STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE GAIL M. COOKSON

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF AN INCREASE IN ELECTRIC AND GAS RATES AND FOR CHANGES IN THE TARIFFS FOR ELECTRIC AND GAS SERVICE, B.P.U.N.J. NO. 16 ELECTRIC AND B.P.U.N.J. NO. 16 GAS, AND FOR CHANGES IN DEPRECIATION RATES, PURSUANT TO N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 AND N.J.S.A. 42:2-21 AND FOR OTHER APPROPRIATE RELIEF	)	**BPU Docket Nos. ER18010029 and GR18010030** **OAL Docket No. PUC 01151-18**

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

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

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

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

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

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

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

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

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

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

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

A. Yes. I have testified on cost of capital and other matters before the Board of Public Utilities ("Board" or "BPU") in gas, water and electric cases during the past 25 years. A listing of those cases is provided in my attached Statement of Qualifications. This includes the submission of testimony on rate of return issues in the recent electric and gas service rate cases of New Jersey Natural Gas Company (BPU Docket No. GR070110889), Elizabethtown Gas (BPU Docket No. GR09030195), Public Service Electric and Gas Company ("PSE&G" or "the Company") (BPU Docket No. GR09050422), and United Water New Jersey, Inc. (BPU Docket No. WR0912087). I participated in the previous Atlantic City Electric Company rate cases on rate of return issues during the past several years, 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"). Please note that Docket No. GR09050422 listed above was PSE&G's last base rate case resolved by Board-approved settlement in 2010.

II. OVERVIEW

A. Summary of Recommendation

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

A. I have been asked by Rate Counsel in this case to develop a recommendation concerning the fair rate of return on the jurisdictional electric and gas distribution utility rate bases of PSE&G. This includes both a review of the Company's proposal concerning rate of return and the preparation of an independent study of the cost of common equity. I am providing my recommendation to Rate Counsel's revenue requirement consultant, Ms. Andrea Crane, for use in calculating the Company's annual revenue requirement for gas and electric service in this case.

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

A. As presented in the Company's 9 + 3 update filing (Exhibit P-2, Schedule SSJ-04 R-1), the Company requests an authorized overall rate of return of 7.39 percent for both gas and electric service. The proposed capital structure is indicated as being the Company's target capital structure which the Company intends to use going forward, which includes 54.0 percent common equity, and 45.5 percent long-term debt and 0.5 percent customer deposits. This proposed capital structure is generally more equity rich (and therefore more expensive) than that of the industry proxy group that I have used, as discussed later in my testimony. The 54 percent equity ratio is also more expensive than the 51.2 percent approved in the Company's last base rate case. This proposed capital structure excludes any recognition of short-term debt. The Company requests a return on the common equity ("ROE") component of 10.3 percent, the same return granted by the Board in the last base rate case in 2010. The overall rate

of return, capital structure and cost of debt recommendations are sponsored by witness Jennings, and the cost of equity recommendation is sponsored by the Company's consultant, Ms. Ann Bulkley. Ms. Bulkley's return on equity ("ROE") recommendation is based on the results of her various studies. Specifically, she identifies a cost of equity range for PSE&G of 9.8 to 10.5 percent, with her ultimate ROE recommendation being slightly above the midpoint (i.e., 10.2 percent) of this range (Exhibit P-5, Direct Testimony of Ann C. Bulkley, p. 7). Her final ROE recommendation of 10.3 percent takes into account the claim of superior cost control performance, customer satisfaction, and adherence to State policy goals, although she makes no specific quantitative adjustment to account for those factors.

Q. WHAT IS PSE&G'S CORPORATE STRUCTURE?

PSE&G is a wholly owned subsidiary of Public Service Enterprise Group ("PSEG"), which is a corporate holding company that owns extensive merchant power plant operations in a separate unregulated subsidiary, PSEG Power, LLC. These merchant power plants are located in PJM and New England. In recent years, PSEG has been emphasizing investments in its monopoly utility operations rather than unregulated power plants, with utility operations expected to provide the majority of PSEG earnings in future years. (P. 16, https://investor.pseg.com/sites/pseg.investorhq.businesswire.com/files/doc_library/file/PSEG-INVESTORCONF-FINAL-052918.pdf).

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

A. As summarized on Schedule MIK-1, page 1 of 1, I am recommending at this time a return on PSE&G's jurisdictional electric and gas distribution rate base of 6.62 percent. Following the Company's approach and that used in the Company's last base rate case, I recommend an identical rate of return for both electric and gas operations. This includes a return on common equity of 9.00 percent and a capital structure and cost of debt similar to but slightly different from Mr. Jennings' recommendation based on provisional information. This recommendation may change slightly as capitalization data from the Company's 12+0 update become

available. Specifically, at this time I recommend a capital structure of 53.2 percent equity, 0.5 percent customer deposits and 46.4 percent long-term debt. This capital structure is based on long-term debt outstanding at May 31, 2018 and the "target" equity balance provided in the Company's 9 + 3 update filing. In addition, I accept the Company's decision to exclude short-term debt from capital structure and instead directly assign it to the financing of Construction Work in Progress ("CWIP"). This recommendation is conditioned on a commitment by the Company to continue this accounting practice (sometimes referred to as "the FERC method").

Q. WHAT IS YOUR COST OF DEBT RECOMMENDATION?

A. I am using at this time a long-term cost of debt of 3.96 percent, which is the Company's actual cost of long-term debt at May 31, 2018, inclusive of appropriate recognition of debt-related expenses. This is a large reduction from the cost of debt used in the Company's last case of more than 6 percent.

Q. HOW DOES MS. BULKLEY DEVELOP HER 9.8 TO 10.5 PERCENT ROE RESULTS?

A. Ms. Bulkley utilizes four cost of equity methods: (1) the standard Discounted Cash Flow (DCF); (2) a "projected" DCF model (3) the Risk Premium; and (4) Capital Asset Pricing Model (CAPM), with each methodology (except for the Risk Premium) applied to a proxy group of 11 publically-traded combination gas/electric companies. Ms. Bulkley's testimony is rather complex, and she develops ranges and multiple estimates using each cost of equity methodology. Focusing on her mean or midpoint results as reported in her summary Table 1 in her testimony, she obtains estimates of 9.6 percent using the standard DCF model, 10.65 percent using the "projected" DCF model, 10.53 percent for the CAPM approach, and 9.98 percent for the Risk Premium study. She does not include a flotation expense adder with her cost of equity results.

Based on these results she identifies a range of 9.8 to 10.5 percent, and she recommends an ROE of 10.3 percent which is near the midpoint of this range. Her recommendation takes into account, in some fashion, the assertions of superior management performance mentioned above, but no specific bonus or "adder" is either calculated or recommended. Moreover, there is no specific recommendation of a positive or negative risk adjustment to reflect differences between PSE&G and her 11 proxy group companies.

Q. HOW HAVE YOU DEVELOPED YOUR 9.0 PERCENT ROE RECOMMENDATION?

A. I rely primarily on the use of the standard DCF model as applied to a proxy group of 12 electric utility companies. This produces a cost of equity range of about 8.1 to 9.1 percent, with a midpoint of 8.6 percent. This is very similar to the group used by Ms. Bulkley but with three changes. I removed Centerpoint Energy due to that company's involvement in a major merger which was announced subsequent to Ms. Bulkley's testimony. To supplement the proxy group, I also added two combination gas and electric utilities that I believe warrant inclusion, Alliant Energy and Duke Energy. I have intentionally used a similar proxy group to facilitate a direct comparison of our respective cost of equity studies and to reduce controversy over proxy group selection. In addition, I have conducted a second DCF study using a proxy group identical to that of Ms. Bulkley (excluding Centerpoint Energy). This study obtains a range of 8.0 to 9.2 percent with a 8.6 percent midpoint. Unfortunately, these proxy groups, while not unreasonable, are an imperfect risk proxy for PSE&G because it measures (to some degree) the risks incurred by several companies of the proxy group associated with generation assets and supply, whereas this case sets rates only for PSE&G's gas and electric distribution service. PSE&G ratepayers already pay for the

risks associated with generation supply in the Basic Generation Service ("BGS") charges or in competitive service rates and should not have to pay twice for that risk.

I also have conducted a cost of equity study using the CAPM method, which produces even lower results – a cost of equity range of about 6.3 to 9 percent. However, I place much less weight on the CAPM results due to the difficulty of reliably identifying a market risk premium, which is a critical model input.

In my opinion, these cost of equity study results, taking into account the current and recent favorable conditions of low capital costs in financial markets, support the reasonableness of my 9.00 percent return on equity recommendation for PSE&G at this time, a reduction of 1.3 percent from the 10.3 percent granted by Board-approved settlement in the Company's last rate case completed in 2010. PSE&G's proposal to maintain the ROE at 10.3 percent is not reasonable given the cost of equity evidence and the reduction in capital costs since 2010.

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

A. At the outset, please note that her "standard" DCF study result of 9.6 percent is well below her recommendation of 10.3 percent. Nonetheless, even this study result is far too high as it results from an improper and arbitrary procedure of deleting the low cost of equity observations in reporting her proxy group average result. I explain this error later in Section V of my testimony. Correcting this bias largely eliminates the discrepancy in our respective DCF results.

The major difference, however, is attributable to her other studies— the projected DCF, the CAPM, and the Risk Premium. In those studies she uses inappropriate and unreasonable data assumptions that "drive" the results far above a

realistic estimate of the market cost of equity for PSE&G. In particular, she assumes and incorporates a substantial increase in long-term interest rates, from actual levels, and she also incorporates an unrealistic equity market risk premium which causes in overstatement in her CAPM results. Section V of my testimony identifies and corrects her unreasonable data assumptions.

Q. DO YOU INCLUDE A FLOTATION ADJUSTMENT?

A. No, I have not. While it is sometimes appropriate to include such an adder, in this case, this is not needed. PSEG (the parent) has not incurred stock issuance expenses in recent years, and does not anticipate incurring such expenses in the near term. The Company has not made a flotation expense claim, and one is not needed.

Q. DO YOU CONSIDER PSE&G TO BE A LOW-RISK UTILITY COMPANY?

A. Yes, very much so. PSE&G provides monopoly gas and electric utility delivery service in its New Jersey service territory, subject to the regulatory oversight of the Board. As Mr. Jennings points out, credit rating agencies have upgraded the ratings on the Company's debt on three occasions since the last base rate case, and the Company has strengthened its capital structure considerably since then. I find that PSE&G is materially less risky than at the time of its last case, and it is also less risky in an overall sense than the proxy companies used by Ms. Bulkley and me. I have factored that relatively lower risk into my recommendation of 9.0 percent. In Section III of my testimony I briefly discuss the business risk attributes for the Company including the views of credit rating agencies.

Q. MR. JENNINGS AND MS. BULKLEY DEFEND THE 10.3 PERCENT REQUEST BASED PARTLY ON ASSERTIONS OF SUPERIOR MANAGEMENT PERFORMANCE IN THE AREAS OF COST CONTROL,

SERVICE QUALITY AND OTHER FACTORS. DO YOU ADDRESS THIS ISSUE IN YOUR RECOMMENDATION?

A. The inclusion of an explicit ROE bonus or adder for management performance is discussed in some detail by Rate Counsel witness Dr. Dismukes, and I defer to his testimony on this topic. He recommends in this case against an explicit ROE adjustment based on his policy analysis of this issue, and I make no explicit adjustment to my ROE. That said, I note that my 9.0 percent ROE is close to the upper end of my DCF range (i.e., 9.1 to 9.2 percent) and is also above the credible CAPM results. Importantly, while the Company witnesses do discuss at some length the assertions of superior performance and the need for rate of return recognition, in the end, there is no specific recommendation for an actual adder or quantified bonus. In fact, the 10.3 percent is very close to the midpoint of 10.2 percent cost of equity estimate. Consequently, there is no request in this case for a specific ROE bonus figure, but merely a vague request that this factor be considered when considering the ROE award.[1]

I would make one further observation. It appears that a combination of cost control efforts and the revenue from the various investment cost trackers for the Company's incremental investments has enabled the Company to avoid base rate cases over the past eight years in which its overall earnings would be carefully scrutinized and its rate of return likely would be lowered. Hence, to the extent the Company has been successful in cost control (on the expense side at least), Company and PSEG shareholders have benefitted.

Aside from management performance, I am troubled that Ms. Bulkley has failed to take into consideration the fact that PSE&G is materially less risky than the

[1] See Direct Testimonies of Michael J. Adams, pp. 2-3, and 27;and Ann E. Bulkley, pp.5, and.40-42.

proxy group companies that she uses to establish her estimated cost of equity range. PSE&G clearly is less risky on average. This is due to several factors including the Company's status as a low-risk distribution utility (no generation risk), whereas several proxy group companies must confront generation risk. The Company's 54 percent target equity ratio used in this case is well above the proxy group average equity ratio (as well as the industry average). As noted PSE&G has enjoyed credit uprates in recent years to the double A level on its secured debt, and it has been able to make extensive use of extremely low-risk cost recovery trackers for vast amounts of its incremental capital investment since 2010 providing contemporaneous and accelerated cost recovery from customers. All of these factors warrant consideration in her ROE recommendation.

Q. HOW DOES PSE&G'S ROE REQUEST COMPARE WITH ELECTRIC UTILITY AWARDS GENERALLY?

A. The requested 10.3 percent ROE is significantly higher than state commission award trends since 2010. Note that the 10.3 percent request in this case also is far higher than the 9.6 percent recently authorized for other New Jersey gas and electric utilities, and it fails to take into account both market conditions and the regulatory trends on ROE awards since 2010.

The ROE trend awards are provided quarterly by Regulatory Research Associates ("RRA") surveys, a source relied upon by Ms. Bulkley. The latest RRA survey (as of July 2018) shows a generally declining trend in electric and gas utility ROE awards in recent years (particularly for delivery service electrics) to well below 10.0 percent—to the low to mid-9s. As I demonstrate later in my testimony, utility company stocks have thrived under this declining capital cost and declining ROE award environment. I show this ROE award trend below on Table 1 for the time

period 2010 to the first half of 2018 for three types of utilities: all electrics (mostly vertically-integrated), distribution electrics and gas utilities. The latter two categories are most relevant to PSE&G, and the first category is provided for comparison. The ROE awards nationwide in 2010 were on average very close to the 10.3 percent granted to PSE&G that year. However, awards have gradually declined since then – falling in 2017 to 9.43 percent for distribution electrics and 9.72 percent for gas. They have declined further in 2018 year-to-date to 9.18 percent for distribution electric and 9.55 percent for gas.

These ROE awards for 2017/2018 are about 0.5 percent above my 9.0 percent recommendation at this time. As I explain later in my testimony, these utilities have financially thrived at these low to mid 9s ROE awards implying that they are conservatively high, and there is room to lower them further and still meet the crucial capital attraction standard. Moreover, I believe that PSE&G is lower in risk than the industry average.

Table 1. State Commission ROE Awards 2010-2018			
	All Electric	**Electric Distribution**	**Gas**
2010	10.29%	9.98%	10.15%
2011	10.19	9.85	9.1
2012	10.02	9.75	9.93
2013	9.82	9.37	9.68
2014	9.76	9.49	9.78
2015	9.60	9.17	9.60
2016	9.60	9.31	9.53
2017	9.68	9.43	9.72
2018	9.58	9.18	9.55
Source: RRA Regulatory Focus, Major Rate Case Decisions – January-June 2018. All figures are averages and 2018 is first half.			

I believe that the Board should recognize these market and state regulatory trends and reduce PSE&G's currently authorized ROE. Clearly, it would be unreasonable to maintain the authorized ROE at the elevated 10.3 percent.

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 2001, through calendar year 2017, on page 1 of Schedule MIK-2. Pages 2, 3, 4, 5, 6 and 7 of that schedule show monthly data for January 2007 through June 2018. The indicators provided include the annualized inflation rate (as measured by the Consumer Price Index), ten-year Treasury note yields, 3-month Treasury bill yields and Moody's Single A yields on long-term utility bonds. While there is some fluctuation, these data series show a generally declining trend in capital costs. For example, in the early part of this ten-year period utility bond yields averaged about 7 to 8 percent, with 10-year Treasury yields of 4 to 5 percent. By 2016, Single A utility bond yields had fallen to an average of 3.9 percent, with ten-year Treasury yields declining to an average of 1.8 percent. During most of

2017, yields on long-term debt remained reasonably close to those historic lows.

As shown on Schedule MIK-2, for the time period 2009 through 2015, short-term Treasury rates have been close to zero, with three-month Treasury bills averaging about 0.1 percent. These extraordinarily low rates (which are also reflected in non-Treasury debt instruments) were the result of an intentional policy of the Federal Reserve Board of Governors ("the Fed") to make liquidity available to the U.S. economy and to promote economic activity. Note that by law, the Fed must implement a policy referred to as the "dual mandate," simultaneously promoting price stability and maximum employment for the U.S. economy.

The Fed has also sought to exert downward pressure on long-term interest rates through its policy of "quantitative easing," although that program effectively ended in 2015, with the Fed announcing the phasing out of that program in October 2014. This policy involved the purchase by the Fed of long-term financial assets in the form of Treasury bonds and federal agency long-term debt (i.e., mortgage bonds). This policy has resulted in an increase over a period of several years in the Fed's balance sheet from less than $1 trillion to over $4 trillion at the conclusion of that program and today. Quantitative easing was intended to support economic recovery by lowering the cost of capital and encouraging credit expansion.

Q. ARE THERE FORCES THAT HAVE CONTRIBUTED TO LOW INTEREST RATES OTHER THAN FED POLICY?

A. Yes. While the decline in short-term rates to near zero in recent years is largely attributable to Fed policy decisions, the behavior of long-term rates reflects more fundamental economic forces as well as Fed policy. Factors that drive down long-term bond interest rates include the past weakness of the U.S. and global macro economy, the inflation outlook and even international events. A weak or only

moderately growing economy 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. The Fed has employed a long-term inflation target of 2.0 percent, and inflation generally has been below or close to that target, as have the market's inflationary expectations.

