Esquire,** Preti, Flaherty, Beliveau & Pachios LLP, 45 Memorial Circle, P.O. Box 1058, Augusta, Maine 04332-1058; **Kay Davoodi,** Director of Utilities Rates/Studies Office, Naval Facilities Engineering, Command Headquarters, 1322 Patterson Avenue, SE, Suite 1000, Washington Navy Yard, DC 20374-5065; **Irene A. Kowalczyk,** Director, Energy Policy & Supply, MeadWestvaco Corp., 299 Park Avenue, 13th Floor, New York, New York 10171; **Kevin O'Donnell,** Nova Energy Consultants, 1350 SE Maynard Road, Suite 101, Cary, North Caroline 27511; **Robert A. Weishaar, Jr., Esquire and Andrew S. Ziegler, Esquire,** McNees Wallace & Nurick LLC, 777 N Capitol Street, NE, Suite 401, Washington, DC 20002-4292; **Kurt J. Boehm, Esquire and Jody K. Cohn, Esquire,** Boehm, Kurtz & Lowry, 36 E 7th Street, Suite 1510, Cincinnati, Ohio 45202; **Kevin M. Goldberg, Esquire,** Fletcher, Heald & Hildreth, P.L.C., 1300 17th Street N Floor 11, Arlington, Virginia 22209; **Nancy F. Loftus, Esquire and Marilyn S. McHugh, Esquire,**

Office of Fairfax County Attorney, 12000 Government Center Parkway, Suite 549, Fairfax, Virginia 22035; **Keith Townsend, Esquire,** Apartment and Office Building Association of Metropolitan Washington, 1050 17th Street, NW, Suite 300, Washington, DC 20036; **Bruce R. Oliver,** Revilo Hill Associates, Inc., 7103 Laketree Drive, Fairfax Station, Virginia 22039; **Caleb A. Jaffe, Esquire, Frank Rambo, Esquire, and Angela Navarro, Esquire,** Southern Environmental Law Center, 201 W Street, Suite 14, Charlottesville, Virginia 22902; **Timothy B. Hyland, Esquire,** Ifrah, PLLC, 1717 Pennsylvania Avenue, N.W., Suite 650, Washington, D.C. 20006, and **William H. Chambliss, Andrea B. Macgill, Alisson O. Pouille** and **K. B. Clowers**, Commission's Office of General Counsel, 1300 East Main Street, Richmond, VA 23219; **Commission Division of Energy Regulation**, 1300 East Main Street, Richmond, VA 23219; **Commission Division of Economics and Finance**, 1300 East Main Street, Richmond, VA 23219; and the **Commission Division of Public Utility Accounting**, 1300 East Main Street, Richmond, VA 23219.

Frann G. Francis

Frann G. Francis, Esquire

COMMONWEALTH OF VIRGINIA

BEFORE THE

STATE CORPORATION COMMISSION

APPLICATION OF VIRGINIA	)	
ELECTRIC AND POWER COMPANY	)	
FOR A 2013 BIENNIAL REVIEW OF	)	
THE RATES, TERMS AND	)	
CONDITIONS FOR THE PROVISION	)	**CASE NO. PUE-2013-00020**
OF GENERATION, DISTRIBUTION	)	
AND TRANSMISSION SERVICES,	)	
PURSUANT TO §56-585.A OF THE	)	
CODE OF VIRGINIA	)	

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF

APARTMENT AND OFFICE BUILDING ASSOCIATION OF METROPOLITAN WASHINGTON

JULY 31, 2013

TABLE OF CONTENTS

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 Apartment and Office Building Association of Metropolitan Washington ("AOBA"). I have offices in Charlottesville, Virginia and Columbia, Maryland.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

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

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

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

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

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

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

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

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

A. Since 2001,1 have worked on a variety of consulting assignments pertaining to electric restructuring, purchase power contracts, environmental compliance, 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 Maryland Public Service Commission, the Maine Public Advocate, Maryland Department of Natural Resources, the Maryland Energy Administration, and MCI.

II. OVERVIEW

A. Recommendation Summary

Q. WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY IN THIS CASE?

A. I am submitting testimony on behalf of AOBA concerning the fair rate of return for the Company. This includes both a review of the Company's proposal concerning rate of return and the preparation of an independent study of the market cost of common equity. I have also reviewed information filed by the Company concerning its operating efficiencies and service quality and how, in the Company's view, this supports its rate of return request.

This case is the Commission's 2013 biennial review of the earnings and rates of Virginia Electric and Power Company, d/b/a Dominion Virginia Power ("DVP" or "the Company"). The review covers the combined calendar year 2011 and 2012 test periods.

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

A. The Company's rate of return proposal in this case, as shown on Schedule 8, is 8.608 percent. This is based on an end-of-test period capital structure (including a 13-month average for short-term debt) and a return on common equity ("ROE") of 11.5 percent. The proposed capital structure includes 39.9 percent long-term debt, 2.85 percent short-term debt, 1.5 percent preferred stock, 0.1 percent JDITC and 55.6 percent common equity. The ROE recommendation is supported by Mr. Robert Hevert, the Company's cost of equity consultant, who identifies a range of 10.5 to 11.5 percent and recommends the adoption of the 11.5 percent upper end. This is supplemented by Company witness Alexander Bailey's "Peer Group" earnings analysis and finding of 10.74 percent. In addition, Company witnesses Christian and Barker present extensive data on the Company's efficiency and service quality performance in recent years, and they rely on that information as a basis for awarding DVP the upper end of Mr. Hevert's asserted market cost of equity range. Company witnesses, particularly Mr. Hevert, Mr. Barker, and Mr. Koonce, also emphasize the large capital spending program as further reason for selecting a return at the higher end of the range.

Q. HAVE COMPANY WITNESSES PROPOSED A SPECIFIC INCREMENT TO THE COMPANY'S COST OF EQUITY ADDER OR BONUS FOR THE ASSERTED SUPERIOR PERFORMANCE?

A. No, they have not proposed or identified a specific performance bonus. Rather, the claim of superior performance is used as an argument for this Commission to adopt the upper end of Mr. Hevert's ROE range rather than his midpoint (11.0 percent) or Mr. Bailey's asserted minimum Peer Group ROE of 10.74 percent.

Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME?

A. As shown on my Schedule MIK-1, I am recommending an overall fair rate of return range of 7.77 to 7.88 percent, inclusive of an ROE range of 10.0 to 10.2 percent. This rate of return incorporates the Company's identified end-of-test period capital structure (including a 13-month average balance of short-term debt) and embedded cost rates for debt and preferred stock. In my opinion, this capital structure is overly expensive, but it does approximately comport with the Commission's decision on this issue in the previous biennial review case in 2011. For that reason, I include this capital structure in my rate of return presentation, but I do not necessarily endorse it as reasonable.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE COMPANY'S CAPITAL STRUCTURE?

A. Yes, I have two recommendations. First, if the Commission adopts DVP's proposed capital structure, it should take into account that DVP's capital structure is overly expensive when considering the appropriate ROE award within the range of cost of equity evidence. Second, I recommend that the Commission issue a finding that the Company's end-of-test period capital structure is unnecessarily expensive and that a more prudent capital structure would move toward that of Mr. Hevert's proxy group average, i.e., roughly 50 percent debt and 50 percent equity. Doing so would likely provide a very large savings for retail customers without restricting the Company's access to capital on reasonable terms.

Q. HOW DID YOU DEVELOP YOUR ROE RECOMMENDATION?

A. I conducted conventional discounted cash flow ("DCF") and Capital Asset Pricing Model ("CAPM") studies using an electric utility proxy group very similar to that of Company Witness Hevert. The DCF study produced a range of 8.4 to 9.4 percent, with a midpoint of 8.9 percent. Using the CAPM as a check on my DCF study, I obtained a range of about 7.0 to 9.0 percent. Thus, I conclude that even the upper bound market cost of equity for DVP at this time is significantly less than 10 percent.

Next, and as required by Virginia statute, I conducted a "Peer Group" analysis of the earned ROE during 2010-2012 for electric utilities in the southeast region of the U.S. Following procedures mandated by statute, I obtained a range of 10.0 to 10.2 percent. Since the "Peer Group" earnings analysis produces the required minimum authorized return on equity, the 10.0 to 10.2 percent range serves as my ROE recommendation in this case. This 10.0 to 10.2 percent range is at least a small premium over even the upper bound for the estimated proxy group cost of equity.

Q. DOES YOUR ROE RECOMMENDATION INCORPORATE A PERFORMANCE BONUS OR PENALTY?

A. No, it does not, for several reasons. First, I note that the Company has not requested a specific ROE performance bonus, instead requesting the top end of Mr. Hevert's proposed market cost of equity range. My ROE recommendation in this case already exceeds the top end of my market cost of capital range. Second, an ROE bonus would be particularly inappropriate due to DVP's unnecessarily expensive capital structure which benefits shareholders and penalizes customers. My overall rate of return recommendation which uses that expensive capital structure already provides the appropriate balance. Third, no such bonus was awarded by the Commission in the previous biennial review case, and no compelling evidence has been provided in this case that would warrant a change to that decision. That is, while DVP witnesses do document some meaningful accomplishments (such as improved reliability by certain measures), there is no clear-cut demonstration of a substantial and overall improvement in the most recent two-year combined test period as compared to the previous (i.e., 2009/2010) test period. While Company metrics show positives by certain measures, by other measures material improvement did not occur.

I recommend that the Commission not incorporate in this case an explicit quantitative ROE bonus adjustment for managerial performance over and above the 10.0 to 10.2 percent range. An ROE in that range is already well above the cost of equity, and a higher return is not warranted.

Q. WHAT RETURN ON EQUITY DID THE COMMISSION AWARD DVP IN THE 2011 BIENNIAL REVIEW?

A. In that case, the Commission awarded DVP 10.9 percent. This return consists of a market cost of equity of 10.4 percent – the upper end of the market cost of equity range identified by the Commission – plus 0.5 percent for a renewable energy portfolio adjustment. The 10.4 percent was roughly confirmed by the Commission's Peer Group earned ROE findings in that case (for the three years ending 2010). Due to recent legislative changes in Virginia, the renewable portfolio ROE adder no longer is applicable. Thus, on an "apples-to-apples" basis, my 10.0 to 10.2 percent recommendation is reasonably close to the Commission's 10.4 percent in the last case. By comparison, the Company seeks a large *increase* to 11.5 percent. It seeks this large increase even though the market cost of capital has declined since the 2011 decision.

