STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE SECOND ENERGY STRONG PROGRAM (ENERGY STRONG II)

BPU Docket Nos. EO18060629 and GO18060630

REBUTTAL TESTIMONY OF ANN E. BULKLEY

Submitted on Behalf
of
PUBLIC SERVICE ELECTRIC AND GAS COMPANY

April 18, 2019

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
REBUTTAL TESTIMONY
OF
ANN E. BULKLEY
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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. I am a Senior Vice President of Concentric Energy Advisors, Inc. ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. On whose behalf are you submitting this testimony?

A. I am testifying on behalf of Public Service Electric and Gas Company ("Public Service" or the "Company"), a wholly-owned subsidiary of Public Service Enterprise Group, Inc. ("PSEG").

Q. Did you previously provide Direct Testimony in this proceeding?

A. No, I did not.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of Kevin W. O'Donnell on behalf of the Division of Rate Counsel ("Rate Counsel") as it relates to the appropriate return on common equity in the Company's Second Energy Strong Program ("Energy Strong II").

Q. Are you sponsoring any exhibits as part of your Rebuttal Testimony?

A. I am sponsoring Exhibits AEB-1 through AEB-8.

II. EXECUTIVE SUMMARY

Q. Please summarize your key conclusions regarding the Direct Testimony of Mr. O'Donnell.

A. My key conclusions are as follows:

1) The authorized ROE must meet all three standards from *Hope* and *Bluefield* – financial integrity, capital attraction, and comparable returns. Mr. O'Donnell's "calculated" ROE of 9.00 percent fails to meet the comparability standard and capital attraction standards. Comparing this return to recently authorized ROEs demonstrates that Mr. O'Donnell's "calculated" return is not comparable to the return that is available to investors in companies with commensurate risk and is not sufficient to allow Public Service to compete for capital with other similar risk firms.

2) The range that Mr. O'Donnell establishes within his DCF results is arbitrary, inconsistent with recently authorized ROEs, and understates the cost of equity. The actual range of Mr. O'Donnell DCF results is from 7.5 percent to 9.8 percent. Within that range, Mr. O'Donnell arbitrarily determines that the range of results for the DCF is "right in the middle" of the range at 8.0 to 9.0 percent.[1] Mr. O'Donnell's range is clearly skewed to the bottom end of the range of his DCF results. Mr. O'Donnell provides no rationale for why the range he sets is 80 basis

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[1] Direct Testimony of Kevin W. O'Donnell, at 24.

points below the high end of the DCF results and only 40 basis points above the low end.

3) Comparing Mr. O'Donnell's range and final recommendation to recently authorized ROEs demonstrate that his return does not meet the standards established in *Hope* and *Bluefield.* Recently authorized ROEs serve as important benchmarks for investors as they gauge their return requirements for regulated utilities such as Public Service. Mr. O'Donnell has provided no evidence or support to justify ignoring these benchmarks; rather he relies on the assertion that Public Service has lower business and financial risk than these other utilities to substantiate his recommendation. As discussed in more detail in my rebuttal testimony, a review of the recovery mechanism of the proxy companies demonstrates that the business and financial risk of Public Service is similar on average to the proxy companies as it pertains to capital recovery mechanisms.

4) Mr. O'Donnell's recommended ROE of 8.50 percent is well below the expected return for regulated electric utilities. Mr. O'Donnell's ROE recommendation is significantly lower than the New Jersey Board of Public Utilities ("BPU" or the "Board") has authorized in the past, including in several recent decisions for Atlantic City Electric and New Jersey Natural Gas. Furthermore, Mr. O'Donnell's recommended ROE is at a level that is lower than has been supported by any regulatory jurisdiction in the United States. In fact, the range that Mr. O'Donnell arbitrarily established from his DCF results of 8.00 percent to 9.00 percent includes only one authorized ROE, at the highest end of his range of

results. In contrast, the settlement ROE of 9.60 percent, a return that the Division of Rate Counsel agreed to in the Company's last rate proceeding in October 2018, six months ago, is well within the range of recently authorized ROEs. Mr. O'Donnell has not demonstrated that there has been any significant change in market conditions or PSEG's overall risk as compared with the proxy group to warrant a departure from the settlement ROE that was established less than six months ago.

5) Reasonable adjustments to Mr. O'Donnell's analysis demonstrate that the low end of the range of DCF results is 9.50 percent and based on the methodology that Mr. O'Donnell has used in prior cases could be as high as 10.8 percent using historical growth rates. Furthermore, reasonable adjustments to Mr. O'Donnell's CAPM results demonstrate a range between 9.15 percent and 10.15 percent. The results of these analyses demonstrate that the settlement ROE of 9.60 percent is reasonable and appropriate.

6) Mr. O'Donnell's recommended downward adjustment to the ROE of 50 basis points, resulting in a return of 8.50 percent, is unsubstantiated and should be disregarded. Mr. O'Donnell purports to adhere to the comparability and capital attraction standards established by the U.S. Supreme Court decision in the *Hope Natural Gas* ("*Hope*") case.[2] However, Mr. O'Donnell abandons these principles in his recommended 50 basis point reduction to the ROE. Mr. O'Donnell has

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[2] *Ibid.*

provided no analysis of the capital trackers that have been implemented by the proxy companies. In agreeing with the principles of *Hope*, Mr. O'Donnell should recognize that the standard for review is the risk of the company *relative to* the proxy group. Mr. O'Donnell has offered no analysis of his proxy group that demonstrates that PSE&G has less overall risk than that group as a result of the Energy Strong II program. Therefore, his recommended reduction to the ROE should be disregarded.

7) In my rebuttal testimony, I provide a summary of capital tracking mechanisms that have been implemented by Mr. O'Donnell's proxy companies. As shown in that summary, approximately half of the proxy companies have implemented capital trackers for generic infrastructure replacement. In addition, many of the proxy companies have generation trackers and decoupling mechanisms. Therefore, PSE&G's Energy Strong II is reasonably comparable from a risk perspective to the proxy group. There is no support for a reduction in PSE&G's ROE as a result of the risk mitigation from this program because the comparable companies have implemented similar programs.

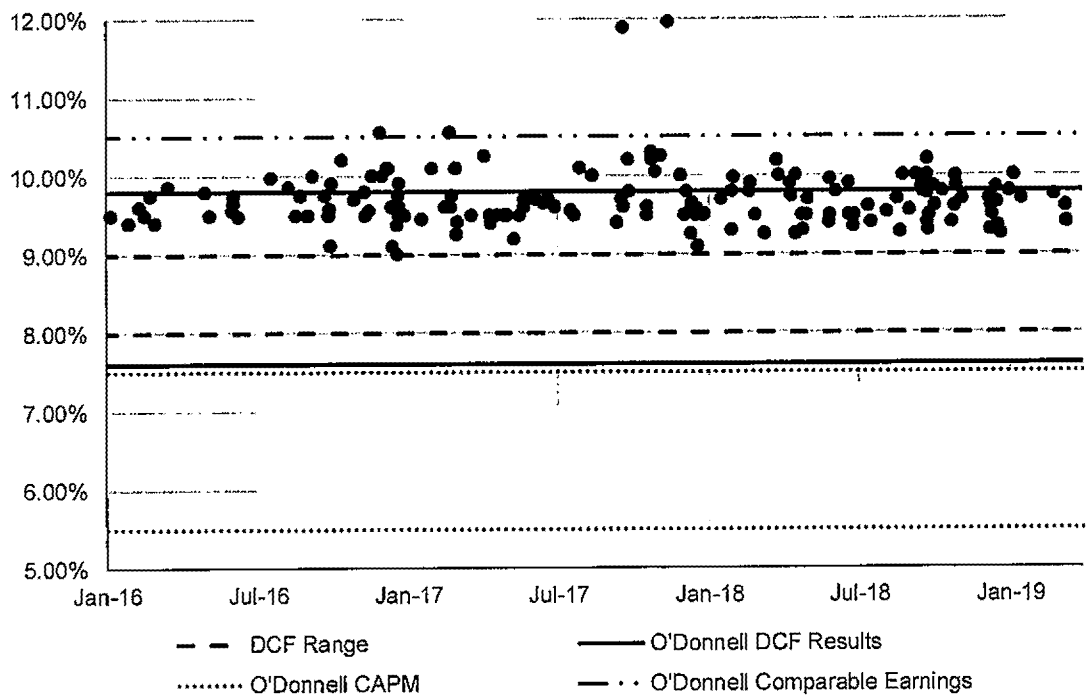
III. FAIR RETURN STANDARD

Q. How does Mr. O'Donnell's ROE recommendation compare to the returns on equity authorized in other jurisdictions?

A. As shown in Figure 1, the majority of authorized ROEs for combination electric and gas utilities from 2016 through the first quarter of 2019 have been around 9.60 percent. Furthermore, the Division of Rate Counsel agreed to an ROE of 9.60 percent for PSE&G in

October 2018 and has agreed to settlements for five other New Jersey utilities in 2017-2018. With this data as context, Mr. O'Donnell's ROE recommendation of 8.50 percent including a 50 basis point adjustment for the Energy Strong II proposal does not meet the comparable return standard.

Figure 1: Recently Authorized Electric and Natural Gas ROEs 2016-2019[3]



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3 Source: SNL Financial. The chart also shows the ranges of results for Mr. O'Donnell's DCF, CAPM, and Comparable Earnings analyses. Note that the dashed line at 9.0% represents both the high end of Mr. O'Donnell's DCF results and the low end of his Comparable Earnings results. Additionally, 15 cases from New York and 6 cases from Illinois have been excluded. The New York decisions included low authorized ROEs as part of multi-year rate settlements, and the Illinois decisions were the result of formula rate plans rather than an analysis based on proxy groups. In Illinois, the authorized ROE for the utility is calculated by adding 580 basis points to the 12-month-average 30-year treasury bond yield.

Q. Has Mr. O'Donnell demonstrated that his recommended return meets the *Hope* and *Bluefield* standards?

A. No, he has not. The *Hope* and *Bluefield* decisions form the legal basis for determining whether a return is just and reasonable.[4] These decisions set forth three standards,[5] each of which must be met in order for the return to be considered just and reasonable:

1) Comparable return standard

2) Financial integrity standard

3) Capital attraction standard

Mr. O'Donnell fails to demonstrate that his ROE recommendation of 8.50 percent offers equity investors a return that is comparable to those returns available to investors in alternative investments with commensurate risk. Furthermore, Mr. O'Donnell fails to demonstrate that his ROE recommendation would allow Public Service to raise equity capital on reasonable terms and conditions. It is important to recognize that equity investors face different risks associated with ownership of common equity including: 1) the risk that dividends on the common stock are not guaranteed, and 2) that they are the residual claimants on the Company's net income in the event of bankruptcy. Public Service is making significant capital investments in order to upgrade and modernize its gas distribution system and related infrastructure through the Infrastructure Investment Program. This program provides utilities the opportunity to invest in utility plant that is non-revenue

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4 Bluefield Water Works Co. v. Publ. Serv. Comm'n., 262 U.S. 679 (1923); Federal Power Comm'n. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

5 *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S., at 603.

producing but important infrastructure to enhances safety, reliability and resiliency and to seek recovery on a periodic basis rather than through general rate proceedings. The comparable return and capital attraction standards are particularly important for Energy Strong II because if the allowed ROE under this program does not satisfy these standards, the incentives that have been established by the IIP regulations will be undermined. If the Company cannot even achieve its authorized ROE on investments that have been placed into service under this program, then investment in the non-revenue generating assets in this program will necessarily reduce the Company's ability to earn its authorized ROE on the base operations. Therefore, establishing a return for this program that is not at least equal to the return that the Company is authorized on the remainder of the investment undermines the goal of the IPP regulations, which is to advance investment in these critical infrastructure projects.

IV. CAPITAL MARKET CONDITIONS AND EFFECT ON MODELS

Q. Please summarize Mr. O'Donnell's testimony regarding current capital market conditions and the impact on the cost of equity for Public Service.

A. Mr. O'Donnell's testimony on market conditions is somewhat inconclusive, as he suggests both strong economic growth and slow economic times all within a short discussion on markets. As evidence of strong economic growth, Mr. O'Donnell characterizes stock market performance as "churning higher".[6] Mr. O'Donnell further states that the utility

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6 Direct Testimony of Kevin W. O'Donnell, at 5.

market has been very strong over the past two years, with the index increasing 15 percent as compared to the S&P 500. Mr. O'Donnell suggests that when utility stock prices increase the expected return decreases and therefore this explains the lower expected return on utility investments that should be considered in rates. However, as evidence of slowing market conditions, Mr. O'Donnell notes that Dow Jones Utility Average has been flat since the Company's last base rate case was settled in October 2018.[7] Finally, he suggests that interest rates suggest a flattening of the yield curve, which he suggest is a "harbinger of slow economic times ahead." Finally, he suggests that the economy in New Jersey is slowing.[8] Mr. O'Donnell's position on the direction of economic conditions, interest rates, and the effect of these indicators on the cost of equity is unclear at best.

Q. What is Mr. O'Donnell's position with respect to interest rates?

A. While Mr. O'Donnell recognizes that the Federal Reserve has increased the Federal Funds rate to 2.2-2.50 percent, and he recognizes that the Federal Reserve may increase interest rates two more times in 2019, he suggests that these increases do not mean that long-term rates will increase correspondingly.[9] In his Direct Testimony Mr. O'Donnell summarizes the historical yields on Treasury bonds on two charts. In Chart 1, Mr. O'Donnell provides the yield on 30-year Treasury bonds for the period from October 2018 through February 2019 and notes that the yields have been flat since December 2018, when the

7 *Id.*, at 6.
8 *Id.*, at 8.
9 *Ibid.*

Federal Reserve last raised interest rates.[10] In Chart 5, Mr. O'Donnell provides a slightly longer historical view back to February 2018. From this chart, he concludes that yields have been flat over the last year, in spite of the fact that the Federal Reserve increased interest rates three times in 2018.[11] Mr. O'Donnell also states that interest rates are likely to remain relatively low for an extended period.