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

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

Q. HAS THE FED PROVIDED MORE RECENT INFORMATION ON ITS POLICY DIRECTION?

A. Yes, it has. Due to positive progress in strengthening labor markets (the U.S. unemployment rate has been gradually declining to 4.0 percent), improvements in economic growth in the near term, and inflation moving up modestly closer toward the 2 percent target, the Fed has moved away from near zero interest rates to a broad policy of monetary "normalization", beginning in late 2015 and continuing to the present day. This consists of a series of increases in short-term interest rates and the unwinding of quantitative easing (i.e., very gradually reducing the Fed's holdings of long-term Treasury and agency debt). This policy shift has been recently affirmed in

the Fed's semi-annual July 2018 *Monetary Policy Report* to Congress and its press release following the June 13, 2018 meeting of the Federal Open Market Committee ("FOMC") at which it raised short-term interest rates to a range of 1.75- 2.00 percent. Fed and FOMC statements make clear that despite the change to a policy of normalization, monetary policy remains "accommodative" with changes being gradual.

As a result of Fed policy, as well as conditions in U.S. and global capital markets, in 2017 long-term interest rates remained extremely low (though slightly higher than the historic lows of 2016), and the stock market flourished. Utility stocks also performed well in most of 2017 despite the gradual firming of short-term and long-term interest rates in the last half of the year.

Q. HAS THE PATTERN BEEN SIMILAR FOR EQUITY MARKETS IN 2018?

A. While January 2018 was a strong month for the stock market (due to the anticipated corporate earnings benefit of the Tax Cut and Jobs Act enacted in December 2017 and a strengthening economy), the past few months as of this writing have seen increased stock market volatility and further gradual increases in interest rates as compared to 2017 lows. Although short-term fluctuations in the stock market are always difficult to interpret, it may be due to a combination of risks of further interest rate increases, rising federal budget deficits (due to both the tax cut bill and Congressional budget decisions) and concerns over international trade policy changes.

Despite this capital market instability, the cost of capital remains quite low by historical standards. In particular, the yield on 30-year Treasury bonds (the benchmark used by both Ms. Bulkley and myself) in recent months has averaged 3.1 percent for the first half of 2018, and as of this writing in late July has been a slightly

lower 3.0 percent. (Please see page 2 of Schedule MIK-6 for the six months ending June 2018.) The cost of long-term debt for single or double A rated utilities (such as PSE&G for secured debt) has also risen slightly since 2017 but remains close to or slightly above 4.0 percent.

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

Yes, to a large extent. Following my past practice, I have based my DCF analysis on market data from the six months ending June 2018. Thus, strictly speaking my analysis measures the utility cost of capital during that recent time period. As of this writing, little has changed since the end of June 2018 in capital markets. However, I shall continue to monitor developments and will revisit the cost of capital at the time of the rebuttal/surrebuttal phase of this case if there are material changes in capital market conditions.

C. Overview of Testimony

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

A. Section III of my testimony briefly discusses the capital structure and cost of debt recommended in this case by the Company. This section also discusses PSE&G's business risk profile. Section IV presents my cost of equity studies which are based on the DCF method, with the application of the CAPM providing a comparison and corroboration. Section V is my review of Ms. Bulkley's cost of equity studies, risk adjustments and her 10.3 percent ROE recommendation. Finally, Section VI provides a summary of major findings and conclusions. In particular, that section explains

why it is appropriate to lower at this time the currently authorized 10.3 percent in light of market, regulatory, and industry trends.

III. CAPITAL STRUCTURE AND PSE&G'S INVESTMENT RISK

A. Capital Structure

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

A. As explained in Mr. Jennings' direct testimony, the Company is requesting approval of a "target" capital structure that includes a 54 percent equity ratio, 0.5 percent customer deposits and 45.5 percent long-term debt. This request compares to the 51.2 percent approved in the Company's last base rate case. At pages 46-47 of his direct testimony, Mr. Jennings argues that this 3 percentage point equity ratio increase is needed to protect the Company's credit metrics and credit ratings. He notes that the 2017 Tax Cut and Jobs Act ("TCJA") has the effect on utilities of somewhat weakening cash flow and therefore credit metrics due to the loss of deferred tax cash flow benefits enjoyed in the past, and that credit rating agencies have expressed concern regarding such weakening. He argues that a higher equity ratio can mitigate that weakening and therefore is warranted. That said, he also acknowledges that the Company's recent actual equity ratio has not reached that target and has been mostly in the 53 to 53.5 percent range. The Company anticipates reaching the 54 percent later this year. (RCR ROR-11)

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

A. No, it is not, as I show on Schedule MIK-3 for the 12 proxy group companies. PSE&G's proposed 54 percent equity ratio compares with an average 48 percent for the proxy group companies, with nearly all of the companies at 51 percent or lower. Please note that these are the projected equity ratios for year-end 2018, as reported by Value Line. Based on these data, I conclude that PSE&G's balance sheet strength is

far greater than that of the gas/electric proxy group. I do not present this comparison to object to the Company's need to strengthen its capital structure and its proposal in this case, but rather I am pointing out that PSE&G is stronger than the proxy companies and has less financial (debt leverage related) risk. This risk advantage should be taken into account when considering the appropriate ROE to be awarded in this case since cost of equity estimation relies on a proxy group of companies riskier (on average) than PSE&G.

Q. DOES THE INCREASE IN THE EQUITY RATIO FROM 51.2 TO 54 PERCENT MATERIALLY AFFECT THE RATE INCREASE REQUEST?

A. Yes, it is a significant cost driver. I calculate that this nearly 3 percentage point increase adds to the annual revenue requirement request in this case by about $28 million for gas and electric combined. This is calculated assuming a $9.8 billion combined rate base, a 4 percent cost of debt, a 10.3 percent ROE and a 1.4x revenue multiplier. This rate burden from the equity ratio increase is notable as the 54 percent ratio request is generally higher than equity ratios approved for other New Jersey utilities and utilities elsewhere. For example, the RRA survey that I cited in Section II indicates that average equity ratios authorized in recent years in gas and electric rate cases have generally been in the 48 to 51 percent range. That said, I do recognize Mr. Jennings' concerns that the TCJA and the Company's large construction program do merit a strengthening of its balance sheet.

There is one other minor observation concerning these capital structure comparisons. PSE&G's target 54 percent equity ratio is computed including customer deposits (0.5 percent) in capital structure, which is nonstandard and not reflected in the presentation of proxy company capital structures. Customer deposits are not considered to be a component of a utility's permanent capital and are not

typically reflected in the ratemaking capital structure. If customer deposits were to be removed or disregarded, then PSE&G's request is really the equivalent of a 54.3 percent equity ratio. I discuss other concerns with customer deposits below.

Q. WHAT IS YOUR CAPITAL STRUCTURE RECOMMENDATION AT THIS TIME?

A. As a general matter, I do not contest the Company's decision to move to a stronger capital structure in light of its current financial needs and changes in tax law. The Company argues that this is needed to protect its credit metrics and ratings, and its strong ratings have produced a relatively low cost of long-term debt. However, at this time, the 54 percent (or 54.3 percent if customer deposits is removed) is a target and not an actual capital structure. Until achieved, it remains aspirational. At this time, I recommend a capital structure of 53.2 percent equity, 0.5 percent customer deposits and 45.4 percent long-term debt, as shown on Schedule MIK-1. As with the Company's practice, I exclude short-term debt as it is assigned to the financing of construction work in progress. I have calculated this capital structure using the actual balance outstanding of long-term debt (per the response to RCR-ROR-28), the Company's target equity balance (from its 9 + 3 filing) of $10.273 billion and the actual balance of customer deposits. This is provisional and should be updated when the actual June 30, 2018 balance sheet data are available, presumably with the 12 + 0 update, so that the ratemaking capital structure can be based on actual data instead of a target that may or may not be realized.

Q. WHAT IS YOUR CONCERN WITH CUSTOMER DEPOSITS?

A. Customer deposits constitute near zero cost capital and therefore should be recognized in the cost of service as a savings for customers. Its inclusion in capital structure is one method, as the Company has done, but alternatively, it could instead

be reflected as a rate base offset. In response to RCR-ROR-25, the Company defends its proposed treatment arguing that customer deposits are similar to long-term debt, and that reflecting this item in rate base (the alternative) would add unnecessary complexity and controversy due to arguments over allocation.

In this case, I understand the Company's argument and have not objected to the Company's treatment as the item is relatively small (0.5 percent of capitalization). Moreover, this same treatment was accepted in the last rate case in 2010. Nonetheless, it should be pointed out that this treatment is beneficial to shareholders as compared to customers. This is because capitalization ($19 billion) is nearly twice the size of rate base ($9.8 billion), and the effect of reflecting the fixed $93 million in capitalization has a dilutive effect compared to rate base. That is, it is a smaller percentage of capitalization than it is of rate base. The reason for this discrepancy is that nearly half of the Company's capitalization actually supports FERC regulated transmission. In response to RCR-ROR-25, the Company acknowledged that for FERC ratemaking it does not reflect customer deposits in capital structure. If it did, then retail customers would see the savings from this near zero cost capital in their FERC transmission rates. Due to this inconsistent treatment, they do not, and the savings for a portion of customer deposits instead goes to shareholders. As I stated, I am not contesting this treatment as it has been used in the past and in any event is a small item. However, it does point out that the capital structure proposal in this case is favorable to shareholders, and this should be recognized in setting the Company's ROE in this case.

Q. WHAT IS PSE&G'S CLAIMED COST RATE FOR LONG-TERM DEBT?

A. In its 9 + 3 filing, the Company employs an embedded cost of long-term debt 4.03 percent. Based on the response to RCR-ROR-28, I have employed the actual cost rate

of long-term debt at May 31, 2018 of 3.96 percent, a cost rate that takes into account $700 million of new debt issues that took place in May.

B. Discussion of Credit Ratings and Risk

Q. HAVE COMPANY WITNESSES IN THIS CASE THOROUGHLY EXPLORED BUSINESS RISKS FACED BY PSE&G?

A. In my opinion, they have not. I believe that it is important to examine the relative risk profile of PSE&G from two perspectives: how does the Company's investment risk compare to that of the cost of equity proxy group, and how has it changed since the Company's last base rate case in 2010. Unfortunately, the Company witnesses have provided limited analysis of those issues. Ms. Bulkley seems to focus largely on one issue – revenue decoupling – in concluding that absent approval of that proposal PSE&G is actually riskier than the proxy group. She fails to consider the broader indicators of risk such as credit ratings, and as a result her comparative review is superficial. As discussed below, it is simply not credible to argue that PSE&G is either as risky or more risky than the proxy group, a finding that is contradicted by available evidence.

Mr. Jennings does report on the Company's credit ratings since the last base rate case and he states that it has been uprated since then on three occasions by Moody's and Standard and Poor's ("S&P"). Importantly, since the last rate case, the Company has been able to make extensive use of very low-risk cost trackers for incremental capital investment (i.e., investment over and above the revenue provided by depreciation expense from existing investment). Also, the Company has moved to a stronger capital structure, to be reflected in rates in this case as discussed above, which lowers its financial and therefore investment risk. Unquestionably, the Company's business and financial risk has declined since the last rate case.

Q. DO YOU REGARD PSE&G AS BEING A LOW-RISK UTILITY COMPANY?

A. Yes, very much so and it clearly is less risky than the proxy group companies, meaning that the cost of equity estimates using the proxy group overstate the PSE&G cost of equity. To begin with, consider the Value Line broad risk indicators shown on Schedule MIK-3 for the proxy companies. For the 12 companies, the average Value Line Safety rating is 1.8, Financial Strength rating ranges from B+ to A, and the average equity ratio is 48 percent. Value Line provides ratings only for PSEG parent rather than PSE&G since the latter is not publically traded. However, PSE&G is the majority and least risky part of PSEG and therefore a comparison between PSEG and the proxy group would be conservative. PSEG's Safety Rating is "1" (the highest), and its Financial Strength rating is A++ (better than any proxy company). The PSE&G equity ratio requested in this case is 54 percent, well above the group average of 48 percent. The risk indicators on Schedule MIK-3 without question demonstrate PSE&G to be less risky than the proxy group.

Another factor that Ms. Bulkley fails to consider in her risk comparison is the risk difference between vertically-integrated (which reflects the risks of owning and operating generation) and delivery service. Her proxy group (and mine) is primarily vertically integrated, with perhaps only Eversource and Con Ed being predominantly delivery service. There is little disagreement among experts that (all else equal) delivery service is less risky than generation. Indeed, this is documented on my Table 1 in Section II which shows that ROE awards to delivery service electrics tend to be about 0.2 to 0.4 percent, on average, lower than for vertically-integrated electrics. PSE&G does, of course, face business risks and has an ongoing need to access capital markets. However, it operates in its service territory as a monopoly provider of a

vital service – electric and gas distribution. For this reason alone, the proxy group overstates the investment risk for PSE&G.

Ms. Bulkley does seem to recognize that the Company has been able to recover costs of much of its incremental investments outside of base rate cases through low- risk cost trackers. However, she is dismissive of this fact suggesting that some of the proxy companies do so as well. It is true that this exists for some companies to some degree. But she has not documented the extent. For example, in its 2018 PSEG Investor Conference (New York Stock Exchange, May 31, 2018) presentation to investors,[2] the Company presented its five- year $12 - $15.5 billion capital spending plan, noting "Over 90 percent of investment receiving contemporaneous or near-contemporaneous regulatory treatment." Credit rating reports for PSE&G also document the extensive use of cost trackers as a positive factor in the business/regulatory risk evaluation. In fact, Ms. Bulkley seems to ignore credit ratings and the fact that PSE&G's ratings are generally stronger than the proxy companies (on average). Moody's rates the Company's secured debt double A, a very high rating for a utility. In response to RCR ROR-24, Ms. Bulkley states that the proxy group credit ratings range from A- to BBB.

In summary, I find PSE&G to be less risky, on average, than the proxy group for the following reasons: (1) its status as a delivery service utility while most of the proxy group is vertically integrated; (2) its superior (PSEG) risk and quality ratings from Value Line, (3) its strong credits ratings that have improved since the last rate case, (4) the Company's extensive use of very-low risk cost trackers for incremental, and (5) its use in this case of a target 54 percent equity ratio which is far above the

[2] P. 36, https://investor.pseg.com/sites/pseg.investorhq.businesswire.com/files/doc_library/file/PSEG-INVESTORCONF-FINAL-052918.pdf

industry and proxy group average. These advantages more than offset the fact that PSE&G does not at this time have a decoupling mechanism for electric service whereas some proxy companies do.

Q. WHAT IS THE ASSESSMENT OF CREDIT RATING AGENCIES?

A. The Company has provided credit rating reports for PSE&G and its parent in response to RCR-ROR-5. This is also discussed in Mr. Jennings testimony. Moody's assigns PSE&G an issuer rating of A2 and assigns its secured bonds a rating of Aa3 (i.e., low double A). Standard & Poors ("S&P") assigns ratings to PSE&G based on its assessment of the consolidated parent, PSEG, which it rates BBB+. Since unregulated merchant power plant operations are considered far riskier than regulated delivery service, this is not a meaningful measure of the Company's risk. Absent the merchant affiliate, the S&P corporate rating clearly would be higher. In fact, S&P rates the Company's secured debt as A (medium single A). I consider these ratings to be quite strong and indicative of low business risk. Both agencies label the outlook as "Stable".

The credit rating reports provide an assessment of Company business risks and financial metrics. Both credit rating agencies find that PSE&G's regulated distribution service to be very low risk and New Jersey regulation supportive. The July 15, 2017 Moody's report states that the A2 issuer rating is "supported by its low risk transmission and distribution (T&D) business model, strong regulatory relationships with New Jersey and the Federal Energy Regulatory Commission (FERC) and an adequate financial profile." On the subject of regulation, it states "PSE&G has a constructive regulatory environment, with timely pass through and recovery of cost." Moody's notes that 70 percent of investment is recovered on a contemporaneous basis through tracker-type mechanisms or FERC formula rates.

Q. ARE THERE SIMILAR COMMENTS FROM S&P?

A. Yes, S&P's assessment seems quite similar, although its corporate rating is based on the consolidated PSEG. The report of April 27, 2017 notes the low-risk nature of the PSE&G delivery service which is propping up the credit ratings of parent PSEG. S&P regards New Jersey regulation as being "generally constructive" in that it permits contemporaneous recovery of costs through riders, allows rates set on a "balanced capital structure" which can "support stable and robust cash flow generation."

IV. COST OF COMMON EQUITY

A. Using the DCF Model

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

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

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

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

A. Generally speaking, I believe it is. A return award commensurate with the cost of equity generally provides fair and reasonable compensation to utility equity investors and normally should allow efficient utility management to successfully finance utility

operations on reasonable terms. Setting the authorized return on equity equal to a reasonable estimate of the cost of equity also is generally fair to ratepayers.

I recognize that there can be exceptions to this general rule. For example, in some instances, utilities have obtained rate of return adders as a reward for asserted good management performance or lowered returns where performance is subpar. In this case, the Company is making no explicit request to raise the authorized equity return above Ms. Bulkley's cost of equity range of results, although she does state that it should be taken into account in the final authorization. While no specific adjustment is proposed, this subject is discussed in more detail by Rate Counsel witness Dr. Dismukes.

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 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 strength and the favorable business risk profile, as assessed by credit rating agencies (i.e., Moody's, Value Line and S&P), also contribute to its relatively low cost of equity.

Q. DOES MS. BULKLEY INCORPORATE THESE PRINCIPLES IN HER TESTIMONY?

A. By and large, Ms. Bulkley does attempt to incorporate these principles. Her studies purport to estimate the market-based cost of capital. However, I disagree with certain of her analytic procedures and data inputs, as well as the relevance of the risk premium study. I also question her risk assessment of PSE&G relative to the proxy group companies.

