STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE-ENERGY CLOUD ("CEF-EC") PROGRAM ON A REGULATED BASIS	**))))))**	**BPU DOCKET NO. EO18101115**

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
P.O. Box 003
Trenton, New Jersey 08625
Phone: 609-984-1460
Email: njratepayer@rpa.nj.gov

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

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

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

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

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

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

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

A. Yes. I have testified before approximately two-dozen state and federal utility commissions, federal courts and the U.S. Congress in more than 440 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 New Mexico Attorney General, 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 Nos. GR09050422 and ER18010029/GR18010030), 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 addition, I have assisted Rate Counsel in numerous other rate and other proceedings that due to settlement did not require the filing of testimony. 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 Nos. ER18010029/GR18010030 listed above was PSE&G's last base rate case filed in 2018 (the "2018 rate case") resolved by a Board-approved settlement in early 2019.

II. OVERVIEW

A. Background and Summary of Recommendations

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

A. PSE&G in this case is requesting the approval of an Advanced Metering Infrastructure ("AMI") program that would be implemented over approximately the next five years that includes a cost recovery mechanism that would provide the Company with periodic rate increases for AMI investments between base rate cases. I have been asked by Rate Counsel in this case to develop a recommendation concerning the fair rate of return on the AMI investments to be used in the proposed between base rate case cost recovery mechanism. My principal focus is on the return on common equity, but I also address the embedded cost of long-term debt and the capital structure to be used in setting the Weighted Average Cost of Capital ("WACC")[1].

Q. IN BROAD TERMS, WHAT IS THE COMPANY'S AMI PROPOSAL IN THIS CASE?

A. As presented in the Company's Updated Verified Petition ("Petition"), for this program, the Company proposes to install new advanced (or "smart") electronic meters on an accelerated basis for substantially all residential and small commercial customers in place of the existing analog meters beginning in 2021 with the conversion largely completed by the end of 2025. This would be an estimated 2.2 million replacement meters. The estimated total investment for this program would be $714 million, with the new meters and their installation being most of the investment along with associated software and other information technology

[1] It should be noted that the Company does not have any preferred stock outstanding at this time.

equipment ("associated IT investments"). [2] In addition, PSEG would incur an estimated $71 million in additional operation and maintenance ("O&M") expense during the five-year program.[3] The Petition argues that this AMI program should be approved under the Board's Infrastructure Investment Program ("IIP") rules, which permit the use of a special between base rate case cost recovery mechanism. The Company further asserts that its proposed cost recovery mechanism is "consistent with" the IIP rules and similar to that used for its Board-approved Energy Strong and Gas System Modernization Program ("GSMP") II programs.[4]

Q. HOW WILL THE PROPOSED COST RECOVERY MECHANISM OPERATE?

A. The details of the proposed cost recovery mechanism are described in the testimony of Mr. Stephen Swetz. Under its proposal, the Company will be permitted to file twice per year (filings to occur in June and December each year) to increase its base rates for the new meters and other associated investments that are or will be in-service within three months of each interim rate increase taking effect. For example, the Company would file (using actual plus projected data) on June 30 of a given year, update the in-service AMI investment to the actual balance on August 31 and implement the rate increase on December 1.[5] The rate increase would be calculated as the AMI rate base (i.e., original cost AMI investment minus depreciation reserve minus balance of deferred taxes) multiplied by the approved WACC from the last base rate case, grossed up for taxes. The interim rate increase also would include depreciation expense associated with the investment but not the O&M mentioned

[2] Petition, page 5.
[3] Id.
[4] Petition, pages 12-13.
[5] Swetz testimony, page 7.

above.[6] The program O&M (an estimated $71 million during the five years of the program) would be deferred (with a return) for rate recovery in the Company's next base rate case.[7] The Company commits to filing a base rate case by year-end 2023,[8] and if it follows this schedule, that means the next rate case would be completed by approximately the end of 2024. Since the Company anticipates the accelerated smart meter installation to be completed by approximately the end of 2025, this implies that the vast majority of AMI costs will have been moved into base rates using its proposed cost recovery mechanism prior to the completion of its next base rate case. The interim, semi-annual rate increases for AMI investments would be subject to refund based on a future prudence review, with that review to occur during the next base rate case following the AMI investments. Mr. Swetz proposes that the semi-annual rate increases for AMI be recovered entirely through the customer charge using the billing determinants from the Company's 2018 base rate case in BPU Docket Nos. ER18010029 and GR18010030.[9]

In theory, the Company could implement the first of the interim rate increases as soon as June 2021. However, following the IIP rules, the Company will not implement a rate increase until at least 10 percent of the total program investment is in service. Using this limitation, the Company anticipates the first filing to occur in June 2022 with rate recovery to begin in December 2022.

The Company also proposes that all of the interim semi-annual rate increases will be subject to an "earnings test". Specifically, the Company may not implement the interim rate increase if its per books earnings on electric distribution operations

[6] Id., page 2.
[7] Petition, pages 15-16.
[8] Swetz testimony, page 9.
[9] Id., page 10. Please note that Rate Counsel witness David Peterson contests Mr. Swetz recommendation for full recovery through the customer charge.

exceed its authorized return on equity from its last base rate case by more than 0.5 percent (50 basis points) during the most recent one-year period, using nine months actual and three months estimated earnings data.[10]

Q. WHAT IS MR. SWETZ'S RECOMMENDATION AT THIS TIME ON RATE OF RETURN FOR THE INTERIM COST RECOVERY MECHANISM?

A. As summarized on his Schedule SS-CEF-EC-1, he proposes that the WACC from the Company's most recent base rate case be employed in each interim rate increase until such time as the next base rate case is completed (presumably in late 2024). That WACC is 6.99 percent, consisting of a 54 percent equity/46 percent debt capital structure (inclusive of 0.5 percent customer deposits), a 3.96 percent cost of long-term debt and a return on common equity ("ROE") of 9.60 percent. That WACC resulted from a settlement in the 2018 base rate case approved by the Board.

After the completion of the next base rate case (which might occur in late 2024), the WACC approved in that case would be used for any subsequent filings. However, based on the Petition it is expected that the program and its schedule of interim, semi-annual rate increases will be mostly completed by that time.

Q. WHAT IS YOUR RATE OF RETURN RECOMMENDATION FOR THE PROPOSED INTERIM RATE RECOVERY MECHANISM?

A. As shown on my Schedule MIK-1, page 1 of 1, I am recommending at this time and subject to updating, that if the Board approves these investments, it award a WACC of 6.54 percent, based on PSE&G actual capitalization data at March 31, 2020. This includes a long-term cost of debt of 3.95 percent, which is 46.11 percent of capitalization, customer deposits of 0.39 percent at a cost of 2.33 percent, and an 8.80

[10] Id., page 8.

percent cost of equity, which is 53.50 percent of capitalization. The 8.80 percent is the midpoint of my present cost of equity study presented in Section IV of my testimony. This is a conservatively high ROE recommendation that takes into account current cost of equity evidence for a low-risk electric distribution company such as PSE&G and the fact that the Company's proposed between rate case cost recovery mechanism is very low risk – far lower than conventional base rate recovery.

My recommendation on capital structure to be used in the cost recovery mechanism is that the equity ratio should be the lower of the actual equity ratio and the 54 percent authorized in the 2018 rate case. The capital structure is fully under the control of PSE&G management. While the Company's stated goal is to maintain the actual equity ratio at the approved 54 percent, it should not be permitted to use an equity ratio higher than that in its ratemaking WACC if its actual ratio is lower than 54 percent. As of March 31, 2020, that figure was 53.5 percent, but for purpose of each of the interim, semi-annual rate filings, the equity ratio should be updated to the latest actual, but not to exceed 54.0 percent. Similarly, the cost of debt to be used in the WACC also should be periodically updated as the Company issues new debt and existing debt issues mature. Section III of my testimony provides additional discussion of these recommendations.

Q. YOU HAVE SET FORTH YOUR WACC RECOMMENDATIONS FOR USE IN THE COMPANY'S INTERIM, COST RECOVERY MECHANISM. DOES THIS MEAN THAT WITH YOUR RECOMMENDED WACC YOU SUPPORT EITHER THE AMI PROGRAM OR THE REQUESTED COST RECOVERY MECHANISM?

A. No, it does not. It is not the purpose of my testimony to evaluate the merits of the as-filed AMI program. Rate Counsel witness Paul Alvarez finds the program, as proposed, not to be cost effective and therefore believes it should not be approved. Moreover, my testimony does not support the need for the Company's between base rate case, single-issue cost recovery mechanism. Rather, in the event that the Board decides to approve the proposed AMI program and its accompanying cost recovery mechanism my testimony provides recommendations for modifying one aspect of that cost recovery mechanism – the WACC. That should not be interpreted as either support for the Company's AMI program or the proposed cost recovery mechanism.