In addition to these charts, Mr. O'Donnell provides his view that the economic forecasters as well as the Federal Reserve all believe that the current interest rate environment is expected to remain relatively stable for many years to come. As support for this statement, Mr. O'Donnell provides a quote attributed to Chairperson Yellen in 2016 suggesting that interest rates would remain low.[12]

Q. Do you agree with Mr. O'Donnell's views on the effect of Federal monetary policy on long-term government bonds?

A. No, I do not. As shown in Figure 2, below, yields on long-term government bonds have increased since the Federal Reserve started to raise the federal funds rate in 2016 and investors expect continued increases in the near term projections.

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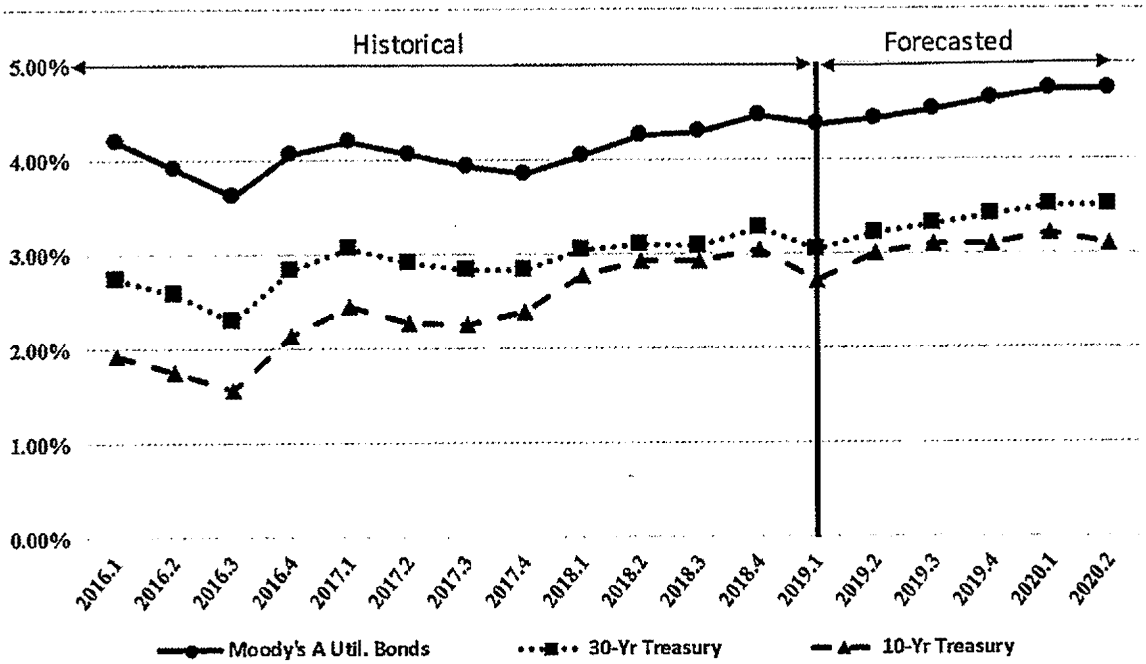
10 Direct Testimony of Kevin W. O'Donnell, Chart 1, at 8.

11 *Id.*, at 29.

12 *Id.*, at 30.

Figure 2: Interest Rate Conditions[13]



However, the increase in long-term government bond yields has not been as pronounced as the rise in short-term interest rates. This is due to a shift in the supply and demand of long-term government bonds that has occurred since 2009. For example, since the Great Recession of 2008-2009 federal debt has increased significantly, which has resulted in an increase in the supply of Treasury bonds in the market. In general, an increase in supply should result in a decrease in the price of Treasury bonds and an increase in yield. However, long-term government bonds yields have not increased as fast as expected given the increase in supply. This is because the demand for Treasury bonds has also increased

[13] Source: Historical data from Bloomberg Professional. Forecast data from Blue Chip Financial Forecasts, Volume. 38, No. 2, February 1, 2019, at 2.

since 2009. As noted in a recent article published by the St. Louis Federal Reserve, the demand for government bonds increased for a number of reasons, some of which included increased holdings of foreign governments as countries in Europe and Asia faced their own economic uncertainty, and increased holdings of commercial banks due to new regulations that required banks to hold a larger portion of high-quality liquid assets.[14] This supply and demand balance resulted in a more gradual increase in the yields on long-term government bonds over the past few years.

While the demand for long-term government bonds had been increasing, throughout the recessionary period, the forward-looking supply and demand balance has shifted, resulting in an expectation for rising interest rates. As noted in the St. Louis Federal Reserve article, the demand for Treasuries has decreased:

> Some evidence suggests that the growth in demand for Treasuries has already begun to soften. [F]oreign holdings have remained more or less constant since 2014, largely because of declining holdings in Japan and China. Likewise, regulation and policy changes such as the Dodd-Frank Act and new rules for prime money market funds may have only transitory effects on the demand for Treasuries. For example, the pace of growth of the ratio of commercial bank Treasury security holdings to private loans has slowed since 2014 . . , as has the growth of investment in government money market funds since 2017 . . . .[15]

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[14] David Andolfatto and Andrew Spewak, Federal Reserve Bank of St. Louis, "On the Supply of, and Demand for, U.S. Treasury Debt," Economic Synopses, No. 5, 2018. https://doi.org/10.20955/es.2018.5.

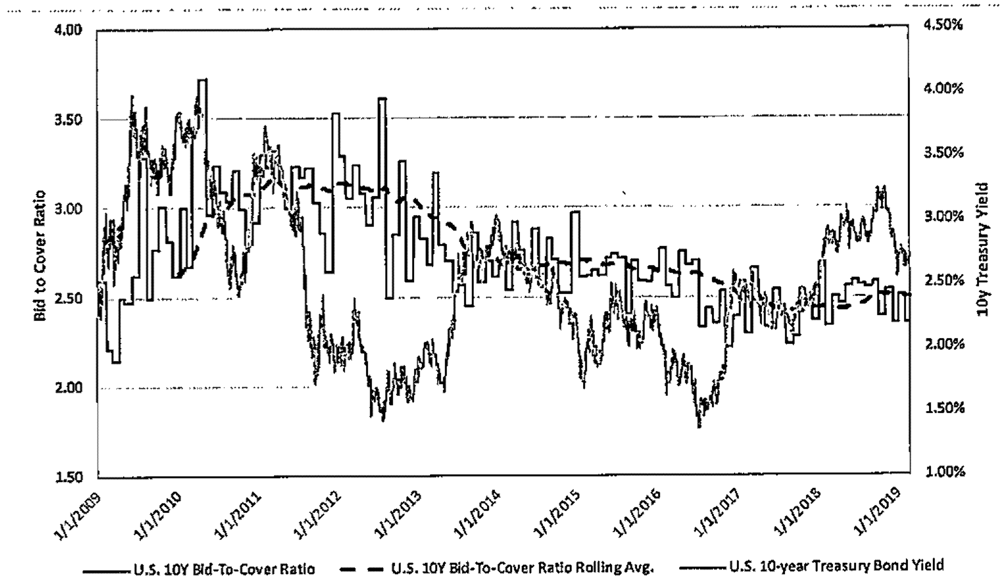
[15] *Ibid.*

Declining demand for Treasuries, when the supply of Treasuries is increasing results in the expectation of rising interest rates on government bonds. Therefore, I disagree with Mr. O'Donnell's view that long-term interest rates will remain low for years to come.

Q. Are there other indicators of the demand for Treasury bonds?

A. Yes. Another indicator of the demand for Treasury bonds is the bid to cover ratio which represents the dollar amount of bids received versus the dollar amount sold in a Treasury security auction. Therefore, a higher bid-to-cover ratio is indicative of an increase in the demand for government bonds. As shown in Figure 3, the bid-to-cover ratio for the 10-year U.S. Treasury bond is currently at its lowest point since 2009, which indicates that the demand for long-term government bonds has declined. The decline in demand is occurring at a time when the supply of Treasury bonds is expected to increase as the Federal Reserve continues its balance sheet unwind and the federal government issues bonds to offset the reduced tax revenue associated with the implementation of the Tax Cuts and Jobs Act ("TCJA" or the "Tax Reform Act"). As a result of this declining demand and increasing supply, prices of long-term government bonds are expected to decline and yields are expected to continue to increase over the near-term, which is consistent with investors' expectations shown in Figure 3.

Figure 3: U.S. 10-year Treasury Bond Bid-to-Cover-Ratio



Q. What effect do rising interest rates have on the cost of equity?

A. As interest rates continue to increase, the cost of equity for the proxy companies using the DCF model is likely to be an overly conservative estimate of investors' required returns, because the proxy group average dividend yield reflects the increase in stock prices that resulted from substantially lower interest rates. As such, rising interest rates support the selection of a return toward the upper end of a reasonable range of ROE estimates resulting from the DCF analysis. Alternatively, my CAPM and Bond Yield Plus Risk Premium analyses include estimated returns based on near-term projected interest rates, reflecting investors' expectations of market conditions over the period that the rates that are determined in this case will be set.

Q. How do equity investors view the utilities sector based on these recent market conditions?

A. Investment advisors have suggested that utility stocks may underperform as a result of market conditions. Barron's recently published its seventh annual review of income-producing investments in which Barron's ranked eleven different sectors based on projected performance in 2019. The utility sector ranked ninth out of the eleven sectors with Barron's noting that utility stocks may be overvalued:

> Utilities, however, aren't cheap; they are valued at an average of 17 times projected 2019 earnings, a premium to the S&P 500, at about 14. That may make it hard for utilities to best the index in 2019, barring a market collapse. Earnings growth is running at a mid-single-digits yearly pace.[16]

Similarly, a recent report on the market outlook for 2019 from J.P. Morgan Asset Management noted that because of rising interest rates the utilities sector is not their current focus for investment:

> As prospects for slower economic growth become clearer in the middle of next year, the Fed may signal it will pause. Such a signal, or a trade agreement with China, could lead multiples to expand, pushing the stock market higher and potentially adding years to this already old bull market. However, even if the bull market does end in the next few years, it is important to remember that late-cycle returns have typically been quite strong.
>
> This leaves investors in a tough spot – should they focus on a fundamental story that is softening, or invest with an expectation that multiples will expand as the bull market runs its course? The best answer is probably a little bit of each. We are comfortable holding stocks as long as earnings growth is positive, but do not want to be over-exposed given an expectation for higher volatility. As such,

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[16] Bary, Andrew. "Best Income Investments for 2019." Barron's, Barron's, 4 Jan. 2019, www.barrons.com/articles/the-best-income-ideas-for-2019-51546632171.

> higher-income sectors like financials and energy look more attractive than technology and consumer discretionary, and we would lump the new communication services sector in with the latter names, rather than the former. However, given our expectation of still some further interest rate increases, it does not yet seem appropriate to fully rotate into defensive sectors like utilities and consumer staples. Rather, a focus on cyclical value should allow investors to optimize their upside/downside capture as this bull market continues to age.[17]

The reports from equity analysts suggest that utility stocks are currently overvalued and that there are expectations for the prices of these stocks to decline. These expectations need to be considered when evaluating the results of the ROE estimation models. To the extent that investors' views are that utility stocks are over-valued, then the dividend yield used in the DCF model will be understated as will the resulting estimate of the cost of equity using that model.

Q. How has the period of abnormally low interest rates affected the valuations and dividend yields of utility shares?

A. The Federal Reserve's accommodative monetary policy has caused investors to seek alternatives to the historically low interest rates available on Treasury bonds. Mr. O'Donnell agrees, stating: "Individuals seeking an income stream see utility dividends as good alternatives at present time with the lack of adequate fixed income (bond) opportunities. As a result, utility stock prices have soared in the past five years."[18] As Mr. O'Donnell correctly notes, this search for higher yield has driven up the share prices for many common stocks,

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17 J.P. Morgan Asset Management, "The investment outlook for 2019: Late-cycle risks and opportunities", November 30, 2018, at 5.

18 Direct Testimony of Kevin W. O'Donnell, at 36.

especially dividend-paying stocks such as utilities, while the dividend yields have decreased to levels well below the historical average.

Q. Have regulatory commissions recognized that anomalous conditions in the capital markets have had an effect on the ROE estimation models?

A. Yes, several regulatory commissions have addressed the effect of capital market conditions on the DCF model. Notably, FERC has addressed this issue and has moved away from its sole reliance on DCF model in favor of equal weightings of multiple ROE estimation models. In addition, the Illinois Commerce Commission ("ICC"), and the Pennsylvania Public Utility Commission ("PPUC") have all considered this factor in recent decisions.

Q. Please summarize the views of these commissions.

A. The FERC, the PPUC and the ICC have all recognized that the DCF model has been affected by recent market conditions. The FERC recognized that the DCF model was understating the cost of equity several years ago in a New England Transmission Owner case ("NETO"). In that case and a subsequent case, discussed in Opinions 531 and 531-B and Opinion 551, the FERC relied on the results of the CAPM to set the ROE within the range established by the DCF model.