Q. WHAT IS THE BASIS OF MR. HEVERT'S 10.5 TO 11.5 PERCENT RANGE FOR THE MARKET COST OF EQUITY?

A. As I discuss later in my testimony, there is no objective basis for the 10.5 to 11.5 percent cost of equity range. Mr. Hevert employs the DCF method, variants of the CAPM, and a risk premium econometric model. Utilizing his DCF results based on "mean" (rather than extreme high or low) earnings growth rates and his CAPM/risk premium results that reflect current (as opposed to possible future) market conditions, he obtains cost of equity results of about 10.25 to 10.75 percent, not 10.5 to 11.5 percent. Even these results are before recognizing that DVP clearly is less risky than his electric utility proxy group.

I later demonstrate why his actual 10.25 to 10.75 percent cost of equity range is unrealistic and overstated.

Q. IS MR. HEVERT'S COST OF EQUITY RANGE CONSISTENT WITH THE COMMISSION'S FINDING IN THE PREVIOUS CASE IN 2011?

A. No. The cost of equity has declined - - at least modestly - - since 2011. Mr. Hevert's range of 10.5 to 11.5 percent greatly exceeds the Commission's cost of equity range of 9.4 to 10.4 percent, or 110 basis points higher. My range of 10.0 to 10.2 percent is slightly lower than the Commission's 10.4 percent (excluding the no longer applicable renewable portfolio bonus adder). This is consistent with trends in markets since 2011.

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

A. Yes, very much so. DVP provides monopoly utility service in its Virginia service territory, subject to this Commission's regulatory oversight. DVP is generally rated low-single A by credit rating agencies, which is indicative of both its low business risk profile and its favorable credit metrics. The Company benefits from both a strong service territory and supportive Virginia regulation. While Company witnesses Hevert, Barker, and Koonce emphasize large capital needs going forward, there is no reason to believe that DVP will encounter any undue difficulty in raising debt or equity capital on reasonable terms. Section III of my testimony discusses the risk attributes of DVP (and its parent), emphasizing the views of credit rating agencies.

B. Capital Cost Trends in Recent Years

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

A. Yes. I show the capital cost trends since 2002, through calendar year 2012, on page 1 of Schedule MIK-1. Pages 2, 3 and 4 of that Schedule show monthly data for January 2007 through June 2013. The indicators provided include the annualized inflation rate (as measured by the Consumer Price Index), 10-year Treasury yields, 3-month Treasury bill yields and Moody's single A and triple B yields on long-term utility bonds. While there is some fluctuation, these data series show a general declining trend in capital costs. For example, in the very early part of this 10-year period, utility bond yields averaged about 7 to 8 percent, with 10-year Treasury yields of 4 to 5 percent. By 2011, single A utility bond yields had fallen to an average of 5.1 percent, with 10-year Treasury yields declining to an average of 2.8 percent. Within the past year (i.e., calendar 2012 into early 2013), Treasury and utility long-term bond rates have declined even further to near or below the lowest levels in many 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.[1] The Fed has also sought to exert downward pressure on long-term interest rates through its policy of "quantitative easing." Quantitative easing is a policy whereby the Fed engages on an ongoing basis in the purchase of financial assets (such as Treasury bonds or agency mortgage backed debt), both to support the market prices of financial assets and to increase the U.S. money supply. The intent of quantitative easing is to keep the cost of capital low (which increases the value of financial assets such as utility stocks) and make credit both cheaper and more abundant. Although that program ended in the summer of 2012, the Fed announced in September 2012 a continuation of its near zero short-term interest rate policy at least through 2015, and an indefinite continuation of quantitative easing. In its December 12, 2012 meeting, the Fed stated that its low interest rate and accommodative policies would continue at least until a much lower U.S. unemployment rate is achieved (i.e., a target of 6.5 percent), an endeavor which is expected to take several years. As a result, interest rates have remained low and have trended down and, for at least an extended period of time, this very low short- and long-term interest rate and cost of capital environment is expected to continue.

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

A. Yes. Information on Fed policy is from its press release issued on January 30, 2013 following a meeting of the Federal Open Market Committee ("FOMC," the monetary policy decision-making forum for the Fed). That statement affirmed that for the foreseeable future its "highly accommodative" policy will continue until progress toward "maximum employment" is achieved. Specifically, the Fed will continue its near zero

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

short-term interest rate policy and will foster lower long-term interest rates by asset purchases, namely $85 billion per month of incremental purchases of mortgage-backed securities and long-term Treasury bonds. The FOMC further stated that an accommodative monetary policy "will remain appropriate for a considerable time after the asset purchase program ends and the economic recovery strengthens." In addition, the FOMC observes that inflation trends have been running below its 2 percent per year target level and that "long-term inflation expectations remain stable." The FOMC's policy outlook, as described above, was broadly confirmed in a press release following its May 1, 2013 meeting, noting that the Fed will carefully monitor economic conditions and labor markets.

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, along with the Fed's asset purchase program. 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, as the FOMC recently noted.

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

A. In a very general sense and over time, that is normally the case, although the utility cost of equity and cost of debt need not move together precisely in lock step or necessarily in the short run. The economic forces mentioned above (and Fed policy) that lead to lower interest rates also tend to exert downward pressure on the utility cost of equity. After all, many investors tend to view utility stocks and bonds as alternative investment vehicles for portfolio allocation purposes, and in that sense utility stocks and long-term bonds are 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), July 10, 2013 edition, which is a survey compilation of approximately 40 major forecast organizations. The "consensus" calls for real GDP growth of 1.8 percent in 2013 and 2.7 percent in 2014 and inflation (GDP deflator) of 1.5 percent and 1.8 percent in 2013 and 2014, respectively. The March 2013 edition of Blue Chip publishes a consensus 10-year inflation forecast of 2.1 percent per year, only slightly higher than the near term. Thus, both the near- and long-term economic outlooks are indicative of modest economic growth and low inflation, implying low market capital costs.

Q. HAS THE PATTERN BEEN SIMILAR FOR EQUITY MARKETS?

A. As one would expect, equity markets exhibit more volatility than bond markets. Following the onset of the financial crisis about four years ago, stock market indices plunged, reaching a bottom in March 2009. Since then, stock prices recovered impressively and the major indices have largely recovered to or above 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 with the debt ceiling crisis. 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 the latter part of 2011. Since 2011, i.e., during most of 2012 and year-to-date 2013, U.S. equity markets have done quite well. This very noticeable improvement is clearly due to the very low and declining capital market environment (both in the U.S. and globally), relative economic stability (albeit with very tepid economic growth, and the tendency for investors to view the U.S. market as a "safe haven" for investing. In particular, the U.S. provides a very favorable capital cost environment for good quality utilities, such as DVP.

Q. HASN'T THERE BEEN A MAJOR CHANGE IN THE INTEREST RATE ENVIRONMENT?

A. Yes, there has been a noticeable change in the long-term bond market behavior in the last two months. This appears to be based on the perceptions of some investors that Fed policy within the next year may become less "accommodative," (i.e., a reduction in the size of the Fed's quantitative easing program) and U.S. economic growth may accelerate. This has resulted, for example, in yields on ten-year Treasuries increasing from slightly less than 2 percent earlier this year to about 2.5 percent as of this writing in late July 2013. Of course, neither the less aggressive Fed accommodation nor accelerating U.S. economic growth has yet to take place. Although the upward interest rate move is significant, long-term rates remain at historically very low levels. More importantly for this case, equity markets have continued to do quite well even with the recent upward interest rate movement.

The market cost of capital, both for DVP and in general, remains extremely low by historical standards and even low compared to 2011 when the last biennial review took place. That was a time period of higher interest rates and capital market turmoil.

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

A. Yes. Specifically, I present DCF evidence that relies on utility stock market data from the six months ending June 2013. Such market data directly incorporate the economic forces, monetary policy choices, and market behavior described above. The use of a recent six months of market data is reasonable for assessing DVP's current cost of capital as it reflects recent market and economic trends.

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

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

A. Section III of my testimony presents my discussion of the capital structure issues and DVP's 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. This section also presents my "Peer Group" earnings analysis, as required by Virginia statute. Section V is my review and critique of Mr. Hevert's cost of equity studies. Section VI presents my review of the DVP performance, service quality, and rates comparison information.

III. CAPITAL STRUCTURE AND DVP'S RISK

A. Comments on Proposed Capital Structure

Q. WHAT IS YOUR CONCERN IN THIS CASE REGARDING DVP'S CAPITAL STRUCTURE?

A. DVP is using for ratemaking purposes its end-of-test period capital structure which includes a 13-month average of short-term debt. This capital structure is unnecessarily expensive, as it contains an excessive amount of common equity. As the Commission is aware, common equity is far more expensive than debt, and its cost must be "grossed up" for federal and state income taxes. The Company's capital structure is far more equity laden than that of witness Hevert's proxy group, and there is no testimony demonstrating that the proposed capital structure is prudent, necessary, or beneficial to customers.

A further problem is that DVP's capital structure differs rather dramatically from that of Dominion Resources on a consolidated basis. Using balance sheets from Dominion's 2012 SEC 10-K annual report, the table below provides the Dominion versus DVP comparison at December 31, 2012:

Dominion Resources vs. DVP Capitalization at December 31, 2012
(million $)

	Dominion		DVP	
	Balance	%	Balance	%
LT Debt	$16,851	52.06	$6,251	36.45
ST Debt	2,412	7.45	992	5.78
Debt due w/in 1 year	2,223	6.87	418	2.44
Preferred	257	0.79	257	1.50
Common Equity	10,625	32.83	9,233	53.83
	$32,368	100%	$17,151	100%

Source: Dominion Resources, SEC 10-K, pages 56 and 64.

Please note that the above capital structure for DVP is somewhat different than the ratemaking capital structure proposed in this case, with almost the entire difference due to short-term debt. The ratemaking capital structure employs the 13-month average which is much smaller than the actual December 31, 2012 balance. The use of the 13-month balance increases the common equity ratio from 53.8 to 55.6 percent.