Q. HOW HAVE YOU DEVELOPED YOUR 8.8 PERCENT ROE RECOMMENDATION?

A. The purpose of my cost of equity analysis in this case is to update the cost of equity analysis from the Company's 2018 base rate case where I served as Rate Counsel's witness. To do so, I rely primarily on the use of the standard DCF model as applied to a proxy group of 12 electric utility companies. This is precisely the same utility company proxy group as I used in the 2018 base rate case. This produces a cost of equity range of about 8.5 to 9.0 percent, with a midpoint of 8.8 percent. This is very similar to the group used by the Company's ROE witness in that case, Ms. Ann Bulkley, but with three changes. I removed one of her proxy companies, Centerpoint Energy, due to that company's involvement in a major merger which was announced subsequent to the preparation of Ms. Bulkley's testimony.[11] To supplement the proxy group, I also added two combination gas and electric utilities that I believe warrant inclusion in the proxy group, Alliant Energy and Duke Energy. In addition, I have conducted a second DCF study using a proxy group identical to that of Ms. Bulkley

[11] While Centerpoint no longer should be excluded due to participation in a merger, which has since closed, it still warrants exclusion today because it recently cut its quarterly dividend.

(excluding Centerpoint Energy). This study obtains ROE results that are essentially identical to those from my main study – a midpoint of about 8.8 percent. 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 is intended to set rates to be charged to PSE&G's electric distribution service customers. 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 5.7 to 9.1 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 but uncertain 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 8.8 percent return on equity recommendation for PSE&G at this time, a reduction of 0.8 percent from the 9.6 percent granted by Board-approved settlement in the Company's last base rate case in 2018. PSE&G's proposal to maintain the ROE at 9.6 percent for its between base rate case cost recovery mechanism is not reasonable given the current cost of equity evidence and the very favorable (for shareholders) risk attributes of its rate recovery mechanism.

Q. DID THE COMPANY'S PETITION PROVIDE ANY EVIDENCE OR SUPPORT FOR ITS RATE OF RETURN REQUEST?

A. No, it did not. Mr. Swetz sponsors the WACC request and merely references the rate of return approved by settlement in the 2018 base rate case. That rate of return was one element of a comprehensive settlement involving a great many issues. The Company's Petition provides no cost of equity analysis or evidence demonstrating that the requested 9.6 percent ROE going forward and in the context of its very low risk interim cost recovery mechanism is appropriate. Since the Petition provides no supporting evidence, Rate Counsel's request RCR-ROR-7 asked the Company why it believes that 9.6 percent is the appropriate return for its cost recovery mechanism. Rather than providing evidence on the current cost of equity, the response simply references the settlement ROE of 9.6 percent (even though that settlement provides no provision to utilize that ROE in any other docket). The response further claims that a lower return would be lower than its cost of equity and therefore would not provide adequate incentive to invest in the AMI equipment (i.e., the $714 million mentioned earlier). In addition, the response notes that the 9.6 percent ROE has been used for rate recovery in other PSE&G programs.

Q. WHY DO YOU CONSIDER THE COMPANY'S INTERIM COST RECOVERY MECHANISM TO BE LOW RISK?

A. The rate mechanism proposed by Mr. Swetz provides, for all practical purposes, automatic and full rate recovery of the AMI costs at issue in this case, without the risks associated with the detailed scrutiny of the Company's overall cost of service, earnings and operations that would normally take place in a conventional base rate case. Moreover, the rate recovery is extremely frequent and timely. The interim rate increases would occur twice per year with a very short lag between the plant-in-service date and the date when the rate increase takes effect, thereby minimizing regulatory lag. The best evidence of the extremely low risk nature of this proposed rate mechanism is the Company's assertions that without the ability to make single issue, contemporaneous rate filings, the Company would not undertake this accelerated investment in AMI equipment.[12]

The Company argues that even with its proposed cost recovery mechanism it is accepting certain operational and prudence risks, as its performance in undertaking this program would be reviewed in the next base rate case. I agree that the proposed cost recovery mechanism does not eliminate (nor should it) all risk for the Company, and the Company's performance should be subject to prudence review at the appropriate time. But it is also clear that my 8.8 percent is not a risk-free rate of return. Indeed, that rate of return fully compensates the Company for its investment risk. That said, as a practical matter, I believe this "prudence disallowance risk" – judging by past experience, is quite modest.

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 I discuss in Section III of this testimony, the Company's credit ratings are quite strong, generally strong Single A. In addition, the Company's ratemaking equity ratio is a relatively expensive 54 percent which is materially above the electric utility average. This further contributes to the Company's relatively favorable risk profile. As mentioned above, PSE&G is lower in overall risk than the average proxy group electric utility used in my cost of equity studies due to its lack of risk

[12] The Company makes this assertion in response to RCR-ROR-9.

associated with generation assets. Despite PSE&G's favorable risk profile, today's very low capital cost environment and the proposed rate recovery mechanism for AMI costs, I am recommending a ROE consistent with the DCF results from my electric utility proxy group.

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

A. The requested 9.6 percent ROE for its AMI cost recovery mechanism is roughly similar to the overall electric utility ROE award averages, but it is above the ROE awards granted to delivery service electric utilities. According to the surveys of state commission rate case decisions published by Regulatory Research Associates ("RRA"), the overall electric utility ROE award was 9.60 percent for 2018, 9.65 percent for 2019 and 9.55 percent for the first half of 2020. However, the RRA survey also indicates that the average ROE award for delivery service electric utilities was 9.38 percent in 2018, 9.37 percent for 2019 and 9.16 percent for the first half of 2020.[13] This indicates that ROE awards for delivery service-only electric utilities is about 0.2 to 0.4 percent lower, on average, as compared to the industry generally. This undoubtedly reflects the lower business risks for delivery service as compared to vertically-integrated operations that includes generation supply. Moreover, my recommendation in this case of 8.8 percent is applicable to the single-issue interim cost recovery filings, not the riskier base rate cases. The trends since the Company's 2018 base rate case, particularly for delivery service electric utilities, support a ROE award for the proposed interim rate recovery mechanism of well below the 9.6 percent from the last rate case.

[13] "Regulatory Research Associates, Major Rate Case Decisions January – June, 2020", S&P Global Market Intelligence, July 2020.

B. Capital Cost Trends in Recent Years

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

A. Yes. I show the capital cost trends since 2001, through calendar year 2019, on page 1 of Schedule MIK-2. Pages 2 through 8 of that schedule show monthly data for January 2007 through July 2020. 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 nearly 20-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 2017 and 2018, capital costs remained very low by historical standards but moved up compared to the then historical lows prevailing in 2016. Notably, in 2018 when PSE&G's last base rate case took place, 10-year Treasury and Single A utility bond yields averaged about 2.9 percent and 4.3 percent, respectively. Inflation (a key determinant of capital costs) went from 1.3 percent in 2016 to 2.5 percent in 2018.

As shown on page 1 of Schedule MIK-2, for the time period 2009 through 2015, short-term Treasury rates were close to zero, with three-month Treasury bills averaging about 0.1 percent. Those 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 recovery from the financial crisis and deep recession of 2009. Note that by law, the Fed must follow a policy referred to as the "dual mandate," simultaneously promoting price stability and maximum employment for the U.S. economy.

The Fed 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) to support the market prices of financial assets and to increase the availability of credit and the money supply. 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. DID THE FED ALTER ITS POLICIES AFTER THE ENDING OF QUANTITATIVE EASING IN 2015?

A. Yes. Due to the positive progress in the strengthening of the labor markets, with unemployment falling below 4 percent, real economic growth accelerating, and inflation moving up toward the Fed's target inflation rate of a symmetric 2 percent range, the Fed moved away from its near zero interest rates to a broad policy of monetary "normalization". This began after 2015 and continued through 2018, with the Fed implementing several interest rate increases and gradually unwinding (reversing) its earlier massive quantitative easing bond buying. Between 2016 and 2018 the short-term interest rates controlled by the Fed moved up from near zero in 2016 to over 2 percent in 2018. It was expected that the Fed would continue this normalization policy through 2019, but this did not happen. Instead, during 2019 economic growth was perceived as slowing, there were fears of a potential U.S. and global recession, and inflation remained below the Fed's 2 percent target. Hence, in response to these emerging concerns, instead of the Fed continuing to increase interest rates in 2019 as expected, the Fed responded by reducing interest rates on several occasions. It lowered the federal funds rate (the short-term rate controlled by the Fed) to 1.5 to 1.75 percent. Thus, the policy of 2019 became one of "monetary accommodation".