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/gas utility companies. However, for reasons discussed in my testimony, I emphasize the DCF model results 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 setting the fair return. As a check (and partly to respond to Ms. Bulkley), I also perform a CAPM study which also is based on my electric/gas utility proxy group companies used in my testimony.

Q. PLEASE DESCRIBE THE DCF MODEL.

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

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

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

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

K_e = cost of equity;

Do = the current annualized dividend;

Po = stock price at the current time; and

g = the long-term annualized dividend growth rate.

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

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly-traded companies, i.e., companies whose market prices (and therefore market valuations) are transparently revealed. Consequently, the model cannot be applied to 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. I have not done so as I am reluctant to rely upon a single-company DCF study (nor does Ms. Bulkley), although in theory that approach could be used. Moreover, PSEG would be a poor

risk proxy for PSE&G due to its extensive unregulated nuclear and other merchant power operations. For that reason, I have elected to not include PSEG in my proxy group, nor does Ms. Bulkley.

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 (i.e., one that is reasonably large) helps to allow such "data anomalies" to cancel out in the averaging process.

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

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

A. I began by reviewing the combination electric/gas utility proxy group selected by Ms. Bulkley, a group of 11 companies. Her selection criteria requires that companies pay quarterly cash dividends; are covered by at least two equity analysis; have investment grade credit ratings by S&P or Moody's; have regulated (i.e., utility) income that is at least 70 percent of total income; have electric income that is at least 50 percent of regulated income (and 10 percent gas); and not be involved in a major merger or similar transaction. In addition, she judgmentally decided to remove Southern

Company even though it apparently survived her screen. While her criteria and resulting proxy group certainly are not perfect, I find her selections to be acceptable.

One of my main concerns is that Ms. Bulkley's criteria permit inclusion of companies that could have up to 30 percent of their income from unregulated operations. As non-regulated operations are significantly riskier than regulated utility operations, this could result in an overstatement of PSE&G's cost of equity. That said, while non-regulated operations are present, I do not believe this to be a serious problem. I also note that most of the proxy companies can be described as vertically-integrated, which I believe almost all experts concede is probably riskier than distribution utility operations, as a broad generalization.

Thus, while her proxy group is acceptable, it is not a perfect risk proxy for PSE&G.

Q. DID YOU ACCEPT MS. BULKLEY'S PROXY GROUP IN ITS ENTIRETY?

A. No, I eliminated one company and added two others. I eliminated Centerpoint Energy due to its pending merger with Vectren, a multi-billion transaction. This merger was announced subsequent to Ms. Bulkley's testimony, but I believe this elimination would be consistent with her criteria of selection. In order to increase the size of the proxy group, I identified two additional companies that would seem to satisfy the selection criteria as being combination gas/electric and primarily regulated utility – Alliant and Duke Energy. Even with these three changes, I believe that I have compiled a proxy group quite similar to that of Ms. Bulkley, largely if not entirely eliminating sample selection as a disputed issue.

While this proxy group is not identical to that of Ms. Bulkley, it is sufficiently similar so as to facilitate a comparison of our respective studies. I list the resulting 12 companies, along with summary risk attributes, on Schedule MIK-1.

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

A. Yes, that would be preferable to Ms. Bulkley's mostly vertically-integrated proxy group, if feasible. Unfortunately, it is not practical to do so. While there are numerous delivery service electric utilities, the vast majority are subsidiaries of companies with vertically-integrated operations and/or merchant generation. While it was feasible to use a delivery service proxy group in the past, due to merger and acquisition activity there are simply too few such publicly-traded companies today.

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

Q. PLEASE IDENTIFY THE 12 COMPANIES INCLUDED IN YOUR GAS/ELECTRIC UTILITY PROXY GROUP.

A. These 12 proxy companies are listed on Schedule MIK-3, page 1 of 1, along with several Value Line risk indicators, including the Safety Rating, Financial Strength Rating, beta and 2018 equity ratio. Please note that PSE&G's ultimate parent, PSEG, is not included in this group for the reasons discussed above.

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

A. Ms. Bulkley does not include any specific risk adjustment in the development of her final ROE range or point value for PSE&G. Her testimony (at pages 44 – 45) argues that with the requested revenue decoupling mechanism PSE&G would be similar in

investment risk to the proxy group. This is a completely unreasonable finding as I explained in Section III of my testimony.

I also have not quantified a specific risk adjustment factor, but in Section III I explained the various reasons why a downward adjustment to the proxy group cost of equity estimate would be needed for PSE&G (i.e., higher equity ratio, stronger credit ratings, status as a delivery service utility, liberal use of low-risk trackers, etc.). Such a cost of equity adjustment decrement would be significant if quantified. In this case, I have identified upper end DCF estimates of slightly above 9.0 percent (i.e., 9.1 to 9.2 percent). Given these upper end results, I recommend a ROE award in this case of 9.0 percent to provide some modest recognition of PSE&G's relative risk advantage.

Q. HOW HAVE YOU APPLIED THE DCF MODEL TO THIS PROXY 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 historical data on month ending closing share prices and quarterly dividends provided publicly by YahooFinance.com, I compiled the month-ending dividend yields for the six months ending June 2018, the most recent data available to me as of this writing. Specifically, each dividend yield is calculated using the then prevailing quarterly dividend multiplied by four divided by the month closing share price. As a general matter, this recent six months has been a time period of volatility for the overall stock market but less so for utility stocks. While there is some month-to-month variation, on the whole utility share prices did not change very much during this six month time period. This seems to mirror long-term bonds, which rose modestly at the beginning of the year, but since then have been remarkably stable.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, January through June 2018. Over this six-month period the proxy group average dividend yields indicate relative stability. The January average was 3.5 percent, moving up in February to 3.70 percent and since then declining modestly to 3.43 percent at the end of June. This is a slight net decline of about 0.1 percent during 2018 year to date. This compares to 2017 in which utility stocks experienced large gains.

For DCF purposes and at this time, I am using a proxy group dividend yield of 3.52 percent.

Q. IS 3.52 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 3.6 percent. This is based on assuming that half of a year growth is 2.75 percent (i.e., assuming a full year growth is 5.5 percent, i.e., the upper end of the DCF growth rate range).

Q. DOES MS. BULKLEY EMPLOY THE SAME GROWTH RATE ADJUSTMENT?

A. I understand that Ms. Bulkley employs an adjustment to the dividend yield, but she uses a full year rather than the more standard half year growth adjustment to the measured dividend yield. Using the full year of growth would result in an adjustment that is too large by about 0.1 percent. Ms. Bulkley 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. Her market data therefore reflect conditions prevailing in mid to late 2017.

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 Ms. Bulkley does not rely upon historical growth rates as an indicator of long-term growth for her 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 Ms. Bulkley places exclusive weight on this information for her DCF studies, and while I agree that it warrants substantial emphasis, it is still useful to consider corroborating evidence.

Q. PLEASE DESCRIBE THE ANALYST EARNINGS GROWTH RATE EVIDENCE.

A. Schedule MIK-4, page 3 presents five available and well-known public sources of analyst earnings growth rate projections. Four of these five sources -- YahooFinance, Zacks, Reuters and CNNfn -- provide averages from securities analyst surveys conducted by or for these organizations (typically they report the mean or median

value). The fifth, Value Line, is that organization's own estimates and is available publically on a subscription basis. Value Line publishes its own projections using annual average earnings per share for a base period of 2015-2017 compared to the annual average for the forecast period of 2021-2023. These are very similar to the sources used by Ms. Bulkley for securities analyst growth rates in her DCF studies, as she also uses Zacks, Yahoo!Finance, and Value Line as data sources.

As this schedule shows, the growth rates for individual companies vary somewhat among the five sources. These proxy group averages are 5.5 percent for CNNfn, 5.5 percent for Yahoo!Finance, 5.4 percent for Zacks, 5.4 percent for Reuters and 6.3 percent for Value Line. Thus, the range of growth rates among the five sources is 5.4 to 6.3 percent. The average of these five sources is 5.6 percent, and I have used these results, along with other evidence described below, in obtaining a reasonable growth rate 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 12 proxy companies tend to be somewhat less (on average) than

analyst growth projections. For the 12 proxy companies, projected dividend growth averages 5.5 percent, book value growth averages 4.1 percent, and earnings retention growth averages 3.7 percent.

Some analysts and regulators favor the use of earnings retention growth (often referred to as "sustainable growth"), which Value Line indicates to be 3.7 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, as shown on page 5 of Schedule MIK-4, I have estimated this "external growth" factor using Value Line projections for these 12 companies of the growth rate (through 2021-2023) 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 12 companies, the external growth rate calculated in this manner averages about 0.5 percent. (Note that three of the 12 proxy companies are not expected to issue any new stock in the near term.) The sum of "internal" or earnings retention growth (i.e., 3.7 percent) and the "external" growth rate (i.e., 0.5 percent) is 4.2 percent.

Given this estimate of 4.2 percent for the sustainable growth rate and 5.6 percent for analyst earnings projections, a reasonable DCF growth rate range is approximately 4.5 to 5.5 percent. I tend to place more weight on the analyst projected growth rates as it is derived from five published data sources, whereas the sustainable growth rate, analysis relies entirely only on one source, i.e., Value Line.

Q. ARE THERE ANY OTHER FACTORS TO CONSIDER?

A. Yes. As previously discussed, analysts sometimes include an adjustment for stock issuance or "flotation" expense associated with public issuances of common stock. As best I can determine, Ms. Bulkley did not incorporate such an adjustment. In response to Rate Counsel data requests, the Company indicated that PSEG parent has not undertaken a public common stock issuance in recent years, and does not expect to do so in the near term future. (Response to RCR ROR-13 and 31) Consequently, there are no such stock issuance expenses to be recovered. For that reason, I do not included a flotation cost adjustment to my recommended cost of equity finding.

Q. HAVE YOU INCLUDED A MANAGEMENT PERFORMANCE BONUS OR ADDER FOR PSE&G?

A. As discussed earlier, I have not done so. As both a factual and policy matter, I defer on this issue to Rate Counsel witness Dr. Dismukes who opposes the award of such a bonus in this case. That said, as noted below, my 9.0 percent recommendation is well above my DCF midpoint and only reflects a very modest consideration of PSE&G's lower than average risk relative to the proxy companies.

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 2018 is 3.6 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 cost of equity of 8.1 to 9.1 percent, and a midpoint result of 8.6 percent. Reliance on analyst earnings projections would tend to support a result toward the upper end of that range, while the sustainable growth rate produces a lower end DCF result. In my opinion, the more reliable evidence should be based on the securities analyst earnings growth rate estimates, which is obtained from five

separate sources, as the sustainable growth rate result is based only on one source. As such, there is less confidence that it reflects the consensus of investor opinion. After also considering PSE&G's lower risk relative to the proxy group, I recommend an ROE award of 9.0 percent which is somewhat above the DCF midpoint but lower than the DCF estimate based just on security analyst projections.

Q. HOW DOES YOUR DCF ROE FINDING COMPARE TO MS. BULKLEY'S DCF ESTIMATE FOR HER PROXY GROUP?

A. Ms. Bulkley reports a series of standard DCF estimates averaging about 9.6 percent using her midpoint growth rates (i.e., the average of her three growth rate sources). This is materially higher than my 9.1 percent. However, as I show in Section V of my testimony, this is due to her arbitrary decision to discard the DCF data for two of her companies because she feels the results are too low. Had she not discarded that information and reflected in her analysis the data for all 11 of her proxy companies, her average DCF result would be 8.9 percent, not 9.6 percent – a result well within my range and slightly below my recommendation. This one essential correction therefore eliminates any material discrepancy in our respective DCF studies.

C. DCF Study Using the Bulkley Proxy Group

Q. HOW HAVE YOU APPROACHED PERFORMING THE DCF ANALYSIS USING MS. BULKLEY'S PROXY GROUP?

A. I have used precisely the same set of procedures, data sources and methods as discussed above for my primary group. My intent was to replicate the DCF analysis using her exact group, but it was nonetheless necessary to eliminate Centerpoint Energy due to its pending merger, consistent with her own proxy group selection criteria.

I present this analysis on Schedule MIK-5, pages 1 – 5, in the same format as on Schedule MIK-4. As the only difference in this second analysis is the removal of two companies (Alliant Energy and Duke Energy), the analytic results do not change much. As shown on page 2 of that schedule the dividend yield for the six months ending June 2018 is 3.44 percent, which is adjusted upward to 3.5 percent. The security analyst earnings growth rate estimates from the same five sources (page 3 of that schedule) average to 5.68 percent. On page 5 of that schedule I present the "sustainable" growth rate analysis derived from Value Line projections which average 4.4 percent. Based on this information, I have adopted a DCF growth rate range of 4.5 – 5.7 percent.

Combining the dividend yield and growth rate range for this group (with no flotation cost adjustment) produces a DCF cost of equity estimate of 8.0 to 9.2 percent, with a midpoint of 8.6 percent. In other words, this result is nearly the same as my primary study since adding or subtracting Alliant Energy and Duke Energy to the proxy group appears to make little difference in the final result. Once again, I place the emphasis on the upper end of the DCF range as it is based on five separate sources of growth rate information.

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

Q. PLEASE DESCRIBE THE CAPM MODEL.

A. The CAPM is a form of the "risk premium" approach and is based on modern portfolio theory. Based on my experience, the CAPM is the cost of equity method most often used in rate cases after the DCF method, and it is one of Ms. Bulkley's four 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 Ms. Bulkley uses those betas along with betas published by Bloomberg, with the latter betas being somewhat lower. The greatest difficulty, however, is in the measurement of the expected stock market return (and therefore the equity risk premium), since that variable cannot be directly observed.

While the beta itself also is "observable," different investor services provide differing calculations of betas depending on the specific procedures and methods that they use. These differences can potentially have large impacts on the CAPM results.

In this case, the betas that Ms. Bulkley and I use are similar, with both of us relying on the betas published by Value Line. She uses 0.685 compared to my slightly lower 0.63.

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 Ms. Bulkley) along with the average beta for the electric/gas utility proxy group. (See Schedule MIK-3 for the company-by-company betas.) In the last six months, long-term (i.e., 30-year) Treasury yields have averaged approximately 3.1 percent (per page 2 of Schedule MIK-6), and the recent Value Line betas for my utility proxy group average 0.63. As of this writing in late July 2018, the 30-year Treasury rate is a slightly lower figure of 3.0 percent, but I believe it more appropriate to use a six month average to reflect current market conditions. I note that Ms. Bulkley has elected to use a risk-free rate in her studies that range from 2.84 to 4.10 percent (averaging 3.42 percent), which is somewhat higher than recent actual Treasury bond yields. Finally, and as explained below, I am using an equity risk premium range of 5 to 8 percent, although I also provide calculations using a higher risk premium as a sensitivity test.

Using these data inputs, the CAPM calculation results are shown on page 1 of Schedule MIK-6. My low-end cost of equity estimate uses a risk-free rate of 3.1 percent, a proxy group beta of 0.63 and an equity risk premium of 5 percent.

$$K_e = 3.1\% + 0.63\ (5.0\%) = 6.3\%$$

The upper-end estimate uses a risk-free rate of 3.1 percent, a proxy group beta of 0.63 and an equity risk premium of 8.0 percent.

$$K_e = 3.1\% + 0.63\ (8.0\%) = 8.1\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 6.3 to 8.1 percent, with a midpoint of 7.3 percent. The CAPM analysis produces a midpoint result significantly lower than the range of results obtained for my electric/gas utility group DCF analysis, but I have not placed reliance on the CAPM returns in formulating my ROE recommendation in this case. In my opinion, this is due to the difficulty in measuring the market risk premium and the fact that the DCF is a more reliable methodology for relatively stable utility companies.

Q. WHAT RESULT WOULD YOU OBTAIN USING MS. BULKLEY'S MARKET RISK PREMIUM?

A. For her CAPM study, Ms. Bulkley has developed a stock market expected return of 13.85 percent which using a prevailing Treasury yield of 3.1 percent would translate into an equity risk premium of 10.75 percent (13.85 minus 3.1 = 10.75). In conjunction with my proxy group beta of 0.63 and a 3.1 percent Treasury bond yield, the CAPM using this market risk premium estimate produces:

$$K_e = 3.1\% + 0.63(10.75\%) = 9.87\%$$

The 9.87 percent CAPM result, based on the recent six-month average Treasury yield, is below Ms. Bulkley's 10.3 percent recommendation, but is much higher than my CAPM range of results. I attribute this result to her unrealistically high 10.75 percent market risk premium estimate (derived from a 13.85 percent overall stock market long-term rate of return), a figure that is both outlandish and unsupportable. I discuss this problem further in Section V of my testimony.

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

A. There is a great deal of disagreement among analysts regarding the reasonably expected market return on the stock market as a whole and therefore the risk premium. In my opinion, a reasonable overall stock market risk premium to use would be about 6 to 7 percent, which today would imply a stock market return of about 9 to 10 percent. Due to uncertainty concerning the true market return value, I am employing a broad range of 5 to 8 percent as the overall market rate of return, which would imply a market equity return of roughly 8.1 to 11.1 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,* eight edition) 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 Ms. Bulkley's 10.75 percent risk premium (relative to a 3.1 percent Treasury rate) greatly exceeds the upper end of that range. My "midpoint" risk premium of roughly 6.5 percent falls well within that 5 to 8 percent range.

There is one important caveat to consider here regarding the 5 to 8 percent range that the authors believe is supported by the relevant 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 been constrained to low levels by Fed policy. It therefore could be argued that the 5 to 8 percent range of Brealey *et al*. is overstated if

a long-term Treasury yield (i.e., the 30-year Treasury) is used as the risk-free rate, i.e., the practice followed by both Ms. Bulkley and me.