The Dominion versus DVP comparison is striking. In particular, DVP accounts for about 87 percent of Dominion's consolidated common equity but only 36 percent of Dominion's consolidated debt. This is disturbing because it indicates that the non-DVP portion of Dominion (including the non-regulated portion) is financed in a far more leveraged manner. It would be far more equitable if Dominion were to increase its equity ratio while DVP reduces its equity ratio to a level far more typical of an electric utility.

Q. CAN DOMINION'S RELATIVELY WEAK CAPITAL STRUCTURE HARM DVP?

A. Yes, potentially it can. For example, the credit rating agency Standard & Poors ("S&P") bases DVP's credit ratings on the consolidated credit profile of Dominion. Hence, DVP's credit rating is impacted by Dominion's relatively weak consolidated capital structure, and the Company's ratepayers do not benefit from the very expensive capital structure embedded in rates.

Q. PLEASE COMPARE DVP'S RATEMAKING CAPITAL STRUCTURE WITH THAT OF THE ELECTRIC UTILITY PROXY GROUP.

A. On Schedule MIK-3, I show an average proxy group capital structure of 51.9 percent, but this excludes short-term debt and debt maturing within one year. To be consistent with DVP's capital structure in this case (which includes short-term debt), the proxy group equity ratio averages 48.1 percent. I note that Mr. Hevert's cost of equity study and recommendation give no recognition of DVP's much thicker equity ratio.

Q. WOULD A CAPITAL STRUCTURE MORE IN LINE WITH THE PROXY GROUP AVERAGE PROVIDE CUSTOMERS WITH COST SAVINGS?

A. Yes, it would. If DVP moved to a more reasonable capital structure with, say, 50 percent common equity, there would be a substantial reduction to the Company's revenue requirement. DVP's equity would be reduced by about $900 million (and debt increased correspondingly), reducing the cost of capital. At present, DVP's authorized return on equity is 10.9 percent, but this increases to approximately 17 percent when an income tax gross up is included. This compares to a utility cost of debt of about 5 percent – a cost rate savings of roughly 12 percent per year on 5 percent of capitalization and rate base.

DVP's relatively expensive capital structure is a cost pass-through to captive customers, and it benefits shareholders by enhancing Dominion parent's credit quality and risk profile.

Q. IN LIGHT OF THIS PROBLEM, WHAT DO YOU RECOMMEND?

A. Assuming the Commission accepts the use of the actual end-of-test period capital structure in this case, I recommend that the Commission consider this expensive capital structure in setting the DVP authorized return on equity. The high equity ratio does improve DVP's investment risk, and it therefore lowers the Company's cost of equity. Second, I recommend that the Commission encourage DVP to move over time to a less expensive capital structure, for example, one more in line with that of Mr. Hevert's proxy group. This would provide substantial savings for ratepayers while preserving reasonable credit quality. More of the equity cost burden should be borne by the remainder of Dominion Resources.

B. <u>Risk and Credit Quality</u>

Q. HAVE YOU REVIEWED THE COMPANY'S CREDIT RATING REPORTS?

A. Yes, the Company (and Dominion parent) are rated by S&P, Moody's Investors Service ("Moody's"), and FitchRatings. All three agencies rate DVP's unsecured debt to be low single A. Based on my review of these reports, all three agencies are in substantial agreement concerning DVP's investment risk attributes.

Q. HOW DOES S&P VIEW DOMINION AND DVP?

A. S&P's February 22, 2013 report for Dominion summarizes the ratings strengths and weaknesses. As noted earlier, S&P states that it bases its DVP ratings on the credit quality of the consolidated Dominion. S&P considers DVP's business risk profile to be "excellent." The report states that DVP's "service territory is attractive, with a large residential and commercial segment, above-average economic activity centered on the Northern Virginia area, and regulatory risk that is much lower than average." (Report, page 2.) The credit rating weaknesses identified by S&P are those associated with the unregulated side, particularly merchant generation. "We view the merchant generation as the most risky part of Dominion." (Report, page 3.) S&P concludes that, "The utility operations are viewed as having low operating risk." (Report, page 6.)

Q. DOES S&P ADDRESS THE ISSUE RAISED IN THIS CASE OF CAPITAL SPENDING?

A. Yes. S&P indicates that Dominion (and, of course, DVP) has good access to capital and banking. One of the rating strengths is that capital spending "is concentrated on the low-risk utility side." (Report, page 2.) In other words, S&P sees large capital spending on the merchant power side as problematic, but not (or not as much) the utility side.

Q. WHAT IS MOODY'S ASSESSMENT?

A. Moody's is similar in many respects to S&P except that it rates Dominion separately from DVP. While it rates DVP's unsecured debt as A(3), it rates parent Dominion's unsecured debt Baa(2), which is two notches lower due to its higher risk. As with S&P, Moody's expresses concern with the riskiness of the Dominion merchant generation business. Moody's also expresses concern that Dominion's debt/capitalization ratio "is already high for the ratings category." In its January 6, 2013 report for DVP, Moody's emphasizes the Company's very supportive regulatory environments in Virginia and North Carolina as the reason for the favorable credit rating. Moody's takes note of DVP's large capital spending plan but states that such expenditures will be supported by load growth and responsive regulatory treatment.

Q. IS FITCHRATINGS' ASSESSMENT SIMILAR?

A. Yes. FitchRatings discusses the same attributes and reaches similar conclusions. Its January 2013 report states that DVP's credit ratings "are supported by the low risk nature of its regulated utility operations, which deliver predictable cash flow metrics due largely to balanced regulatory treatment." (Report, page 1.) Then FitchRatings discusses the capital spending outlook stating that, "The growth plan is supported by positive demographic trends within the utility service territory." (*Id.*) The report anticipates that capital spending will be supported by debt issues, when needed, and regulatory treatment. FitchRatings views DVP as having adequate liquidity and manageable debt refinancing needs going forward.

Q. DVP HAS A LARGE CAPITAL SPENDING PLAN. DOES IT HAVE ADEQUATE ACCESS TO CAPITAL ON REASONABLE TERMS GOING FORWARD?

A. Yes, very much so, as confirmed by the credit rating reports. DVP has strong and stable credit ratings, as discussed above, and adequate bank credit agreements to provide short-term liquidity. DVP obtains new external equity, when needed, through its parent. Dominion has raised its per share dividend every year since 2003, and is projected by Value Line to keep increasing the dividend through 2018. Dominion can raise new equity for DVP, if needed, through its dividend reinvestment and optional stock purchase plans and through public issuances, if needed. Dominion's stock price is nearly three times its book value per share which makes it attractive to issue new stock, if needed to fund capital spending. Value Line's May 24, 2013 edition indicates only a modest need for new external equity over the next five years, with common shares outstanding through 2018 expected to increase by less than 1 percent per year.

In summary, DVP's capital spending plan, while substantial, seems manageable with adequate sources of liquidity and debt/equity capital available on reasonable terms, as needed. This cannot serve as a basis for requesting an unusually high rate of return in this case.

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 Commission 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.

Virginia statute requires and allows for additional considerations in setting the electric utility fair rate of return. In addition to the market cost of equity, the authorized ROE must not be lower than the average earned return of a "Peer Group" of Southeast region electric utilities meeting certain criteria. This is discussed later in this section of my testimony. In addition, the Commission at its discretion may award or penalize the Company by up to plus or minus 100 basis points, based on its consideration of customer service, generating plant performance, and operating efficiency. The Commission in the 2011 case declined to approve either an ROE bonus or penalty.

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

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

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

A. Witness Hevert's studies purport to estimate the market-based cost of capital. However, I disagree with certain of his data inputs, as well as his risk premium study. I also note that his recommended ROE is not supported by his study results, as explained in Section V.

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

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

Q. PLEASE DESCRIBE THE DCF MODEL.

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

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

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

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

K_e = cost of equity;

Do = the current annualized dividend;

Po = stock price at the current time; and

g = the long-term annualized dividend growth rate.

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

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly-traded companies, i.e., companies whose market prices (and therefore market valuations) are transparently revealed. Consequently, the model cannot be applied to DVP, which is a wholly-owned subsidiary of Dominion Resources parent, and therefore, a market proxy is needed. In theory, Dominion parent could serve as that market proxy, and I have included it as a member of my electric 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 far more reliable than a single company study. This is because there is "noise" or fluctuations in stock price or other data that cannot always be readily accounted for in a simple DCF study. The use of an appropriate and robust proxy group helps to allow such "data anomalies" to cancel out in the averaging process.

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

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

A. I have reviewed Mr. Hevert's group of eleven vertically-integrated electric companies, and I find his group to be generally acceptable in this case as a cost of equity proxy for DVP. Hence, I have accepted all eleven companies. In addition, I have added DVP's parent, Dominion Resources, thereby obtaining a final group of twelve proxy companies. I believe that using essentially the same companies as Mr. Hevert makes it easier to compare our respective DCF studies, without company selection issues or disagreements clouding the comparisons.

I must note that even though I use almost the same proxy group as Mr. Hevert, this does not mean that I believe DVP has the same investment risk as the proxy group average. In fact, I believe that DVP is, on average, somewhat less risky than this group. Schedule MIK-3 presents risk indicators for all twelve proxy companies. This information suggests that DVP's parent is somewhat less risky than the group, despite Dominion's relatively risky unregulated merchant generation exposure. Also, this schedule does not show DVP's 56 percent common equity ratio compared to a group average ratio of 48.1 percent.

Despite the indications of DVP's lower than average risk, I propose no downward risk adjustment to my cost of equity analysis. Mr. Hevert's testimony fails to present a risk comparison between DVP and the proxy companies, other than discussing capital spending. For this reason, his cost of equity study results should be viewed as overstating DVP's cost of equity.

B. DCF Study Using the Electric Utility Proxy Group

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

A. I have elected to use a six-month time period to measure the dividend yield component (Do/Po) of the DCF formula. Using the Standard & Poor's *Stock Guide*, I compiled the month-ending dividend yields for the six months ending June 2013, the most recent data available to me as of this writing. This covers the first two calendar quarters of 2013. As a general matter, this six months has been a time period of an improving stock market, although less so for utilities than the broader markets.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, January - June 2013. Over this six-month period the proxy group average dividend yields indicate a generally stable pattern for the group. During January through April, yields gradually declined, to a low of 3.56 percent, and in May and June, yields increased, perhaps due to rising long-term interest rates. By June 2013 (month end), yields for the group had risen to 3.99 percent. In this case, I am using the six-month average of 3.82 percent.