Fed policy, however, changed dramatically in late February and March of 2020 with the onset of the Covid-19 pandemic and the consequent implementation of emergency shutdowns of portions of the U.S. economy. With the sharp sell-off of the stock markets in March, the spiking of unemployment and resulting threats to the health of the financial system, the Fed took sudden and dramatic action to expand credit and support financial markets. It immediately returned to its pre-2016 policy of zero interest rates and resumption of quantitative easing with massive purchases of government, government agency and even corporate bonds. Arguably, in 2020 the Fed has gone much further than the emergency supportive actions that it took during the 2018-2019 financial crisis. It has implemented or announced facilities for the support of the banking system, money market funds, municipal bonds, and even corporate bonds. The Fed's actions, along with market forces, have dramatically lowered both short-term and long-term interest rates for both U.S. Treasury and corporate debt, and therefore the cost of capital as compared to conditions prevailing prior to the pandemic. Moreover, it has lowered the cost of capital by a substantial amount as compared to 2018. At this time (in mid-August), 30-year Treasury bonds are yielding less than 1.5 percent and Single A utility bonds about 3 percent – in both cases more than a full percentage point below 2018 levels.

While the Fed retains flexibility to alter its policy as conditions change and economic data warrant, its June 2020 outlook anticipates a continuation of this highly accommodative monetary policy for an extended time period, flooding markets with liquidity and continuing asset purchases perhaps through end of next year.[14]

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 manner utility stocks and long-term bonds are related by market forces.

Q. ARE THERE FORCES CONTRIBUTING TO LOW INTEREST RATES AND A LOW COST OF CAPITAL OTHER THAN FED POLICY?

A. Yes, there are. While the decline in short-term interest rates since 2018 (and particularly this year) clearly is the result of Fed policy, the behavior of long-term interest rates also reflects more fundamental economic forces. Factors that affect long-term rates and the cost of capital generally include the ongoing strength and weakness of the U.S. and global macro economies, the inflation outlook and even international events. A weak or even moderately growing economy exerts downward pressure on the cost of capital due to weak demand for credit and capital. Very slow inflation also contributes to a declining or low cost of capital.

A weak economy is certainly the case today, and it is expected to continue

[14] https://www.federalreserve.gov/newsevents/pressreleases/monetary/20200610a.htm. Please also see the Fed's "Monetary Policy Report", June 12, 2020, available on the Fed's website.

through the rest of this year and perhaps next year. While inflation can fluctuate from month to month, inflationary expectations remain quite subdued, well below the Fed's 2 percent (symmetric) target level. With the pandemic and related shutdowns, the U.S. personal savings rate has sharply increased due to many consumers being unable to spend their incomes as they would under normal conditions. In addition, capital spending by corporations has been relatively weak, in part due to uncertainty over consumer demand. All of this means that there is a surplus of savings seeking a return and chasing investment opportunities.

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 July 2020. Such market data incorporate the Fed policies and fundamental economic forces described above. Those forces and resulting market behavior are directly priced into the shares of the utility stocks used in my proxy group DCF analysis. The CAPM study uses the 30-year Treasury bond yields from 2020. Thus, strictly speaking my analysis measures the utility cost of capital during that recent time period. I believe that the use of the most recent six months of stock market pricing data and Treasury yields is reasonable at this time for gauging the current cost of equity.

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

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

A. Section III of my testimony provides additional discussion of the rationale for my recommendations summarized in Section II.A. above. 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. Finally, Section V provides a summary of major findings and conclusions.

III. DISCUSSION OF RECOMMENDATIONS AND PSE&G'S INVESTMENT RISK

A. Discussion of Recommendations

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND THAT THE COMPANY USE IN ITS PROPOSED COST RECOVERY MECHANISM?

A. For purposes of all interim AMI cost recovery filings, Mr. Swetz proposes to use the Board-approved capital structure from the most recent base rate case. This would include a common equity ratio of 54 percent until the completion of the next base rate case which may occur in late 2024. The 54 percent figure was the approved common equity ratio in the Board-approved settlement from the 2018 base rate case.

I accept Mr. Swetz's recommendation provided that the Company's actual capital structure contains 54 percent common equity or more. I note that the Company's actual common equity ratio at March 30, 2020 is slightly lower, 53.5 percent, as I show on my Schedule MIK-1. My recommendation is that the Company utilize a common equity ratio no higher than the 54 percent (or whatever is approved in a future base rate case), but it should use the actual common equity ratio if it is lower than base rate case value of 54 percent. For example, for a June 1 filing under the Company's interim rate mechanism, the Company should use the actual common equity ratio at March 31 of that year, though no higher than the 54 percent.

It is not the purpose of my testimony to oppose or support any specific capital structure, and I recognize that the 54/46 percent capital structure was incorporated into the settlement of the last case. That said, there was no provision in that settlement authorizing the use of that capital structure for ratemaking in any future case. My position in this case is that it is inappropriate for PSE&G to use in its interim cost recovery mechanism an equity ratio that is higher than its actual equity ratio, particularly since this mechanism is very favorable and low risk for shareholders. Doing so will overcharge customers. Similarly, the common equity ratio in the interim rate recovery mechanism should be capped at 54 percent since a common equity ratio higher than 54 percent for PSE&G has not been reviewed or approved by the Board. An additional consideration, as I explain below, is that the requested 54 percent is a relatively high ratemaking common equity ratio for an electric utility.

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 46.5 percent for the proxy group companies, with nearly all of the companies at about 51 percent or lower. Please note that these are the actual equity ratios for year-end 2019, 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 financing decisions and use of a 54 percent equity ratio for ratemaking (if consistent with actuals), but rather I am pointing out that PSE&G is financially stronger than the proxy companies and therefore has less financial (debt leverage related) risk. This risk advantage for PSE&G and the costliness of using this capital structure for ratemaking should be taken into account when considering the appropriate ROE for use in the interim cost recovery mechanism. It further supports capping the equity ratio at 54 percent.

Q. DOES THE 54 PERCENT EQUITY RATIO EXCEED THE EQUITY RATIO TYPICALLY APPROVED FOR RATEMAKING FOR ELECTRIC UTILITIES?

A. Yes, it is significantly above average. In Section II.A. of my testimony I referred to the RRA rate case survey for electric utilities published in July 2020. That survey reports that for state electric utility rate cases, the average approved equity ratio was 49.02 percent in 2018, 49.94 percent in 2019 and 48.61 percent for the first half of 2020. These averages are materially lower (and therefore less expensive for consumers) than the locked-in 54 percent proposed by the Company for its interim cost recovery mechanism.

The PSE&G capital structure is completely under control of Company management. Hence, since management determines the actual equity ratio, there is no reason to use a figure higher than actual for the interim cost recovery mechanism.

Q. WHAT IS YOUR COST OF DEBT RECOMMENDATION AT THIS TIME?

A. As shown on Schedule MIK-1, the Company's embedded cost of debt is 3.95 percent or nearly identical to the embedded cost of debt approved in the Company's most recent base rate case and adopted by Mr. Swetz. I recommend the use of the actual embedded cost of debt in the interim cost recovery mechanism rather than a locked in figure from the last rate case. Admittedly, the Company's embedded cost of long-term debt does not change significantly from year to year. However, over the next several years, the Company expects to issue several billions of dollars of new long-term debt to fund capital expansion and redemptions of maturing debt. As discussed in Section II.C., the cost of new debt at this time is historically low and these credit market conditions are expected to continue due to extraordinarily accommodative Fed policies, very low inflation and macroeconomic weakness. For example, in recent weeks the Company was able to issue new 30-year debt under its Medium-Term Note program at an extremely low 2.05 percent.[15] This suggests that the Company's

[15] "Public Service Electric and Gas completes $375 million note offering", August 7, 2020, S&P Global Market Intelligence.

embedded cost of long-term debt could gradually drift down over the next couple of years from Mr. Swetz's base rate case value of 3.96 percent. Unlike the common equity, however, I am not recommending a cap on the cost of debt component of the WACC for use in the interim cost recovery mechanism. This is because, unlike the equity ratio, the cost of debt depends to a large extent on market conditions and is not completely under the Company's control.

Q. THE COMPANY PROPOSES TO USE THE 2018 BASE RATE CASE WACC OF 6.99 PERCENT, INCLUDING THE SETTLEMENT ROE OF 9.6 PERCENT. WHAT ARE ITS JUSTIFICATIONS FOR DOING SO FOR ITS INTERIM RATE RECOVERY MECHANISM?