In October 2018, the FERC issued an Order in response to the remand from the U.S. Court of Appeals for the District of Columbia in the NETO case, indicating plans to establish authorized ROEs based on an equal weighting of the results of four financial models: the DCF, CAPM, Expected Earnings and Risk Premium. In that October 2018 decision, FERC explained its reasons for moving away from sole reliance on the DCF model, noting that the DCF alone does not capture how investors view utility returns, that investors use multiple models, and that different models will produce results that move in opposite directions over time:

> Our decision to rely on multiple methodologies in these four complaint proceedings is based on our conclusion that the DCF methodology may no longer singularly reflect how investors make their decisions. We believe that, since we adopted the DCF methodology as our sole method for determining utility ROEs in the 1980s, investors have increasingly used a diverse set of data sources and models to inform their investment decisions. Investors appear to base their decisions on numerous data points and models, including the DCF, CAPM, Risk Premium, and Expected Earnings methodologies. As demonstrated in Figure 2 below, which shows the ROE results from the four models over the four test periods at issue in this proceeding, these models do not correlate such that the DCF methodology captures the other methodologies. In fact, in some instances, their cost of equity estimates may move in opposite directions over time. Although we recognize the greater administrative burden on parties and the Commission to evaluate multiple models, we believe that the DCF methodology alone no longer captures how investors view utility returns because investors do not rely on the DCF alone and the other methods used by investors do not necessarily produce the same results as the DCF. Consequently, it is appropriate for our analysis to consider a combination of the DCF, CAPM, Risk Premium, and Expected Earnings approaches.[19]

In a 2012 decision for PPL Electric Utilities, while noting that the PPUC has traditionally relied primarily on the DCF method to estimate the cost of equity for regulated utilities, the PPUC recognized that market conditions were causing the DCF model to produce results that were much lower than other models such as the CAPM and Bond Yield Plus Risk Premium. The PPUC's Order explained:

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[19] Federal Energy Regulatory Commission, Docket No. EL 11-66-001, et al., Order Directing Briefs, issued October 16, 2018, at para. 40.

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[20]

The PPUC ultimately concluded:

> As such, where evidence based on the CAPM and RP methods suggest that the DCF-only results may understate the utility's current cost of equity capital, we will give consideration to those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[21]

In a recent ICC case, Docket No. 16-0093, Staff relied on a DCF analysis that resulted in average returns for their proxy groups of 7.24 percent to 7.51 percent. The Company (Illinois-American Water Company) demonstrated that those results were inappropriately low by comparing the results of Staff's models to recently authorized ROEs for regulated utilities and the return on the S&P 500.[22] The ICC agreed with the Company that Staff's proposed ROE of 8.04 percent was anomalous and recognized that a return that is not competitive will deter investment in Illinois.[23] In setting the return in that proceeding, the ICC recognized that it was necessary to consider other factors beyond the outputs of the financial models, particularly whether the return is sufficient to attract capital, maintain

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20 Pennsylvania Public Utility Commission, PPL Electric Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.

21 *Id.*, at 81.

22 State of Illinois Commerce Commission, Docket No. 16-0093, Illinois-American Water Company Initial Brief, August 31, 2016, at 10.

23 Illinois Staff's analysis and recommendation in that proceeding were based on its application of the multi-stage DCF model and the CAPM to a proxy group of water utilities.

financial integrity, and is commensurate with returns for companies of comparable risk, while balancing the interests of customers and shareholders.[24]

Q. What are your conclusions concerning the impact of capital market conditions on the cost of equity for Public Service's Energy Strong II case?

A. Recent historical market conditions may not be reflective of the market conditions that will be present when the rates for the ESII investments will be in effect. Over the last several years, regulators have recognized that sole reliance on one ROE estimation model is not prudent and have begun to place emphasis on the results of multiple models in determining the appropriate ROE.

V. <u>THE EFFECT OF TAX REFORM ON THE RETURN ON EQUITY</u>

Q. Did Mr. O'Donnell consider the effects of tax reform on utilities?

A. No, he did not.

Q. Is it important to consider how the recent tax legislation has affected regulated utilities?

A. Yes, it is. In January 2018 the credit rating agencies issued reports that viewed the effect of the Tax Reform Act on regulated utilities as credit negative. Since that time, Moody's has downgraded its outlook on the entire utilities segment and has downgraded the credit ratings of many utilities as a result of tax reform.[25] In summary, the Tax Reform Act

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[24] State of Illinois Commerce Commission Decision, Docket No. 16-0093, Illinois-American Water Company, 2016 WL 7325212 (2016), at 55.

[25] Moody's Investor Service, Global Credit Research, Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform, January 19, 2018. See also, Moody's Investors Service, "Regulated

is expected to reduce utility revenues due to the lower federal income taxes and the requirement to return excess accumulated deferred income taxes. This change in revenue is expected to reduce funds from operations ("FFO") metrics across the sector, and absent regulatory mitigation strategies, is expected to lead to weaker credit metrics and negative ratings actions for some utilities.[26] The rating agencies have identified several financial tools to address weakness in cash flow metrics including higher returns on equity and higher equity ratios. Therefore, it is important to consider the effect of tax reform on utilities when determining the appropriate ROE. At a time when the credit rating agencies are suggesting greater equity components of the capital structure and higher ROEs as the remedy for weakness in cash flow metrics, the determination of a lower ROE than what has recently been agreed to for the Company seems to be counter to investor expectations and may be viewed as credit negative.

Q. Has the Board addressed changes in tax laws for utilities?

A. Yes. In its recent decision in BPU Docket No. AX180100001, the Board required the utilities that it regulates to establish new tariffs that reduce the collection of Federal income tax from 35 percent to 21 percent effective April 1, 2018.

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utilities – US: 2019 outlook shifts to negative due to weaker cash flows, continued high leverage", June 18, 2018, at 3.

26 FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.

Q. Please summarize the rating agencies' views of tax reform for utilities.

A. Each of the rating agencies addressed tax reform in January 2018. Moody's issued a report changing the rating outlook for twenty-four regulated utilities from Stable to Negative.[27] At that time, Moody's noted that the rating change affected companies with limited cushion in their ratings for deterioration in financial performance. In June 2018, Moody's issued a report in which the rating agency downgraded the outlook for the entire regulated utility industry from stable to negative for the first time ever. Moody's cited ongoing concerns about the negative effect of the TCJA on cash flows of regulated utilities. While noting that "[r]egulatory commissions and utility management teams are taking important first steps"[28] and that "we have seen some credit positive developments in some states in response to tax reform,"[29] Moody's concludes that "we believe that it will take longer than 12-18 months for the majority of the sector to show any material financial improvement from such efforts."[30]

Q. Has Moody's changed its outlook for utilities in 2019?

A. No. Consistent with the prior reports issued by Moody's in January and June of 2018, Moody's is maintaining its negative outlook for regulated utilities in 2019 as a result of

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27 Moody's Investor Service, Global Credit Research, Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform, January 19, 2018.

28 Moody's Investors Service, "Regulated utilities – US: 2019 outlook shifts to negative due to weaker cash flows, continued high leverage", June 18, 2018, at 3.

29 *Ibid.*

30 *Ibid.*

continued concerns over the effect of the TCJA on cash flows as well as increasing debt.[31] Moody's notes that "[t]he combination of financial pressures is expected to keep the sector's ratio of funds from operations to debt down around 15% in the year ahead".[32]

Q. What does it mean for Moody's to downgrade a credit outlook?

A. A Moody's rating outlook is an opinion regarding the likely rating direction over what it refers to as "the medium term." A Stable outlook indicates a low likelihood of a rating change in the medium term. A Negative outlook indicates a higher likelihood of a rating change over the medium term. While Moody's indicates that the time period for changing a rating subsequent to a change in the outlook from Stable will vary, on average Moody's indicates that a rating change will follow within a year of a change in outlook.[33]

Q. Have any utilities experienced a downgrade related to cash flow metrics resulting from the TCJA?

A. Yes. Figure 4 summarizes credit rating downgrades for utilities that have resulted from tax reform.

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31 Moody's Investors Service, Research Announcement: Moody's: US regulated utilities sector outlook for 2019 remains negative, November 8, 2018.

32 *Ibid.*

33 Moody's Investors Service, Rating Symbols and Definitions, July 2017, at 27.

Figure 4: Credit Rating Downgrades Resulting from TCJA

Utility	Rating Agency	Credit Rating before TCJA	Credit Rating after TCJA	Downgrade Date
American Water	Moody's	A3	Baa1	4/1/2019
Xcel Energy	Moody's	A3	Baa1	3/28/2019
ALLETE	Moody's	A3	Baa1	3/26/2019
Brooklyn Union Gas Company	Moody's	A2	A3	2/22/2019
Avista Corp.	Moody's	Baa1	Baa2	12/30/2018
Consolidated Edison Company of New York	Moody's	A2	A3	10/30/2018
Consolidated Edison, Inc.	Moody's	A3	Baa1	10/30/2018
Orange and Rockland Utilities	Moody's	A3	Baa1	10/30/2018
Southwestern Public Service Company	Moody's	Baa1	Baa2	10/19/2018
Dominion Energy Gas Holdings	Moody's	A2	A3	9/20/2018
Piedmont Natural Gas Company, Inc.	Moody's	A2	A3	8/1/2018
OGE Energy Corp.	Moody's	A3	Baa1	7/5/2018
Oklahoma Gas & Electric Company	Moody's	A1	A2	7/5/2018

Q. Have other rating agencies commented on the effect of the TCJA on ratings?

A. Yes. S&P and Fitch have also commented on the implications of the TCJA on utilities. S&P published a report on January 24, 2018 entitled "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound" in which S&P concludes:

> The impact of tax reform on utilities is likely to be negative to varying degrees depending on a company's tax position going into 2018, how its regulators react, and how the company reacts in return. It is negative for credit quality because the combination of a lower tax rate and the loss of stimulus provisions related to bonus depreciation or full expensing of capital spending will create headwinds in operating cash-flow generation capabilities as customer rates are lowered in response to the new tax code. The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement

> from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses. Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.
>
> Finally, if the regulatory response does not adequately compensate for the lower cash flows, we will look to the issuers, especially at the holding company level, to take steps to protect credit metrics if necessary. Some deterioration in the ability to deduct interest expense could occur at the parent, making debt there relatively more expensive. More equity may make sense and be necessary to protect ratings if financial metrics are already under pressure and regulators are aggressive in lowering customer rates. It will probably take the remainder of this year to fully assess the financial impact on each issuer from the change in tax liabilities, the regulatory response, and the company's ultimate response. We have already witnessed differing responses. We revised our outlook to negative on PNM Resources Inc. and its subsidiaries on Jan. 16 after a Public Service Co. of New Mexico rate case decision incorporated tax savings with no offsetting measures taken to alleviate the weaker cash flows. It remains to be seen whether PNM will eventually do so, especially as it is facing other regulatory headwinds. On the other hand, FirstEnergy Corp. issued $1.62 billion of mandatory convertible stock and $850 million of common equity on Jan. 22 and explicitly referenced the need to support its credit metrics in the face of the new tax code in announcing the move. That is exactly the kind of proactive financial management that we will be looking for to fortify credit quality and promote ratings stability.[34]

In S&P's 2019 trends report, the rating agency notes that the utility industry's financial measures weakened in 2018 and attributed that to tax reform, capital spending and negative load growth. In addition, S&P expects that weaker credit metrics will continue into 2019 for those utilities operating with minimal financial cushion. S&P further expects that

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[34] Standard and Poor's Global Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound", January 24, 2018.

these utilities will look to offset the revenue reductions from tax reform with equity issuances. The rating agency reported that in 2018 regulated utilities issued nearly $35 billion in equity, which is more than twice the equity issuances in 2016 and 2017.[35]

Finally, FitchRatings recognized the implications of tax reform but indicated that any ratings actions will be guided by the response of regulators and the management of the utilities. Fitch notes that the solution will depend on the ability of utility management to manage the cash flow implications of the TCJA. Fitch offers several solutions to provide rate stability and to moderate changes to cash flow in the near term, including increasing the authorized ROE and/or equity ratio as measures that can be implemented.[36]

Q. What is your conclusion on the importance of tax reform in determining the appropriate ROE in the ESII case?

A. It is important to recognize the concerns of the rating agencies and the expectations of investors with respect to the effect of tax reform on utility credit metrics. The rating agencies have identified tax reform as a negative factor for the entire utility industry and have offered solutions to utility management and regulators that include increasing ROEs or equity ratios. Furthermore, Moody's has been actively downgrading companies that fail to achieve the metrics as a result of tax reform. Therefore, at a time when the market perceives weakness in financial metrics for the industry as a whole and sees higher ROEs and equity ratios as

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35 Standard & Poor's Ratings, "Industry Top Trends 2019, North America Regulated Utilities", November 8, 2019.

36 FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.

reasonable solutions to this problem, it does not seem appropriate to consider lower ROEs for the Company's ESII investments.

VI. ROE ESTIMATION METHODOLOGIES

A. Proxy Group Selection

Q. Please summarize the proxy groups that Mr. O'Donnell relied on in his analysis.

A. Mr. O'Donnell has developed his proxy groups to estimate the appropriate ROE for Public Service using companies that are followed by the Value Line Investment Survey that own electric and natural gas distribution subsidiaries and meet two criteria: 1) S&P's Global Market Intelligence Quality Ranking, which measures growth and stability of earnings and dividends, 2) exclusion of the companies that could be involved in a merger. In addition, Mr. O'Donnell excludes PG&E Corporation from the group due to the fires in California and its resulting bankruptcy filing.[37]

Q. Do you agree with the screening criteria that Mr. O'Donnell relied on to develop his electric utility proxy group for Public Service?

A. No, I do not. While I recognize that the screening criteria that are applied by analysts can differ, the objective is to establish a proxy group that is comparable to the subject company. In addition, it is necessary that the data that is used in the models be representative of investors' expectations. While Mr. O'Donnell suggests that he has established screening criteria to include companies that are similar in risk to Public Service, his application of the

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[37] Direct Testimony of Kevin W. O'Donnell, at 15.

screening criteria fail to meet that objective. In addition, the data that Mr. O'Donnell has relied on is not representative of investors' expectations.

As shown in Exhibit AEB-2, two of the companies Mr. O'Donnell's proxy group were involved in merger related activity over his analytical period, Avista and Dominion Resources.[38] Mr. O'Donnell noted that he had excluded Dominion Resources and Scana from his proxy group based their merger activity, however Exhibit KWO-1 includes Dominion. While Avista terminated its merger plans in January 2019, the data set that Mr. O'Donnell relied on includes prices over the period for which the merger effort was ongoing and should therefore be eliminated.