V. REPLY TO WITNESS BULKLEY

A. Overview of Ms. Bulkley's Recommendation

Q. MS. BULKLEY IDENTIFIES A COST OF EQUITY RANGE OF 9.8 TO 10.5 PERCENT AND AN ROE AWARD OF 10.3 PERCENT. HOW DID SHE DEVELOP THAT COST OF EQUITY RANGE AND ROE RECOMMENDATION FOR PSE&G?

A. Ms. Bulkley employs four cost of equity estimation methodologies, the standard DCF, the projected DCF, CAPM and Risk Premium, although she is not clear about the weight she attaches to each method in developing her recommendation.

She presents a number of different cost of equity estimation calculations using each method. She presents three proxy group "mean" DCF calculations ranging from 9.54 to 9.62 percent based on differing time periods for measuring share prices (i.e., the averages for 30, 90 or 180 days ending December 29, 2017). For the "projected" DCF, she reports a cost rate of 9.65 percent. She presents three CAPM calculations ranging from 10.38 to 10.78, averaging 10.56 percent, based on three separate Treasury yield values (one actual and two projected). Finally, she presents three Risk Premium cost of equity calculations which range from 9.77 to 10.33 percent, averaging 10.0 percent, again based on three different interest rate assumptions.

While Ms. Bulkley does not specifically assign weights, if each of the four average cost of equity results is given equal weight, this produces an overall average of 10.2 percent, and she identifies a range of 9.8 to 10.5 percent. The final recommendation of 10.3 percent in some fashion takes into account management performance, but in point of fact is very close to her midpoint for the proxy group.

B. Ms. Bulkley's DCF Results

Q. DO YOU HAVE ANY OBJECTIONS TO MS. BULKLEY'S "STANDARD" DCF STUDY?

A. I have only one major disagreement with her standard DCF study. As she shows on her Schedule AEB-2, she performs her study in the normal way – very similar to my proxy group study – but with one crucial difference. She removes the DCF estimates for two of her 11 proxy companies because she believes such figures to be unduly low. Had she used the results from her full data set of all 11 companies, her standard DCF would have produced a cost of equity estimate of about 8.9 percent, entirely consistent with the results of my own DCF study and my 9.0 percent ROE recommendation. By arbitrarily deleting the two lowest observations (and not as a matter of fairness and symmetry also removing the two highest observations) she artificially increases her DCF study result from 8.9 percent to about 9.6 percent. Arbitrarily removing the two lowest observations (and not also removing the two highest observations to provide balance) shows bias and is simply not an acceptable analytical procedure. Indeed, the entire purpose of using a robust proxy group is so that the effects of unusually high and low observations can cancel out. After all, it is the proxy group average that matters, not the individual company results. If she is concerned that an unduly low observation (or alternatively an unduly high observation) is distorting the results, an alternative often used by analysts would be to utilize the median instead of the mean. On page 1 of her schedule, the median DCF result for her 11 company proxy group is 8.96 percent – a result very close to the mean estimate when all 11 companies are included.

I understand that Ms. Bulkley's criterion for deleting an observation is if it produces a DCF result lower than 7 percent. It should be noted that none of my

individual company DCF results produce such a result and thus all data in my DCF study should be used even if her improper criterion is applied.

Q. DO YOU OBJECT TO HER "PROJECTED"DCF" STUDY?

A. Yes, I do, as this is simply not an accepted cost of equity methodology and is completely inconsistent with the financial theory underlying the DCF model. I testify extensively on cost of capital in numerous states and at FERC, and I have never seen this method used and presented let alone accepted by regulators as valid. For that reason, Rate Counsel in RCR ROR-18 asked Ms. Bulkley whether this method had ever previously been adopted by a regulatory commission. She responded, "Ms. Bulkley is not aware of whether any state or federal utility jurisdiction has adopted, accepted or endorsed this methodology."

Ms. Bulkley on her Schedule AEB-3 reports a cost of equity estimate of 10.65 percent using this methodology, but again this is biased upward by the fact that she deleted an observation she finds to be unduly low (again, without deleting an unusually high observation). Had she used her full data set, her estimate would be 9.98 percent using this method, and not 10.65 percent.

Q. HOW DOES HER "PROJECTED" DCF MODEL DIFFER FROM THE ACCEPTED STANDARD DCF MODEL?

A. The calculation procedures are essentially the same, but instead of using observed market data she substitutes projections (to the year 2021) published by Value Line for (a) the annual dividend per share, and (b) the share price for each of the 11 proxy companies. Please note that Value Line does not actually have a projection of share prices but rather provides a very wide range of possible futures. She simply adopts the midpoint of that range. The midpoint of that range is not Value Line or anyone else's projection. The projected DCF produces a very high DCF result – about a full

percentage point higher – due to an increase in the dividend yield. That is, the proxy group (adjusted) dividend yield is increased from the actual, current average value of about 3.4 percent in her standard DCF (and mine as well) to 4.4 percent.

The crucial question to be asked is what causes this sharp (i.e., over 30 percent) increase in the projected dividend yield as compared to the actual. This sharp increase is driven by the fact that she is projecting for her 11 proxy companies that over the next three to four years (allegedly citing to Value Line) share prices (compared to today) will grow only very slowly or will actually decline. In fact, I compared the year 2021 share prices she used (excluding Centerpoint) with current (June 30, 2018) actual share prices. For six of the ten companies the share prices she used for the year 2021 are lower. For the other four companies, there is an increase, but it is quite modest. This is obviously implausible as representing the views of investors (the purpose of all market-based cost of equity models). It is not credible to suggest that investors would purchase these company shares today if they expected those share prices to actually decline over the next three to four years.

Q. SHOULD THIS "PROJECTED" DCF MODEL BE REJECTED?

A. Yes, it should for multiple reasons. Most fundamentally, it is inconsistent with DCF theory and the entire rationale for using the DCF model. The virtue of that model and reason for its widespread acceptance is that it is grounded in actual financial market data that can be readily observed (as is the CAPM). Specifically, it employs three basic parameters: the per share dividend, the company's share price and the long-term growth rate. The first two are based on actual observed market data and are therefore completely objective. The third, the growth rate, is most often based on published analyst projections and can be subject to dispute. In this case, however, there is little disagreement over the proxy group growth rate. The fact that the DCF is grounded in

actual, observed market data is the basis for its validity and the claim that it can measure investor return requirements. DCF financial theory is very clear on that point.

Ms. Bulkley's projected approach abandons this bedrock principle of using actual observed market data for the dividend and share price and instead substitutes projected data. Consequently, this method, by definition, cannot measure investor return requirements for holding or purchasing utility stocks. At best is a measure of what a DCF study conducted in the year 2021 would produce, a hypothetical that is obviously irrelevant to this case. Even that hypothetical requires the heroic assumption that the Value Line projections to 2021 exactly match the consensus of investor opinion. This clearly cannot be true given the assumptions that company share prices will decline from today's levels. Put another way, Ms. Bulkley conducts this DCF study based on the assumption that the proxy group dividend yield is 4.4 percent. This is factually inaccurate as representing current market conditions where the actual observed dividend yield is 3.4 percent. The projected DCF therefore cannot measure the current market cost of equity. At best, it is an attempt to measure a hypothetical cost of equity in the year 2021 based upon hypothesized future share prices, prices that investors are probably not expecting. In that sense, it is both irrelevant to the cost of equity estimation task in this rate case and a rejection of the use of observed market data. For all of these reasons, this study method is not worthy of consideration.

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

Q. WHAT ARE YOUR OBJECTIONS TO MS. BULKLEY'S CAPM STUDY?

A. I have only two significant differences with Ms. Bulkley concerning her CAPM analyses -- the market risk premium value that she selected and her partial use of

forecasted in place of actual Treasury yields. Both she and I use similar values for the beta, both of us use the 30-year Treasury as a measure of the risk-free rate, and we use the same CAPM formula.

My first objection to her CAPM studies is her use of market risk premium estimates that are excessive. Specifically, she employs a risk premium figure based on today's Treasury yield (of about 3.1 percent) of about 10.75 percent – a figure far above the reasonable and plausible range. This very high figure is based on her DCF study of the S&P 500 which produces an investor market rate of return of 13.85 percent.

As noted in Section IV of my testimony, the reasonable range for the equity market risk premium would be about 5 to 8 percent. The 10.75 percent value greatly exceeds the top end of the range and is simply not reasonable. This is because the nearly 14 percent assumed long-term rate of return on the overall stock market itself is not reasonable as a plausible measure of investor expectations.

Q. WHAT TREASURY BOND YIELDS DID MS. BULKLEY USE?

A. She uses a relatively current value (as of the time of her testimony) of 2.84 percent, a near-term forecast of 3.32 percent and a long-term forecast of 4.10 percent.

Q. WHAT IS YOUR OBJECTION TO THESE TREASURY YIELDS?

A. Ms. Bulkley's selection of 2.84 percent at the time of her testimony was reasonable, although that figure does need to be updated for more recent actual 2018 conditions. Doing so will increase it modestly to my 3.1 percent, an increase of about 0.2 to 0.3 percent.

The near-term projection may have been her attempt to reflect expected cost of equity conditions as of the completion of this rate case, which is understandable. The problem is that such forecasts at best are speculative. Moreover, the projections

of interest rate increases in the past have a consistent track record of being wrong and overstated. While the 3.32 percent is Ms. Bulkley's expectation of an interest rate increase from the actual 2.84 percent at year-end 2017, instead 30-year Treasury yields initially increased slightly at the beginning of 2018 and have remained stable or fallen slightly since then.

Finally, the 4.10 percent figure may reflect forecasters (but clearly not investors') views regarding Treasury yields many years in the future. Consequently, this has nothing to do with the cost of equity for this rate case in 2018. Capital cost conditions in future years will be addressed in future PSE&G rate cases. This is irrelevant to investor requirements today, as well as being speculative. It is improper to base an ROE award using a forecast of what might occur in the future. Rather, it is more appropriate to rely on current observed market data.

Q. HAVE YOU COMPARED MS. BULKLEY'S CLAIMED 14 PERCENT S&P 500 RATE OF RETURN ESTIMATE AGAINST OTHER SOURCES?

A. Yes, and other information suggests that the nearly 14 percent investor rate of return/11 percent risk premium values are excessive and unrealistic. For example, Yahoo Finance (which reports growth rates from First Call, a source relied upon by Ms. Bulkley) publishes at this time an earnings growth projection for the S&P 500 of 11 percent.[3] Since according to Ms. Bulkley the S&P 500 dividend yield is about 1.9 percent, this implies a rate of return on the overall stock market of about 12.9 percent. While lower than Ms. Bulkley's nearly 14 percent rate of return, even this First Call based result is unrealistically high. It is undoubtedly distorted upward by the one-time (not sustained) contributions to earnings growth resulting from the massive

[3] I note that the March 10, 2018 edition of Blue Chip reports a consensus long-term annual growth rate in U.S. nominal pre-tax corporate profits of 4.4 percent—a figure far below Ms. Bulkley's 11 percent earnings growth rate figure.

corporate tax cut enacted in 2017. Thus, the current rapid near-term (even five years) earnings growth rate projections that we observe are distorted figures and do not reflect the sustainable long-term growth rate that the DCF model requires. For cost of equity purposes in this case, it is unreasonable to rely upon the assumption that investors expect and require a 14 percent long-term rate of return on the stock market. The return expectation and requirement is far lower than that.

D. Ms. Bulkley's Risk Premium Study

Q. HOW DID MS. BULKLEY ESTIMATE THE COST OF EQUITY USING THE RISK PREMIUM METHOD?

A. Ms. Bulkley estimated a regression model in which the historic electric and gas utility risk premium is "explained" by the level of 30-year U.S. Treasury yield. The risk premium data series itself is based upon 25 years (1992 – 2017) of historical state commission ROE awards as reported by Regulatory Research Associates ("RRA"). Her estimated equation is:

$$RP = -0.5558(x) + 0.085$$

Thus, at Ms. Bulkley's recent (late 2017) Treasury yield of 2.84 percent, her regression model indicates a risk premium of about 6.93%:

$$RP = -0.5558(0.0284) + 0.085 = 6.93\%$$

Adding back the 2.84 percent Treasury yield produces a cost of equity of 9.77 percent. Using the relatively current 3.1 percent Treasury yield would imply a risk-premium derived cost of equity of about 9.9 percent.

Ms. Bulkley, however, did not only use the actual Treasury yield of 2.84 percent, but she also assumed Treasury bond yields would increase to 3.32 percent near term and spike to 4.10 percent long term. Using this assumption of higher capital costs (Treasury rates) in the future, she obtains an alternative risk premium

cost of equity estimates of 9.98 and 10.32 percent using this model. I explained in the last section above why such assumptions about rising interest rates are both factually incorrect and/or irrelevant to this rate case.

Q. IS THIS MODEL SPECIFICALLY APPLICABLE TO PSE&G?

A. No, it is not. Even if this model is completely valid and accurate (which it is not), at best, it measures a kind of "generic" or industry-wide cost of capital. The industry, however, is largely or mostly made up of vertically-integrated utilities, such as Ms. Bulkley's proxy companies. PSE&G is a much less risky distribution utility, and it therefore follows that its equity risk premium would be less than the industry average figure. I demonstrated that ROE awards to distribution utilities have been lower than for vertically integrated companies in Section II of my testimony.

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

A. At best, it can be used as a reality check (noting the biases described above), but it is not a reliable cost of equity estimation method. The model in reality is attempting to explain state commission ROE awards since it is based on these decisions rather than market data. What it explains, perhaps correctly, is that state commissions often tend to be conservative in their ROE awards, changing them only very gradually as long-term interest rates change. State commissions in their rate decisions try to avoid making unnecessarily abrupt changes on a year-to-year basis and take into account precedent. These awards, on average, therefore only roughly reflect the cost of equity at given times. While the model attempts to explain the behavior of state commissions relative to this one factor (long-term interest rates), Ms. Bulkley's model is not terribly accurate as a predictor of what state commissions would actually do in any given year. For example, for 2018 with Treasury rates at 3.1 percent, the

model "predicts" that average ROE awards "should be" 9.9 percent. Unfortunately, that does not comport with what we can actually observe. Rather, ROE awards have been lower.

This raises a fundamental question. The "driver" of the model is the historically awarded ROEs from state commissions. But since we can directly and timely observe what those state commission ROE awards are, what does this model add to our understanding? I demonstrated in Section II, during the first half of 2018 ROE awards have been materially lower than the predicted 9.9 percent, in the mid 9s generally and low 9s for distribution electrics. The statistical risk premium model therefore does not add anything, and in fact, it can mislead by implying that state commission ROE awards are higher than they actually are. Thus, I question whether the model is actually a cost of equity methodology and whether it provides any useful information concerning PSE&G's actual cost of equity.

VI. CONCLUSIONS

Q. WHAT ARE YOUR MAJOR FINDINGS AND CONCLUSIONS?

A. Based on my review of the testimony, discovery responses and market information, I find that PSE&G is a financially sound and low-risk electric/gas distribution utility company presently operating in a very low capital cost environment. In this case, the Company is proposing to maintain its currently authorized return on equity of 10.3 percent despite the clear evidence of declining company risk and market capital costs since its last rate case in 2010. In addition, the Company is seeking a large increase in its authorized equity ratio to 54 percent, a request that adds substantially to the rate request for gas and electric service. The requested 10.3 percent ROE, which reflects capital cost conditions and ROE awards from another time period should be reduced to 9.0 percent based on current capital market conditions, PSE&G's risk profile and the credible cost of equity evidence in this case.

Q. WOULD A REDUCTION TO THE CURRENT 10.3 PERCENT BE UNREASONABLE OR PUNITIVE TO SHAREHOLDERS?

A. No, not at all. As I have just shown in my testimony that since 2010, there has been a declining trend in state commission ROE awards, albeit a gradual trend. For the utility industry as a whole, in electric base rate cases the average award was 9.68 percent in 2017 and 9.58 percent (to date) in 2018. The ROE awards for delivery service electrics are even lower, averaging 9.43 percent in 2017 and 9.18 percent in 2018 to date. For gas utilities, the average ROE award was 9.72 percent in 2017 and 9.55 percent in 2018 to date.

Given this declining trend in ROE awards, a legitimate question is how have utility stocks performed? Do investors find these lowered ROE awards to be acceptable? Do ROE awards in the low to mid 9s meet the crucial capital attraction

standard. The evidence demonstrates that the utility stocks have performed extremely well and utility management has shown no reluctance to invest aggressively. With respect to investment, please see Table 2 below. This table shows for all 12 of my proxy electric/gas companies the increase in net plant between 2010 and 2018 (i.e., net investment in excess of depreciation expense) and the projected increase in net plant to 2022. This table demonstrates that there was a willingness to invest aggressively historically as ROE awards have gradually declined as well as a willingness to invest in new capital going forward. The Edison Electric Institute ("EEI") reports both robust electric utility industry investments in recent years and going forward. (Per SNL, "EEI boosts Cap Ex estimates in 2018, 2019", July 17, 2018.) Quoting from the EEI publication, SNL reports, "Industry Cap Ex in 2017 totaled $113.6 billion, marking the sixth consecutive year in which we've set a record high . . .the industry plans to maintain an elevated level of capital spending for at least the near term." Clearly the state commission ROE awards have not discouraged capital investment spending, as management finds robust capital spending to be attractive.

Table 2. Historical and Projected Net Plant (millions $)			
Company	**2010**	**2018**	**2021-2023**
Alliant	$6,731	$11,125	$12,900
Ameren	17,853	22,800	27,900
Avangrid	--	24,175	29,800
Black Hills	2,495	4,765	5,525
CMS	10,069	17,925	22,100
Con Ed	23,863	40,150	47,800
DTE	12,992	23,075	27,500
Duke	--	92,675	108,700
Eversource	--	25,800	31,600
Northwestern	2,118	4,465	4,975
WEC Energy	--	23,000	28,700
Xcel	20,663	36,775	42,700
Source: Value Line Investment Survey, April 27, May 18, and June 15, 2018. The 2010 data for four companies excluded due to unavailability or post 2010 mergers.			