A. There is no substantive discussion of investment risk or the going forward cost of capital anywhere in the Petition. However, the Company did provide its defense of its WACC request in response to certain Rate Counsel data requests, specifically RCR-ROR-7, 9 and 10. In response to RCR-ROR-7, the 9.6 percent ROE is justified based on its approval (through settlement) in a base rate case, further arguing that a ROE lower than that would not provide adequate incentive to invest in the AMI program. Moreover, in the recent past, previous infrastructure-type programs have been allowed to use the 9.6 percent settlement ROE. In response to RCR-ROR-9, the Company asserts that it is subject to prudence review on its performance in executing the approved AMI program, which review must specifically take place in the next base rate case. In other words, the Company asserts that there will be heightened attention in the base rate case on the AMI program performance prudence. While the Company acknowledges that it benefits from the accelerated cost recovery (for all practical purposes contemporaneous cost recovery), it asserts that it bears risks comparable to those in a base rate case. Moreover, the Company claims that absent this favorable cost recovery mechanism it would not be willing to undertake the as-proposed AMI program. The response to RCR-ROR-10 is similar, with the Company also asserting that it is still exposed to at least some regulatory lag.

Mr. Swetz in his testimony also mentions that the Company under its program (and the Board's IIP rules) is subject to a periodic earnings test.[16] If the Company is unable to pass the earnings test (i.e., its earnings are too high), it may not implement its interim semi-annual rate increase, and therefore the cost recovery would be delayed. This is apparently viewed by the Company as a customer protection or guard rail that helps to justify its proposed rate recovery mechanism and the use of the settlement WACC in that mechanism.

Q. WHAT IS YOUR RESPONSE TO THESE ARGUMENTS SUPPORTING THE USE OF THE SETTLEMENT WACC AND ROE?

A. The Company's arguments, provided in discovery, that the 2018 settlement WACC and ROE should or must be used in the interim cost recovery mechanism are unconvincing. At the outset, I observe that there is nothing in the 2018 rate case settlement that authorizes (or mandates) the use of the 9.6 percent ROE for use in any other cost recovery docket or mechanism. Also, the fact that the Company has been permitted to use the 9.6 percent ROE in other infrastructure-type programs does not support its use here.

There are several reasons why the Company's support for the use of the 9.6 percent ROE, taken from the settlement in another case, is unconvincing. As mentioned earlier, there is no cost of equity support for the use of that return or any discussion of or reference to current financial market conditions.

[16] Swetz testimony, page 8.

The Company does attempt to make the argument that the risks associated with its proposed cost recovery mechanism somehow are comparable to (not less than) the risks it faces in a general base rate case. Such alleged risks include potential prudence disallowance if the Company fails to properly execute its AMI program, regulatory lag and other unspecified cost recovery risks. In fact, the Company's cost recovery mechanism largely protects it against any significant regulatory lag, with twice per year rate increase filings based on actual AMI net plant in-service balances just prior to the rate increases taking effect. Moreover, the Company will use billing determinants (number of customers, potentially along with kwh sales as recommended by Rate Counsel witness Peterson) from the 2018 base rate case in its twice per year rate mechanism over the next several years providing an opportunity to offset any minimal regulatory lag ("contemporaneous or near contemporaneous" cost recovery of investment as asserted by the Company in communications to investors). Absent the discovery of a mathematical or administrative error in the semi-annual filing, there is every reason to believe that the Company will recover 100 percent or extremely close to 100 percent of the rate increase in these filings. A base rate case, by comparison, is an arduous and detailed process where parties challenge the requested rate increase, and the utility normally ends up receiving only a portion of its rate increase request. It is simply not true that the cost recovery risks under the proposed interim cost recovery are comparable to that of a base rate case. And the best evidence of that is the Company's assertion that absent approval of its interim cost recovery mechanism it simply would not be willing to proceed with its proposed AMI program.

It is true (and should be true) that the Company – at least theoretically – is exposed to prudence disallowances in the next base rate case from failure to properly execute on its approved AMI program. However, the track record on such prudence disallowances for special investment programs indicates that this is simply not a significant risk exposure. The Company has not been able to cite any such prudence disallowances. Moreover, the Company is seeking Board approval in this docket of the overall AMI program which approval would help to mitigate future disallowance exposure risk. In other words, the Company's prudence risk exposure is a narrow one that is limited to the "execution risk" associated with carrying out a detailed program of investment that in this docket would be effectively pre-approved by the Board.

The Company insists that it is improper that a ROE lower than its cost of equity be used for rate recovery of AMI investments, and I do not disagree with that. The use of the cost of equity as the fair return on equity is consistent with economic efficiency and provides the right investment incentives. The problem is, as a factual matter, 9.6 percent is not the Company's cost of equity going forward at this time, particularly in the context of its unusually low-risk interim cost recovery mechanism. My 8.8 percent is a conservative estimate of the cost of equity in this context. Moreover, I am recommending that this ROE only be used for that interim cost recovery (until completion of the next base rate case), and the ROE to be used for the AMI investments on a long-term basis (i.e., over the 20-year life) will be determined in future base rate cases.

Finally, Mr. Swetz mentions the use of the earnings test as a type of customer protection to help ensure that the semi-annual rate increases do not produce unreasonably high earnings for the Company. I agree that this is a helpful protection. But it does not support the Company's proposed WACC or 9.6 percent ROE. The earnings test provides only limited protection against unreasonable earnings because it permits an interim rate increase to go forward as long as earnings do not exceed

10.1 percent. This is 50 basis points above the settlement ROE and 130 basis points above my estimate of the going-forward cost of equity for the Company. Moreover, the calculated actual earnings under this test are essentially per books (using FERC Form 1 data) and do not fully account for the type of cost adjustments that normally would be reflected in a rate case (e.g., consolidated tax adjustments). That is, the earnings test does not necessarily calculate the Company's earned ROE on a regulatory or "Board" basis. For all of these reasons the inclusion of an earnings test does not justify the use of a ROE that exceeds a reasonable estimate of the cost of equity associated with the proposed interim cost recovery mechanism.

B. Discussion of Credit Ratings and Risk

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

A. No, neither the Petition nor any of the testimony provide any discussion of the Company's risk profile or the risks that the Company is accepting. As noted above, the Company does attempt to highlight what it claims are the risks associated with its proposal in response to Rate Counsel data requests, but that discussion is brief and not very convincing.

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 1.7, Financial Strength rating ranges from B+ to A, and the average equity ratio is 46.5 percent. Value Line provides ratings only for Public

Service Enterprise Group ("PEG") parent rather than PSE&G since the latter is not publicly traded. However, PSE&G is the majority and least risky part of the consolidated PEG and therefore a comparison between PEG and the proxy group would be conservative. PEG's Safety Rating is "1" (the highest), and its Financial Strength rating is A++ (better than any proxy company).[17] The PSE&G equity ratio requested in this case is 54 percent, well above the group average of 46.5 percent. The risk indicators on Schedule MIK-3 without question demonstrate PSE&G to be less risky than the proxy group.

Another factor to consider regarding a risk comparison with the proxy group is the risk difference between vertically-integrated (which reflects the risks of owning and operating generation) and delivery service. The proxy group companies are primarily vertically integrated, with perhaps only Eversource and Consolidated Edison among the 12 companies 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 in earlier discussion 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.

An additional favorable risk attribute of the Company is derived from its extensive use of trackers or special cost recovery mechanisms for its large capital investment programs. The Company has claimed that it has been able to receive

[17] Value Line report for Public Service Enterprise Group, August 14, 2020.

essentially contemporaneous or near contemporaneous cost recovery for over 90 percent of its capital investment.[18] This favorable rate recovery along with its strong balance sheet helps to explain its relatively strong credit ratings (i.e., single A issuer or corporate ratings). PSE&G is rated strong single A whereas the proxy companies are a mix of low single A and triple B.

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 (PEG) risk and quality ratings from Value Line, (3) its strong credits ratings , (4) the Company's extensive use of very-low risk cost trackers or contemporaneous mechanisms for the vast majority of incremental investments, and (5) its use in this case of a target 54 percent equity ratio which is far above the industry and proxy group average.

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-4. Moody's assigns PSE&G an issuer rating of A2 and assigns its secured bonds a rating of Aa3 (i.e., low double A, "stable"). Standard & Poor's ("S&P") also assigns strong ratings to PSE&G based on its assessment with an issuer or corporate rating of A- and a secured debt rating of 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 PSE&G's regulated distribution service to be very low risk and New Jersey regulation supportive. The

[18] This is reported in the S&P ratings report for PSE&G of December 11, 2019. Response to RCR-ROR-4.