Considering the market data available for the remainder of his proxy group, two of Mr. O'Donnell's companies are only covered by Value Line, which is an individual analyst. Therefore, for these companies, the data that Mr. O'Donnell has relied on are not consensus estimates of the projected growth of the company. Finally, while Entergy does have a consensus estimate of EPS growth, it is a negative growth rate, which violates the assumptions of the Constant Growth DCF model and therefore should be eliminated.

Q. Do you agree with Mr. O'Donnell's use of PSEG in his ROE analysis?

A. No, I do not. In order to avoid the circular logic that otherwise would occur, it is my general practice to exclude the subject company, or its parent holding company, from the proxy group.

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[38] While Mr. O'Donnell's testimony is not specific as to the end date of his analytical period, he has relied on Value Line reports through February 15, 2019. Therefore, I have considered merger activity that would have been ongoing for the thirteen weeks prior to this date.

Q. Are there other factors that you would typically consider in developing the proxy group?

A. Yes. I typically require that the proxy companies be comparable to the subject company in terms of the amount of net operating activity derived from electric and natural gas operations. Several of Mr. O'Donnell's proxy companies do not generate as much net income from natural gas operations as Public Service.

B. Constant Growth DCF Analysis

Q. Please summarize Mr. O'Donnell's Constant Growth DCF analysis.

A. Mr. O'Donnell performs a Constant Growth DCF analysis on his proxy group and PSEG (the parent holding company for Public Service). While Mr. O'Donnell summarizes many forms of growth rates, he does not specifically rely on any of those growth rates to develop his DCF analysis. Instead of applying any of the company-specific growth rate estimates, Mr. O'Donnell selects his own estimates of 4.0 percent to 6.0 percent.[39] Mr. O'Donnell applies these growth rates to the 4-week and 13-week average dividend yields for the proxy group which produces a range of ROE estimates of 7.60 percent to 9.80 percent for proxy group and 7.5 percent to 9.60 percent for PSEG.[40]

Q. Please comment on the range that Mr. O'Donnell establishes for the DCF results.

A. The range that Mr. O'Donnell establishes is not based on the results of his DCF model. Without justification, Mr. O'Donnell's range is skewed to the low end of the results

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39 Direct Testimony of Kevin W. O'Donnell, at 23.
40 *Id.*, at 24.

of his DCF models. Mr. O'Donnell provides no rationale for how he establishes his recommended range of results, which is from 8.0 percent to 9.0 percent, only that it is "right in the middle" of the results of his analyses. In fact, Mr. O'Donnell's range is 40 basis points above the low end of the range of results for his comparable group and 80 basis points below the high end of the range of results for this group. The only explanation provided for the range that is established is Mr. O'Donnell's judgement.[41] Reviewing Mr. O'Donnell's prior testimonies identified over the past few years, while there are DCF results are routinely higher than 9.0 percent in his analyses, it appears that Mr. O'Donnell has concluded that this is the appropriate range, in all but one case, for natural gas distribution companies and electric utilities in 2018. In that one case, which was for Jersey Central Power and Light, Mr. O'Donnell's range shifted upward by 25 basis points to 8.25 percent to 9.25 percent.

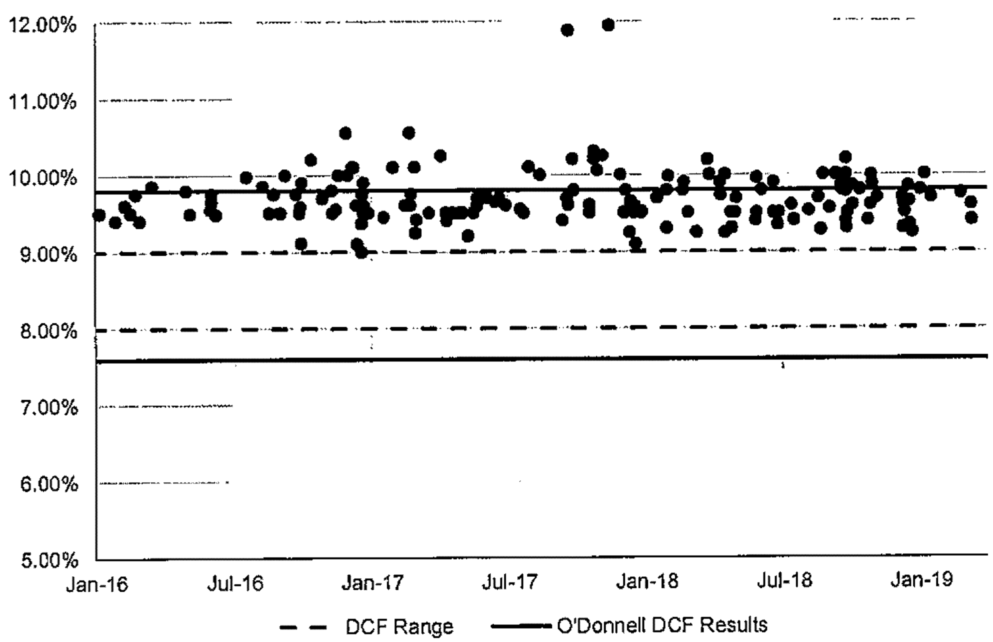
Q. How does Mr. O'Donnell's recommended range compare with recently authorized ROEs?

A. As shown in Figure 5, which compares Mr. O'Donnell's DCF results and the range he establishes with recently authorized ROEs, the low end of Mr. O'Donnell's Constant Growth DCF results and the low end of his established range are well below the authorized returns for combination electric and gas companies in other jurisdictions. The high end of Mr. O'Donnell's range represents the low end of the recently authorized ROEs, whereas the high end of Mr. O'Donnell's DCF results represent the average of recently authorized returns.

41 Response to PSE&G KWO-24.

Finally, the high end of the results of Mr. O'Donnell's DCF analyses of 9.80 percent is well within the range of recently authorized ROEs.

Figure 5: Comparison of O'Donnell's DCF Results and recommendations with Authorized ROEs.[42]



Rather than questioning why the DCF model is producing results that are so far outside the range of comparable returns for other regulated utilities, Mr. O'Donnell justifies his reliance on the DCF model with the unsubstantiated statement that it is "used more often than any other method",[43] and that it is "intuitively a very simple model to understand."[44] Mr. O'Donnell has not conducted any analysis of cases beyond those where he has offered

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[42] Sources: SNL Energy, Direct Testimony of Kevin W. O'Donnell, at 24.

[43] Direct Testimony of Kevin W. O'Donnell, at 15.

[44] *Id.*, at 17.

testimony to substantiate the conclusion that the DCF is used more often than any other methodology.[45] Mr. O'Donnell also offered in his testimony as support for this methodology that much information can be found about this approach through an internet search.[46] While I can agree that the DCF model is commonly presented in regulatory proceedings and that there may be much information available in public sources about this and other ROE estimation models, the frequency with which the model is presented or discussed publicly does not relate to the accuracy of the model in estimating investor expectations. As discussed previously, the FERC, which had relied on the DCF exclusively for many years, has recently proposed to rely on an equal weighting of four methodologies to determine the ROE because in its view, investors consider the results of multiple models. Since the ROE that is set in this proceeding is intended to reflect investor expectations, it is important to consider the results of multiple methods. Furthermore, each ROE estimation model has its strengths and limitations, therefore review of multiple models will produce a more informed result.

Q. Does Mr. O'Donnell suggest that simplicity is a key factor in the development of the DCF model?

A. No, he does not. Mr. O'Donnell agrees that simplicity should not be confused with accuracy. However, Mr. O'Donnell further suggests that the DCF model can accurately and promptly include all known and relevant information into the model and suggests it may

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[45] Response to PSE&G -KWO-5.

[46] Direct Testimony of Kevin W. O'Donnell, at 17.

therefore be more accurate than the CAPM.[47] While the availability of the dividend yield may make the analysis more prompt, Mr. O'Donnell recognizes that "irrational behavior" may and has affected share prices.[48] Since share prices affect the dividend yield in the DCF model, the effect of irrational behavior on this term in the DCF model may also affect the reliability of the results of the model.

Q. Do you agree with Mr. O'Donnell's application of the DCF model?

A. No, I do not. Mr. O'Donnell's analysis is not based on the market's view of the growth of the proxy companies, nor is it based on the specific growth rates for the companies that are included in his proxy group. Rather, his analysis relies on a 4-week and 13-week average dividend yield for the proxy companies and his judgement as to the appropriate average growth for the proxy group. Mr. O'Donnell's chosen growth rates do not reflect the market view of the expected growth for his proxy companies.

Q. Please summarize Mr. O'Donnell's testimony regarding the appropriate growth rate in the DCF model.

A. Mr. O'Donnell offers as support for the 4 percent growth rate that this estimate is "close to the midpoint of the 10-year and 5-year historical growth in dividends". [49] He offers similar vague support for the high-end growth rate, stating that this growth rate "is

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[47] Response to PSE&G-KWO-17.
[48] Direct Testimony of Kevin W. O'Donnell, at 16.
[49] *Id.*, at 23.

approximately equal to the high end of the range for the forecasted growth in earnings for the comparable group".[50]

Q. Do you agree with Mr. O'Donnell's approach to selecting the growth rates to be relied on in the DCF model?

A. No, I do not. Mr. O'Donnell's selection of the growth rates used in the DCF model are arbitrary selections that are not at all based on the growth rates that he summarizes in this case. As shown in Exhibit KWO-1, the average growth rates summarized by Mr. O'Donnell range from 1.0 percent to 7.2 percent. The projected growth rates are within a narrower range, from 4.5 percent to 7.2 percent. In Public Service's recent GSMP II case, the average growth rates summarized by Mr. O'Donnell ranged from -0.5 percent to 7.5 percent and the projected growth rates ranged from 3.8 to 5.6 percent. In each of these cases, Mr. O'Donnell selected a growth rate range of 4.0 percent to 6.0 percent.

Furthermore, Mr. O'Donnell's rationale for the selection of his growth rates in the current case is inconsistent with the methodology that he used in the GSPM II case. In the GSMP II case, Mr. O'Donnell again selected a range of 4.0 percent to 6.0 percent. In that case, he offered a completely different rationale to support this range:

> Over the past 10-years, the combination utility group has grown in the range of approximately 3.0% to 4.0%. The forecasted growth rates for the combination utility group are higher than the historical growth rates for the combination utility comparable group and are in the range of 4.0% to 6.0%. Based on these results, I believe the proper growth rate range to use in the DCF model for the combination utility group is 4.0% to 6.0%. The low-end of this range is equal to the high end of the

[50] *Ibid.*

> range for the historical results whereas the high end of the range is slightly above the highest forecasted growth rate range for the comparable group.[51]

As shown in Figure 6 below, while the range of growth rates that Mr. O'Donnell compiles is wide, the selected range that he has relied on in the last several years is very narrow. Furthermore, the approach used to select the range changes considerably from case to case.

Figure 6: Summary of Growth Rates Developed in Mr. O'Donnell's Recent Testimonies

Date	Company	Docket/State	Actual Range of Growth Rates	Selected Range	Rationale
2018	Duke Energy Progress	E-2Sub 1142/NC	Historical: 4.0%-7.0% Projected: 4.2%-5.6%	4.75%-5.75%	Low is set above the low of historical and projected growth rates. High is "almost identical to the high end of the forecasted growth rates"
2018	Baltimore Gas and Electric	9484/MD	Historical: -0.2%-4.7% Projected: 5.6%-12.2%	5.5%-6.5%	Weighs Valueline forecasted EPS growth rates and moves the forecast above the 5.0%-6.0% growth rate averages excluding "Outliers".

[51] BPU Docket No. GR17070776, Direct Testimony of Kevin W. O'Donnell, at 23-24.

2018	Jersey Central Power & Light	EO18070728/ NJ	Historical: 2.2%-4.4% Projected: 4.3%-5.9%	4.0%-6.0%	Low end is set close to the historical dividend growth rates and the high end is equal to the high end of the forecasted earnings growth rates.
2018	Elkton Gas	FC 9488	Historical 0.9%-4.9% Projected: 5.9%-11.7%	5.0%-6.0%	Range is on target with forecast range of growth rates, higher than plowback and gives weight to strong historical results.

Therefore, while Mr. O'Donnell suggests that he is considering numerous growth rates in the development of his DCF analysis, he simply relies on a narrow range of growth rates from one case to the next, regardless of the market data at the time of his analysis. Furthermore, because Mr. O'Donnell performs his analysis using the low and high growth rates, rather than individual company results, the major driver of his DCF results is the average dividend yield of the proxy group that he relies on.

Q. What growth rates would result if you applied the criteria that Mr. O'Donnell used in the GSMP II case to the growth rates that are summarized in Exhibit KWO-1 in this proceeding?

A. In the GSMP II case, Mr. O'Donnell established the high end of his range using the high end of the range of historical and projected growth rates. As shown in Exhibit KWO-1, establishing the range using the high end of the historical growth rates would result in an average growth rate of 7.0 percent. Considering the high end of the forecasted growth rates, the average growth rate would be 7.2 percent.

Q. Have you conducted any analysis to determine the return on equity that would have resulted from using these growth rates, consistent with Mr. O'Donnell's approach in the GSMP II case?

A. Yes, I have. As shown in Exhibit AEB-3R, the results of this analysis would be an ROE of 10.8 percent to 11.1 percent, excluding the proxy companies referenced previously that should be excluded.

Q. What are the most relevant growth rates to rely on in the DCF analysis?

A. Earnings per share growth rates are the appropriate growth rates to rely on in the Constant Growth DCF model. To reduce the long-term growth rate to a single measure, one must assume that the dividend payout ratio remains constant and that earnings per share, dividends per share, and book value per share all grow at the same constant rate. Over the long run, dividend growth can only be sustained by earnings growth. Earnings growth rates tend to be least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Since such decisions may directly affect near-term dividend payout ratios, estimates of earnings growth are more indicative of long-term investor expectations than are dividend or book value growth estimates. Furthermore, earnings per share growth rates are the more prevalent growth rate estimates. As can be seen in Mr. O'Donnell's Exhibits KWO-1 and KWO-2, projected DPS and BPS growth rates are only provided by Value Line and the Plowback Ratio is calculated using Value Line's projections. The only projected growth rates that are reported by multiple analysts are EPS growth rates.