Investors have also found investing in utility company shares to be highly attractive. Table 3 below provides a compilation of utility share prices for each of the 12 members of my proxy group at June 30, 2010 (approximately the completion date of the Company's last base rate case) and June 30, 2018. (Note that the 2010 share price data for one company, AVANGRID, is not available as the Company did not exist at that time.) The third column in that table shows the percentage price increase over those eight years. Over this time period of declining capital costs and ROE awards, the average company share price increased by 232 percent. This is an average annual growth rate of 11 percent which is in addition to the annual dividend yield during that time of about 4 percent. In other words, investors found these utility companies to be extremely attractive investments and bid up share prices aggressively notwithstanding declining ROE awards. Further evidence of investor attractiveness to utility company shares is shown on page 5 of Schedule MIK-4. That table shows the stock price premiums over book value per share. Those premiums range from a low of 7 percent to a high of nearly 161 percent, averaging 72 percent. This indicates

that electric utility valuations are very strong, and investors find electric utility stocks with the sub 10 percent (or sub 9.75 percent) ROE awards to be very attractive.

Table 3.
Increases in Share Prices
June 30, 2010 to June 30, 2018

Company	2010	2018	% Increase
Alliant	$15.87	$42.32	267%
Ameren	23.77	60.85	256
Avangrid	N/A	52.93	N/A
Black Hills	28.47	61.21	215
CMS	14.65	47.28	323
Con Ed	43.10	77.98	178
DTE	45.61	103.63	227
Duke	48.00	79.08	165
Eversource	25.48	58.61	230
Northwestern	26.20	57.25	219
WEC Energy	25.37	64.65	255
Xcel	20.61	45.68	222
Average			**232%**
Annualized Growth Rate			**11%**

Source: YahooFinance.com. Figures adjusted for stock splits.

Investors clearly are attracted to utility stocks and are bidding up share prices notwithstanding declining ROE awards. This is because the cost of capital has been declining by even more than the ROE awards. The message from capital markets is clear: the reduction in ROEs to the low- to mid-9s has not harmed the attractiveness of utility stocks to investors, nor has it impaired the ability of utilities to attract needed capital. In fact, it demonstrates that there is room to further reduce the allowed ROE and still meet the capital attraction test.

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

A. I am recommending at this time a 6.62 percent return on PSE&G gas and electric distribution rate bases, including a 9.0 percent return on common equity. This ROE is supported by current market conditions and the following studies:

(1) DCF Study of 12 Electric/Gas Proxy Companies

8.1 to 9.1 percent, with an 8.6 percent midpoint

(2) CAPM Calculations

6.3 to 8.1 percent, with a 7.2 percent midpoint. My "high sensitivity" case is 8.8 percent.

In addition, I find that PSE&G is generally less risky on average than the proxy group due to (a) its higher than average (54 percent) target equity ratio, (2) its ability to make extensive use of low-risk trackers for contemporaneous cost recovery of incremental capital investment, (3) its very strong credit ratings and Value Line risk indicators, (4) its status as a delivery service electric with no generation risk. Thus, my ROE recommendation for PSE&G is consistent with my range of cost of equity evidence and is conservative.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE GAIL M. COOKSON

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF AN INCREASE IN ELECTRIC AND GAS RATES AND FOR CHANGES IN THE TARIFFS FOR ELECTRIC AND GAS SERVICE, B.P.U.N.J. NO. 16 ELECTRIC AND B.P.U.N.J. NO. 16 GAS, AND FOR CHANGES IN DEPRECIATION RATES, PURSUANT TO N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 AND N.J.S.A. 42:2-21 AND FOR OTHER APPROPRIATE RELIEF	)	**BPU Docket Nos. ER18010029 and GR18010030** **OAL Docket No. PUC 01151-18**

SCHEDULES ACCOMPANYING THE
DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE
DIVISION OF RATE COUNSEL

STEFANIE A. BRAND, ESQ.
DIRECTOR, DIVISION OF RATE COUNSEL

140 East Front Street, 4th Floor
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Trenton, New Jersey 08625
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Dated: August 6, 2018

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Provisional Weighted Average Cost of Capital
($Millions)

	Amount	Percent	Embedded Cost	Weighted Cost
Long-Term Debt	$8,958[(1)]	46.36%	3.96%(1)	1.84%
Customer Deposits	93[(2)]	0.48	0.87	0.00
Common Equity	10,273[(2)]	53.16	9.00[(3)]	4.78
Total	**$19,324**	**100.00%**	--	**6.62%**

[(1)] Response to RCR-ROR-28, May 31, 2018 Update

[(2)] Schedule SSJ-04 R-1.

[(3)] DCF evidence and PSE&G's inherent investment risk.

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
2001	2.9%	5.0%	3.5%	7.8%
2002	1.6	4.6	1.6	7.4
2003	1.9	4.1	1.0	6.6
2004	2.7	4.3	1.4	6.2
2005	3.4	4.3	3.0	5.6
2006	2.5	4.8	4.8	6.1
2007	2.8	4.6	4.5	6.3
2008	3.8	3.4	1.6	6.5
2009	(0.4)	3.2	0.2	6.0
2010	1.6	3.2	0.1	5.5
2011	3.1	2.8	0.0	5.1
2012	2.1	1.8	0.1	4.1
2013	1.5	2.3	0.1	4.5
2014	1.7	2.5	0.0	4.3
2015	0.1	2.2	0.0	4.1
2016	1.3	1.8	0.0	3.9
2017	2.1	2.3	1.0	4.0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

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

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
2011				
January	1.6%	3.4%	0.1%	5.6%
February	2.1	3.6	0.1	5.7
March	2.7	3.4	0.1	5.6
April	2.2	3.5	0.1	5.6
May	3.6	3.2	0.0	5.3
June	3.6	3.0	0.0	5.3
July	3.6	3.0	0.0	5.3
August	3.8	2.3	0.0	4.7
September	3.9	2.0	0.0	4.5
October	3.5	2.2	0.0	4.5
November	3.0	2.0	0.0	4.3
December	3.0	2.0	0.0	4.3
2012				
January	2.9%	2.0%	0.0%	4.3%
February	2.9	2.0	0.0	4.4
March	2.7	2.2	0.1	4.5
April	2.3	2.1	0.1	4.4
May	1.7	1.8	0.1	4.2
June	1.7	1.6	0.1	4.1
July	1.4	1.5	0.1	3.9
August	1.7	1.7	0.1	4.0
September	2.0	1.7	0.1	4.0
October	2.2	1.8	0.1	3.9
November	1.8	1.7	0.1	3.8
December	1.7	1.7	0.1	4.0

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
2013				
January	1.6%	1.9%	0.1%	4.2%
February	2.0	2.0	0.1	4.2
March	1.5	2.0	0.1	4.2
April	1.1	1.8	0.1	4.0
May	1.4	1.9	0.0	4.2
June	1.8	2.3	0.1	4.5
July	2.0	2.6	0.0	4.7
August	1.5	2.7	0.0	4.7
September	1.2	2.8	0.0	4.8
October	1.0	2.6	0.1	4.7
November	1.2	2.7	0.1	4.8
December	1.5	2.9	0.1	4.8
2014				
January	1.6%	2.9%	0.0%	4.6%
February	1.1	2.7	0.1	4.5
March	1.5	2.7	0.1	4.5
April	2.0	2.7	0.0	4.4
May	2.1	2.6	0.0	4.3
June	2.1	2.6	0.1	4.3
July	2.0	2.5	0.0	4.2
August	1.7	2.4	0.0	4.1
September	1.7	2.5	0.0	4.2
October	1.7	2.3	0.0	4.1
November	1.3	2.3	0.0	4.1
December	0.8	2.2	0.0	4.0

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury	Single A Utility Yield
2017				
January	2.5%	2.4%	0.5%	4.1%
February	2.7	2.4	0.5	4.2
March	2.4	2.5	0.8	4.2
April	2.2	2.3	0.8	4.1
May	1.9	2.3	0.9	4.1
June	1.6	2.2	1.0	3.9
July	1.7	2.3	1.1	4.0
August	1.9	2.2	1.0	3.9
September	2.2	2.2	1.1	3.9
October	2.0	2.4	1.1	3.9
November	2.2	2.4	1.3	3.8
December	2.1	2.4	1.3	3.8
2018				
January	2.1	2.6	1.4	3.9
February	2.2	2.9	1.6	4.1
March	2.4	2.8	1.7	4.2
April	2.5	2.9	1.8	4.2
May	2.8	3.0	1.9	4.3
June	2.9	2.9	1.9	4.3

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

List of the Electric/Gas Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2018 Common Equity Ratio*
1.	Alliant Energy	2	A	0.70	50.0%
2.	Ameren Corp	2	A	0.65	49.5
3.	AVANGARD, Inc.	2	B++	0.40	71.5
4.	Black Hills Corp	2	A	0.90	41.5
5.	CMS Energy	2	B++	0.65	35.5
6.	Consolidated Edison	1	A+	0.50	51.0
7.	DTE Energy	2	B++	0.65	42.0
8.	Duke Energy	2	A	0.60	46.0
9.	Eversource Energy	1	A	0.65	47.5
10.	Northwestern Corp	3	B+	0.65	50.5
11.	WEC Energy Group	1	A+	0.60	51.0
12.	Xcel Energy	1	A+	0.60	42.0
	Average	**1.8**	**--**	**0.63**	**48.2%**

*The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2018 equity ratio including short-term debt and current maturities averages 45.7 percent.
Source: *Value Line Investment Survey*, April 27, 2018, May 18, 2018, and June 15, 2018.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DCF Summary for the
Electric/Gas Company Proxy Group

1.	Dividend Yield (January – June 2018)[(1)]	3.52%
2.	Adjusted Yield ((1) x 1.0275)	3.6%
3.	Long-Term Growth Rate[(2)]	4.5 – 5.5%
4.	Total Return ((2) + (3))	8.1 – 9.1%
5.	Flotation Expense	0.0%
6.	Cost of Equity ((4) + (5))	8.1 – 9.1%
7.	Midpoint	8.6%
	Recommendation	**9.0%**

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Dividend Yields for the Electric/Gas Company Proxy Group
(January - June 2018)

	Company	January	February	March	April	May	June	Average
1.	Alliant Energy	3.4%	3.5%	3.3%	3.1%	3.2%	3.2%	3.27%
2.	Ameren Corp	3.2	3.4	3.2	3.1	3.1	3.0	3.18
3.	AVANGRID, Inc.	3.5	3.6	3.4	3.3	3.3	3.3	3.38
4.	Black Hills	3.4	3.7	3.5	3.4	3.3	3.1	3.40
5.	CMS Energy	3.2	3.4	3.2	3.0	3.1	3.0	3.15
6.	Consolidated Edison	3.6	3.8	3.7	3.6	3.7	3.7	3.67
7.	DTE Energy	3.3	3.5	3.4	3.3	3.4	3.4	3.40
8.	Duke Energy	4.5	4.7	4.6	4.4	4.6	4.5	4.57
9.	Eversource Energy	3.2	3.5	3.4	3.4	3.5	3.4	3.42
10.	Northwestern Corp	4.0	4.3	4.1	4.0	4.0	3.8	4.06
11.	WEC Energy Group	3.4	3.7	3.5	3.4	3.5	3.4	3.50
12.	Xcel Energy	3.2	3.3	3.2	3.2	3.3	3.3	3.26
	Average	**3.50%**	**3.70%**	**3.53%**	**3.44%**	**3.51%**	**3.43%**	**3.52%**

Source: YahooFinance! website, accessed June 2018. Dividend yields based on month closing share prices and quarterly dividends.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Company	Value Line	Yahoo	Zacks	Reuters	CNN	Average
1.	Alliant Energy	6.50%	5.85%	5.58%	5.85%	6.00%	5.86%
2.	Ameren Corp	7.50	6.30	6.54	6.30	7.00	6.73
3.	AVANGRID, Inc.	13.00	10.40	9.41	9.20	9.71	10.29
4.	Black Hills	5.00	3.86	4.14	3.86	5.27	4.43
5.	CMS Energy	7.00	7.05	6.35	7.05	7.00	6.89
6.	Consolidated Edison	3.00	3.39	4.00	3.39	3.53	3.46
7.	DTE Energy	7.00	5.59	5.33	5.59	4.87	5.68
8.	Duke Energy	5.50	4.22	4.64	4.22	4.70	4.66
9.	Eversource Energy	5.50	5.64	5.75	5.64	5.50	5.61
10.	Northwestern Corp	3.50	3.16	3.01	3.16	3.00	3.17
11.	WEC Energy Group	7.00	4.43	4.13	4.43	3.80	4.76
12.	Xcel Energy	5.50	5.86	5.67	5.86	6.00	5.78
	Average	**6.33%**	**5.48%**	**5.36%**	**5.38%**	**5.53%**	**5.61%**

Source: *Value Line Investment Survey*, April 27, 2018, May 18, 2018, and June 15, 2018. YahooFinance.com, Zacks.com, CNNMoney.com, Reuters.com, public websites, June 2018.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Company	Dividend per Share	Book Value per Share	Earnings Retention
1.	Alliant Energy	6.0%	5.0%	4.0%
2.	Ameren Corp	5.5	4.5	4.5
3.	AVANGRID, Inc.	5.0	1.5	2.0
4.	Black Hills	6.0	5.5	4.0
5.	CMS Energy	7.0	6.5	5.5
6.	Consolidated Edison	3.5	3.5	2.5
7.	DTE Energy	6.5	5.5	4.5
8.	Duke Energy	4.5	2.0	1.5
9.	Eversource Energy	6.0	3.5	3.5
10.	Northwestern Corp	4.5	3.5	3.5
11.	WEC Energy Group	6.0	4.0	4.5
12.	Xcel Energy	5.5	4.5	4.0
	Average	**5.50%**	**4.13%**	**3.67%**

Source: *Value Line Investment Survey*, April 27, 2018, May 18, 2018 and June 15, 2018. The earnings retention figures are projections for 2021-2023.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Fundamental Growth Rate Analysis for
Electric/Gas Company Proxy Group

	Company	Shares 2017-2022[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	Alliant Energy	0.3%	109.2%	0.3%	4.0%	4.3%
2.	Ameren Corp	0.6	85.2	0.5	4.5	5.0
3.	AVANGRID, Inc.	0.0	6.6	0.0	2.0	2.0
4.	Black Hills	2.1	54.4	1.2	4.0	5.2
5.	CMS Energy	0.9	160.6	1.4	5.5	6.9
6.	Consolidated Edison	0.7	47.4	0.3	2.5	2.8
7.	DTE Energy	1.7	77.3	1.3	4.5	5.8
8.	Duke Energy	1.3	27.6	0.3	1.5	1.8
9.	Eversource Energy	0.0	58.1	0.0	3.5	3.5
10.	Northwestern Corp	0.7	43.8	0.3	3.5	3.8
11.	WEC Energy Group	0.0	96.5	0.0	4.5	4.5
12.	Xcel Energy	0.6	93.7	0.5	4.0	4.5
	Average			**0.5%**	**3.7%**	**4.2%**

[1] Projected growth rate in shares outstanding; 2017-2022.
[2] % Premium of share price ("Recent Price") over 2017 book value per share.
[3] sv is growth rate in shares x % premium.
[4] br is Value Line projection as of 2021-2023.
Source: *Value Line Investment Survey*, April 27, 2018, May 18 2018, and June 15, 2018.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DCF Summary for the Bulkley
Electric/Gas Company Proxy Group

1.	Dividend Yield (January – June 2018)[(1)]	3.44%
2.	Adjusted Yield ((1) x 1.0275)	3.5%
3.	Long-Term Growth Rate[(2)]	4.5 – 5.7%
4.	Total Return ((2) + (3))	8.0 – 9.2%
5.	Flotation Expense	0.0%
6.	Cost of Equity ((4) + (5))	8.0 – 9.2%
7.	Midpoint	8.6%
	Recommendation	**9.0%**

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Dividend Yields for the Bulkley Electric/Gas Company Proxy Group
(January - June 2018)

	Company	January	February	March	April	May	June	Average
1.	Ameren Corp	3.2%	3.4%	3.2%	3.1%	3.1%	3.0%	3.18%
2.	AVANGRID, Inc.	3.5	3.6	3.4	3.3	3.3	3.3	3.38
3.	Black Hills	3.4	3.7	3.5	3.4	3.3	3.1	3.40
4.	CMS Energy	3.2	3.4	3.2	3.0	3.1	3.0	3.15
5.	Consolidated Edison	3.6	3.8	3.7	3.6	3.7	3.7	3.67
6.	DTE Energy	3.3	3.5	3.4	3.4	3.5	3.4	3.40
7.	Eversource Energy	3.2	3.5	3.4	3.4	3.5	3.4	3.42
8.	Northwestern Corp	4.0	4.3	4.1	4.0	4.0	3.8	4.06
9.	WEC Energy Group	3.4	3.7	3.5	3.4	3.5	3.4	3.50
10.	Xcel Energy	3.2	3.3	3.2	3.2	3.3	3.3	3.26
	Average	**3.41%**	**3.62%**	**3.45%**	**3.37%**	**3.43%**	**3.35%**	**3.44%**

Source: YahooFinance! website, accessed June 2018. Dividend yields based on month closing share prices and quarterly dividends.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Company	Value Line	Yahoo	Zacks	Reuters	CNN	Average
1.	Ameren Corp	7.50%	6.30%	6.54%	6.30%	7.00%	6.73%
2.	AVANGRID, Inc.	13.00	10.40	9.41	9.20	9.71	10.29
3.	Black Hills	5.00	3.86	4.14	3.86	5.27	4.43
4.	CMS Energy	7.00	7.05	6.35	7.05	7.00	6.89
5.	Consolidated Edison	3.00	3.39	4.00	3.39	3.53	3.46
6.	DTE Energy	7.00	5.59	5.33	5.59	4.87	5.68
7.	Eversource Energy	5.50	5.64	5.75	5.64	5.50	5.61
8.	Northwestern Corp	3.50	3.16	3.01	3.16	3.00	3.17
9.	WEC Energy Group	7.00	4.43	4.13	4.43	3.80	4.76
10.	Xcel Energy	5.50	5.86	5.67	5.86	6.00	5.78
	Average	**6.40%**	**5.57%**	**5.41%**	**5.45%**	**5.57%**	**5.68%**