Q. IS 3.82 PERCENT YOUR FINAL DIVIDEND YIELD?

A. Not quite. Strictly speaking, the dividend yield used in the model should be the value the investor expects to receive over the next 12 months. Using the standard "half year" growth rate adjustment technique, the DCF adjusted yield becomes 3.9 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 reported 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 late 2012 to early 2013, i.e., roughly six to nine months 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 somewhat volatile and are not necessarily reliable as prospective measures. I note that Mr. Hevert does not rely upon historical growth rates as an indicator of long-term growth for his proxy companies for DCF purposes. The DCF growth rate should be prospective, and one useful source of information on prospective growth is the projections of earnings per share growth rates (typically five years) prepared by securities analysts and reported in public surveys. It appears that Mr. Hevert places exclusive weight on this information for his DCF studies, and while I agree that it warrants substantial emphasis, it should not be relied upon exclusively.

Q. PLEASE DESCRIBE THE ANALYST EARNINGS GROWTH RATE EVIDENCE.

A. Schedule MIK-4, page 3 presents five available and well-known public sources of analyst earnings growth rate projections. Four of these five sources – YahooFinance, 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 2010-2012 compared to the annual average for the forecast period of 2016-2018. These are very similar to the sources used by Mr. Hevert for securities analyst growth rates in his DCF studies, although Mr. Hevert uses just three sources.

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, 5.5 percent for YahooFinance, 5.2 percent for MSNMoney, 5.5 percent for Reuters and 6.8 percent for Value Line. Please note that Value Line's average is distorted by one aberrant observation – a 21.5 percent growth rate for Otter Tail. Removing the Otter Tail observation, the Value Line average becomes 5.5 percent – similar to the other four sources. Thus, the range of growth rates among the five sources is 5.0 to 5.5 percent. The average of these five sources is 5.3 percent (or 5.6 percent with Otter Tail), and I have used these results (along with other evidence) in obtaining a reasonable range growth range for the group of 4.5 to 5.5 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 twelve proxy companies tend to be somewhat less (on average) than analyst growth projections. For the twelve companies, projected dividend growth averages 5.2 percent, book value growth averages 3.8 percent, and earnings retention growth averages 3.9 percent.

Some analysts and regulators favor the use of earnings retention growth (often referred to as "sustainable growth"), which Value Line indicates to be 3.9 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 twelve companies of the growth rate (through 2016-2018) 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 five companies, the external growth rate calculated in this manner averages about 0.6 percent. The sum of "internal" or earnings retention growth (i.e., 3.9 percent) and the "external" growth rate (i.e., 0.6 percent) is 4.5 percent.

Given this estimate of 4.5 percent for the sustainable growth rate and 5.3 percent (or 5.6 percent if the Value Line figure for Otter Tail is retained) for analyst earnings projections, a reasonable DCF growth rate range is approximately 4.5 to 5.5 percent.

Q. WHAT IS YOUR DCF CONCLUSION?

A. I summarize my DCF analysis on page 1 of Schedule MIK-4. The adjusted dividend yield for the six months ending June 2013 is 3.9 percent for this group. Available evidence would support a long-run growth rate in the range of approximately 4.5 to 5.5 percent, as explained above. Summing the adjusted yield, growth rate range produces a total return of 8.4 to 9.4 percent, and a midpoint result of 8.9 percent. Reliance on analyst earnings projections (Mr. Hevert's preferred method) 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 8.9 PERCENT DCF MIDPOINT COMPARE TO MR. HEVERT'S DCF ESTIMATE FOR HIS PROXY GROUP?

A. Mr. Hevert reports a series of DCF estimates of about 10.75 percent using his midpoint growth rates (i.e., the average of his three sources). I explain in Section V why I believe his results are overstated.

C. The CAPM Analysis

Q. PLEASE DESCRIBE THE CAPM MODEL.

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

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

The CAPM formula is:

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

K_e =the firm's cost of equity

R_m =the expected return on the overall market

R_f =the yield on the risk free asset

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

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

While the beta itself also is "observable," different investor services provide differing calculations of betas depending on the specific procedures and methods that they use. These differences can potentially have large impacts on the CAPM results. In this case, the betas that Mr. Hevert and I use are essentially identical, with Mr. Hevert's ranging from 0.71 to 0.72.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. For purposes of my CAPM analysis, I have used a long-term (i.e., 30-year) Treasury yield as the risk-free return (as has Mr. Hevert) along with the average beta for the electric utility proxy group, i.e., 0.72. (See Schedule MIK-3 for the company-by-company betas.) In the last six months, long-term (i.e., 30-year) Treasury yields have averaged approximately 3.1 percent, and the recent Value Line betas for my distribution utility proxy group average 0.72. However, given the interest rate increases in recent weeks, I have used 3.25 percent instead of the six-month average. I note that Mr. Hevert has elected to use a risk-free rate in his studies that range from 3.12 to 3.25 percent. He also employs a very speculative 5.1 percent which is improper and far out of line with present market conditions. 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 0.72 and an equity risk premium of 5 percent.

$$K_e = 3.25\% + 0.72\ (5.0\%) = 6.9\%$$

The upper-end estimate uses a risk-free rate of 3.25 percent, a proxy group beta of 0.72 and an equity risk premium of 8.0 percent.

$$K_e = 3.25\% + 0.72\ (8.0\%) = 9.0\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 6.9 to 9.0 percent, with a midpoint of 8.0 percent. The CAPM analysis produces a midpoint result significantly lower than the range of results obtained for my electric utility group DCF analysis, but I have not placed reliance on the CAPM returns in formulating my 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 uncertainty regarding monetary policy. These market conditions make it difficult to assess equity risk premiums at this time. I read Mr. Hevert's testimony as expressing similar concerns regarding reliance on the CAPM for setting the authorized ROE.

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

A. For his CAPM study, Mr. Hevert has selected a market risk premium range of 6.03 to 9.88 (average of about 7.94 percent) percent. In conjunction with the Value Line utility beta of 0.72 (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:

$$K_e = 3.25\% + 0.72\ (7.94\%) = 9.0\%$$

While I view Mr. Hevert's 9.88 percent high end market risk premium estimate as unrealistic and excessive, given current data on long-term Treasury yields and electric utility betas (from Value Line), the CAPM using even this relatively high equity risk premium value produces a cost of equity of 10.36 percent. This is well below the Company's request of 11.5 percent and close to my range of 10.0 to 10.2 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 9.5 to 10.5 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.

Q. DO YOU HAVE A SOURCE FOR THAT RANGE?

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

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

I would note that Mr. Hevert's 7.94 percent risk premium midpoint exceeds the upper end of that range. My "midpoint" risk premium of roughly 6.5 percent falls well within that range.

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

D. Peer Group Earnings Analysis

Q. HOW HAS MR. BAILEY CONDUCTED HIS PEER GROUP EARNINGS ANALYSIS?

A. For the Peer Group earnings study, Mr. Bailey cites to the parameters for company inclusion under Va. Code §56-585.1 A 2 a and b, as follows:

(1) The utility must report its earnings data to the Securities and Exchange Commission ("SEC") for the three-year benchmark period (in this case, 2010 – 2012).

(2) Principal operations for the utility must be east of the Mississippi River in the Southeast U.S., south of Virginia but excluding Tennessee.

(3) The electric utility must be vertically-integrated and state regulated.

(4) The electric utility must have at least a Baa rating.

(5) The electric utility must not be a corporate affiliate of the Virginia utility undergoing the rate review.

Using these criteria, Mr. Bailey identified twelve qualifying Peer Group companies, and he reports their average earned ROEs for 2010 – 2012 on his Schedule 3. Again, following the statute, he removes the two lowest ROE companies and the two highest ROE companies, leaving eight companies in the Peer Group.

Q. WHAT IS THE AVERAGE REPORTED ROE FOR THIS GROUP OF EIGHT?

A. Using the data on Schedule 3, I calculate this to be 10.46 percent.

Q. IS THIS THE FIGURE THAT MR. BAILEY REPORTS?

A. No. Mr. Bailey goes further and identifies four companies which, because of certain events that occurred during 2010 – 2012, he considers to be "outliers." He argues that the Commission has the discretion to delete these four companies. It turns out that for two of these companies the discretionary elimination is moot due to the fact that they are already removed because they are among the two lowest or two highest ROE companies that must be automatically removed. Consequently, his "anomalous company" analysis results in only two companies being removed – Entergy Mississippi (10.06 percent) and Progress Energy Carolinas (9.15 percent).

After these two "anomalous" removals, the Peer Group average increases from 10.46 percent to 10.74 percent.

Q. DOES MR. BAILEY'S ANALYSIS AFFECT THE COMPANY'S ROE REQUEST IN THIS CASE?

A. No, not directly. The Company's request is for 11.5 percent, which is the upper end of Mr. Hevert's market cost of equity recommended range. The 10.74 percent is unrelated to Mr. Hevert's recommendation. The 10.74 percent only becomes relevant – as a claimed ROE award floor – if Mr. Hevert's recommended range is not accepted by the Commission.

Q. DO YOU SEE MERIT IN MR. BAILEY'S ANOMALY ADJUSTMENT TO THE PEER GROUP?

A. While I agree with Mr. Bailey that the Commission has the discretion to define and limit the Peer Group, his two incremental deletions in this case are improper. They are one-sided because they go only in the direction of *increasing* the ROE floor. Moreover, such deletions must be done with considerable care because it suggests the need to comprehensively scrutinize three years of earnings for every included Peer Group company to determine if its earnings truly are "normal" *in every year* and do not reflect abnormal or "anomalous" circumstances. This would be an impractical task. For example, he includes Georgia Power with its 12.36 percent earnings. What assurance do we have that this reflects that company's "normal" profitability?

In this case, he eliminated two qualifying companies whose earnings average about 9.6 percent. This rate of return is not highly unusual or anomalous, and it is well within (or even above) the range of evidence on the market cost of equity in this case. In fact, it is Mr. Bailey himself who urges restraint in selectively removing companies, noting that "it is the Company's general position and operating presumption that the use of all remaining peer utilities will best fulfill the purpose of the statute…." (Testimony, page 6.) The quote then goes on to state that the alleged earnings anomaly in this case justifies a departure from the Company's "general position."