Q. Do you agree with Mr. O'Donnell that the sustainable ('plowback") growth rate should be used in the DCF model?

A. In general, I do not agree with the use of sustainable growth rates in the Constant Growth DCF model. Academic research has shown that there is not a positive correlation between retention growth rates and future earnings growth. In 2006, for example, two articles appeared in Financial Analysts Journal, which addressed the theory that high dividend payouts (i.e., low retention ratios) are associated with low future earnings growth.[52] Both of those articles cite a 2003 study by Arnott and Asness[53] who found that, over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[54]

In addition, I do not agree with how Mr. O'Donnell has calculated his sustainable growth rates. However, since Mr. O'Donnell has not presented Constant Growth DCF results based solely on sustainable growth rates, I have not corrected his calculation.

From a theoretical perspective, Mr. O'Donnell's calculation of sustainable growth rates considers only the product of earnings retention rates and earned returns on common equity, or what are commonly known as internally-generated funds. In the sustainable growth formula, this is commonly referred to as the product of "b*r", where "b" is the retention ratio or the portion of net income not paid in dividends, and "r" is the expected

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52 Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See* also Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 1, 2006.

53 Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

54 Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

ROE on the portion of net income that is retained within the Company as a means for future growth. Mr. O'Donnell fails to consider that earnings growth also occurs as a result of new equity issuances, or what are commonly known as externally-generated funds. In the sustainable growth formula, this is shown as the product of "s*v", where "s" represents the growth in shares outstanding and "v" is that portion of the M/B ratio that exceeds unity. This methodology is recognized as a common approach to calculating the sustainable growth rate.[55]

Q. What support does Mr. O'Donnell provide for his suggestion that analysts give "great weight" to dividend and book value growth rates?

A. Mr. O'Donnell's conclusion with respect to the weight analysts give to dividend and book value growth rates is unsubstantiated. In response to a data request, Mr. O'Donnell states that he has not conducted any analysis on analysts' use of dividend and book value growth rates, noting as his support only that these growth rates are published by Value Line.[56]

Q. Have other regulatory commissions abandoned the use of sustainable growth rates in its electric transmission ROE methodology?

A. Yes. In Opinion No. 531, the FERC changed its approach on the DCF methodology to be applied in public utility rate cases.[57] In summary, the FERC adopted the same two-step DCF methodology it has employed in gas and oil pipeline rate proceedings since the mid-

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55 *See* Roger Morin, New Regulatory Finance, at 306.

56 Response to PSE&G-KWO-16 (a).

57 Opinion No. 531 147 FERC ¶ 61,234 (June 19, 2014).

1990s, in place of the one-step methodology previously used. The FERC's two-stage DCF approach does not rely on a sustainable growth calculation.

Q. Do you believe it is important to rely on historical growth rates in the DCF model?

A. No, I do not. The Constant Growth DCF model is a forward-looking model that evaluates investors' required returns based on future cash flows. As such, the appropriate measure of growth to incorporate for DCF analyses is investors' expectations. Furthermore, historical results can be influenced by past events that may not be expected to continue into the future. For example, if a company is expected to adjust its dividend payout ratio, then using historical EPS and DPS growth rates may not be appropriate since the historical growth rates would assume that the historical dividend payout ratio continues into the forecast period. In this case, it is more appropriate to use securities analysts' forecasted earnings growth rates which would incorporate historical performance to the extent the analysts believe it is likely to continue. Moreover, since analysts consider historical conditions in developing projections, relying on historical growth rates in addition to projections provides no meaningful incremental information regarding the proxy companies' future growth potential.

Q. Would the results of Mr. O'Donnell's DCF analysis change if he had relied on a risk-comparable proxy group and projected earnings per share growth rates?

A. Yes. As shown in Exhibit AEB-4, using the 13-week dividend yields relied on by Mr. O'Donnell and the earnings per share growth rates summarized in Schedule KWO-1, the DCF results for a risk-comparable proxy group would be 9.5 percent. Considering the adjustments to the proxy group that I discussed previously, the mean return increases to 9.60 percent.

Q. Do you believe it is appropriate to rely solely on the Constant Growth DCF in setting the ROE in this proceeding?

A. No, I do not. As discussed previously in my Rebuttal Testimony recent market conditions have affected the dividend yields in the DCF model such that the results of this model understate the cost of equity at this time. Other jurisdictions, such as the FERC have recognized that it is not appropriate to only rely on the results of the DCF model. Therefore, while the results of the DCF model should be considered, these results must be considered along with the results of other ROE models.

C. Comparable Earnings

Q. Please summarize Mr. O'Donnell's Comparable Earnings analyses.

A. Mr. O'Donnell presents two Comparable Earnings analyses.[58] The first is based on the earned returns on common equity for the companies in his combination proxy group, as well as PSEG, over the period of 2017-2024. This analysis, which is shown in Exhibit KWO-3 produces a range from 10.3 percent to 11.5 percent. Mr. O'Donnell states that the second analysis is based on authorized ROEs for electric and natural gas distribution companies across the U.S. from 2003-2017.[59] Chart 4 in Mr. O'Donnell's Direct Testimony shows the general decline in authorized returns since 2001, as well as the increase that

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[58] Direct Testimony of Kevin W. O'Donnell, at 25-26.

[59] *Id.*, at 25.

occurred from 2016 to 2017. Mr. O'Donnell notes that the average authorized ROE for electric utilities in 2018 was 9.57 percent and the average authorized ROE for natural gas utilities was 9.59 percent. Mr. O'Donnell concludes that his Comparable Earnings analyses produce a range of returns from 9.5 percent to 10.5 percent.[60]

Q. Do you have any comments on these analyses?

A. Yes. While I will address each of the analyses that Mr. O'Donnell has prepared, the conclusions he reaches from his comparable earnings analyses are 50 to 150 basis points above his final unadjusted ROE recommendation.

Mr. O'Donnell's first Comparable Earnings analysis demonstrates that the earned return on common equity for the proxy group of combination electric and gas utilities that he determined is comparable to PSEG averaged 10.3 percent in 2017 and that the expected return for this group is between 10.50 percent and 11.50 percent. These expectations are 150-250 basis points above his unadjusted ROE recommendation of 9.00 percent. Furthermore, these expectations suggest that the settlement ROE in the Company's last rate proceeding was conservative in comparison to market expectations.

Regarding Mr. O'Donnell's second Comparable Earnings analysis, the universe of authorized ROEs that he relies on in his analysis is inconsistent with the comparability analysis that was used to establish his proxy group that was relied on for the remainder of the analyses in his testimony. While Mr. O'Donnell selects a proxy group that he believes is

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60 *Id.*, at 26.

comparable to PSEG from the Value Line electric utilities, with emphasis on those companies that have electric and natural gas operations, his comparable earnings analysis includes the returns that were authorized for vertically integrated electric utilities, combination gas and electric utilities and natural distribution operations.

Despite the differences in the companies that he relies on in the second comparable earnings analysis, the results reported by Mr. O'Donnell demonstrate that the average authorized ROE for each of the groups that he has considered are within 1-3 basis points of the 9.60 return that was agreed to by the Division of Rate Counsel in the Company's rate case, which was settled in October 2018. Therefore, without consideration of the individual authorized returns that are included in the 2018 sample group, Mr. O'Donnell's own analysis supports the conclusion that his recommendation in this proceeding is unreasonably low.

D. CAPM Analysis

Q. Please summarize Mr. O'Donnell's CAPM analysis.

A. Mr. O'Donnell expresses reservations about the CAPM, especially when it is applied using a forecasted market risk premium or forecasted interest rates. However, he recognizes that the FERC has recently expressed an interest in reviewing additional model and he is aware that the Maryland Public Service Commission is also interested in other models. For that reason, Mr. O'Donnell has performed a CAPM analysis to supplement his DCF and

Comparable Earnings analyses, but he indicates that he has not given the CAPM analysis much weight.[61]

Mr. O'Donnell develops his CAPM analysis using the high, low and average yields on 30-year Treasury bonds over the past year as the risk-free rate, beta coefficients reported by Value Line, and a market risk premium of 4.0 percent to 6.0 percent. It is important to note that Mr. O'Donnell's market risk premium is based on historical returns as published in the 2014 edition of the Ibbotson SBBI Classic yearbook, several market return estimates that were published in January 2016 and the results from the Duke University CFO study published in March of 2018. Based on these inputs and assumptions, Mr. O'Donnell's CAPM analysis produces a return estimate in the range of 5.3 percent to 7.0 percent for the comparison group and 5.5 percent to 7.4 percent for PSEG Enterprises.[62]

Q. Please comment on the results of Mr. O'Donnell's CAPM analysis.

A. Mr. O'Donnell's CAPM results of 5.30 percent to 7.40 percent are entirely inconsistent with the returns required by equity investors for companies with commensurate risk. To place these results in context, they are 220 to 430 basis points below the settlement ROE of 9.60 percent that was agreed to in October 2018. Furthermore, Mr. O'Donnell's entire range of CAPM results has ever been observed as an authorized ROE for any electric or gas utility in at least the past 35 years.[63]

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61 *Id.*, at 27.
62 See Exhibit KWO-4.
63 Source: Regulatory Research Associates.

Q. What are your concerns with the inputs and assumptions that Mr. O'Donnell has used to develop his CAPM estimate?

A. I disagree with two aspects of Mr. O'Donnell's CAPM analysis: 1) the use of only the current Treasury bond yield as the risk-free rate; and 2) the use of an under-stated market risk premium that is, in part, based on historical returns and which does not reflect the inverse relationship between interest rates and the equity risk premium.

Q. How does Mr. O'Donnell justify his use of the current Treasury bond yield as the risk-free rate in his CAPM analysis?

A. Mr. O'Donnell testifies that he used the current Treasury bond yield as the risk-free rate in the CAPM analysis because economic forecasters and the Federal Reserve believe the current interest rate environment is expected to remain relatively stable for many years to come.[64] He cites a June 2016 quote from outgoing Fed Chair Yellen as support for his view that interest rates are expected to remain relatively stable for many years to come.

Q. What is your response?

A. As explained in Section III of my Rebuttal Testimony, capital markets have experienced a prolonged period of low interest rates as central banks in the U.S. and around the world have taken extraordinary steps to stimulate the economy after the financial crisis and Great Recession. Utility regulators in other jurisdictions are struggling with how to interpret the results of financial models that are being impacted by what the FERC has characterized as "anomalous" capital market conditions. Some regulators, such as the Massachusetts DPU support the use of projected Treasury bond yields in the CAPM analysis

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[64] Direct Testimony of Kevin W. O'Donnell, at 31.

as one way to adjust the inputs to the models during this period of low interest rates.[65] Furthermore, as discussed in Section III there is evidence that suggests that the growth in demand for Treasuries has begun to soften at a time when the supply will necessarily increase, requiring higher returns to stimulate demand. As a result, yields on long-term government bonds are expected to continue to increase over the near-term which is consistent with investors' expectations shown in Figure 2 above.

Q. Can you provide an example of another time when the use of current interest rates would not have been appropriate?

A. Yes. Following Mr. O'Donnell's logic that current interest rates will remain relatively stable, the Board would have based ROE determinations in the early 1980s on government bond yields of 15-18 percent, even though those interest rates had started a long, steady decline. As a result, ratepayers would have been paying unnecessarily high capital costs. Today, the situation is reversed. Interest rates are near historic lows but have been increasing as the Federal Reserve continues tightening monetary policy and unwinding the asset purchases made after the Great Recession, and as the effects of tax reform and increased government debt flow through to long-term Treasury yields. Setting the cost of equity for in this case based on the assumption that current interest rates will continue in perpetuity is very likely to under-compensate investors as capital costs increase.

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[65] D.P.U. 17-05 Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism, November 30, 2017, at 693.

Q. Please explain why you disagree with Mr. O'Donnell's use of a market risk premium in the CAPM analysis that is based on historical returns.

A. First, it is important to recognize that not only is Mr. O'Donnell's market risk premium largely based on historical returns, but the historical data points that he has relied on are two to five years out of date. The Ibbotson data that Mr. O'Donnell relies on is based on data through 2013. Furthermore, given the current low yields on Treasury bonds, and the inverse relationship between interest rates and the market risk premium, my concern is that Mr. O'Donnell's market risk premium estimate based on historical returns of 4.60 percent to 6.20 percent is understated. As shown in Table 6 of Mr. O'Donnell's testimony, using data through 2013, the average historical return on long-term government bonds is 5.50 percent (geometric mean) and 5.90 percent (arithmetic mean), while the average yield on long-term government bonds at the time that he filed his testimony was approximately 3.12 percent.[66] The historical market risk premium as reported by Duff and Phelps is 6.91 percent through 2018.[67] Because interest rates on long-term government bonds are well below the historical average of 5.50 percent or 5.90 percent, the inverse relationship between interest rates and the marker risk premium implies that the forward-looking market risk premium should be higher than the historical average of 6.91 percent.

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[66] Exhibit KWO-4.

[67] Duff and Phelps 2017 Valuation Handbook- U.S. Guide to Cost of Capital, Chapter 5, p. 14.