May 20, 2019 Moody's report states that the A2 issuer rating is supported by its "low risk transmission and distribution (T&D) business model".

Q. ARE THERE SIMILAR COMMENTS FROM S&P?

A. Yes, S&P's risk and credit quality assessment of PSE&G seems quite similar to that of Moody's. The S&P report of December 11, 2019 notes the Company's "low-risk regulated transmission and distribution and gas distribution operations" which have been supportive of maintaining strong and stable earnings. The report designates the Company's business risk as "excellent".

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 the ROE approved in the 2018 base rate case settlement.

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. Moreover, a unique factor in this case is that the Company intends recovering its capital costs through a twice per year, interim rate mechanism that avoids the detailed scrutiny of a base rate case.

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

A. No, not in any direct sense since neither he nor any part of the Petition presents cost of equity evidence. The stated support for the 9.6 percent ROE is the settlement of the 2018 base rate case and that the Company has previously been authorized to use the 9.6 percent in other special infrastructure-type cost recovery mechanisms.[19]

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

A. I employ both the DCF and CAPM models, applied to two proxy groups of 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 because this method was used by the Company in the 2018 rate case), I also perform a CAPM study which also is based on my electric/gas utility proxy group companies.

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.

[19] Company response to RCR-ROR-7.

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 Public Service Enterprise Group ("PEG") parent, and therefore, a market proxy is needed. In theory, PEG 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 did Company witness Ms. Bulkley in the last rate case), although in theory that approach could be used. Moreover, PEG would be a questionable risk proxy for PSE&G (which is a pure delivery service company) due to its extensive unregulated nuclear and other merchant power operations. For that reason, I have elected to not include PEG in my proxy group, nor did Ms. Bulkley in the last case.

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. 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. In order to address the current and prospective cost of equity in the most straightforward and efficient manner, I am using a proxy group that is identical to the proxy group that I used in the 2018 base rate case. In that case, I began by reviewing the utility proxy group selected by Company witness Ms. Bulkley, a group of 11 utility 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 the 2018 base rate case, I accepted her proxy group inclusion criteria as being generally reasonable.

One caveat is that her criteria do permit inclusion of companies that have some unregulated operations. As unregulated 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 electric utility operations, as a broad generalization.

Thus, while his proxy group is acceptable, it is not a perfect risk proxy for PSE&G and may at least to some degree overstate the PSE&G cost of equity.

Q. DID YOU ACCEPT MS. BULKLEY'S PROXY GROUP IN ITS ENTIRETY IN THE LAST RATE CASE?

A. No, I eliminated one company and added two others. I eliminated Centerpoint Energy due to its pending merger with Vectren, a multi-billion dollar transaction.[20] 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. For consistency purposes, I therefore use that same proxy group for the purposes of this testimony.

[20] It no longer is necessary to exclude Centerpoint due to the merger which has long since been resolved. However, since Centerpoint recently reduced its quarterly dividend, it is inappropriate for DCF modeling purposes. Thus, I continue to exclude Centerpoint.

I list the resulting 12 proxy utility 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. This was true in the 2018 base rate case, and remains true 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. Please note that PSE&G's ultimate parent, PEG, is not included in this group for the reasons discussed above.

Q. HAVE EITHER YOU 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. No, I 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 potentially would be appropriate for PSE&G (i.e., higher than average equity ratio, stronger credit ratings, status as a delivery service utility, the low-risk attributes of the interim cost recovery mechanism in this case, etc.). Such a cost of equity adjustment decrement would be significant if quantified. In this case, I have identified upper end DCF estimates of about 9.0 percent and a midpoint for the proxy group of 8.8 percent. Given these DCF results, I recommend a ROE award in this case of 8.8 percent. While lower than the settlement ROE of 9.6 percent, this is consistent with today's cost of equity evidence and recognizes PSE&G's very low risk.

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 July 2020, 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 great volatility for the overall stock market and to some but a lesser degree for the proxy utility stocks. While there is some month-to-month variation, on the whole utility share prices did not change dramatically during this six-month time period when averaged over the 12 companies.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, February through July 2020. That is, I used a six-month time period that encompassed the impacts on the U.S. economy and financial markets of the pandemic. Over this six-month period the proxy group average dividend yields indicate relative stability. The February average was 3.16 percent, moving up in March (a month of severe market turmoil) to 3.45 percent and since then declining somewhat to 3.25 percent at the end of July. This is a slight net increase of about 0.1

percent during this six-month period. The average for the entire six months is 3.36 percent, which is about 0.1 percent above the July figure.

For DCF purposes and at this time, I am using a proxy group dividend yield of 3.36 percent.

Q. IS 3.36 PERCENT YOUR FINAL DIVIDEND YIELD?

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 3.5 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. 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. 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 in her 2018 rate case testimony placed 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 four available and well-known public sources of analyst earnings growth rate projections.[21] Three of these four sources -- YahooFinance, Zacks, and CNNfn -- provide averages from securities analyst surveys conducted by or for these organizations (typically they report the mean or median value). The fourth, 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 2017-2019 compared to the annual average for the forecast period of 2023-2025. These are very similar to the sources used by Ms. Bulkley in her 2018 testimony for securities analyst growth rates in her DCF studies, as she also uses Zacks, YahooFinance and Value Line as data sources.

As this schedule shows, the growth rates for individual companies vary somewhat among the four sources, but the proxy group averages are very consistent. These proxy group averages are 5.55 percent for CNNfn, 5.24 percent for Yahoo!Finance, 5.34 percent for Zacks, and 5.1 percent for Value Line. Thus, the range of growth rates among the four sources is 5.1 to 5.6 percent. The average of these four sources is 5.36 percent, and I have used these results, along with other

[21] In my 2018 testimony, I also used one other source Reuters. However, Reuters for all practical purposes is the same as YahooFinance! since both obtain their growth rates from IBES. Thus, there is no need to include Reuters here.

evidence described below, in obtaining a reasonable growth rate range for the group of 5.0 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 5.0 percent, book value growth averages 4.5 percent, and earnings retention growth averages 3.4 percent.

Some analysts and regulators favor the use of earnings retention growth (often referred to as “sustainable growth”), which Value Line indicates to be 3.4 percent. However, at least in theory, the sustainable growth rate also should include “an adder” to reflect potential future earnings growth from issuing new common stock at prices above book value (referred to as “external growth” or the “s x v” factor). In practice, this is difficult to estimate since future stock issuances of companies over the long-term are an unknown and rarely discussed by analysts. Nonetheless, I have estimated this “external growth” factor using Value Line projections for these 12 companies of the growth rate (through 2023-2025) 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 1.2 percent. The sum of "internal" or earnings retention growth (i.e., 3.4 percent) and the "external" growth rate (i.e., 1.2 percent) is 4.6 percent.

Given this estimate of 4.6 percent for the sustainable growth rate and 5.36 percent for analyst earnings projections, a reasonable DCF growth rate range is approximately 5.0 to 5.5 percent. I tend to place most of the weight on the analyst projected growth rates as it is derived from four 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. In the 2018 base rate case, neither Ms. Bulkley nor I incorporated such an adjustment in our final ROE recommendations (although witness Bulkley did perform a flotation cost analysis). There is no basis for including such an adjustment in this case, and I have not done so.

Q. HAVE YOU INCLUDED A RISK ADJUSTMENT DECREMENT OR ADDER FOR PSE&G RELATIVE TO THE PROXY GROUP DCF ESTIMATE?

A. As discussed earlier, I have not done so. As discussed in Section III of my testimony, there are a number of reasons as to why such a risk decrement for PSE&G relative to the proxy group in this case could be justified

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 July 2020 is 3.5 percent for this group. Available evidence would support a long-run growth rate in the range of approximately 5.0 to 5.5 percent, as explained above, giving most weight to published earnings per share growth rates. Summing the adjusted yield, growth rate range produces a total cost of equity of 8.5 to 9.0 percent, and a midpoint result of 8.8 percent. For purposes of the AMI interim cost recovery mechanism, I recommend a ROE of 8.8 percent in place of Mr. Swetz's 9.6 percent to be in effect until the completion of the Company's next base rate case.

C. <u>DCF Study Using the Bulkley Proxy Group</u>

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 recent dividend cut and consistent with its exclusion in the 2018 case.