Source: *Value Line Investment Survey*, April 27, 2018, May 18, 2018, and June 15, 2018. YahooFinance.com, Zacks.com, CNNMoney.com, Reuters.com, public websites, June 2018.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

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

	Company	Dividend per Share	Book Value per Share	Earnings Retention
1.	Ameren Corp	5.5%	4.5%	4.5%
2.	AVANGRID, Inc.	5.0	1.5	2.0
3.	Black Hills	6.0	5.5	4.0
4.	CMS Energy	7.0	6.5	5.5
5.	Consolidated Edison	3.5	3.5	2.5
6.	DTE Energy	6.5	5.5	4.5
7.	Eversource Energy	6.0	3.5	3.5
8.	Northwestern Corp	4.5	3.5	3.5
9.	WEC Energy Group	6.0	4.0	4.5
10.	Xcel Energy	5.5	4.5	4.0
	Average	**5.50%**	**4.25%**	**3.85%**

Source: *Value Line Investment Survey*, April 27, 2018, May 18, 2018 and June 15, 2018. The earnings retention figures are projections for 2021-2023.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Fundamental Growth Rate Analysis for Bulkley
Electric/Gas Company Proxy Group

	Company	Shares 2017-2022[1]	% Premium[2]	sv[3]	br[4]	sv + br
1.	Ameren Corp	0.6%	85.2%	0.5%	4.5%	5.0%
2.	AVANGRID, Inc.	0.0	6.6	0.0	2.0	2.0
3.	Black Hills	2.1	54.4	1.2	4.0	5.2
4.	CMS Energy	0.9	160.6	1.4	5.5	6.9
5.	Consolidated Edison	0.7	47.4	0.3	2.5	2.8
6.	DTE Energy	1.7	77.3	1.3	4.5	5.8
7.	Eversource Energy	0.0	58.1	0.0	3.5	3.5
8.	Northwestern Corp	0.7	43.8	0.3	3.5	3.8
9.	WEC Energy Group	0.0	96.5	0.0	4.5	4.5
10.	Xcel Energy	0.6	93.7	0.5	4.0	4.5
	Average			**0.6%**	**3.9%**	**4.4%**

[1] Projected growth rate in shares outstanding; 2017-2022.
[2] % Premium of share price ("Recent Price") over 2017 book value per share.
[3] sv is growth rate in shares x % premium.
[4] br is Value Line projection as of 2021-2023.
Source: *Value Line Investment Survey*, April 27, 2018, May 18 2018, and June 15, 2018.

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 = 3.1% (Long-term Treasury bond yield for the most recent six months)

Rm = 8.1 – 11.1% (equates to equity risk premium of 5.0 - 8.0%)

Beta = 0.63 (See Schedule MIK-3)

C. Model Calculations

Low end:	$K_e = 3.1\% + 0.63 (5.0) = 6.3\%$
Midpoint:	$K_e = 3.1\% + 0.63 (6.5) = 7.2\%$
Upper End:	$K_e = 3.1\% + 0.63 (8.0) = 8.1\%$
High Sensitivity:	$K_e = 3.1\% + 0.63 (9.0) = 8.8\%$

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Long-Term Treasury Yields
(January – June 2018)

Month	30-Year	20-Year	10-Year
January	2.88%	2.73%	2.58%
February	3.13	3.02	2.86
March	3.09	2.97	2.84
April	3.07	2.96	2.87
May	3.13	3.05	2.95
June	3.05	2.98	2.91
Average	**3.06%**	**2.95%**	**2.84%**

Source: Federal Reserve, www.federalreserve.gov website, July 2018.

APPENDIX A

MATTHEW I. KAHAL

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

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

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

Professional Experience

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

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

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

Publications and Consulting Reports

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Conference and Workshop Presentations

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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	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

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	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)

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	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
403.	E013020155 and G013020156 October 2013	Public Service Electric and Gas Company	New Jersey	Rate Counsel	Cost of capital
404.	U-32507 November 2013	Cleco Power	Louisiana	Staff	Environmental Compliance Plan
405.	DE11-250 December 2013	Public Service Co. New Hampshire	New Hampshire	Consumer Advocate	Power plant investment prudence
406.	4434 February 2014	United Water Rhode Island	Rhode Island	Staff	Cost of Capital
407.	U-32987 February 2014	Atmos Energy	Louisiana	Staff	Cost of Capital
408.	EL 14-28-000 February 2014	Entergy Louisiana Entergy Gulf States	FERC	LPSC	Avoided Cost Methodology (affidavit)
409.	ER13111135 May 2014	Rockland Electric	New Jersey	Rate Counsel	Cost of Capital

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

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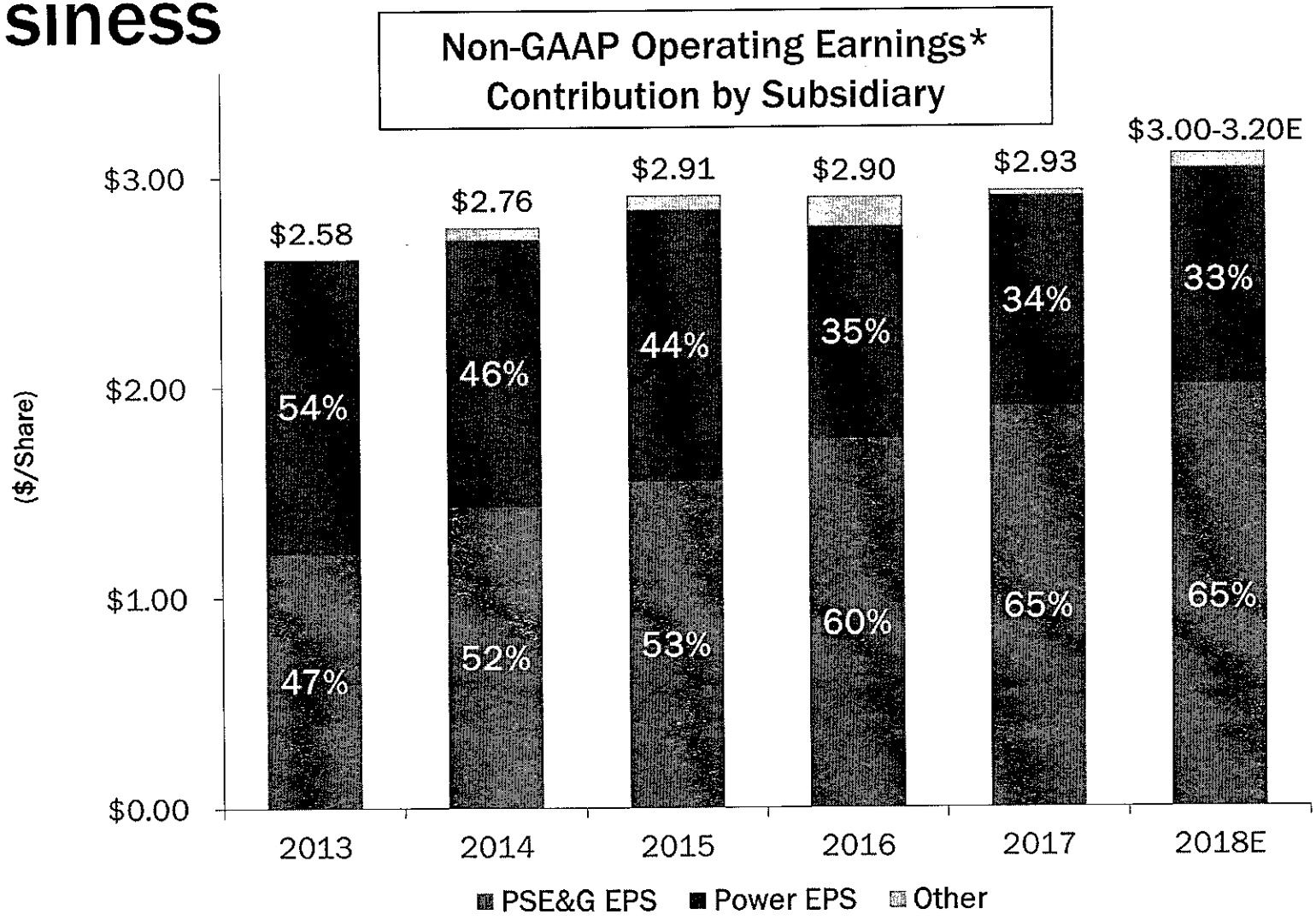
	Docket Number	Utility	Jurisdiction	Client	Subject
424.	EM15060733 August 2016	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Transmission Divestiture
425.	16-395-EL-SSO November 2016	Dayton Power & Light Company	Ohio	Ohio Consumer's Counsel	Electric Security Plan
426.	PUE-2016-00001 January 2017	Washington Gas Light	Virginia	AOBA	Cost of Capital
427.	U-34200 April 2017	Southwestern Electric Power Co.	Louisiana	Commission Staff	Design of Formula Rate Plan
428.	ER-17030308 August 2017	Atlantic City Electric Co.	New Jersey	Rate Counsel	Cost of Capital
429.	U-33856 October 2017	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Prudence
430.	4:11 CV77RWS December 2017	Ameren Missouri	U.S. District Court	U.S. Department of Justice	Expert Report FGD Retrofit
431.	D-17-36 January 2018	Narragansett Electric Co.	Rhode Island	Division Staff	Debt Issuance Authority
432.	4770 April 2018	Narragansett Electric Co.	Rhode Island	Division Staff	Cost of Capital
433.	4800 June 2018	Suez Water	Rhode Island	Division Staff	Cost of Capital
434.	17-32-EL-AIR et.al. June 2018	Duke Ohio	Ohio	Ohio Consumer's Counsel	Electric Security Plan

APPENDIX B

Strategic focus generating growth in earnings with increased contribution from regulated business



*SEE SLIDES A, B AND C FOR ITEMS EXCLUDED FROM NET INCOME/(LOSS) TO RECONCILE TO NON-GAAP OPERATING EARNINGS FOR PSEG, PSE&G, PSEG POWER AND ENTERPRISE/OTHER. E – ESTIMATE.

Public Service Electric and Gas Company
Case Name: 2018 PSE&G Rate Case
Docket No(s): ER18010029 and GR18010030

Response to Discovery Request: RCR-ROR-0011
Date of Response: 4/4/2018
Witness: Jennings, Scott
Dividend payment policies of PSE&G and PSEG

Question:
Please describe in detail the dividend payment policies of PSE&G and PSEG.

Attachments Provided Herewith: 0

Response:
PSEG has a 111 year history of paying a common dividend. PSEG seeks to provide shareholders with opportunity for consistent and sustainable dividend growth.

PSEG expects to continue to pay cash dividends on its common stock; however, the declaration and payment of future dividends will be at the discretion of the Board of Directors and will depend upon many factors, including financial condition, earnings, capital requirements of its businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors the Board of Directors deems relevant.

Dividends from and/or Capital Contributions to PSE&G are sized based on achieving the Company's targeted capital structure. The Company is targeting a capital structure having a 54% equity ratio because this ratio is important to support PSE&G's current credit ratings. PSE&G is committed to strong investment grade credit ratings in order to ensure consistent access to the capital markets at reasonable costs. PSE&G is currently maintaining an equity ratio range between 53.0% and 53.5%, and expects to move towards 54% later in 2018.

Public Service Electric and Gas Company
Case Name: 2018 PSE&G Rate Case
Docket No(s): ER18010029 and GR18010030

Response to Discovery Request: RCR-ROR-0028
Date of Response: 6/11/2018
Witness: N/A
Updated Embedded Cost of Debt as of May 31, 2018

Question:
Petition Exhibit P-2, Schedule SSJ -05 provides the embedded cost of debt at November 30, 2017. Please update this schedule of long-term debt through May 31, 2018, including all new long-term debt issued since November 30, 2017. Also, please include in this response the issue date (month/year) of all outstanding issues of long-term debt.

Attachments Provided Herewith: 1
RCR-ROR_0028_LTD Embedded Cost 5.31.18.xlsx

Response:
Please see the attached Excel file "LTDEmbedded Cost 5.31.18.xlsx". The embedded cost of debt as of May 31, 2018 was 3.9567%.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMBEDDED COST OF LONG TERM DEBT
AS OF MAY 31,.2018
INCLUDING NET UNAMORTIZED PREMIUM - INCLUDING AMOUNT DUE WITHIN ONE YEAR

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
SERIES CC DUE 6/1/21	9.448%	$134,380,000.00	($38,663.17)	($1,728.00)	($40,391.17)	$134,339,608.83	1.5120%	0.1429%
SERIES DUE 6/1/37	8.136%	$7,462,900.00	$0.00	$0.00	$0.00	$7,462,900.00	0.0840%	0.0068%
SERIES DUE 7/1/37	5.085%	$7,537,800.00	$0.00	$0.00	$0.00	$7,537,800.00	0.0848%	0.0043%
SERIES A DUE 11/06/20	7.334%	$9,000,000.00	($7,092.30)	($8,178.00)	($15,270.30)	$8,984,729.70	0.1011%	0.0074%
SERIES D DUE 7/1/35	5.443%	$250,000,000.00	($448,437.50)	($1,221,884.90)	($1,670,322.40)	$248,329,677.60	2.7949%	0.1521%
SERIES D DUE 12/1/36	5.912%	$250,000,000.00	($654,696.73)	($1,343,364.79)	($1,998,061.52)	$248,001,938.48	2.7912%	0.1650%
SERIES E DUE 5/1/37	5.996%	$350,000,000.00	($430,872.56)	($1,878,163.29)	($2,309,035.85)	$347,690,964.15	3.9132%	0.2346%
SERIES G DUE 11/1/2039	5.572%	$250,000,000.00	($574,118.91)	($1,556,022.15)	($2,130,141.06)	$247,869,858.94	2.7897%	0.1554%
SERIES G DUE 3/1/2040	5.711%	$300,000,000.00	($1,042,500.26)	($1,871,713.61)	($2,914,213.87)	$297,085,786.13	3.3436%	0.1909%
SERIES G DUE 8/15/2020	3.823%	$250,000,000.00	($138,603.28)	($413,060.06)	($551,663.34)	$249,448,336.66	2.8075%	0.1073%
SERIES H DUE 5/1/2042	4.136%	$450,000,000.00	($2,308,044.59)	($3,116,898.62)	($5,424,943.21)	$444,575,056.79	5.0036%	0.2069%
SERIES H DUE 9/1/2042	3.823%	$350,000,000.00	($1,378,953.37)	($2,575,362.25)	($3,954,315.62)	$346,045,684.38	3.8947%	0.1489%
SERIES H DUE 1/1/2043	3.983%	$400,000,000.00	($2,089,879.35)	($2,885,116.54)	($4,974,995.89)	$395,025,004.11	4.4459%	0.1771%
SERIES I DUE 5/15/2023	2.689%	$500,000,000.00	($789,314.94)	($1,864,267.75)	($2,653,582.69)	$497,346,417.31	5.5975%	0.1505%
SERIES I DUE 9/15/2018	2.805%	$350,000,000.00	($5,652.56)	($130,917.86)	($136,570.42)	$349,863,429.58	3.9376%	0.1104%
SERIES I DUE 3/15/2024	4.035%	$250,000,000.00	($12,394.91)	($1,030,807.76)	($1,043,202.67)	$248,956,797.33	2.8020%	0.1131%
SERIES I DUE 6/1/2019	2.335%	$250,000,000.00	($90,801.84)	($332,545.49)	($423,347.33)	$249,576,652.67	2.8089%	0.0656%
SERIES I DUE 6/1/2044	4.208%	$250,000,000.00	($2,056,576.76)	($1,978,301.20)	($4,034,877.96)	$245,965,122.04	2.7683%	0.1165%
SERIES J DUE 8/15/2019	2.542%	$250,000,000.00	($123,044.79)	($399,823.77)	($522,868.56)	$249,477,131.44	2.8078%	0.0714%
SERIES J DUE 8/15/2024	3.461%	$250,000,000.00	($277,591.66)	($1,183,067.44)	($1,460,659.10)	$248,539,340.90	2.7973%	0.0968%
SERIES J DUE 11/15/2024	3.396%	$250,000,000.00	($773,281.84)	($1,244,693.46)	($2,017,975.30)	$247,982,024.70	2.7910%	0.0948%
SERIES K DUE 5/15/2025	3.300%	$350,000,000.00	($250,638.88)	($1,540,149.70)	($1,790,788.58)	$348,209,211.42	3.9190%	0.1293%
SERIES K DUE 5/1/2045	4.233%	$250,000,000.00	($1,118,180.53)	($1,820,197.33)	($2,938,377.86)	$247,061,622.14	2.7806%	0.1177%
SERIES K DUE 11/1/2045	4.310%	$250,000,000.00	($233,171.12)	($1,851,987.36)	($2,085,158.48)	$247,914,841.52	2.7902%	0.1203%
SERIES K 1.90% DUE 2021	2.421%	$300,000,000.00	($262,897.41)	($1,050,524.86)	($1,313,422.27)	$298,686,577.73	3.3617%	0.0814%
SERIES K 3.80% DUE 2046	3.972%	$550,000,000.00	($2,259,477.58)	($4,485,166.33)	($6,744,643.91)	$543,255,356.09	6.1142%	0.2428%
SERIES L 2.25% DUE 2026	2.560%	$425,000,000.00	($1,158,738.62)	($2,553,916.33)	($3,712,654.95)	$421,287,345.05	4.7415%	0.1214%
SERIES L 3.00% DUE 2027	3.321%	$425,000,000.00	($1,112,446.30)	($2,874,366.11)	($3,986,812.41)	$421,013,187.59	4.7384%	0.1574%
SERIES L 3.60% DUE 2047	3.747%	$350,000,000.00	($251,358.04)	($3,045,142.03)	($3,296,500.07)	$346,703,499.93	3.9021%	0.1462%
SERIES M 3.70% DUE 2028	4.043%	$375,000,000.00	($1,414,696.89)	($2,794,277.52)	($4,208,974.41)	$370,791,025.59	4.1732%	0.1687%
SERIES M 4.05% DUE 2048	4.239%	$325,000,000.00	($2,006,905.10)	($2,919,795.28)	($4,926,700.38)	$320,073,299.62	3.6024%	0.1527%
TOTAL PSE&G LONG TERM DEBT		$8,958,380,700.00	($23,309,031.79)	($49,971,439.79)	($73,280,471.57)	$8,885,100,228.43	100.0000%	3.9567%

Public Service Electric and Gas Company
Case Name: 2018 PSE&G Rate Case
Docket No(s): ER18010029 and GR18010030

Response to Discovery Request: RCR-ROR-0025
Date of Response: 4/6/2018
Witness: Jennings, Scott
Customer Deposits in Cap Structure

Question:
Please explain why it is appropriate to include customer deposits in capital structure rather than as an offset to rate base. Provide any supporting analysis conducted or relied upon for the Company's position on this issue. Please state whether PSE&G includes customer deposits in its ratemaking capital structure for FERC regulated transmission.