Q. Is there evidence that the use of a historical market risk premium may produce counter-intuitive results?

A. Yes. Relying on the historical market risk premium may produce results that are not consistent with investor sentiment and current conditions in capital markets. For example, Morningstar has observed:

> It is important to note that the expected equity risk premium, as it is used in discount rates and the cost of capital analysis, is a forward-looking concept. That is, the equity risk premium that is used in the discount rate should be reflective of what investors think the risk premium will be going forward.[68]

In addition, in 2017 Duff & Phelps addressed the risk of relying on the historical market risk premium that includes the negative market returns that were the result of the financial market collapse in 2008.[69]

> If one simply added an estimate of the ERP taken from commonly used sources before the Financial Crisis to the spot yield on 20-year U.S. government bonds at month-end December 2008, one would have arrived at an estimate of the cost of equity capital that was too low.
>
> For example, as illustrated in Exhibit 3.11, at December 2007 the yield on the 20-year U.S. government bonds equaled 4.5%, and the realized risk premium reported based on the average realized risk premiums for 1926-2007 was 7.1%. But at December 2008, the yield on 20-year U.S. government bonds was 3.0%, and the realized risk premium reported based on the average realized risk premiums for 1926-2008 was 6.5%.
>
> So just at the time that the risk in the economy increased to arguably the highest point, the base cost of equity capital using realized risk

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68 Morningstar Inc., 2010 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook, at 55. Morningstar is the prior publisher of the Valuation Handbook that is now published by Duff and Phelps.

69 Duff & Phelps acquired and maintains the Ibbotson historical return data referenced in the Ibbotson Stocks, Bonds Bills and Inflation Valuation Handbook.

premiums decreased from 11.6% (4.5% plus 7.1%) to 9.5% (3.0% plus 6.5%).[70]

Figure 7 illustrates the problem with relying on a historical market risk premium. From 2007-2009, for example, when market volatility had increased significantly and in 2008 in particular, when the market returned the largest negative return since the Great Depression, the historical market risk premium *decreased.*

Figure 7: Historical Market Risk Premium and Market Volatility

	Historical Market Risk Premium[71]	**Market Volatility**
2009	6.70%	31.48
2008	6.50%	32.69
2007	7.10%	17.54

The assumption that investors would expect or require a *lower* risk premium during periods of increased volatility is counter-intuitive and leads to unreliable analytical results. The relevant issue in the application of the CAPM is to ensure that all three components of the model (i.e., the risk-free rate, Beta, and the market risk premium) are consistent with market conditions and investor perceptions. Assuming a lower market risk premium during periods of increased risk aversion is at odds with that premise.

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70 Duff & Phelps, 2017 Valuation Handbook, U.S. Guide to Cost of Capital, at 3-37; 3-38.

71 Morningstar Inc., 2008 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook, at 28. Morningstar Inc., 2009 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook, at 23. Morningstar Inc., 2010 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook, at 23. Historical Market Risk Premium equals total return on large company stocks less income only return on long-term government securities.

Q. Is there support for the use of a forward-looking market risk premium in the CAPM analysis?

A. Yes. The Federal Regulatory Energy Commission ("FERC") has stated:

> A CAPM analysis is backward-looking if its market risk premium component is determined based on historical, realized returns. A CAPM analysis is forward-looking if its market risk premium component is based on a DCF study of a large segment of the market. In a forward-looking CAPM analysis, the market risk premium is calculated by subtracting the risk-free rate from the result produced by the DCF study.[72]

The New York PSC also relies on a forward-looking market risk premium that is based on projected returns for the broad market less the Treasury bond yield.

Q. Please comment on the sources that Mr. O'Donnell uses to develop his market risk premium estimate.

A. The majority of the sources relied on by Mr. O'Donnell to estimate the market risk premium are between three and five years out of date. In addition to the criticisms noted previously about the use of historical data to develop the market risk premium, the "Ibbotson" data that Mr. O'Donnell relied on as an estimate of the historical market risk premium is based on a historical data set from 1929 to 2013. This data set does not consider any data in the last six calendar years.

The Morningstar article cited by Mr. O'Donnell was published more than three years ago and is based on the outlooks of the reporting analysts for the time period from April 2015 to January 2016. Therefore, these views are not representative of the "forward-looking" market risk premium to be used in 2019. Furthermore, the relatively small sample; only six

[72] 150 FERC ¶ 61,165, Docket Nos. EL11-66-002, Opinion No. 531-B, para., at 108.

analysts that were quoted in the article is not a reasonable representation of the market's view of expected returns. Finally, it is not appropriate to calculate a forward-looking market risk premium in 2019 by relying on the expected return on the market in 2015 less the average yield on 30-year Treasury bonds in 2019.

Q. Do you agree with the use of the Duke CFO survey estimated market risk premium of 4.42 percent?

A. No, I do not. While this study, which was published approximately one year ago, is the most current source that Mr. O'Donnell relied on, the risk premium that he sites is the expected 10-year return on the S&P 500 as compared with the 10-year Treasury yield, not the 30-year Treasury yield that Mr. O'Donnell relies on. Importantly, the study, which is survey based also provides results on the disagreement between survey members on the risk premium and also notes that hurdle rates are significantly higher than the cost of capital that is implied by the market risk premium estimates.

Q. Are there other important factors to consider in the Duke survey?

A. Yes. While Mr. O'Donnell suggests that the DCF model is the most widely used model, according to the authors of the Duke survey, three quarters of companies use the CAPM to estimate the equity return. [73]

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[73] "The Equity Risk Premium in 2018", John R. Graham and Campbell R. Harvey, Duke University, March 27, 2018.

Q. What is the appropriate methodology that should be used to calculate the market risk premium?

A. The forward-looking market premium is calculated by subtracting a measure of the projected risk-free rate from a projected return on the overall market. This methodology has also been endorsed by the FERC, which stated:

> In this proceeding, the NETOs submitted a forward-looking CAPM study, using 30-year Treasury bonds for the risk-free rate, betas published by Value Line, and a market risk premium based on a DCF study of all S&P 500 companies that were paying dividends. The NETOs' CAPM approach is a generally accepted methodology routinely relied upon by investors and, therefore, one appropriately used to corroborate our own analysis.[74]

Q. Have you estimated the projected market risk premium?

A. Yes. As shown in Exhibit AEB-5, I relied on an approach that is consistent with the methodology that the FERC recently approved. I estimated the expected return on the market by applying the Constant Growth DCF to the S&P 500 companies using the expected earnings growth rates for those companies as reported by Bloomberg. I deducted the risk-free rate to estimate the market risk premium. As show in Exhibit AEB-5, I relied the three measures of the risk-free rate that Mr. O'Donnell relied on in Exhibit KWO-4 to estimate the range of the market risk premium. Based on those estimates of the risk-free rate, the market risk premium is 10.31 percent to 10.85 percent. I also considered the short- and longer-term projected yield on the 30-year Treasury bond for the risk-free rate. The market risk premium

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[74] 150 FERC ¶ 61,165, Docket Nos. EL11-66-002, Opinion No. 531-B, para., at 109.

using the projected yields on Treasury bonds resulted in a range for the market risk premium of 9.87 percent to 10.49 percent.

Q. Is there additional support for the reasonableness of the market return you have used to calculate the forward-looking market risk premium?

A. Yes, other alternative sources provide reputable forecasts of market returns that are significantly higher than the historical and projected returns relied on by Mr. O'Donnell. In Table 1, I provide the S&P 500 return as reported by Bank of America/Merrill Lynch and additional estimations of the S&P 500 return calculated using earnings growth projections from Bloomberg Professional, Yahoo!Finance, and Standards and Poor's. The calculated returns for the S&P 500 range from 11.30 percent (Bloomberg Professional) to 14.42 percent (Standard and Poor's). Therefore, the total return for the S&P 500 Index that I used to determine the forward-looking market risk premium in my CAPM analysis is well supported by the range of returns shown in Figure 8. By contrast, Mr. O'Donnell's estimated market returns and resulting risk premiums are well outside this range and do not represent investor expectations under current market conditions.

Figure 8: S&P 500 Return Estimates[75]

Source	Estimate Date	Dividend Yield	Growth Estimate	S&P 500 Return
Bloomberg Professional	February 28, 2019	1.97%	10.55%	12.63%
Bank of America – Merrill Lynch[76]	January 11, 2019	N/A	N/A	11.30%
Yahoo!Finance	February 28, 2019	1.97%	11.00%	13.08%
Standard and Poor's	February 28, 2019	1.97%	12.33%	14.42%

Q. How would the range that you calculated for the market risk premium change the results of Mr. O'Donnell's CAPM analysis?

A. As shown in Exhibit AEB-6 and Figure 9 below, updating Mr. O'Donnell's CAPM analysis to rely on the range for the market risk premium discussed previously produces mean returns for the combination utility proxy group of 9.43 percent to 9.54 percent. The mean CAPM results for PSEG are between 10.06 percent and 10.15 percent.

[75] Bloomberg and Yahoo!Finance do not report a dividend yield for the S&P 500; therefore, the average dividend yield reported in the February 28, 2019, S&P 500 Earnings and Estimate Report was used to calculate the total return.

[76] Required Return - Bank of America Merrill Lynch, Quantitative Profiles, January 11, 2019, at 58.

Figure 9: Summary of Adjusted CAPM Results

	Risk-Free Rate	MRP	CAPM Results
Proxy Group Results			
O'Donnell Treasury - Maximum	3.46%	10.31%	9.55%
O'Donnell Treasury - Average	3.12%	10.65%	9.41%
O'Donnell Treasury - Minimum	2.92%	10.85%	9.33%
		Mean	**9.43%**
O'Donnell Treasury - Average	3.12%	10.65%	9.41%
Treasury - Projection (2019-2020)	3.28%	10.49%	9.47%
Treasury - Projection (2020-2024)	3.90%	9.87%	9.73%
		Mean	**9.54%**
PSEG Results			
O'Donnell Treasury - Maximum	3.46%	10.31%	10.16%
O'Donnell Treasury - Average	3.12%	10.65%	10.04%
O'Donnell Treasury - Minimum	2.92%	10.85%	9.97%
		Mean	**10.06%**
O'Donnell Treasury - Average	3.12%	10.65%	10.04%
Treasury - Projection (2019-2020)	3.28%	10.49%	10.10%
Treasury - Projection (2020-2024)	3.90%	9.87%	10.31%
		Mean	**10.15%**

Q. What is your conclusion regarding Mr. O'Donnell's CAPM analysis?

A. My conclusion is that Mr. O'Donnell's CAPM analysis is based on flawed assumptions and inputs which are not forward-looking. As such, the results of his CAPM analysis are well below any authorized return for a gas or electric utility over the past 35 years and cannot be relied upon to estimate the cost of equity for Public Service's Energy Strong II. Furthermore, when corrected to reflect a forward-looking market risk premium ad projected Treasury bond yields, the results of the CAPM support the 9.60 percent ROE that was agreed to by the Company and the Division of Rate Counsel in the Company's rate proceeding in October 2018.

Q. Do you agree with Mr. O'Donnell's proposal to reduce the ROE by 50 basis points for the risk reduction of Energy Strong II?

A. No, I do not. First, implementing an ROE that is lower than the ROE that was established in the base proceeding is contrary to the intention of the program. The goal of the Energy Strong II program is to encourage investment in infrastructure. A reduction in the ROE for the assets that are included in this program reverses any incentive that was intended by the program. Therefore, reducing the ROE in this case below the return that was agreed to in the base rate proceeding creates a disincentive to invest in assets between rate proceedings.

Furthermore, the proposed reduction in the ROE is inconsistent with the fundamental principles that Mr. O'Donnell relied on in estimating the appropriate ROE. By relying on a proxy group of companies to estimate the ROE, Mr. O'Donnell is benchmarking the Company to the proxy group for the purposes of setting the ROE. The proxy group that Mr. O'Donnell has relied on has implemented various rate recovery mechanisms that affect the overall risk profile of that group. Therefore, the relevant comparison is not whether Energy Strong II mitigates risk for the Company, but whether or not Energy Strong II reduces the Company's risk as compared to the proxy group. Mr. O'Donnell has provided no evidence that demonstrates that this program provides risk mitigation to Public Service that does not exist in operating companies of the proxy companies. Therefore, on a methodological basis, his recommended reduction to the ROE for Energy Strong II is without foundation.

Q. Have you conducted any analysis of the stabilization and capital tracking mechanisms that have been implemented by the proxy companies?

A. Yes, I have. As shown in Exhibit AEB-7, nearly half of the operating companies in Mr. O'Donnell's proxy group have capital tracking mechanisms that are similar to the Energy Strong II. Therefore, any risk reducing elements of cost recovery mechanisms such as the Energy Strong II are already reflected in the ROE of the proxy group, and no adjustment is needed to authorized ROE for Public Service.

E. Capital Structure

Q. Please summarize Mr. O'Donnell's capital structure recommendation.

A. Mr. O'Donnell provides a review of the equity ratios of the proxy group companies. While he ultimately recommends the use of the Company's proposed capital structure composed of 54.0 percent equity, 45.53 percent debt and 0.47 percent customer deposits, Mr. O'Donnell suggests that he is concerned that "PSEG's equity ratio is 'equity thick' for ratemaking purposes".[77]

Q. Please comment on the analysis that Mr. O'Donnell provides of the equity ratios of the proxy companies.

A. Mr. O'Donnell's capital structure analysis is summarized in Table 9 of his Direct Testimony. As shown in this table, Mr. O'Donnell provides an estimate of the 2018 equity

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77 Direct Testimony of Kevin W. O'Donnell, at 45.

ratio the proxy companies and concludes that the average equity ratio is 44.00 percent. While there is no source provided for the information, these figures appear to be at the holding company level, rather than the operating utility level. In addition, Mr. O'Donnell observes that the average authorized equity ratio for electric utilities in 2018 was 48.95 percent and for gas utilities was 50.09 percent.