I present this analysis on in summary fashion on Schedule MIK-4, pages 2 – 5, in the same format as previously. As the only difference in this second analysis is the removal of two companies (Alliant Energy and Duke Energy) that she did not include, the analytic results do not change much. As shown on page 2 of that schedule the dividend yield for the six months ending July 2020 is 3.27 percent, which is adjusted upward to 3.4 percent. This is a difference from my proxy group analysis of a mere 0.1 percent. The security analyst earnings growth rate estimates from the same five sources (page 3 of that schedule) average to 5.42 percent as compared to 5.36 percent for the full 12 company group. On page 5 of that schedule I present the "sustainable" growth rate analysis derived from Value Line projections which average 4.6 percent, which is identical to my 12-company proxy group result. Based on this information, the adjusted dividend yield (3.4 percent) plus the overall average of the published earnings growth rates (5.4 percent) produces a DCF estimate for her proxy group of 8.8 percent – identical to my recommendation. The result would be slightly lower if some weight were to be given to the Value Line earnings retention growth rate of 4.6 percent.

My conclusion is that modifying the proxy group to exclude the two companies not included by Ms. Bulkley would not alter materially the DCF estimates.

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 in her 2018 testimony used those betas along with betas published by Bloomberg. 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, I note that in recent months Value Line has substantially increased the electric utility company betas for reasons that are not clear. At this time those betas are about (on average) 0.2 higher (on the order of 25 percent higher) than in 2018. The Value Line betas for the proxy group at this time average 0.84 as shown on Schedule MIK-3. I have used those Value Line betas even though they seem unusually high.

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 did Ms. Bulkley in her 2018 testimony) along with the average beta for the 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 moved down sharply and have averaged approximately 1.5 percent, and as mentioned the recent Value Line betas for my utility proxy group average 0.84. As of this writing in mid-August 2020, the 30-year Treasury rate is a slightly lower figure of about 1.3 percent, but I believe it more appropriate to use a six-month average to reflect current market conditions. Finally, and as explained below, I am using an equity risk premium range of 5 to 8 percent, although I also provide calculations using a higher risk premium as a sensitivity test.

Using these data inputs, the CAPM calculation results are shown on page 1 of Schedule MIK-5. The low-end cost of equity estimate uses a risk-free rate of 1.5 percent, a proxy group beta of 0.84 and an equity risk premium of 5 percent.

$$K_e = 1.5\% + 0.84\ (5.0\%) = 5.7\%$$

The upper-end estimate uses a risk-free rate of 1.5 percent, a proxy group beta of 0.84 and an equity risk premium of 8.0 percent.

$$K_e = 1.5\% + 0.84\ (8.0\%) = 8.2\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 5.7 to 8.2 percent, with a midpoint of 7.0 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. 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 8 to 9 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 7 to 10 percent for the overall stock market.

Q. DO YOU HAVE A SOURCE FOR THAT RANGE?

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

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

My "midpoint" risk premium of roughly 6.5 percent falls well within that 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 have been constrained to near zero levels by Fed policy as explained in Section II.B. of my testimony. 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.

V. **CONCLUSIONS**

Q. WHAT IS THE COMPANY'S POSITION IN THIS DOCKET ON RATE OF RETURN?

A. The program proposed by the Company involves an investment in AMI and related IT equipment totaling about $714 million plus an additional $71 million in associated O&M expense. Beginning in 2022, the Company projects that it will begin making single-issue cost recovery filings twice per year to recover the return of and on the AMI net investment. This ratemaking mechanism is intended to provide the Company with essentially contemporaneous and full cost recovery of the AMI investments, with minimal risk for shareholders. The proposed WACC to be used in this low-risk rate mechanism is 6.99 percent and includes a ROE of 9.6 percent, a long-term debt cost rate of 3.96 percent and a capital structure with a 54 percent common equity ratio. This WACC is to remain in effect until completion of the Company's next base rate case which may not occur until the end of 2024 at which time the WACC would be updated. The Company's Petition provides no support or evidence for using these WACC cost elements going forward, and instead, they are extracted from the Board-approved settlement from the 2018 base rate case.

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S PROPOSAL?

A. Given current financial market conditions, the Company's very favorable risk profile and the low-risk attributes of the semi-annual, between rate case cost recovery mechanism, I believe the 6.99 percent WACC is excessive. Unlike the Company, I have conducted an updated cost of equity study, and that supports a ROE to be used in the ratemaking mechanism (if such a mechanism is approved by the Board) of 8.8 percent. I recommend that the capital structure used in the rate mechanism be the actual capital structure not to exceed a 54 percent equity ratio. I also recommend periodic updating of the cost of debt to ensure that customers benefit from the current very low cost of debt environment. The Company attempts to argue that the risks it encounters with its semi-annual cost recovery mechanism are comparable to a base rate case, but this is simply not the case. The degree of "regulatory lag" is minimal (since the AMI rate base gets updated for new investment every six months). The Company is subject to prudence reviews on its execution of its AMI program, which reviews are to take place in base rate cases. That said, this seems to be a minimal risk based on the absence of any prudence disallowances imposed on infrastructure type program investments in the past. My 8.8 percent more than compensates the Company for such minimal risks under its proposed program and cost recovery mechanism.

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

A. I am recommending at this time a 6.54 percent return on PSE&G's AMI rate bases to be used in its semi-annual rate mechanism filings, including an 8.8 percent return on common equity, until the completion of the next base rate case (anticipated to be late 2024). The capital structure and cost of debt would be subject to periodic updating as explained in my testimony. This is supported by current market conditions and the following studies:

(1) **<u>DCF Study of 12 Electric/Gas Proxy Companies</u>**

8.5 to 9.0 percent, with an 8.8 percent midpoint.

(2) **<u>CAPM Calculations</u>**

5.7 to 8.2 percent, with a 7.0 percent midpoint. My "high sensitivity" case is 9.1 percent.

A ROE far lower than the requested 9.6 percent, as derived from the 2018 base rate case settlement, should be used due to the low risk attributes of the interim cost recovery mechanism. In addition, I find that PSE&G is generally less risky on average than the utility proxy group due to (1) its higher than average (54 percent) target equity ratio, (2) its ability to make extensive use of low-risk rate mechanisms for contemporaneous cost recovery of incremental capital investment, (3) its very strong credit ratings and Value Line risk indicators, (4) its status as a low-risk delivery service electric with no generation risk (relative to a proxy group of mostly vertically-integrated companies). Thus, my ROE recommendation for PSE&G is consistent with my range of cost of equity evidence and is conservative given the relatively low-cost recovery risks under the Company's cost recovery mechanism proposal.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NEW JERSEY
BEFORE THE BOARD OF PUBLIC UTILITES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE – ENERGY CLOUD ("CEF-EC") PROGRAM ON A REGULATED BASIS	**))))))**	**BPU Docket No. EO1801115**

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
P.O. Box 003
Trenton, New Jersey 08625
Phone: 609-984-1460
Email: njratepayer@rpa.nj.gov

FILED: August 31, 2020

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Weighted Average Cost of Capital at 3/31/2020
($ Millions)

	Amount	Percent	Embedded Cost	Weighted Cost
Long-Term Debt	$10,508.4[1]	46.11%	3.95% (1)	1.82%
Customer Deposits	88.4[2]	0.39	2.33	0.01
Common Equity	12,508.4[2]	53.50	8.80[3]	4.71
Total	**$23,101.2**	**100.00%**	**--**	**6.54%**

[1] Response to RCR-ROR-1 (update) and 2. Cost of debt per response to RCR-ROR-3.

[2] Response to RCR-ROR-1 and 18.

[3] DCF evidence and PSE&G’s cost recovery mechanism investment risk.

PUBLIC SERVICE ELECTRI 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
2018	2.5	2.9	2.0	4.3
2019	1.8	2.2	2.1	3.8

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
July	2.9	2.9	2.0	4.3
August	2.7	2.9	2.1	4.3
September	2.3	3.0	2.2	4.3
October	2.5	3.2	2.3	4.5
November	2.2	3.1	2.4	4.5
December	1.9	2.8	2.4	4.4

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
2019				
January	1.6%	2.7%	2.4%	4.4%
February	1.5	2.7	2.4	4.3
March	1.9	2.6	2.5	4.2
April	2.0	2.5	2.4	4.1
May	1.8	2.4	2.4	4.0
June	1.6	2.1	2.2	3.8
July	1.8	2.1	2.2	3.7
August	1.7	1.6	2.0	3.4
September	1.7	1.7	1.9	3.5
October	1.8	1.7	1.7	3.4
November	2.1	1.8	1.6	3.4
December	2.3	1.9	1.6	3.4
2020				
January	2.5	1.8	1.6	3.3
February	2.3	1.5	1.5	3.1
March	1.5	0.9	0.3	3.5
April	0.3	0.7	0.1	3.2
May	0.1	0.7	0.1	3.1
June	0.6	0.7	0.2	3.2
July	1.0	0.6	0.1	3.1(p)

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

List of the Electric/Gas Utility Proxy Companies

	Company	Safety Rating	Financial Strength	Beta	2019 Common Equity Ratio*
1.	Alliant Energy	2	A	0.80	50.0%
2.	Ameren Corp	2	A	0.80	49.5
3.	AVANGARD, Inc.	2	B++	0.80	71.5
4.	Black Hills Corp	2	A	1.00	41.5
5.	CMS Energy	2	B++	0.80	35.5
6.	Consolidated Edison	1	A+	0.75	51.0
7.	DTE Energy	2	B++	0.90	42.0
8.	Duke Energy	2	A	0.85	46.0
9.	Eversource Energy	1	A	0.90	47.5
10.	Northwestern Corp	2	B++	0.90	50.5
11.	WEC Energy Group	1	A+	0.80	51.0
12.	Xcel Energy	1	A+	0.75	42.0
	Average	**1.7**	**--**	**0.84**	**46.5%**

*The common equity ratio excludes short-term debt (and current maturities of long-term debt). Actual 2019 equity ratio including short-term debt and current maturities averages 43.5 percent.