In my opinion, there is insufficient reason to delete these two companies since the reported earnings fall very close to or within a reasonable ROE range. The proposed deletions are one-sided and only serve to bias the analysis against customers.

Q. ARE THERE ANY OTHER ISSUES RAISED IN MR. BAILEY'S STUDY?

A. Yes, there are two other issues. As he discusses in his testimony, he eliminates Appalachian Power Company ("APCo") on the grounds that it is "primarily" a Virginia utility even though it also operates in Tennessee (at wholesale) and West Virginia. This proposed decision was a debated issue in the 2011 case with proponents of retaining APCo noting that the majority of its asset base is located in West Virginia. Mr. Bailey's only two substantive arguments are that APCo serves more customers in Virginia than West Virginia and the *sum* of MWh sales in Virginia plus Tennessee exceed those in West Virginia. He is careful not to claim that Virginia accounts for the majority of APCo's MWh sales. In its 2011 Decision (at footnote 20), the Commission noted the dispute among the parties but did not specifically rule on the issue.

The second issue is that Mr. Bailey includes Entergy Gulf States, L.L.C. ("EGSL") as a qualifying utility even though this company was rejected in the Commission's 2011 Order. (See page 19 of that Order.) Specifically, the Commission questioned whether EGSL operated primarily east of the Mississippi River, stating that DVP failed to provide any evidence. Mr. Bailey also presents no such supporting evidence concerning EGSL in his testimony here.

Q. WHAT IS YOUR POSITION ON THESE TWO ISSUES?

A. Mr. Bailey has not shown clearly that APCo is "primarily" a Virginia utility, and therefore I believe the Commission should err on the side of inclusiveness in this case. However, I also note that this is a disputed issue, and therefore I present my Peer Group ROE results both with and without APCo to obtain a range.

EGSL should *not* be included in the Peer Group since there is no evidence whatsoever presented by the Company that it operates primarily east of the Mississippi River. Also, the Commission previously deleted EGSL.

Q. ARE YOU FAMILIAR WITH EGSL?

A. Yes, I have dealt extensively with that company. While it is true that EGSL serves much of the Baton Rouge metropolitan area, which is on the east bank of the River, most of its service territory and power supply system are to the west of the River. EGSL has a sprawling service area that extends along the southern part of Louisiana to approximately the Texas border. In fact, a very large portion of EGSL's power supply comes from two major Texas power plants, Sabine and Lewis Creek. It also has extensive power supply (generation and transmission) located in Louisiana, west of the River.

Unfortunately, EGSL does not to my knowledge publish its operating data on an east versus west of the River basis. Given this lack of information, coupled with my understanding of EGSL's extensive service territory, and the Commission's 2011 decision on this question, EGSL should not be included in the Peer Group.

Q. PLEASE SUMMARIZE YOUR PEER GROUP ANALYSIS.

A. I present my Peer Group earnings on my Schedule MIK-6. This is the same as Mr. Bailey's presentation (and I use his earnings data), but with two changes. I present the Peer Group with APCo, and I exclude EGSL. Also, in computing the Peer Group average, I did not remove the two companies that Mr. Bailey claimed to be anomalous.

My Peer Group average does, of course, delete the two lowest and two highest ROEs as required by statute, resulting in an eight-company average of 10.01 percent. This average embodies a range of ROEs of 8.80 to 10.86 percent which is approximately consistent with or higher than my market cost of equity estimates.

As a second analysis, I delete APCo, which produces a seven-company ROE average of 10.19 percent and a range of 9.15 percent to 10.86 percent.

The Peer Group ROE average under Virginia statute determines the ROE floor. A reasonable analysis would produce a range of 10.0 to 10.2 percent, with the higher figure being the Company's position on APCo. I recommend the Commission consider this range. Since both 10.0 and 10.2 percent are well above DVP's market cost of equity, I recommend that the Commission in this case authorize an ROE in this range and no higher than 10.2 percent.

V. REPLY TO WITNESS HEVERT

A. Overview of Mr. Hevert's Recommendation

Q. MR. HEVERT IDENTIFIES A COST OF EQUITY RANGE OF 10.5 TO 11.5 PERCENT AND AN AWARD OF 11.5 PERCENT. HOW DID HE DEVELOP THAT RECOMMENDATION FOR DVP?

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

He presents a number of different cost of equity estimation calculations using each method. He presents 18 DCF calculations with results ranging from 8.80 to 13.19 percent based on differing time periods for measuring share prices (i.e., average for 30, 90 or 180 days) and based on using low, average (mean) or high earnings growth rates. He presents 18 CAPM calculations using differing risk-free rates (30-year Treasury bond yields), betas and market risk premium values, with results ranging from 7.42 to 12.20 percent. Finally, he presents his three Risk Premium calculations which range from 10.23 to 10.76 percent, based on three different interest rate assumptions.

Mr. Hevert discusses in some detail one other factor that appears to play a role in his recommendation for DVP – the Company's large capital spending plan. Exactly how this affects his recommendation and cost of equity finding is unclear from his testimony. He does not quantify a cost of equity adjustment to the proxy group cost of equity for this risk factor.

Q. CAN YOU SUMMARIZE HIS QUANTITATIVE RESULTS?

A. Yes. Since Mr. Hevert presents nearly 40 separate cost of equity calculations, it is necessary to distill down his results in order to determine whether his studies can support a range of 10.5 to 11.5 percent.

First, while Mr. Hevert provides high, mean and low DCF calculations, the high and low figures are based on the highest and lowest of three securities analyst growth rate forecasts. The mean is the average of the three. The only way to make sense of his results is to focus on his reported "mean" growth rate result, and I believe that is what he intended. This produces a relatively narrow DCF range of 10.60 to 10.86 percent, averaging about 10.75 percent for the proxy group.

Second, both the CAPM and Risk Premium studies use three different Treasury bond yields: 3.12 percent (actual); 3.25 percent (near-term projected); and 5.10 percent (projected future long-term). The 5.10 percent is merely a speculative forecast of where Treasury yields might go at some unspecified time in the future. While this forecast eventually could turn out to be right or wrong (no one knows), it has nothing whatsoever to do with investor market requirements in 2013 and for this biennial review. At best, it is an expectation (speculative at that) of the cost of capital that may prevail in some future biennial review. Hence, one can only make sense of Mr. Hevert's results if the CAPM and Risk Premium results based on the 3.12 and 3.25 percent Treasury yields are used. Mr. Hevert will have the opportunity to update, if market conditions warrant.

Using the two "reality-based" Treasury yields, Mr. Hevert's CAPM calculations average 9.33 percent, and his Risk Premium averages 10.24 percent. In summary, focusing on the "mean" DCF results and disregarding the speculative future year Treasury yield of 5.1 percent (which is unrelated to a 2013 rate review), his results are:

DCF	10.75%
CAPM	9.33
Risk Premium	10.24
Average	10.11%

These results are consistent with my recommendation of 10.0 to 10.2 percent, but they fail to support his range of 10.5 to 11.5 percent, let alone his 11.5 percent recommendation.

B. Mr. Hevert's DCF Study

Q. MR. HEVERT OBTAINED, ON AVERAGE, MUCH HIGHER DCF RESULTS THAN YOU OBTAINED. WHY?

A. Given that Mr. Hevert and I use essentially the same proxy group and very similar data sources, there are only three factors that explain our differences:

(1) Dividend yield timing. To calculate the dividend yield, Mr. Hevert uses 30, 90 and 180 trading days ending February 15, 2013, whereas I use six months ending June 2013. My more recent data produces a dividend yield that is roughly 0.2 percent lower.

(2) Growth rate methodology. I employ *both* security analyst projections and the sustainable growth rate to obtain a range, recognizing the limitations of both methods. Mr. Hevert uses security analyst projections exclusively. For discussion purposes in this section, I therefore compare only our respective DCF studies based on the security analyst projections of earnings growth.

(3) Problems with Value Line. Mr. Hevert's growth rate analysis is distorted by his use of Value Line projections of earnings growth for one company – Otter Tail Corporation, which has a 24 percent growth rate. That one extraordinary figure distorts his entire study and should have been removed.

Q. PLEASE EXPLAIN FURTHER THE VALUE LINE GROWTH RATE ISSUE.

A. Due primarily to the Otter Tail 24 percent growth rate (a figure that is obviously unusable for DCF purposes), Mr. Hevert obtains a group average growth rate from Value Line of 8.05 percent. This is averaged in with his two other growth rate sources to obtain an overall average of 6.5 percent. Had Mr. Hevert merely chosen to remove the Otter Tail figure, his Value Line average would fall to 6.5 percent, and his three-source overall average would be 5.9 percent.

Please further note that Value Line projections have declined in recent months, aside from the Otter Tail issue. I show on page 3 of my Schedule MIK-4 that the Value Line proxy group average absent Otter Tail now has become 5.5 percent. Importantly, this makes Value Line consistent with all other earnings growth rate sources that both Mr. Hevert and I have used. All of the other growth rate sources produce proxy group averages in the 5 to 6 percent range, as shown on page 3 of Schedule MIK-4.

I have used a securities analyst growth rate of 5.5 percent in my DCF study. If Mr. Hevert would remove the Otter Tail Value Line figure and update, he would obtain results essentially the same as my upper bound – a DCF estimate in the mid 9s, and certainly below 10 percent.

Q. DOES MR. HEVERT OBJECT TO REMOVING THE OTTER TAIL FIGURE?

A. No. In fact, he has done exactly that in a pending rate case in New Jersey (Atlantic City Electric Company, BPU Docket No. ER12121071). In that case, he used an almost identical proxy group as in this case, including Otter Tail. However, in that case he deleted the extraordinary Otter Tail Value Line growth rate figure from his DCF study, and he acknowledged this deletion in his testimony (page 14) in that case. Notably, in that case he supported an ROE recommendation of 10.25 percent compared to his 11.5 percent in this case.

C. **<u>Mr. Hevert's CAPM Study</u>**

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

A. Yes. I have already commented on his calculations based on a hypothetical future 5.1 percent Treasury yield, a figure which simply has no place in a 2013 rate proceeding. I will not comment further on that, but I do have one other concern. Mr. Hevert employs three measures of the market risk premium, with two being about 9.8 percent. The

9.8 percent equity risk premium value is unrealistically high and well beyond the plausible range that I identified of 5 to 8 percent.