Q. Do you agree with Mr. O'Donnell's analysis of the capital structures of the proxy companies?

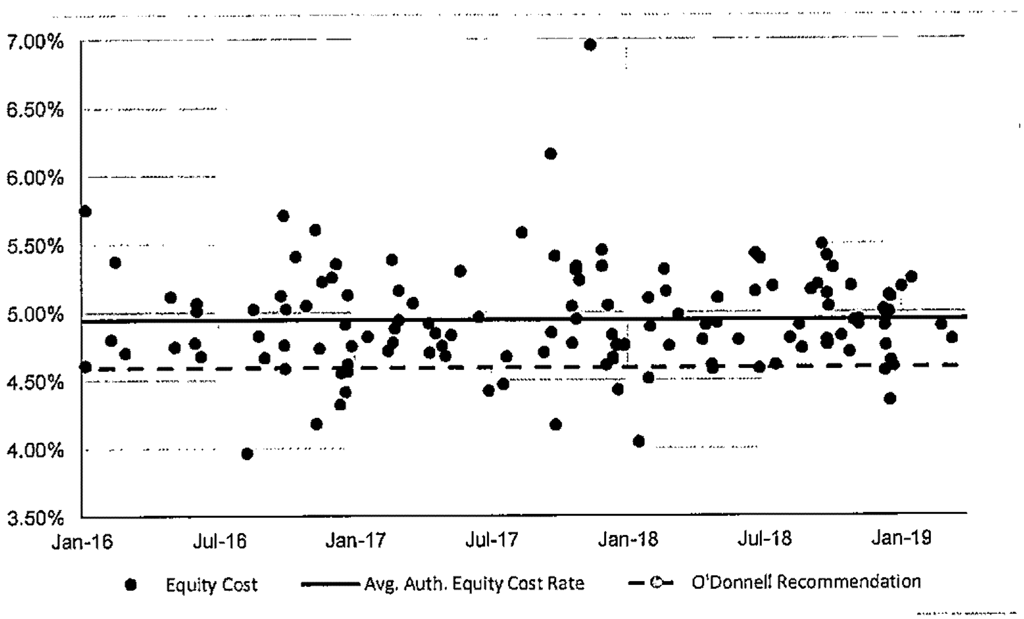
A. No, I do not. In Exhibit AEB-8, I have summarized the capital structures of the utility operating companies of Mr. O'Donnell's proxy group of combination electric and gas utilities. As shown in that analysis, the mean equity ratio is 52.60 percent and the highest equity ratio is 58.18 percent. Based on that analysis, Public Service's requested common equity ratio for purposes of the Energy Strong II of 54.00 percent is reasonable and appropriate.

VII. SUMMARY AND CONCLUSIONS

Q. How do Mr. O'Donnell's proposed return on equity and equity ratio compare with the recently authorized ROEs and capital structures for the electric and natural gas utilities in other jurisdictions?

A. The equity cost rate, which is the product of the equity ratio and the return on equity, is the return to shareholders. Chart 4 calculates the equity cost rates that result from recently authorized ROEs and equity ratios in 2016-2019. Figure 10 demonstrates that Mr. O'Donnell's proposed equity cost rate of 4.59 percent is significantly below the average authorized equity cost rate over this time-period.

Figure 10: Recently Authorized Electric and Natural Gas Equity Cost Rates 2017-2019



Q. Please summarize your conclusions and recommendations.

A. For the reasons outlined in my Rebuttal Testimony, I find that Mr. O'Donnell's recommended ROE of 8.50 percent is not reasonable and does not meet the requirements of *Hope* and *Bluefield* for a just and reasonable return. I conclude that Public Service's requested ROE of 9.60 percent for the Energy Strong II cost recovery mechanism, which is consistent with the return that the Rate Counsel agreed to in the Company's rate proceeding in October 2018, is reasonable based on a reasonable review of the analysis presented in Mr. O'Donnell's Direct Testimony, the analyses presented in my rebuttal testimony and a review of recently authorized state jurisdictional equity returns for electric utilities.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Ann E. Bulkley
Senior Vice President

Ms. Bulkley has more than two decades of management and economic consulting experience in the energy industry. Ms. Bulkley has extensive state and federal regulatory experience on both electric and natural gas issues including rate of return, cost of equity and capital structure issues. Ms. Bulkley has provided expert testimony on the cost of capital in more than 30 regulatory proceedings before regulatory commissions in Arizona, Arkansas, Colorado, Connecticut, Kansas, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, South Dakota, West Virginia, and the Federal Energy Regulatory Commission. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings. In addition, Ms. Bulkley has worked on acquisition teams with investors seeking to acquire utility assets, providing valuation services including an understanding of regulation, market expected returns, and the assessment of utility risk factors. Ms. Bulkley has assisted clients with valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and accounting and financial purposes. In addition, Ms. Bulkley has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring and regulatory and litigation support. Prior to joining Concentric, Ms. Bulkley held senior expertise-based consulting positions at several firms, including Reed Consulting Group and Navigant Consulting, Inc. where she specialized in valuation. Ms. Bulkley holds an M.A. in economics from Boston University and a B.A. in economics and finance from Simmons College. Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Analysis and Ratemaking

Ms. Bulkley has provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking. Specific services have included: cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies; development of merchant function exit strategies; analysis and program development to address residual energy supply and/or provider of last resort obligations; stranded costs assessment and recovery; performance-based ratemaking analysis and design; and many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation).

Cost of Capital

Ms. Bulkley has provided expert testimony on the cost of capital in more than 30 regulatory proceedings before regulatory commissions in many states including Arizona, Arkansas, Colorado, Connecticut, Kansas, Kentucky, Maine, Massachusetts, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, South Dakota, West Virginia, and the Federal Energy Regulatory Commission. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings in which she did not testify.

Valuation

Ms. Bulkley has provided valuation services to utility clients, unregulated generators and private equity clients for a variety of purposes including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Ms. Bulkley's appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice. In addition, Ms. Bulkley has relied on other simulation based valuation methodologies.

Representative projects/clients have included:

- Northern Indiana Fuel and Light: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Kokomo Gas: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost and comparable sales approaches.
- Confidential Utility Client: Prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.

- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

Ratemaking

Ms. Bulkley has assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Analyzed and evaluated rate application. Attended hearings and conducted investigation of rate application for regulatory staff. Prepared, supported and defended recommendations for revenue requirements and rates for the company. Developed rates for gas utility for transportation program and ancillary services.

Strategic and Financial Advisory Services

Ms. Bulkley has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed, and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Senior Vice President
Vice President
Assistant Vice President
Project Manager

Navigant Consulting, Inc. (1995 – 2002)
Project Manager

Cahners Publishing Company (1995)
Economist

EDUCATION

M.A., Economics, Boston University, 1995

B.A., Economics and Finance, Simmons College, 1991

Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-‑01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Federal Energy Regulatory Commission				
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Sea Robin Pipeline Company LLC	11/30/18	Sea Robin Pipeline Company LLC	Docket# RP19-__-000	Return on Equity
Indiana Utility Regulatory Commission				
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kansas Corporation Commission				
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-00194	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Commonwealth of Massachusetts Appellate Tax Board				
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Commonwealth of Massachusetts Department of Public Utilities				
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Rate Case
Michigan Public Service Commission				
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-2085 Case No. SR-17-2086	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Montana Public Service Commission				
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D0218.9.60	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Return on Equity
New Jersey Board of Public Utilities				
Public Service Electric and Gas Company	1/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
Public Service Electric and Gas Company	2/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-001398-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
New York State Department of Public Service				
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Gas 17-G-0460 Electric 17-E-0459	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0059	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
New York State Electric and Gas Company	05/15	New York State Electric and Gas Company	Case No. 15-G-0284	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. C-17-E-0238	Return on Equity
North Dakota Public Service Commission				
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Public Utility Commission of Pennsylvania				
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	4/19	Cascade Natural Gas Corporation	Docket NO. UG-19__	Return on Equity
Public Service Commission of West Virginia				
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity

Company	Ticker	Covered by More Than One Analyst	Positive EPS Forecast from More Than 1 Source	Pays Dividends / No Cuts	Credit Rating	Regulated Income / Total Income	Regulated Electric Income / Total Regulated Income	Regulated Gas Income / Total Regulated Income	Regulated Gas Assets / Total Gas Assets	Merger & Acquisition Activity	Nuclear Risk	Other
Alliant Energy	LNT	Yes	Yes	Yes	A-	101%	95%	6%	9%	No	No	
Ameren	AEE	Yes	Yes	Yes	BBB+	101%	89%	11%	10%	No	No	
Avista	AVA	Yes	Yes	Yes	BBB	101%	80%	20%	21%	Yes	No	
Black Hills	BKH	Yes	Yes	Yes	BBB+	88%	56%	44%	45%	No	No	
CMS Energy	CMS	Yes	Yes	Yes	BBB+	95%	74%	26%	33%	No	No	
Consolidated Edison	ED	Yes	Yes	Yes	A-	96%	80%	17%	19%	No	No	
Dominion Resources	D	Yes	Yes	Yes	BBB+	97%	69%	31%	38%	Yes	Yes	
DTE Energy	DTE	Yes	Yes	Yes	BBB+	100%	80%	20%	19%	No	No	
Duke Energy	DUK	Yes	Yes	Yes	A-	106%	95%	5%	7%	No	No	
Entergy Corp	ETR	Yes	No	Yes	BBB+	102%	99%	1%	1%	No	No	
Exelon Corp.	EXC	Yes	Yes	Yes	BBB+	63%	91%	9%	8%	No	No	
Fortis	FTS	No	No	Yes	A-	102%	NA	0%	0%	No	No	Canadian
MGE Energy	MGEE	No	No	Yes	AA-	71%	77%	23%	23%	No	No	
Sempra Energy	SRE	Yes	Yes	Yes	BBB+	72%	53%	47%	50%	No	No	
Southern	SO	Yes	Yes	Yes	A-	95%	88%	12%	16%	No	Yes	
Xcel	XEL	Yes	Yes	Yes	A-	100%	85%	15%	12%	No	No	
Companies Excluded		2	3	0		1	0	5	6	2	2	1

Constant Growth DCF Using Highest Historical Growth Rate

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	13 Wk. Avg. Dividend Yield	Adjusted Dividend Yield	Average Growth Rate	ROE	ROE, With Proxy Group Exclusions
Alliant Energy	LNT	3.1%	3.3%	7.0%	10.3%	10.3%
Ameren	AEE	2.9%	3.1%	7.0%	10.1%	10.1%
Avista	AVA	3.2%	3.4%	7.0%	10.4%	
Black Hills	BKH	3.2%	3.4%	7.0%	10.4%	10.4%
CMS Energy	CMS	3.0%	3.2%	7.0%	10.2%	10.2%
Consolidated Edison	ED	3.8%	4.1%	7.0%	11.1%	11.1%
Dominion Resources	D	5.0%	5.4%	7.0%	12.4%	
DTE	DTE	3.3%	3.5%	7.0%	10.5%	10.5%
Duke Energy	DUK	4.4%	4.7%	7.0%	11.7%	11.7%
Entergy	ETR	4.3%	4.6%	7.0%	11.6%	11.6%
Exelon	EXC	3.2%	3.4%	7.0%	10.4%	10.4%
Fortis	FTS	4.1%	4.4%	7.0%	11.4%	
MGE Energy	MGEE	2.1%	2.2%	7.0%	9.2%	
Sempra Energy	SRE	3.3%	3.5%	7.0%	10.5%	10.5%
Southern	SO	5.4%	5.8%	7.0%	12.8%	12.8%
Xcel	XEL	3.2%	3.4%	7.0%	10.4%	10.4%
Companies Excluded		3.6%	3.8%	7.0%	10.8%	10.8%

[1] Exhibit KWO-1
[2] Equals [1] multiplied by (1 plus [3])
[3] Schedule KWO-1, Page 1; 10-year historical BPS growth rate
[4] Equals [2] + [3]
[5] Equals [4] for all companies that should be included in the proxy group

Constant Growth DCF Using Highest Projected Growth Rate

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	13 Wk. Avg. Dividend Yield	Adjusted Dividend Yield	Average Growth Rate	ROE	ROE, With Proxy Group Exclusions
Alliant Energy	LNT	3.1%	3.3%	7.2%	10.5%	10.5%
Ameren	AEE	2.9%	3.1%	7.2%	10.3%	10.3%
Avista	AVA	3.2%	3.4%	7.2%	10.6%	
Black Hills	BKH	3.2%	3.4%	7.2%	10.6%	10.6%
CMS Energy	CMS	3.0%	3.2%	7.2%	10.4%	10.4%
Consolidated Edison	ED	3.8%	4.1%	7.2%	11.3%	11.3%
Dominion Resources	D	5.0%	5.4%	7.2%	12.6%	
DTE	DTE	3.3%	3.5%	7.2%	10.7%	10.7%
Duke Energy	DUK	4.4%	4.7%	7.2%	11.9%	11.9%
Entergy	ETR	4.3%	4.6%	7.2%	11.8%	11.8%
Exelon	EXC	3.2%	3.4%	7.2%	10.6%	10.6%
Fortis	FTS	4.1%	4.4%	7.2%	11.6%	
MGE Energy	MGEE	2.1%	2.3%	7.2%	9.5%	
Sempra Energy	SRE	3.3%	3.5%	7.2%	10.7%	10.7%
Southern	SO	5.4%	5.8%	7.2%	13.0%	13.0%
Xcel	XEL	3.2%	3.4%	7.2%	10.6%	10.6%
Companies Excluded		3.6%	3.9%	7.2%	11.1%	11.1%

[1] Exhibit KWO-1
[2] Equals [1] multiplied by (1 plus [3])
[3] Schedule KWO-1, Page 1; Schwab Forecasted EPS growth rate
[4] Equals [2] + [3]
[5] Equals [4] for all companies that should be included in the proxy group