Attachments Provided Herewith: 0

Response:
Customer deposits can be treated in two ways for computing revenue requirements: as a component of the Company's capital structure or as a reduction to rate base with an above the line expense equivalent to interest paid to customers. The Company has argued in the past and continues to maintain that it is most appropriate to include customer deposits as a component of rate base. First, customer deposits are a consistent source of funds, no different than long-term debt. Like long-term debt, the Company pays interest and the funds are used to support our capital investments. Second, since the Company has one capital structure for its electric and gas operation, there is no need to use a questionable allocation methodology for customer deposits between electric and gas operations, as required if customer deposits are used as a rate base deduction. Finally, the Company's last two BPU regulated programs approved by the Board, the Solar 4 All Extension II Program (Docket No. EO1650412) and the Energy Efficiency 2017 Program (Docket No. EO17030196), have included customer deposits as a component of each program's capital structure.

With respect to the Company's FERC regulated transmission, there are no customer deposits.

PSE&G Base Rate Filing: A path to long-term rate stability

Base rate case filed January 2018 and updated in May 2018, calls for an overall increase in electric and gas revenue of 3%

Requested Amounts	Electric	Gas
Revenue Increase	$134 Million	$108 Million
Rate Base	$5.7 Billion	$4.2 Billion

- First base rate request since 2010
- Filing updated to reflect the April 1, 2018 rate reduction associated with decline in the federal corporate tax rate; Net of tax benefits, request is 1%
- Seeks return on and of increased levels of investment in rate base
- Incorporates an electric revenue de-coupling mechanism to support investments in energy efficiency
- Requests a change in depreciation
- Effect of Tax Reform on cash flow further supports capital structure request
- Schedule calls for Rate Counsel and other intervenors to file testimony July 2018; Hearings are scheduled for September - October 2018; Expect a decision in Q4 2018

Public Service Electric and Gas Company
Case Name: 2018 PSE&G Rate Case
Docket No(s): ER18010029 and GR18010030

Response to Discovery Request: RCR-ROR-0024
Date of Response: 4/6/2018
Witness: Bulkley, Ann
Relative E&G Business Risks Compared To Vertically Itegrated

Question:
Please provide Witness Bulkley's opinion concerning the relative business risks of electric and gas utility distribution operations as compared with those risks for vertically-integrated electric utility operations.

Attachments Provided Herewith: 0

Response:
Ms. Bulkley selected a proxy group of companies that have similar financial and business risk characteristics as Public Service based on the screening criteria listed on page 23 of her Direct Testimony. Each of the proxy companies has an investment grade credit rating between A- and BBB, and each company derives the majority of its operating earnings from regulated utility operations. As discussed on page 25 of Ms. Bulkley's Direct Testimony, Public Service is viewed by investors as a combination electric and gas utility, and the Company raises capital on that basis. For that reason, Ms. Bulkley selected combination electric and gas utilities that derive a similar percentage of their operating income from electric utility and gas distribution operations as Public Service, making them risk comparable to Public Service in terms of business operations.

The ROE analysis requires an assessment of the relative business and financial risks of the subject company (in this case, Public Service) to the business and financial risks of each individual operating company held by the proxy group companies. The business, financial and regulatory risks of each individual company are different, and must be evaluated against the risks of the subject company in order to determine if the subject company has average, above average, or below average risk relative to the proxy group. One of the many factors that Ms. Bulkley considered in her overall risk assessment is whether the operating utility company is a gas distribution utility, an electric transmission and distribution utility, or a vertically-integrated electric utility. Based on the results of that assessment, Ms. Bulkley establishes an ROE recommendation within the range of analytical results produced by the various models used to estimate the cost of equity.

Public Service Electric and Gas Company
Case Name: 2018 PSE&G Rate Case
Docket No(s): ER18010029 and GR18010030

Response to Discovery Request: RCR-ROR-0005
Date of Response: 4/4/2018
Witness: N/A

Copies of all Public Service Enterprise Group ("PSE&G") and PSE&G credit rating reports issued since January 1, 2017 to the present

Question:
Please provide copies of all Public Service Enterprise Group ("PSE&G") and PSE&G credit rating reports issued since January 1, 2017 to the present.

Attachments Provided Herewith: 3
RCR-ROR_0005_Moodys PSE and G.pdf
RCR-ROR_0005_S and P PSEG and PSE and G.pdf
RCR-ROR_0005_Moodys PSEG.pdf

Response:
Please see the attached credit rating reports since January 2017.

INFRASTRUCTURE AND PROJECT FINANCE

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
2 June 2017

Update

Rate this Research

RATINGS

Public Service Electric and Gas Company

Domicile	New Jersey, United States
Long Term Rating	A2
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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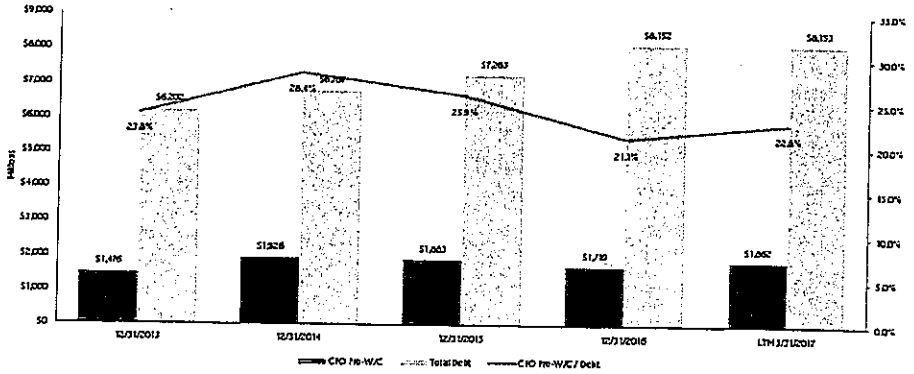
Public Service Electric and Gas Company

T&D Utility and key subsidiary of PSEG Inc.

Summary Rating Rationale

Public Service Electric and Gas Company's (PSE&G) A2 issuer rating is supported by its low risk transmission and distribution (T&D) business model, strong regulatory relationships with New Jersey and the Federal Energy Regulatory Commission (FERC) and an adequate financial profile. PSE&G has substantial capex plans of about $12.3 billion over the next five years, with a majority in FERC-regulated transmission projects. Our expectation is that the company will continue to generate financial metrics appropriate for its rating despite this capex program. Supporting its financial profile are regulatory mechanisms that provide fairly contemporaneous cost recovery and Moody's expectation that PSE&G, which has paid no dividends to parent Public Service Enterprise Group Incorporated (PSEG, Baa2 positive) for the past several years, will continue to moderate its dividend policy policy to maintain its capital structure through this period of heavy capital investment.

Exhibit 1
Historical CFO Pre-W/C, Total Debt, and CFO Pre-W/C to Debt
($ in millions)



Source: Moody's Financial Metrics

Credit Strengths

» Low-risk business model

» Supportive regulatory environment

» Financial profile adequate for the rating

Credit Challenges

» Large capex program continues to pressure credit metrics

Rating Outlook

PSE&G's stable rating outlook reflects our expectation that the company will successfully manage its large capital spending program and maintain a consistent financial profile.

Factors that Could Lead to an Upgrade

» Given PSE&G's strong credit rating and its ongoing capex program, an upward movement in ratings is unlikely at this point

» A sustained improvement in credit metrics, with cash from operations before changes in working capital (CFO pre-WC) coverage of debt in excess of 26%

Factors that Could Lead to a Downgrade

» Regulatory relationship became more contentious

» PSE&G's CFO pre-WC coverage of debt fell below 19% on a sustained basis

Key Indicators

Exhibit 2

KEY INDICATORS [1]
Public Service Electric and Gas Company

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	3/31/2017(L)
CFO pre-WC + Interest / Interest	5.3x	7.0x	6.4x	5.7x	6.0x
CFO pre-WC / Debt	23.8%	28.4%	25.9%	21.1%	22.8%
CFO pre-WC – Dividends / Debt	23.8%	28.4%	25.9%	21.1%	22.8%
Debt / Capitalization	37.7%	37.5%	36.4%	36.0%	35.2%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Detailed Rating Considerations

LOW RISK REGULATED T&D BUSINESS MODEL

PSE&G is a low risk T&D utility, with electric and natural gas distribution and electric transmission businesses. Over the past five years, the transmission business has grown strongly to approximately 44% of rate base at the end of 2016 from about 20% in 2011.

PSE&G retains provider of last resort obligations for electric supply, but contractually transfers that risk through auctions to Basic Generation Service (BGS) providers, including volumetric risks and the risk of customer migration to competitive suppliers. PSE&G retains replacement risk if a BGS provider were to default on its obligation, but any costs would be recoverable in rates. The electric distribution business retains volume exposure between rate cases while gas distribution benefits from a weather normalization clause.

SUPPORTIVE REGULATORY ENVIRONMENT

PSE&G's electricity and gas distribution activities are regulated by the New Jersey Board of Public Utilities (BPU), and its electricity transmission business is regulated by the Federal Energy Regulatory Commission (FERC). In our opinion, PSE&G has a constructive regulatory environment, with timely pass through and recovery of costs. Its storm response, reputation for reliability and outage rates

compare favorably to in-state peers, allowing the company to maintain positive relationships with major stakeholders in the rate making process. PSE&G's last rate case in 2010 resulted in a negotiated settlement with an allowed ROE of 10.3% on 51.2% common equity. PSE&G plans to file a distribution base rate case proceeding no later than November 1, 2017, in which it would seek recovery of distribution investments not covered by mechanisms as well as recovery of approved storm costs. The company has also stated the possibility of pursuing decoupling and interim rates which, if approved, would be credit positive.

FERC regulation on transmission is also credit-friendly and an increasingly important consideration given transmission's large share of the rate base. Because the FERC rate setting processes do not require rate hearings at the state commission level, and since they work to ensure timely recovery through mechanisms such as forward looking formula rates, we generally consider revenues determined under this FERC regulatory framework to be more stable and predictable than other regulated utility businesses.

LARGE CAPEX PROGRAM CONTINUES

PSE&G has a large $12.3 billion capital program for the 2017-21 period, with approximately $6.2 billion in transmission, $3.2 billion in gas distribution, $2.7 billion in electric distribution, and the balance in solar and energy efficiency. With the potential extension and expansion of current programs, subject to state approval, the total capex spending could reach approximately $13.8 billion during the five year period. Under the base scenario, PSE&G would have a rate base of $21.6 billion by 2021, compared to $15.2 billion at the end of 2016, representing an approximately 7% CAGR. Transmission assets would account for as much as 48% of the company's rate base.

PSE&G expects to execute its capex plan with limited effect on customer rates. While declining gas prices over the years have played an important role, the expiration of stranded cost transition charges in 2015 (an adder to rates that had been in place since 2000, when New Jersey transitioned to competitive electric generation) and the expiry of certain legacy, high cost non-utility generator power purchase agreements also contribute to alleviating rate pressure going forward.

FINANCIAL PROFILE PRESSURED BY CAPEX PROGRAM BUT EXPECTED TO REMAIN ADEQUATE

PSE&G's financial metrics have historically been comfortable for the rating. PSE&G's adjusted CFO pre-WC coverage of interest and debt for the last three years has been 6.2x and 24.0%, respectively. Given that PSE&G has not been paying dividends for the last several years, its retained cash flow to debt has been very strong as well.

A combination of the large capex program, and the expiry of collections related to stranded cost recovery, will weaken the financial profile somewhat going forward. We expect CFO Pre-WC coverage of interest and debt in the 5.0-5.5x and 19-21% range, respectively. Nevertheless, these ratios remain adequate for the rating considering the risk mitigating strong regulatory environment. The financial impact of the large capex program is partly mitigated by the fact that PSE&G will recover over 70% of its investments in rates on a contemporaneous basis through a capital rider clause or FERC formula rates. We also expect PSE&G to continue to moderate its dividend policy to maintain its current capital structure during this period of heavy capital expenditure.

Liquidity Analysis

PSE&G's liquidity is adequate. As of March 31, 2017, the company had $153 million of cash on hand and a $600 million 5-year revolving credit facility that matures in March 2022, of which $586 million was available. PSE&G also has access, if required, to parent PSEG's $1.5 billion revolving credit facility. There is no material adverse change clause that could prevent borrowings under the facility. The only covenant is a maximum debt to capitalization covenant of 65%, where PSE&G has ample headroom. 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, PSEG Power or other affiliates.

PSE&G's next upcoming debt maturity is $400 million in senior notes due in May 2018.

Corporate Profile

Public Service Electric and Gas Company (PSE&G, A2 stable) is the largest regulated T&D utility in the state of New Jersey, with about 2.2 million electric and 1.8 million gas customers accounting about 70% of the state's population. PSE&G is a 100% owned subsidiary of Public Service Enterprise Group Incorporated (PSEG, Baa2 positive) and it accounted for approximately 58% of PSEG's CFO Pre-WC as of LTM March 31, 2017. PSEG also owns PSEG Power Co., a merchant generator with about 11.6 GW of generation capacity located in PJM and New England.

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors Public Service Electric and Gas Company Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.2x	Aa	5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	24.0%	A	19% - 21%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	24.0%	A	19% - 21%	A
d) Debt / Capitalization (3 Year Avg)	36.4%	A	36% - 38%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching				
a) Indicated Rating from Grid		A2		A2
b) Actual Rating Assigned		(P)A2		(P)A2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2017(L);
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Ratings

Exhibit 4

Category	Moody's Rating
PUBLIC SERVICE ELECTRIC AND GAS COMPANY	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Senior Secured	Aa3
Senior Unsecured Shelf	(P)A2
Pref. Stock	Baa1
Commercial Paper	P-1
PARENT: PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	
Outlook	Positive
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Pref. Shelf	(P)Ba1
Commercial Paper	P-2

Source: Moody's Investors Service

REPORT NUMBER 1075098

MOODY'S INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
26 July 2017

Update

Rate this Research

RATINGS

Public Service Enterprise Group Incorporated

Domicile	Newark, New Jersey, United States
Long Term Rating	Baa1
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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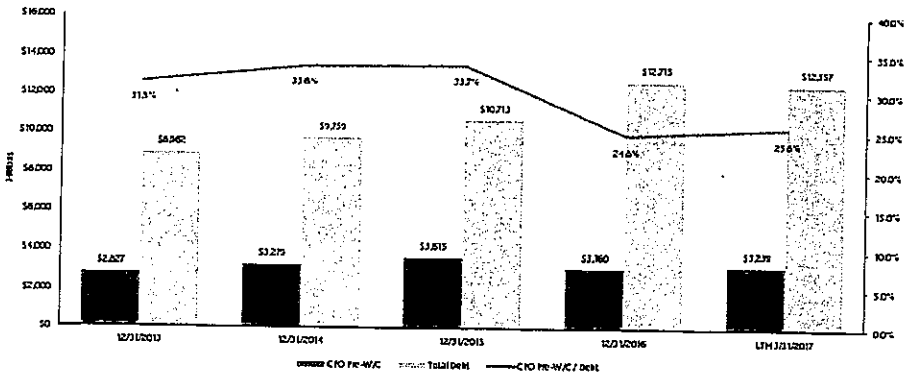
Public Service Enterprise Group Incorporated

Diversified holding company of PSE&G and PSEG Power

Summary Rating Rationale

Public Service Enterprise Group Incorporated's (PEG) Baa1 unsecured rating reflects the well positioned business and financial profile of its utility subsidiary Public Service Electric and Gas Company (PSE&G, A2 stable) and its merchant business PSEG Power LLC (PSEG Power, Baa1 stable). It incorporates PSE&G's increasing contribution, relative to PSEG Power, in terms of consolidated cash flow and especially in distributions to the parent over the next few years. Due to its strong ongoing capital expenditure (capex) program (over $12 billion over the next five years), PSE&G has not up-streamed any dividends to PEG since 2011, but is expected to resume doing so starting in 2018. Going forward, we expect PEG's consolidated cash from operations before working capital changes (CFO pre-WC) and retained cash flow (RCF) coverage of debt to be 20-25% and 15-18%, respectively, over the 2017-19 period. Furthermore, over the next few years, parent level debt is expected to be remain below 20% of the consolidated total, which is more than adequately incorporated into the two notch rating differential between PEG and its primary utility subsidiary PSE&G.