Q. HOW DID MR. HEVERT OBTAIN THE 9.8 PERCENT MARKET RISK PREMIUM?

A. Mr. Hevert uses two approaches to the stock market risk premium: the *ex ante* method which produces the 9.8 percent figure, and the *ex poste* of 6.0 percent. Part of the problem is that gives two-thirds weight to the much higher *ex ante* measure. Had he given the two methods equal weight, his average risk premium would be about 8 percent, which is high but consistent with the upper end of my risk premium range.

The 9.8 percent risk premium is based on two DCF studies of the S&P 500 conducted by Mr. Hevert. These studies produced an S&P 500 market rate of return of 13 percent, and since the S&P 500 dividend yield is about 2 percent, his study embodies a long-term sustainable growth rate of about 11 percent.

Both the 13 percent market rate of return and the 11 percent long-term growth rate are unrealistically high. For example, YahooFinance publishes an S&P 500 earnings growth rate (from the securities analyst survey) of 9.39 percent. This implies a DCF estimate for the S&P 500 of about 11.5 percent and a risk premium today of about 8 percent. While even 8 percent is quite high, it is consistent with the upper end of my range.

In any event, both Mr. Hevert and I obtain CAPM results that are well below my recommended range of 10.0 to 10.2 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:

$$RP = -0.0294 \ln (x) - 0.0308 \quad R^2 = 0.69$$

Thus, at recent Treasury yields of 3.25 percent, his model indicates a risk premium of about 7.0%:

$$RP = -0.0294 \ln (0.0325) - 0.0308 = 6.99\%$$

Adding back the 3.25 percent Treasury yield, produces a cost of equity of 10.24 percent.

Mr. Hevert, however, did not only use a Treasury yield of 3.25 percent, but he also assumed Treasury bond yields would spike to 5.1 percent. Using his assumption of sharply higher capital costs in the future, he obtains an alternative risk premium cost of equity of 10.78 percent. While this conceivably could occur sometime in the future, it has nothing to do with today's cost of equity for DVP.

Q. IS THIS MODEL SPECIFICALLY APPLICABLE TO DVP?

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 ROE award. The model is not in any way designed to be applicable to DVP, which has much less risk than the average electric utility.

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 numerous 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 market 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 bond yields *cause* changes in the equity risk premium. Absent a convincing and rigorously developed explanatory 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.

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

A. No. The model is actually designed to "explain" or predict state utility commission behavior rather than estimating today's market cost of equity. However, Mr. Hevert's 10.24 percent ROE estimate from his model, while certainly above DVP's market cost of equity, is reasonably close to my recommended 10.0 to 10.2 percent range.

VI. PERFORMANCE INDICATORS

Q. WHAT ROLE DO PERFORMANCE INDICATORS PLAY IN THIS PROCEEDING?

A. The Company presents testimony by Mr. Christian on DVP historical generator performance and compares the Company's performance to that of broader groups. Mr. Barker presents trend information on service quality, customer rate comparisons and O&M expense. These witnesses use this information to argue that DVP's performance is (a) generally favorable relative to other utilities; and/or (b) is improving over time. The Company's filed case is vague, as it does not request a specific, quantified ROE performance bonus. Rather, the Company uses these testimony presentations to help support Mr. Hevert's recommended 11.5 percent ROE, which he allegedly bases on his cost of equity study results.

Q. DID THE COMMISSION ADDRESS THE ISSUE OF A PERFORMANCE BONUS IN THE 2011 BIENNIAL REVIEW?

A. Yes. At pages 22-23 of the 2011 Order, the Commission declined to approve either a positive or negative incentive adjustment to its ROE finding in that case. The Commission stated that a rulemaking proceeding would be initiated to develop "workable criteria" for evaluating performance. The Commission's January 11, 2013 Order in PUE-2012-00021 developed rules and regulations to implement the Performance Incentive authorized by § 56-585.1 A 2 c of the Code of Virginia ("Code").

Q. DID THE VIRGINIA ASSEMBLY ADDRESS THE ISSUE OF A PERFORMANCE BONUS IN THE 2013 LEGISLATIVE SESSION?

A. Yes. The Virginia General Assembly amended and reenacted §§ 56-585.1 and 56-585.2 of the Code of Virginia with the approval of H 2261, which became effective on February

14, 2013, and revised the criteria for Commission approval of a performance bonus adjustment to the ROE.

Q. AFTER REVIEWING THE INFORMATION PRESENTED BY WITNESSES CHRISTIAN AND BARKER, WHAT IS YOUR ASSESSMENT?

A. My review is based upon the Company's witnesses direct testimony filed on March 28, 2013. These witnesses present information intended to highlight the Company's positive attributes and accomplishments. While much of this information appears to be favorable, it does not in all cases demonstrate tangible progress or outstanding performance.

Q. CAN YOU PROVIDE EXAMPLES?

A. In my review, I focused on the Company's performance during the current test period (i.e., 2011 – 2012) versus the previous test period (i.e., 2009 – 2010). Mr. Barker shows improvement for the customer service quality measures of SAIDI and SAIFI when major storms are excluded, but reduced service quality for 2011/2012 (compared with 2009/2010) when major storms are included.

Mr. Christian compiles various metrics for DVP generating units including forced outage rates, heat rates, production expense, unit availability, nuclear capacity factor and so forth. In some but not all cases, DVP performed better than the comparison groups that he employed. However, as a general matter, the performance metrics for DVP were either weaker or did not materially improve for the 2011/2012 test period as compared to 2009/2010. For example, in the most recent test period, the forced outage rates were slightly higher than the earlier period and unit availability or average capacity factor was weaker. Thus, Mr. Christian's presentation includes a mix of both positive and negative results.

Q. MR. BARKER PRESENTS A RATES COMPARISON USING EEI DATA. DOES THIS SUPPORT A CONCLUSION OF SUPERIOR PERFORMANCE?

A. Again, this is a mixed picture and only partially positive. In fairness to Mr. Barker, his testimony makes an effort to discuss the limitations of all of these metrics and the difficulty of interpreting them as being indicative of Company efficiency and performance. His caveats are certainly appropriate. That said, Mr. Barker presents information showing that DVP's retail rates are below both the national average and the South Atlantic regional average. He also compares DVP's rates with the PJM average, again finding a large advantage for DVP.

Q. PLEASE COMMENT ON MR. BARKER'S RATES COMPARISON FINDINGS.

A. I also believe the rates analysis must be approached with caution to ensure the comparisons are appropriate and meaningful. It is certainly correct that DVP's retail rates are lower than the U.S. and the South Atlantic region averages. However, a critical problem with the comparison is that a major portion of the U.S. (perhaps about a third) and some of the South Atlantic (Maryland, Delaware, and the District of Columbia) operate under retail access regimes and are not regulated, vertically-integrated. Since the retail access states are far more expensive, this distorts the rates comparison. His PJM comparison certainly is not meaningful. Second, even for the U.S. and South Atlantic region, DVP's rates advantage has been diminishing over time.

I have prepared Schedule MIK-7 which compares DVP's total retail rates for each year 2009 – 2012 and for the two most recent test periods with (a) the U.S. average; (b) the South Atlantic region; and (c) the East South Central region. This schedule confirms Mr. Barker's findings for the U.S. and South Atlantic, but it also shows a rates disadvantage as compared to the East South Central region. The South Atlantic (absent the retail access portion of Maryland, Delaware, and the District of Columbia) and the East South Central region together largely coincide with the geographic region used by Mr. Bailey in the Peer Group ROE study. An important conclusion is that DVP's rates are roughly in-line with the average of the combined (non-retail access) South Atlantic and East South Central regions. DVP simply does not have an overall retail rates advantage (nor disadvantage) as compared with this relevant vertically-integrated region.

The following table also illustrates how DVP's rates advantage compares for the last two test periods. Specifically, it shows that some deterioration has taken place. For the U.S. and the South Atlantic (including the retail access portion), DVP's rate advantage has diminished in 2011/2012 compared to 2009/2010. Similarly, for the East South Central region, the DVP rate disadvantage has increased.

DVP's Retail Rate Advantage (or Disadvantage)
vs. Other Regions for 2009/2010 and 2011/2012

Compared to:	2009/2010	2011/2012
U.S.	19.4%	14.1%
South Atlantic	11.1%	6.5%
East South Central	(2.5%)	(5.6%)

Source: Schedule MIK-7.

This presentation illustrates the complexity of the rates comparison issue and places the DVP interregional comparison in its proper perspective.

Q. HOW DO DVP'S RETAIL RATES COMPARE TO AVERAGE RETAIL RATES IN OTHER STATES IN THE SOUTHEAST?

A. The table below lists average retail rates for 2011/2012 in each of the states comprising the South Atlantic and East South Central regions (i.e., the Southeast region east of the Mississippi River), excluding the "retail access" states of Maryland and Delaware. Those two states operate under an entirely different paradigm for electric service and determining retail rates. The group includes nine states in the two regions.

This table shows that DVP is similar to or slightly more expensive than the two regions as a whole. Five states are (on average) less expensive than DVP, one state is about the same, and three states are more expensive. While I do not view this comparison as being particularly negative or adverse for DVP, it certainly does not support a Commission award of an explicit ROE bonus above either the cost of capital or the Peer Group earned ROE for superior management performance.

Total Retail Rates
DVP vs. South Atlantic /
East South Central Regions
(cents/Kwh, 2011-2012 average)

(1) Tennessee	7.02 cents
(2) Kentucky	7.56
(3) Mississippi	7.85
(4) West Virginia	8.29
(5) North Carolina	8.38
(6) South Carolina	8.86
(7) Alabama	9.12
(8) Georgia	9.16
(9) Florida	10.24
Average	**8.50 cents**
Dominion Virginia Power	**8.84 cents**

Source: Edison Electric Institute Typical Bills, Winter 2013 edition.

Q. WHAT DO YOU CONCLUDE?

A. The Company has not requested an explicit ROE bonus, nor is one warranted at this time. My ROE recommendation of 10.0 to 10.2 percent fully compensates DVP shareholders, particularly in light of the Company's very low market cost of equity and its proposal to employ a very expensive 55.6 percent common equity ratio for ratemaking purposes.