Source: *Value Line Investment Survey*, May 15, June 12 and July 24, 2020.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DCF Summary for the
Electric/Gas Company Proxy Group

1.	Dividend Yield (February – July 2020)[(1)]	3.36%
2.	Adjusted Yield ((1) x 1.0275)	3.5%
3.	Long-Term Growth Rate[(2)]	5.0 – 5.5%
4.	Total Return ((2) + (3))	8.5 – 9.0%
5.	Flotation Expense	0.0%
6.	Cost of Equity ((4) + (5))	8.5 – 9.0%
7.	Midpoint	8.8%
	Recommendation	**8.8%**

(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
(February - July 2020)

	Company	Feb	March	April	May	June	July	Average
1.	Alliant Energy	2.9%	3.0%	3.1%	3.1%	3.2%	2.8%	3.02%
2.	Ameren Corp	2.5	2.7	2.7	2.6	2.8	2.5	2.65
3.	AVANGRID, Inc.	3.5	3.9	4.1	4.5	4.2	3.5	3.88
4.	Black Hills	3.0	3.3	3.3	3.5	3.8	3.7	3.42
5.	CMS Energy	2.7	2.8	2.9	2.8	2.8	2.5	2.74
6.	Consolidated Edison	3.9	3.9	3.9	4.1	4.3	4.0	4.00
7.	DTE Energy	3.6	4.3	3.9	3.8	3.8	3.5	3.81
8.	Duke Energy	4.2	4.8	4.6	4.5	4.8	4.6	4.57
9.	Eversource Energy	2.6	2.9	2.8	2.7	2.7	2.5	2.72
10.	Northwestern Corp	3.4	4.0	4.2	4.0	4.4	4.3	4.04
11.	WEC Energy Group	2.7	2.9	2.8	2.8	2.9	2.7	2.78
12.	Xcel Energy	2.8	2.9	2.7	2.6	2.8	2.5	2.70
	Average	**3.16%**	**3.45%**	**3.41%**	**3.37%**	**3.53%**	**3.25%**	**3.36%**
	Excluding Alliant & Duke							**3.27%**

Source: YahooFinance! website, accessed July 2020. 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	CNN	Average
1.	Alliant Energy	6.50%	5.30%	5.54%	5.08%	5.86%
2.	Ameren Corp	6.50	5.85	6.75	6.75	6.34
3.	AVANGRID, Inc.	6.00	5.20	5.57	6.30	5.77
4.	Black Hills	3.50	5.13	5.76	5.76	5.04
5.	CMS Energy	7.50	7.16	6.99	7.00	7.16
6.	Consolidated Edison	3.00	2.65	2.00	3.00	2.56
7.	DTE Energy	5.00	5.84	5.53	6.00	5.59
8.	Duke Energy	5.00	3.86	4.44	3.94	4.31
9.	Eversource Energy	6.50	6.23	6.13	6.25	6.28
10.	Northwestern Corp	1.50	3.70	3.39	4.00	3.15
11.	WEC Energy Group	6.00	5.90	5.91	6.48	6.07
12.	Xcel Energy	6.00	6.10	6.05	6.05	6.05
	Average	**5.21%**	**5.24%**	**5.36%**	**5.55%**	**5.36%**
	Excluding Alliant & Duke					**5.42%**

Source: *Value Line Investment Survey*, May 15, June 12 and July 24, 2020. YahooFinance!, Zacks.com and CNNbusiness.com public websites, July 2020.

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	5.5%	7.5%	3.5%
2.	Ameren Corp	5.0	5.5	4.5
3.	AVANGRID, Inc.	2.5	1.0	1.5
4.	Black Hills	6.0	4.5	3.0
5.	CMS Energy	7.0	7.5	5.5
6.	Consolidated Edison	3.5	3.0	2.5
7.	DTE Energy	6.5	5.5	4.0
8.	Duke Energy	2.0	2.5	2.5
9.	Eversource Energy	6.0	5.0	4.0
10.	Northwestern Corp	4.0	3.0	2.0
11.	WEC Energy Group	6.5	3.5	4.0
12.	Xcel Energy	6.0	5.0	4.0
	Average	**5.04%**	**4.46%**	**3.42%**
	Excluding Alliant & Duke	**5.03%**	**4.35%**	**3.50%**

Source: *Value Line Investment Survey*, May 15, June 12 and July 24, 2020. The earnings retention figures are projections for 2023-2025.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Fundamental Growth Rate Analysis for
Electric/Gas Company Proxy Group

	Company	Shares 2019-2024[(1)]	% Premium[(2)]	sv[(3)]	br[(4)]	sv + br
1.	Alliant Energy	2.3%	132.9%	3.1%	3.5%	6.6%
2.	Ameren Corp	2.2	127.2	2.8	4.5	7.3
3.	AVANGRID, Inc.	0.0	(16.2)	0.0	1.5	1.5
4.	Black Hills	0.8	56.2	0.5	3.0	3.5
5.	CMS Energy	1.1	233.8	2.6	5.5	8.1
6.	Consolidated Edison	1.9	42.4	0.8	2.5	3.3
7.	DTE Energy	1.3	78.5	1.0	4.0	5.0
8.	Duke Energy	1.4	35.0	0.5	2.5	3.0
9.	Eversource Energy	1.5	111.0	1.6	4.0	5.6
10.	Northwestern Corp	1.1	31.4	0.3	2.0	2.3
11.	WEC Energy Group	0.0	190.5	0.0	4.0	4.0
12.	Xcel Energy	0.9	154.2	1.4	4.0	5.4
	Average			**1.2%**	**3.4%**	**4.6%**
	Excluding Alliant & Duke					**4.6%**

(1) Projected growth rate in shares outstanding; 2019-2024.
(2) % Premium of share price ("Recent Price") over 2019 book value per share.
(3) sv is growth rate in shares x % premium.
(4) br is Value Line projection as of 2023-2025.
Source: *Value Line Investment Survey*, May 15, June 12 and July 24, 2020.

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 = 1.5% (Long-term Treasury bond yield for the most recent six months)

Rm = 6.5 – 9.5% (equates to equity risk premium of 5.0 - 8.0%)

Beta = 0.84 (See Schedule MIK-3)

C. Model Calculations

Low end:	K_e = 1.5% + 0.84 (5.0) = 5.7%
Midpoint:	K_e = 1.5% + 0.84 (6.5) = 7.0%
Upper End:	K_e = 1.5% + 0.84 (8.0) = 8.2%
High Sensitivity:	K_e = 1.5% + 0.84 (9.0) = 9.1%

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Long-Term Treasury Yields
(February – July 2020)

Month	30-Year	20-Year	10-Year
February	1.97%	1.81%	1.50%
March	1.46	1.26	0.87
April	1.27	1.06	0.66
May	1.38	1.12	0.67
June	1.49	1.27	0.73
July	1.31	1.09	0.62
Average	**1.48%**	**1.27%**	**0.84%**

Source: Federal Reserve, www.federalreserve.gov website, August 2020.