Exhibit 1
Historical CFO Pre-W/C, Total Debt, CFO Pre-W/C to Total Debt
($ in millions)



Source: Moody's Financial Metrics

Credit Strengths

» Shifting business mix, with a growing regulated component

» Well positioned utility and merchant businesses

» Adequate financial profile

Credit Challenges

» Heightened capital expenditure program

Rating Outlook

The stable outlook incorporates our expectation for a continued stable financial performance at PEG and over the next few years, we expect CFO pre-WC coverage of debt to range from 20-25% and parent level debt to remain under 20%.

Factors that Could Lead to an Upgrade

PEG's ratings could be upgraded if the company can sustain a stronger financial performance, such that CFO pre-WC/Debt is in the high 20% range.

Factors that Could Lead to a Downgrade

PEG's ratings could be downgraded if CFO pre-WC/Debt falls to the high teens percent on a sustained basis. In addition, the incurrence of material holding company debt in excess of our assumptions, or in conjunction with a shareholder oriented financial strategy (other than capex), could also place downward pressure on the rating.

Key Indicators

Exhibit 2

KEY INDICATORS [1]

Public Service Enterprise Group Incorporated

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	3/31/2017(L)
CFO pre-WC + Interest / Interest	6.8x	8.0x	8.1x	6.9x	7.0x
CFO pre-WC / Debt	31.5%	33.6%	33.7%	24.8%	25.8%
CFO pre-WC – Dividends / Debt	23.4%	25.9%	26.4%	18.3%	19.1%
Debt / Capitalization	32.5%	33.5%	33.7%	37.1%	36.9%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Detailed Rating Considerations

SHIFTING BUSINESS MIX, WITH A GROWING REGULATED COMPONENT

PSE&G's share of PEG's operating income has grown over the past few years from about 45% to nearly 2/3rd in 2017, strengthening PEG's credit profile. The shift in contribution mix is driven by both higher cash flows at PSE&G as it starts earning on its substantial capex program as well as weaker merchant cash flows at PSEG Power. Historically, PEG's ratings were constrained given that PSEG Power had been the sole source of dividends to the parent for the past several years. Going forward, we expect that PSE&G will start to be a material contributor of dividends to PEG starting in 2018 and the amount is expected to grow from 2019 onwards. With this changing profile, we will also evaluate PEG under our regulated utilities methodology going forward rather than under the unregulated utilities methodology used historically.

WELL POSITIONED UTILITY AND MERCHANT BUSINESSES

PSE&G is a low risk, fully regulated T&D utility with no generation. The company continues to operate under a favorable regulatory environment both with respect to New Jersey and with the FERC for its transmission assets. Transmission currently accounts for approximately 44% of PSE&G's rate base (2016) and is set to grow further to 48% of the rate base by 2021. Regulatory provisions at FERC (forward looking rates) and in NJ (trackers) allow PSE&G to earn contemporaneously on over 70% of its upcoming capex over the next five years.

PSEG Power exhibits a higher risk profile as, like all merchant generators, the company is exposed to operating risks and volatile power prices. However, PSEG Power has perhaps the best competitive position among all merchant generators (and is one of the highest rated unregulated power companies in the US), driven mainly by the very favorable location of its assets which gives the company premium capacity pricing in auctions. In addition, PSEG Power benefits from relatively low leverage, efficient operations, and a ratable hedging strategy.

Although financial ratios are expected to weaken going forward, with CFO pre-WC to debt in the 35-40% range compared with 40-50% historically, these ratios remain adequate for the rating. PSEG Power has prudently financed $1.5 billion in capex during 2015-18 to construct three new combined cycle gas plants totaling 1780 MW in PJM and ISO-NE. The three plants include a 540 MW plant at Sewaren in NJ, the 755 MW CCGT Keys Energy Center in Maryland (both in PJM and expected to be in service in 2018) and a 485 MW CCGT unit at Bridgeport Harbor, CT (in ISO NE) which should be in service in 2019. Construction was financed largely from retained cash flows and we expect absolute debt levels to decline back to 2014 levels by 2020. While we expect PSEG Power to pursue opportunistic additions to its generating portfolio such as these, we do not expect management to undertake any large merchant portfolio acquisitions.

ADEQUATE FINANCIAL PROFILE DESPITE LARGE CAPEX PROGRAM

PEG has historically maintained a strong financial profile. As of March 31, 2017 PEG's adjusted CFO pre-WC and RCF coverage of debt averaged 29.5% and 22.7%, respectively, over the past three years. These metrics were 25.8% and 19.1%, respectively, for the LTM ended March 31, 2017. Going forward, we expect PEG's consolidated CFO pre-WC and RCF coverage of debt to be somewhat weaker in the 20-25% and 15-18% range, respectively, over the 2017-19 period, but nevertheless adequate for the rating.

PSE&G continues to have a robust capex program with $11.6 billion spent during 2012-2016 and a planned $12.3 billion for 2017-2021. However, we expect growing cash flows at PSE&G from ongoing rate base investments and moderating capex at PSEG Power after 2018 will enable PEG to be closer to free cash flow neutrality towards the end of this decade.

PEG historically had no debt at the parent level, but issued $1.2 billion in 2015-16 and will issue additional debt in 2017. Debt issuance at the parent largely reflects a drop in dividends from PSEG Power owing to that subsidiary's own capex program as well as equity investments by the parent into PSE&G. Notwithstanding the additional debt, financial metrics are expected to remain adequate to support the Baa1 rating at PEG. Over the next few years, parent level debt is expected to remain below 20% of the consolidated total, which is more than adequately incorporated into the two notch rating differential between PEG and its primary utility subsidiary PSE&G.

Liquidity Analysis

PEG's liquidity is adequate to support its P-2 commercial paper rating. As of March 31, 2017, PEG had $193 million in cash and cash equivalents. In March 2017, PEG, PSE&G and PSEG Power amended their credit agreements, extending the expiration dates to March 2022. PEG increased its existing $1 billion in credit facilities to $1.5 billion, and as of March 31, 2017, there was $1,168 million in availability. PSEG Power decreased its existing $2.6 billion in credit facilities to $2.1 billion, while PSE&G maintained its total facilities amount of $600 million. On an aggregate basis, the total facility commitment in the PEG family now aggregates $4.2 billion and as of March 31, 2017, the total available credit capacity was $3.6 billion. There are no material adverse change clauses that could restrict borrowings. The only covenant is a maximum debt to capitalization covenant of 70% under which there is ample cushion. The credit agreement contains cross defaults to certain indebtedness of its major subsidiaries (as defined and including PSE&G and PSEG Power).

PEG is expected to remain free cash flow negative over the next year given the robust capex program at PSE&G and PSEG Power and the dividend payout. Furthermore, PEG has a $500 million senior unsecured term loan maturing in November 2017.

Corporate Profile

Public Service Enterprise Group Incorporated (PEG, Baa1 stable) is the parent holding company of PSEG Power LLC (PSEG Power, Baa1 stable), a wholesale merchant generator with approximately 10.5 GW of capacity and Public Service Electric and Gas Company (PSE&G, A2 stable), New Jersey's largest regulated electric and gas transmission and distribution (T&D) utility. Other subsidiaries include PSEG Energy Holdings L.L.C. (Holdings), which owns a portfolio of leveraged leases, and PSEG Long Island LLC, which effective January 1, 2014, operates the Long Island Power Authority's T&D system under a contractual agreement.

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors Public Service Enterprise Group Incorporated Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	7.4x	Aa	6x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	29.5%	A	20% - 25%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	22.3%	A	15% - 20%	A
d) Debt / Capitalization (3 Year Avg)	34.6%	Aa	33% - 38%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching		-1		-1
a) Indicated Rating from Grid		A3		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2017(L);
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures
Source: Moody's Financials Metrics

Ratings

Exhibit 4

Category	Moody's Rating
PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	
Outlook	Stable
Senior Unsecured	Baa1
Subordinate Shelf	(P)Baa2
Pref. Shelf	(P)Baa3
Commercial Paper	P-2
PUBLIC SERVICE ELECTRIC AND GAS COMPANY	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Senior Secured	Aa3
Senior Unsecured Shelf	(P)A2
Pref. Stock	Baa1
Commercial Paper	P-1
PSEG POWER LLC	
Outlook	Stable
Senior Unsecured	Baa1

Source: Moody's Investors Service

REPORT NUMBER 1084462

S&P Global
Ratings

RatingsDirect®

Research Update:

Public Service Enterprise Group Inc. And Subsidiary Ratings Affirmed; Outlook Stable

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Table Of Contents

Research Update:

Public Service Enterprise Group Inc. And Subsidiary Ratings Affirmed; Outlook Stable

Overview

- We expect utility holding company Public Service Enterprise Group Inc.'s (PSEG) financial performance will weaken somewhat over the next few years, mainly as a result of ongoing softness in wholesale power prices.
- We now expect PSEG's financial performance will be characterized by funds from operations (FFO) to debt that is in the range of 20%-22% compared to our earlier expectation of 23%-25%.
- The consistent growth of the regulated operations within PSEG helps support our assessment of the company's business risk profile, while still recognizing the meaningful contribution of the company's merchant generation business.
- We are affirming our 'BBB+' issuer credit rating on PSEG and its subsidiary Public Service Electric & Gas Co. because the expected weakening of the financial profile is somewhat offset by the increasing contribution of the regulated utility operations. The outlook remains stable.
- The stable outlook reflects our expectation that this updated level of financial performance will persist over the next few years, supporting current ratings.

Rating Action

On April 27, 2017, S&P Global Ratings affirmed its 'BBB+' issuer credit ratings on Public Service Enterprise Group Inc. (PSEG) and its subsidiary Public Service Electric & Gas Co. The outlook remains stable.

Rationale

While we expect that PSEG's financial profile will weaken somewhat over the next few years, such weakness is modest and offset in part by the increasing contribution of the regulated utility operations.

The ratings affirmation on PSEG and Public Service Electric & Gas accounts for our expectation that PSEG's financial profile will weaken somewhat over the next few years, mainly as a result of persistent weak wholesale power prices at its merchant generation operations and an incrementally higher debt burden at the group level. Despite this weakness, we expect that PSEG's financial measures will remain sufficient to support current ratings.

The ratings on PSEG incorporate the increasing contribution of the company's

regulated utility operations, which we expect to provide as much as 70% of the company's overall credit profile by 2019-2020. Importantly, the transmission business constitutes about 50% of regulated rate base, enhancing PSEG's business risk profile but not, however, moving it to the next stronger category.

The company's regulated utility operations encompass electric and natural gas transmission and distribution operations that benefit from operating under a generally constructive state (New Jersey) and very constructive federal (Federal Energy Regulatory Commission) regulatory frameworks that provide for the ability to recover certain distribution infrastructure (both electric and gas) capital spending and transmission investments via riders and set rates based on a balanced capital structure, factors that help support stable and robust cash flow generation. Public Service Electric & Gas has a large customer base consisting of 2.2 million electric and 1.8 million gas distribution customers over a service territory that covers the most populated and economically active parts of New Jersey. While the customer base is large and has no meaningful industrial exposure, the service territory lacks geographic diversity.

We ascribe significantly higher business risk to merchant generation operations at PSEG Power LLC, whose contribution has been declining over time primarily as a result of consistently weak wholesale power prices. PSEG Power is currently building three new combined-cycle, gas-fired generation facilities totaling 1,755 MW of capacity to replace planned retirements. PSEG Power will maintain total generating capacity of about 11,500 MW while improving the fleet's efficiency and competitiveness. PSEG Power hedges its output on a three-year rolling basis, improving revenue stability without eliminating exposure over time to prevailing market prices. While we expect a modest decline in PSEG Power's contribution to the group over time, we do not anticipate that total generating capacity will be reduced, reflecting PSEG's commitment to the business.

Under our base-case scenario, we project that PSEG's financial performance will sufficiently support current ratings with FFO to debt that remains consistently in the 20%-22% range while debt to EBITDA remains below 4x. While this level of financial performance is somewhat weaker than that of prior years, it adequately supports current ratings.

Our base-case scenario is based on our expectation of gross margin growth that averages 3%-4% annually and accounts for the recovery of designated infrastructure investments via riders, a reasonable result in the utility's upcoming rate case filing, its growing transmission investment, and ongoing weakness in wholesale power prices. We expect capital spending will total about $4.7 billion in 2017 and decline to about $2.2 billion by 2019 and we expect dividends to grow by 4%-6% annually.

Liquidity

We assess PSEG's liquidity as adequate to cover its needs over the next 12 months. We expect the company's liquidity sources to exceed its uses by 1.1x or more, the minimum threshold for regulated utilities under our criteria, and that the company will also meet our other requirements for such a designation. PSEG's liquidity benefits from stable cash flow generation, ample availability under the revolving credit facilities, and manageable debt maturities over the next few years.

As of Dec. 31, 2016, the PSEG group has $4.2 billion in revolving credit facilities, with $1 billion available at the parent, $600 million available at PSE&G, and $2.6 billion at PSEG Power. The facilities mature in 2019 and 2020.

Principal liquidity sources:

- Revolving credit facilities totaling 4.2 billion;
- Cash FFO of about $3.0 billion-$3.4 billion; and
- Cash and cash equivalents on hand of $423 million.

Principal liquidity uses:

- Debt maturities of about $750 million over the next 12 months, including commercial paper;
- Capital spending of about $4.3 billion over the next 12 months; and
- Dividends of about $870 million-$890 million.

Outlook

The stable outlook on PSEG and its subsidiaries reflects the incremental strengthening of the company's business risk profile with the continued growth of the regulated utility operations, while taking into account a weakening of the financial risk profile, largely due to the impact of lower wholesale power prices. Under our base-case scenario, we expect FFO to debt to range from 20%-22% over the next 12 to 24 months, while debt to EBITDA will remain consistently under 4x.

Downside scenario

We could lower the ratings by one notch on PSEG and its subsidiaries if credit protection measures weaken further with FFO to debt that is consistently less than 20% as a result of additional declines in wholesale power prices or the company's inability to recover invested capital in a timely manner in the regulated operations. We could also lower the ratings by one notch if the contribution of the merchant generation business increases without a corresponding improvement in credit metrics.

Upside scenario

While unlikely over the next two years, we could raise the ratings by one notch on PSEG and its subsidiaries if credit protection measures strengthen such that FFO to debt consistently exceeds 26% absent any moderation in

business risk, or if the ongoing growth of the regulated utility operations results in an improved business risk profile.

Ratings Score Snapshot

Corporate Credit Rating: BBB+/Stable/A-2

Business risk: Strong
- Country risk: Very low
- Industry risk: Low
- Competitive position: Strong

Financial risk: Significant
- Cash flow/Leverage: Significant

Anchor: bbb

Modifiers
- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Strong (no impact)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: bbb+
- Group credit profile: bbb+

Related Criteria

- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings , April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Ratings List

Ratings Affirmed; Recovery Ratings Unchanged

Public Service Enterprise Group Inc.	
Public Service Electric & Gas Co.	
Corporate Credit Rating	BBB+/Stable/A-2
Public Service Enterprise Group Inc.	
Senior Unsecured	BBB
Commercial Paper	A-2
Public Service Electric & Gas Co.	
Senior Secured	A
Recovery Rating	1+
Senior Secured	AA/Stable
Senior Secured	AA-/Stable
Commercial Paper	A-2

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on the S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

Public Service Electric and Gas Company
Case Name: 2018 PSE&G Rate Case
Docket No(s): ER18010029 and GR18010030

Response to Discovery Request: RCR-ROR-0013
Date of Response: 4/4/2018
Witness: Jennings, Scott
PSEG's plans for issuing equity

Question:
Please describe and identify PSEG's plans for issuing new common equity through a public issuance during the past three years. Also, please state whether PSEG has conducted any public issuances of common stock during the past five years to date. (This would not include such minor issuances as employee stock option plans or dividend reinvestment plans.) Identify each such public issuance indicating the proceeds and issuance expense (including underwriting fees).

Attachments Provided Herewith: 0

Response:
PSEG has not issued common equity through a public issuance during either the past three or five years to date.

Public Service Electric and Gas Company
Case Name: 2018 PSE&G Rate Case
Docket No(s): ER18010029 and GR18010030

Response to Discovery Request: RCR-ROR-0031
Date of Response: 6/8/2018
Witness: Jennings, Scott
Plans for a public issuance of common stock

Question:
Please provide a description of any plans for a public issuance of common stock for the time period between now and the end of 2021 by parent company PSEG.

Attachments Provided Herewith: 0

Response:
PSEG does not have any plans on issuing common stock by the end of 2021.

Public Service Electric and Gas Company
Case Name: 2018 PSE&G Rate Case
Docket No(s): ER18010029 and GR18010030

Response to Discovery Request: RCR-ROR-0018
Date of Response: 4/4/2018
Witness: Bulkley, Ann
Projected DCF

Question:
Witness Ms. Bulkley employs a "Projected DCF" as one of her four cost of equity methods (testimony, page 4). Is Witness Bulkley aware of any state or federal regulatory utility jurisdiction that has adopted, accepted or endorsed this methodology in a rate proceeding? If so, please provide a citation or reference to the case indicating the jurisdiction, utility, approximate date of the decision and docket number.

Attachments Provided Herewith: 0

Response:
Ms. Bulkley is not aware of whether any state or federal utility jurisdiction has adopted, accepted or endorsed this methodology in a rate proceeding.

Nevertheless, as explained on page 33 of Ms. Bulkley's Direct Testimony, because of analysts' views that utility stocks may currently be at unsustainably high prices due to market conditions, she also considered the results of a projected Constant Growth DCF model. Rather than using historical prices, this DCF analysis relies on Value Line's projected average stock prices and projected dividends for the period from 2020-2022 and the five-year projected EPS growth rates. This DCF scenario is developed to demonstrate the expected cost of capital over the projected period, if stock prices were to be at levels expected by analysts as investors respond to changes in market conditions and investment options.

Ms. Bulkley notes that the S&P Utilities Index has declined by approximately 7.0% since December 29, 2017, which was the cutoff data for market data in her Direct Testimony, as interest rates on government bonds have continued to move higher and market volatility has increased significantly. This confirms the reasonableness of also considering the results of the projected DCF analysis.