Q. HAS THE COMPANY FILED SUPPLEMENTAL AND REVISED DIRECT TESTIMONY IN SUPPORT OF A PERFORMANCE BONUS?

A. On June 28, 2013, the Company filed a Motion for Leave to file supplemental and revised direct testimony on the performance bonus issue. On July 17, 2013, the Company filed supplemental and revised direct testimony in support of its request for a performance bonus. As of this writing, the Commission has not granted the Company's Motion. While I believe that the Company has not demonstrated a convincing basis for Commission approval of a performance bonus, AOBA reserves the right to file additional testimony should the Commission approve the Company's Motion.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF VIRGINIA

BEFORE THE

STATE CORPORATION COMMISSION

APPLICATION OF VIRGINIA	)	
ELECTRIC AND POWER COMPANY	)	
FOR A 2013 BIENNIAL REVIEW OF	)	
THE RATES, TERMS AND	)	
CONDITIONS FOR THE PROVISION	)	**CASE NO. PUE-2013-00020**
OF GENERATION, DISTRIBUTION	)	
AND TRANSMISSION SERVICES,	)	
PURSUANT TO §56-585.A OF THE	)	
CODE OF VIRGINIA	)	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF

APARTMENT AND OFFICE BUILDING ASSOCIATION OF METROPOLITAN WASHINGTON

JULY 31, 2013

DOMINION VIRGINIA POWER

Rate of Return Summary at
December 31, 2012

Capital Type	Balance (Millions $)	% of Total	Cost Rate	Weighted Cost
Long-Term Debt	$6,609.7	39.91%	6.41%	2.089%
Short-Term Debt	471.7	2.85	0.47	0.013
Preferred Stock	252.6	1.53	6.53	0.100
Common Equity	9,212.1	55.62	10.0 - 10.2	5.562-5.673
JDITC	8.7	0.09	7.88	0.007
Total	$16,561.5	100%	--	7.77-7.88%

Source: Company Schedule 8. For return on equity range, see testimony and Schedule MIK-4 and 6.

DOMINION VIRGINIA POWER

Trends in Capital Costs

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield	Baa Utility Yield
2002	1.6%	4.6%	1.6%	7.4%	8.0%
2003	1.9	4.1	1.0	6.6	6.8
2004	2.7	4.3	1.4	6.2	6.4
2005	3.4	4.3	3.0	5.6	5.9
2006	2.5	4.8	4.8	6.1	6.3
2007	2.8	4.6	4.5	6.1	6.3
2008	3.8	3.4	1.6	6.5	7.2
2009	(0.4)	3.2	0.2	6.0	7.1
2010	1.6	3.2	0.1	5.5	6.0
2011	3.1	2.8	0.0	5.0	5.6
2012	2.1	1.8	0.1	4.1	4.9

DOMINION VIRGINIA POWER

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

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield	Baa Utility Yield
2007					
January	2.1%	4.8%	5.1%	6.0%	6.2%
February	2.4	4.7	5.2	5.9	6.1
March	2.8	4.6	5.1	5.9	6.1
April	2.6	4.7	5.0	6.0	6.2
May	2.7	4.8	5.0	6.0	6.2
June	2.7	5.1	5.0	6.3	6.5
July	2.4	5.0	5.0	6.3	6.5
August	2.0	4.7	4.3	6.2	6.5
September	2.8	4.5	4.0	6.2	6.5
October	3.5	4.5	4.0	6.1	6.4
November	4.3	4.2	3.4	6.0	6.3
December	4.1	4.1	3.1	6.2	6.5
2008					
January	4.3%	3.7%	2.8%	6.0%	6.4%
February	4.0	3.7	2.2	6.2	6.6
March	4.0	3.5	1.3	6.2	6.7
April	3.9	3.7	1.3	6.3	6.8
May	4.2	3.9	1.8	6.3	6.8
June	5.0	4.1	1.9	6.4	6.9
July	5.6	4.0	1.7	6.4	7.0
August	5.4	3.9	1.8	6.4	7.0
September	4.9	3.7	1.2	6.5	7.2
October	3.7	3.8	0.7	7.6	8.6
November	1.1	3.5	0.2	7.6	9.0
December	0.1	2.4	0.0	6.5	8.1

DOMINION VIRGINIA POWER

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

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield	Baa Utility Yield
2009					
January	0.0%	2.5%	0.1%	6.4%	7.9%
February	0.2	2.9	0.3	6.3	7.7
March	(0.4)	2.8	0.2	6.4	8.0
April	(0.7)	2.9	0.2	6.5	8.0
May	(1.3)	2.9	0.2	6.5	7.8
June	(1.4)	3.7	0.2	6.2	7.3
July	(2.1)	3.6	0.2	6.0	6.9
August	(1.5)	3.6	0.2	5.7	6.4
September	(1.3)	3.4	0.1	5.5	6.1
October	(0.2)	3.4	0.1	5.6	6.1
November	1.8	3.4	0.1	5.6	6.2
December	2.5	3.6	0.1	5.8	6.3
2010					
January	2.6%	3.7%	0.1%	5.8%	6.2%
February	2.1	3.7	0.1	5.9	6.3
March	2.3	3.7	0.2	5.8	6.2
April	2.2	3.9	0.2	5.8	6.2
May	2.0	3.4	0.2	5.5	6.0
June	1.1	3.2	0.1	5.5	6.0
July	1.2	3.0	0.2	5.3	6.0
August	1.1	2.7	0.2	5.0	5.6
September	1.1	2.7	0.2	5.0	5.5
October	1.2	2.5	0.1	5.1	5.6
November	1.1	2.8	0.1	5.4	5.9
December	1.2	3.3	0.1	5.6	6.0

DOMINION VIRGINIA POWER

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

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield	Baa Utility Yield
2011					
January	1.6%	3.4%	0.1%	5.6%	6.1%
February	2.1	3.6	0.1	5.7	6.1
March	2.7	3.4	0.1	5.6	6.0
April	2.2	3.5	0.1	5.6	6.0
May	3.6	3.2	0.0	5.3	5.7
June	3.6	3.0	0.0	5.3	5.7
July	3.6	3.0	0.0	5.3	5.7
August	3.8	2.3	0.0	4.7	5.2
September	3.9	2.0	0.0	4.5	5.1
October	3.5	2.2	0.0	4.5	5.2
November	3.0	2.0	0.0	4.3	4.9
December	3.0	2.0	0.0	4.3	5.1
2012					
January	2.9%	2.0%	0.0%	4.3%	5.1%
February	2.9	2.0	0.0	4.4	5.0
March	2.7	2.2	0.1	4.5	5.1
April	2.3	2.1	0.1	4.4	5.1
May	1.7	1.8	0.1	4.2	5.0
June	1.7	1.6	0.1	4.1	4.9
July	1.4	1.5	0.1	3.9	4.9
August	1.7	1.7	0.1	4.0	4.9
September	2.0	1.7	0.1	4.0	4.8
October	2.2	1.8	0.1	3.9	4.5
November	1.8	1.7	0.1	3.8	4.4
December	1.7	1.7	0.1	4.0	4.6
2013					
January	1.6%	1.9%	0.1%	4.2%	4.7 %
February	2.0	2.0	0.1	4.2	4.7
March	1.5	2.0	0.1	4.2	4.7
April	1.1	1.8	0.1	4.0	4.5
May	1.4	1.9	0.0	4.2	4.7
June	1.8	2.3	0.1	4.7 (p)	5.2 (p)

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

DOMINION VIRGINIA POWER

Listing of the Electric Utility Delivery Service Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2012 Common Equity Ratio*
1.	Consolidated Edison	1	A+	0.60	54.1%
2.	Centerpoint Energy	2	B++	0.80	34.0
3.	Northeast Utilities	2	B++	0.70	55.4
4.	PHI Holdings	3	B	0.75	52.7
5.	UIL Holdings	2	B++	0.70	41.1
	Average	**2.0**	--	**0.71**	**47.4%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2012 equity ratio including short-term debt and current maturities averages 43.0 percent.

Source: *Value Line Investment Survey*, March 22 and May 24, 2013.

DOMINION VIRGINIA POWER

Listing of the Electric Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2012 Common Equity Ratio*
1.	American Electric Power	3	B++	0.65	49.4%
2.	Cleco Corp.	1	A	0.65	54.4
3.	Empire District	2	B++	0.65	50.9
4.	Great Plains	3	B+	0.80	54.4
5.	Dominion Resources	2	B++	0.65	38.2
6.	Idacorp, Inc.	3	B+	0.70	54.5
7.	Otter Tail Corp.	3	B+	0.90	54.4
8.	Pinnacle West	1	A	0.70	55.4
9.	PNM Resources	3	B	0.95	48.7
10.	Portland General	2	B++	0.75	52.9
11.	Southern Co.	1	A	0.55	47.3
12.	Westar Energy	2	B++	0.75	48.8
	Average	**2.2**	--	**0.72**	**51.9%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). The actual 2012 common equity ratio including short-term debt and current maturities averages 48.1 percent.

Source: *Value Line Investment Survey*, May 3, May 24, and June 21, 2013.

DOMINION VIRGINIA POWER

DCF Summary for the
Electric Utility Proxy Group

1. Dividend Yield (January - June 2013)[1]	3.82%
2. Adjusted Yield ((1) x 1.025)	3.9%
3. Long-Term Growth Rate[2]	4.5 - 5.5%
4. Total Return ((2) + (3))	8.4 - 9.4%
5. Flotation Expense	0.0%
6. Cost of Equity ((4) + (5))	8.4 - 9.4%
7. Midpoint	8.9%
Recommendation[3]	**10.0 to 10.2%**

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(1) Schedule MIK-4, page 2 of 5.
(2) Schedule MIK-4, pages 3 of 5, 4 of 5 and 5 of 5.
(3) Schedule MIK-6.