APPENDIX

APPENDIX A

QUALIFICATIONS OF MATTHEW I. KAHAL

MATTHEW I. KAHAL

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

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

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

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

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

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

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

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

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

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

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

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

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

	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
435.	Docket No. ER18010029/ GR18010030 August 2018	Public Service Electric & Gas Co.	New Jersey	Division of Rate Counsel	Rate of Return
436.	4:11 CV77RWS April 2019	Ameren Missouri	U.S. District Court	U.S. Department of Justice	Oral Trial Testimony— Environmental Compliance
437.	A-2018-3006061 April 2019	Aqua American/Peoples Gas	Pennsylvania	Office of Consumer Advocate	Merger Issues

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	Docket Number	Utility	Jurisdiction	Client	Subject
438.	4929 April 2019	Narragansett Electric	Rhode Island	Division Staff	Wind Energy PPA
439.	ER19050552 October 2019	Rockland Electric Co.	New Jersey	Division of Rate Counsel	Rate of Return
440.	19-00170-UT November 2019	Southwest Public Service Co.	New Mexico	Attorney General	Rate of Return
441.	D-19-17 November 2019	Narragansett Electric	Rhode Island	Division of Public Utilities	Debt Issuance
442.	ER-20-1074-000 March 2020	Marsh Landing	FERC	California PUC	Capital Structure
443.	9-00317-UT July 2020	New Mexico Gas Company	New Mexico	Attorney General	Rate of Return

RELEVANT DISCOVERY RESPONSES

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-ROR-0001
Date of Response: 5/19/2020
Witness: Powell, Donna
PSE&G Capital Structure 3/31/2020

Question:
Please provide the Public Service Electric and Gas Company ("PSE&G" or "the Company") actual regulatory capital structure as of March 31, 2020, both in percentages and in dollar balances. The term "regulatory capital structure" in this context is intended to mean employing the same capital structure elements and definitions as used in the last base rate case (e.g., no short-term debt, including current maturities of long-term debt, including customer deposits, etc.).

Attachments Provided Herewith: 0

Response:
PSE&G's actual regulatory capital structure as of March 31, 2020 will be provided upon the filing of the FERC Form 3Q as of March 31, 2020, which is required to be filed no later than May 31, 2020.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-ROR-0001-UPDATE
Date of Response: 5/29/2020
Witness: Powell, Donna
PSE&G Capital Structure as of 03/31/20

Question:

Please provide the Public Service Electric and Gas Company ("PSE&G" or "the Company") actual regulatory capital structure as of March 31, 2020, both in percentages and in dollar balances. The term "regulatory capital structure" in this context is intended to mean employing the same capital structure elements and definitions as used in the last base rate case (e.g., no short-term debt, including current maturities of long-term debt, including customer deposits, etc.).

Attachments Provided Herewith: 0

Response:
Please see the table below for the capital structure for Public Service Electric and Gas Company (PSE&G) as of March 31, 2020.

PSE&G Capital Structure - March 31, 2020		
	Amount ($M)	Percent
Long-term Debt	$ 10,508	46.11%
Customer Deposits	$ 88	0.39%
Common Equity	$ 12,192	53.50%
Total	$ 22,788	100.00%

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-ROR-0002-UPDATE
Date of Response: 5/29/2020
Witness: Powell, Donna
PSE&G 2020 1st Qtr. Financials

Question:

Please provide the Company's financial statements (i.e., income statement, balance sheet, and cash flow statement) at March 31, 2020 when available.

Attachments Provided Herewith: 1
RCR-ROR_0002-UPDATE_2020 1st Qtr. PSEandG Financials.pdf

Response:
Please see the attached document "2020 1st Qtr. PSEandG Financials.pdf" for Public Service Electric and Gas Company (PSE&G) financial statements as of March 31, 2020.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-ROR-0002
Date of Response: 5/19/2020
Witness: Powell, Donna
PSE&G Capital Structure 3/31/2020

Question:
Please provide the Company's financial statements (i.e., income statement, balance sheet, and cash flow statement) at March 31, 2020 when available.

Attachments Provided Herewith: 0

Response:
The Company's financial statements will be provided upon the filing of the FERC Form 3Q as of March 31, 2020, which is required to be filed no later than May 31, 2020.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-ROR-0003
Date of Response: 5/19/2020
Witness: N/A
Embedded Cost Rate of Debt

Question:
Please provide the Company’s embedded cost rate of long-term debt at March 31, 2020. In the case of long-term debt, please include a schedule showing the calculation of the embedded cost rate. The schedule would show each outstanding long-term debt issue including its date of issue, scheduled maturity date, cost rate, amount outstanding and annual amortization of debt expense.

Attachments Provided Herewith: 1
RCR-ROR_0003_PSEandG LTD Embedded Cost.xlsx

Response:
The Company’s embedded cost of long term debt rate as of March 31, 2020 is approximately 3.95%. Please see the attached Excel file “PSEandG LTD Embedded Cost.xlsx”.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-ROR-0004
Date of Response: 5/19/2020
Witness: N/A
Rating Agency Reports since 1/1/2019

Question:
Please provide copies of all credit rating reports for PSE&G and Public Service Enterprise Group (PEG) issued since January 1, 2019. Please update for new reports issued during the pendency of this case.

Attachments Provided Herewith: 4
RCR-ROR_0004_Moodys PSEG 20May19.pdf
RCR-ROR_0004_SP PSEandG 11Dec19.pdf
RCR-ROR_0004_Moodys PSEandG 20May19.pdf
RCR-ROR_0004_SP PSEG 31May19.pdf

Response:
Please see the attached credit rating reports “Moodys PSEandG 20May19.pdf”, “Moodys PSEG 20May19.pdf”, “SP PSEandG 20May19.pdf” and “SP PSEG 31May19pdf”, all issued since January 1, 2019.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-ROR-0007
Date of Response: 5/19/2020
Witness: Swetz, Stephen
Appropriate ROE

Question:
Please explain why the Company believes that the latest approved return on equity ("ROE") from its last rate case (i.e., in this case 9.6 percent derived from the 2018 base rate case) is appropriate to use in its cost recovery methodology (as described by witness Swetz), given the low risk nature of that methodology.

Attachments Provided Herewith: 0

Response:
In the Company's 2018 base rate case, the Parties to the case all agreed that PSE&G should be allowed an ROE at 9.6%. If the Company were to invest in the CEF-EC Program at an ROE of less than 9.6%, it would be earning less than its cost of capital, which would bring down the utility's overall ROE and dis-incentivize the accelerated investment the Infrastructure Investment regulations were intended to incent. In addition, the ROE for the Company's approved infrastructure investment programs, the extension of the Gas System Modernization program and Energy Strong II, both earn a return at the allowed ROE of 9.6% from the Company's 2018 base rate case.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-ROR-0009
Date of Response: 5/19/2020
Witness: Swetz, Stephen
Earnings' Risks

Question:
Please provide a complete description of the cost recovery and earnings risks that PSE&G is accepting under its CEF-EC Program cost recovery methodology.

Attachments Provided Herewith: 0

Response:
PSE&G objects to this request on the ground that it is vague, overbroad and unduly burdensome, that it would require PSE&G to conduct analyses that are not clearly defined, and that it is generally an improper discovery request, since it does not seek the factual or policy underpinning or support for PSE&G's proposal. Subject to and notwithstanding that objection, PSE&G states that the CEF-EC Program is subject to operational risk as the Company proposes to replace millions of meters on an accelerated time frame. Further, the Company is subject to prudency risk, arguably greater risk than a normal base rate investment, as the expenditures will be subject to a much more focused review. Once in rates, recovery from customers will bear the exact same recovery risk as other meters recovered through base rates. The only benefit of the proposed cost recovery methodology compared to recovery through a base rate case is the ability to accelerate recovery.

It is important to note that the purpose of the Infrastructure Investment Regulations ("IIR") is to "provide a rate recovery mechanism that encourages and supports necessary accelerated construction, installation, and rehabilitation of certain utility plants and equipment." The Company would not initiate the accelerated replacement of meters as proposed in the CEF-EC Program without the accelerated recovery mechanism allowed in the IIR. There is inherently more operational, prudency, and recovery risk to implement the CEF-EC Program compared to making no investment at all.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-ROR-0010
Date of Response: 5/19/2020
Witness: Swetz, Stephen
CEF vs Conventional Base Rate Case

Question:
Please provide a comparison of the cost recovery risks that would confront PSE&G under its proposed CEF-EC Program cost recovery mechanism with the risks associated with conventional base rate case cost recovery (i.e., PSE&G under conventional ratemaking would simply file a base rate case at a time of its choosing to recover all CEF-EC costs).

Attachments Provided Herewith: 0

Response:
Please see the response to RCR-ROR-0009. PSE&G would not initiate the CEF-EC program through a conventional base rate case. Even under the Company's proposed cost recovery mechanism it will incur recovery lag between rate adjustment filings, which will reduce its allowed return on equity. Waiting for base rate recovery would exacerbate the recovery lag and discourages the accelerated investment that the Infrastructure Investment Regulations were developed to incentivize.