DOMINION VIRGINIA POWER

Dividend Yields for the Electric Utility Proxy Group
(January - June 2013)

	Company	January	February	March	April	May	June	Average
1.	American Electric Power	4.2%	4.0%	3.9%	3.8%	4.3%	4.5%	4.12%
2.	Cleco Corp	3.2	3.1	2.9	2.9	3.2	3.2	3.08
3.	Empire District	4.7	4.7	4.5	4.3	4.5	4.6	4.55
4.	Great Plains Energy	4.1	4.0	3.8	3.6	3.8	3.9	3.87
5.	Dominion Resources	4.2	4.0	3.9	3.6	3.9	4.1	3.95
6.	IDACORP	3.3	3.3	3.1	3.1	3.2	3.2	3.20
7.	Otter Tail Corp	4.4	4.1	3.8	3.8	4.3	4.4	4.13
8.	Pinnacle West	4.1	3.9	3.8	3.6	3.8	4.1	3.88
9.	PNM Resources	2.7	2.9	2.8	2.7	2.9	3.1	2.85
10.	Portland General	3.7	3.6	3.6	3.3	3.6	3.7	3.58
11.	Southern Company	4.5	4.4	4.2	4.2	4.6	4.7	4.43
12.	Westar Energy	4.3	4.3	4.1	3.9	4.3	4.4	4.22
	Average	**3.95%**	**3.86%**	**3.70%**	**3.56%**	**3.86%**	**3.99%**	**3.82%**

Source: S&P *Stock Guide*, February - July 2013.

DOMINION VIRGINIA POWER

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

	Company	Value Line	Yahoo	MSN	Reuters	CNN	Average
1.	American Electric Power	4.5%	3.84%	3.4%	3.84%	4.50%	4.02%
2.	Cleco Corp	5.5	8.00	8.0	8.00	8.00	7.50
3.	Empire District	5.0	3.00	3.0	3.00	3.00	3.40
4.	Great Plains Energy	6.5	6.26	5.1	6.26	5.00	5.82
5.	Dominion Resources	6.0	7.27	4.6	6.84	3.80	5.70
6.	IDACORP	2.0	4.00	4.0	4.00	4.00	3.60
7.	Otter Tail Corp	21.5	6.00	6.0	6.00	6.00	9.10
8.	Pinnacle West	5.0	6.00	4.1	6.00	4.20	5.06
9.	PNM Resources	12.0	6.43	7.3	6.43	6.15	7.66
10.	Portland General	3.5	5.69	6.5	5.84	6.60	5.63
11.	Southern Company	4.5	4.84	4.8	5.00	5.00	4.83
12.	Westar Energy	6.0	4.83	5.1	4.83	4.00	4.95
	Average	**6.83%**	**5.51%**	**5.16%**	**5.50%**	**5.02%**	**5.61%**
	Adjusted Average*	**5.50%**					**5.29%**

* Average excludes the anomalous Value Line growth rate of 21.5% for Otter Tail.

Sources: *Value Line Investment Survey*, May 3, May 24, and June 21, 2013. YahooFinance.com, MSNMoney.com, CNNMoney.com, Reuters.com, public websites, June 2013.

DOMINION VIRGINIA POWER

Other Value Line Measure of Growth for the
Electric Utility Proxy Group

	Company	Dividend Per Share	Book Value Per Share	Earnings Retention
1.	American Electric Power	4.0%	4.0%	4.0%
2.	Cleco Corp	10.0	5.0	4.5
3.	Empire District	3.5	2.5	2.5
4.	Great Plains Energy	6.0	2.5	3.0
5.	Dominion Resources	5.5	4.5	5.0
6.	IDACORP	7.0	4.5	4.0
7.	Otter Tail Corp	1.5	2.0	4.0
8.	Pinnacle West	2.0	3.5	3.5
9.	PNM Resources	12.5	4.0	4.0
10.	Portland General	3.5	3.5	3.5
11.	Southern Company	3.5	4.0	4.0
12.	Westar Energy	3.0	5.0	4.5
	Average	**5.17%**	**3.75%**	**3.88%**

Source: *Value Line Investment Survey*, June 21, May 3, and May 24, 2013. The earnings retention figures are projections for 2016-2018.

DOMINION VIRGINIA POWER

Fundamental Growth Rate Analysis for the
Electric Utility Proxy Group

		Shares 2012-2017[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	American Electric Power	0.78%	44.6%	0.4%	4.0%	4.4%
2.	Cleco Corp	0.00	81.2	0.0	4.5	4.5
3.	Empire District	1.72	29.3	0.5	2.5	3.0
4.	Great Plains Energy	0.32	3.9	0.1	3.0	3.1
5.	Dominion Resources	0.82	229.5	1.9	5.0	6.9
6.	IDACORP	0.33	37.9	0.1	4.0	4.1
7.	Otter Tail Corp	2.03	94.1	1.9	4.0	5.9
8.	Pinnacle West	0.94	65.5	0.6	3.5	4.1
9.	PNM Resources	0.09	18.6	0.0	4.0	4.0
10.	Portland General	0.31	37.8	0.1	3.5	3.6
11.	Southern Company	0.84	119.4	1.0	4.0	5.0
12.	Westar Energy	1.31	37.6	0.5	4.5	5.0
	Average			**0.6%**	**3.9%**	**4.5%**

(1) Projected growth rate in shares outstanding, 2012-2017.

(2) % Premium of share price ("Recent Price") over 2012 Book Value per share.

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

(4) br is Value Line's projection as of 2016-2018.

Source: *Value Line Investment Survey*, June 21, May 3, and May 24, 2013.

DOMINION VIRGINIA POWER

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% (Approximately long-term Treasury bond yield for the most recent six months, see page 2 of 2)

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

Beta = 0.72 (See Schedule MIK-3.)

C. Model Calculations

Low end: K_e = 3.25% + 0.72 (5.0) = 6.9%

Midpoint: K_e = 3.25% + 0.72 (6.5) = 7.9%

Upper End: K_e = 3.25% + 0.72 (8.0) = 9.0%

High Sensitivity: K_e = 3.25% + 0.72 (9.0) = 9.7%

DOMINION VIRGINIA POWER

Long-Term Treasury Yields
(January – June 2013)

Month	30-Year	20-Year	10-Year
January 2013	2.80	2.39	1.65
February	2.88	2.47	1.72
March	3.08	2.68	1.91
April	3.17	2.78	1.98
May	3.11	2.73	1.93
June	3.40	3.07	2.30
Average	**3.07%**	**2.69%**	**1.92%**

Source: Federal Reserve, "Statistical Release," publication H.15, February – July 2013.

DOMINION VIRGINIA POWER

Peer Group ROE Results
2010-2012

	Electric Utility	Average ROE 2010-2013
1.	Appalachian Power Co.	6.46%
2.	Progress Energy Florida	7.24
3.	South Carolina Electric & Gas Co.	8.80
4.	Progress Energy Carolinas	9.15
5.	Duke Energy Carolinas	9.26
6.	Entergy Mississippi	10.06
7.	Florida Power & Light Co.	10.44
8.	Gulf Power Co.	10.72
9.	Mississippi Power	10.81
10.	Tampa Electric	10.86
11.	Georgia Power Co.	12.36
12.	Alabama Power Co.	13.20
	Average (minus 2 highest and 2 lowest)	**10.01%**
	Average (minus 2 highest , 2 lowest and APCO)	**10.19%**

Source: Company witness Bailey, Schedule 3 Appalachian Power ROE calculated from 2012 SEC Form 10-K (American Electric Power), pages 149-151.

DOMINION VIRGINIA POWER

Total Retail Rate Comparisons, 2009-2012
(¢/kWh)

Year	DVP	U.S.	South Atlantic	East South Central
2009	8.68¢	9.83¢	9.28¢	8.01¢
2010	7.89	9.96	9.14	8.15
Average	8.29¢	9.90¢	9.21¢	8.08¢
2011	9.03	10.09	9.43	8.34
2012	8.64	10.09	9.38	8.29
Average	8.84¢	10.09¢	9.41¢	8.32¢

Source: Edison Electric Institute, *Typical Electric Bills*, 2010-2013 winter editions.

APPENDIX A

QUALIFICATIONS OF MATTHEW I. KAHAL

MATTHEW I. KAHAL

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

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

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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Conference and Workshop Presentations:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Louisiana State Bar Association, Public Utility Section, 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.

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
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

	Docket Number	Utility	Jurisdiction	Client	Subject
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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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)

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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

Expert Testimony
of Matthew I. Kahal

	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
379.	R-2012-2285985 May 2012	Peoples Natural Gas Company	Pennsylvania	Office of Consumer Advocate	Cost of capital

	Docket Number	Utility	Jurisdiction	Client	Subject
380.	U-32153 July 2012	Cleco Power	Louisiana	Commission Staff	Environmental Compliance Plan
381.	U-32435 August 2012	Entergy Gulf States Louisiana LLC	Louisiana	Commission Staff	Cost of equity (gas)
382.	ER-2012-0174 August 2012	Kansas City Power & Light Company	Missouri	U. S. Department of Energy	Rate of return
383.	U-31196 August 2012	Entergy Louisiana/ Entergy Gulf States	Louisiana	Commission Staff	Power Plant Joint Ownership
384.	ER-2012-0175 August 2012	KCP&L Greater Missouri Operations	Missouri	U.S. Department of Energy	Rate of Return
385.	4323 August 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Rate of Return (electric and gas)
386.	D-12-049 October 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Debt issue
387.	GO12070640 October 2012	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of capital
388.	GO12050363 November 2012	South Jersey Gas Company	New Jersey	Rate Counsel	Cost of capital
389.	R-2012-2321748 January 2013	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Cost of capital
390.	U-32220 February 2013	Southwestern Electric Power Co.	Louisiana	Commission Staff	Formula Rate Plan
391.	CV No. 12-1286 February 2013	PPL et al.	Federal District Court	MD Public Service Commission	PJM Market Impacts (deposition)
392.	EL13-48-000 February 2013	BGE, PHI subsidiaries	FERC	Joint Customer Group	Transmission Cost of Equity
393.	EO12080721 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
394.	EO12080726 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
395.	CV12-1286MJG March 2013	PPL, PSEG	U.S. District Court for the District of Md.	Md. Public Service Commission	Capacity Market Issues (trial testimony)
396.	U-32628 April 2013	Entergy Louisiana and Gulf States Louisiana	Louisiana	Staff	Avoided cost methodology
397.	U-32675 June 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	RTO Integration Issues
398.	ER12111052 June 2013	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Cost of capital
399.	PUE-2013-00020 July 2013	Dominion Virginia Power	Virginia	Apartment & Office Building Assoc. of Met. Washington	Cost of capital