Combination Utility Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	13 Wk. Avg. Dividend Yield	Adjusted Dividend Yield	Value Line EPS Forecast	CFRA Forecasted EPS	Schwab Forecasted EPS	Average Growth Rate	ROE	ROE, With Proxy Group Exclusions
Alliant Energy	LNT	3.1%	3.3%	6.5%	7.0%	7.3%	6.9%	10.2%	10.2%
Ameren	AEE	2.9%	3.1%	7.5%	7.0%	7.7%	7.4%	10.5%	10.5%
Avista	AVA	3.2%	3.4%	5.5%	NA	NA	5.5%	8.9%	
Black Hills	BKH	3.2%	3.5%	6.5%	15.0%	3.6%	8.4%	11.8%	11.8%
CMS Energy	CMS	3.0%	3.2%	7.0%	7.0%	6.9%	7.0%	10.2%	10.2%
Consolidated Edison	ED	3.8%	3.9%	3.0%	3.0%	2.9%	3.0%	6.9%	6.9%
Dominion Resources	D	5.0%	5.3%	6.5%	7.0%	5.7%	6.4%	11.7%	
DTE	DTE	3.3%	3.5%	7.5%	4.0%	4.2%	5.2%	8.7%	8.7%
Duke Energy	DUK	4.4%	4.6%	5.5%	5.0%	4.4%	5.0%	9.6%	9.6%
Entergy	ETR	4.3%	4.2%	1.0%	NM	-3.7%	-1.4%	2.9%	
Exelon	EXC	3.2%	3.3%	7.5%	2.0%	3.1%	4.2%	7.5%	7.5%
Fortis	FTS	4.1%	4.5%	9.0%	NA	NA	9.0%	13.5%	
MGE Energy	MGEE	2.1%	2.3%	7.5%	NA	NA	7.5%	9.8%	
Sempra Energy	SRE	3.3%	3.6%	9.5%	10.0%	7.6%	9.0%	12.6%	12.6%
Southern	SO	5.4%	5.5%	3.5%	1.0%	2.7%	2.4%	7.9%	7.9%
Xcel	XEL	3.2%	3.4%	5.5%	6.0%	6.6%	6.0%	9.4%	9.4%
Companies Excluded		3.6%	3.8%	6.2%	6.2%	4.5%	5.7%	9.5%	9.6%

[1] Exhibit KWO-1
[2] Equals [1] multiplied by (1 plus [6])
[3] Schedule KWO-1, Page 1;
[4] Schedule KWO-1, Page 1;
[5] Schedule KWO-1, Page 1;
[6] Average of [3], [4], and [5]
[7] Equals [2] plus [6]
[8] Equals [7] if [7] is greater than 7%

[1] Estimated Weighted Average Dividend Yield	2.03%
[2] Estimated Weighted Average Long-Term Growth Rate	11.62%
[3] S&P 500 Estimated Required Market Return	13.77%
[4] Risk-Free Rate	3.46% / 3.12% / 2.92%
[5] Implied Market Risk Premium	10.31% / 10.65% / 10.85%

		[6]	[7]	[8]	[9]	[10]
Name	Ticker	Weight in Index	Estimated Dividend Yield	Cap. Weighted Div. Yield	Long-Term Growth Estimate	Cap. Weighted Long-Term Growth Estimate
LyondellBasell Industries NV	LYB	0.13%	4.68	0.01%	6.80	0.01%
American Express Co	AXP	0.38%	1.45	0.01%	14.99	0.06%
Verizon Communications Inc	VZ	0.97%	4.23	0.04%	2.30	0.02%
Broadcom Inc	AVGO	0.45%	3.85	0.02%	13.15	0.06%
Boeing Co/The	BA	1.03%	1.87	0.02%	15.15	0.16%
Caterpillar Inc	CAT	0.33%	2.50	0.01%	13.35	0.04%
JPMorgan Chase & Co	JPM	1.42%	3.07	0.04%	7.00	0.10%
Chevron Corp	CVX	0.94%	3.98	0.04%	6.36	0.06%
Coca-Cola Co/The	KO	0.80%	3.53	0.03%	6.72	0.05%
AbbVie Inc	ABBV	0.48%	5.40	0.03%	8.81	0.04%
Walt Disney Co/The	DIS	0.70%	1.56	0.01%	3.76	0.03%
FleetCor Technologies Inc	FLT	0.08%	n/a	n/a	16.50	0.01%
Extra Space Storage Inc	EXR	0.05%	3.59	0.00%	4.39	0.00%
Exxon Mobil Corp	XOM	1.39%	4.15	0.06%	15.74	0.22%
Phillips 66	PSX	0.18%	3.32	0.01%	5.70	0.01%
General Electric Co	GE	0.37%	0.39	0.00%	1.60	0.01%
HP Inc	HPQ	0.13%	3.25	0.00%	3.08	0.00%
Home Depot Inc/The	HD	0.87%	2.94	0.03%	10.72	0.09%
International Business Machines Corp	IBM	0.51%	4.55	0.02%	0.72	0.00%
Concho Resources Inc	CXO	0.09%	0.45	0.00%	31.00	0.03%
Johnson & Johnson	JNJ	1.51%	2.63	0.04%	6.83	0.10%
McDonald's Corp	MCD	0.58%	2.52	0.01%	8.74	0.05%
Merck & Co Inc	MRK	0.87%	2.71	0.02%	8.76	0.08%
3M Co	MMM	0.49%	2.78	0.01%	7.70	0.04%
American Water Works Co Inc	AWK	0.08%	1.79	0.00%	8.45	0.01%
Bank of America Corp	BAC	1.16%	2.06	0.02%	9.70	0.11%
Brighthouse Financial Inc	BHF	0.02%	n/a	n/a	11.14	0.00%
Baker Hughes a GE Co	BHGE	0.06%	2.73	0.00%	40.82	0.02%
Pfizer Inc	PFE	1.00%	3.32	0.03%	5.45	0.05%
Procter & Gamble Co/The	PG	1.02%	2.91	0.03%	6.51	0.07%
AT&T Inc	T	0.94%	6.56	0.06%	4.92	0.05%
Travelers Cos Inc/The	TRV	0.14%	2.32	0.00%	17.69	0.03%
United Technologies Corp	UTX	0.45%	2.34	0.01%	9.80	0.04%
Analog Devices Inc	ADI	0.16%	2.02	0.00%	11.98	0.02%
Walmart Inc	WMT	1.19%	2.14	0.03%	5.20	0.06%
Cisco Systems Inc	CSCO	0.94%	2.70	0.03%	6.84	0.06%
Intel Corp	INTC	0.99%	2.38	0.02%	8.54	0.08%
General Motors Co	GM	0.23%	3.85	0.01%	6.03	0.01%
Microsoft Corp	MSFT	3.56%	1.64	0.06%	11.68	0.42%
Dollar General Corp	DG	0.13%	0.98	0.00%	15.75	0.02%
Cigna Corp	CI	0.27%	0.02	0.00%	12.65	0.03%
Kinder Morgan Inc/DE	KMI	0.18%	4.18	0.01%	10.00	0.02%

Name	Ticker	[6] Weight in Index	[7] Estimated Dividend Yield	[8] Cap. Weighted Div. Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth Estimate
Citigroup Inc	C	0.62%	2.81	0.02%	11.07	0.07%
American International Group Inc	AIG	0.16%	2.96	0.00%	11.00	0.02%
Honeywell International Inc	HON	0.47%	2.13	0.01%	7.88	0.04%
Altria Group Inc	MO	0.41%	6.11	0.02%	8.50	0.03%
HCA Healthcare Inc	HCA	0.20%	1.15	0.00%	11.56	0.02%
Under Armour Inc	UAA	0.02%	n/a	n/a	34.93	0.01%
International Paper Co	IP	0.08%	4.36	0.00%	6.08	0.00%
Hewlett Packard Enterprise Co	HPE	0.09%	2.75	0.00%	6.09	0.01%
Abbott Laboratories	ABT	0.56%	1.65	0.01%	11.69	0.07%
Aflac Inc	AFL	0.15%	2.20	0.00%	3.43	0.01%
Air Products & Chemicals Inc	APD	0.16%	2.56	0.00%	12.30	0.02%
Royal Caribbean Cruises Ltd	RCL	0.10%	2.36	0.00%	11.72	0.01%
American Electric Power Co Inc	AEP	0.17%	3.30	0.01%	6.08	0.01%
Hess Corp	HES	0.07%	1.73	0.00%	-9.49	-0.01%
Anadarko Petroleum Corp	APC	0.09%	2.76	0.00%	23.31	0.02%
Aon PLC	AON	0.17%	0.93	0.00%	10.90	0.02%
Apache Corp	APA	0.05%	3.01	0.00%	-5.19	0.00%
Archer-Daniels-Midland Co	ADM	0.10%	3.29	0.00%	1.40	0.00%
Automatic Data Processing Inc	ADP	0.28%	2.07	0.01%	14.00	0.04%
Verisk Analytics Inc	VRSK	0.09%	0.79	0.00%	9.57	0.01%
AutoZone Inc	AZO	0.10%	n/a	n/a	13.22	0.01%
Avery Dennison Corp	AVY	0.04%	1.93	0.00%	5.75	0.00%
MSCI Inc	MSCI	0.06%	1.26	0.00%	13.10	0.01%
Ball Corp	BLL	0.08%	0.73	0.00%	6.50	0.00%
Bank of New York Mellon Corp/The	BK	0.21%	2.13	0.00%	7.33	0.02%
Baxter International Inc	BAX	0.16%	1.02	0.00%	12.20	0.02%
Becton Dickinson and Co	BDX	0.28%	1.24	0.00%	12.41	0.03%
Berkshire Hathaway Inc	BRK/B	1.14%	n/a	n/a	-1.60	-0.02%
Best Buy Co Inc	BBY	0.08%	2.91	0.00%	10.65	0.01%
H&R Block Inc	HRB	0.02%	4.14	0.00%	10.00	0.00%
Boston Scientific Corp	BSX	0.23%	n/a	n/a	33.46	0.08%
Bristol-Myers Squibb Co	BMY	0.35%	3.17	0.01%	11.02	0.04%
Fortune Brands Home & Security Inc	FBHS	0.03%	1.87	0.00%	9.97	0.00%
Brown-Forman Corp	BF/B	0.06%	1.34	0.00%	9.86	0.01%
Cabot Oil & Gas Corp	COG	0.04%	1.14	0.00%	26.58	0.01%
Campbell Soup Co	CPB	0.04%	3.89	0.00%	1.75	0.00%
Kansas City Southern	KSU	0.05%	1.33	0.00%	8.97	0.00%
Hilton Worldwide Holdings Inc	HLT	0.10%	0.72	0.00%	13.62	0.01%
Carnival Corp	CCL	0.13%	3.46	0.00%	10.93	0.01%
Qorvo Inc	QRVO	0.04%	n/a	n/a	11.83	0.00%
CenturyLink Inc	CTL	0.06%	16.38	0.01%	-2.80	0.00%
UDR Inc	UDR	0.05%	2.90	0.00%	5.54	0.00%
Clorox Co/The	CLX	0.08%	2.43	0.00%	4.91	0.00%
CMS Energy Corp	CMS	0.06%	2.81	0.00%	6.61	0.00%
Newell Brands Inc	NWL	0.03%	5.67	0.00%	-11.86	0.00%
Colgate-Palmolive Co	CL	0.24%	2.55	0.01%	6.24	0.01%
Comerica Inc	CMA	0.06%	3.08	0.00%	16.41	0.01%
IPG Photonics Corp	IPGP	0.03%	n/a	n/a	12.00	0.00%
Conagra Brands Inc	CAG	0.05%	3.64	0.00%	8.00	0.00%
Consolidated Edison Inc	ED	0.11%	3.59	0.00%	3.73	0.00%
SL Green Realty Corp	SLG	0.03%	3.75	0.00%	-0.59	0.00%
Corning Inc	GLW	0.11%	2.30	0.00%	10.39	0.01%
Cummins Inc	CMI	0.10%	2.96	0.00%	6.81	0.01%
Danaher Corp	DHR	0.38%	0.50	0.00%	9.01	0.03%
Target Corp	TGT	0.16%	3.52	0.01%	6.35	0.01%

Name	Ticker	[6] Weight in Index	[7] Estimated Dividend Yield	[8] Cap. Weighted Div. Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth Estimate
Deere & Co	DE	0.22%	1.85	0.00%	10.39	0.02%
Dominion Energy Inc	D	0.25%	4.95	0.01%	5.72	0.01%
Dover Corp	DOV	0.05%	2.12	0.00%	10.97	0.01%
Alliant Energy Corp	LNT	0.04%	3.10	0.00%	6.29	0.00%
Duke Energy Corp	DUK	0.27%	4.14	0.01%	4.97	0.01%
Regency Centers Corp	REG	0.05%	3.59	0.00%	4.78	0.00%
Eaton Corp PLC	ETN	0.14%	3.56	0.00%	9.23	0.01%
Ecolab Inc	ECL	0.20%	1.09	0.00%	13.43	0.03%
PerkinElmer Inc	PKI	0.04%	0.30	0.00%	15.49	0.01%
Emerson Electric Co	EMR	0.17%	2.88	0.00%	8.95	0.02%
EOG Resources Inc	EOG	0.23%	0.94	0.00%	11.57	0.03%
Entergy Corp	ETR	0.07%	3.90	0.00%	-0.96	0.00%
Equifax Inc	EFX	0.05%	1.42	0.00%	7.16	0.00%
IQVIA Holdings Inc	IQV	0.11%	n/a	n/a	16.28	0.02%
Gartner Inc	IT	0.05%	n/a	n/a	14.02	0.01%
FedEx Corp	FDX	0.20%	1.44	0.00%	14.25	0.03%
Macy's Inc	M	0.03%	6.09	0.00%	1.67	0.00%
FMC Corp	FMC	0.05%	1.79	0.00%	10.27	0.01%
Ford Motor Co	F	0.14%	6.84	0.01%	-0.70	0.00%
NextEra Energy Inc	NEE	0.37%	2.66	0.01%	4.90	0.02%
Franklin Resources Inc	BEN	0.07%	3.19	0.00%	10.00	0.01%
Freeport-McMoRan Inc	FCX	0.08%	1.55	0.00%	-12.55	-0.01%
Gap Inc/The	GPS	0.04%	3.82	0.00%	8.63	0.00%
General Dynamics Corp	GD	0.20%	2.19	0.00%	10.09	0.02%
General Mills Inc	GIS	0.12%	4.16	0.00%	6.43	0.01%
Genuine Parts Co	GPC	0.07%	2.80	0.00%	8.99	0.01%
Atmos Energy Corp	ATO	0.05%	2.12	0.00%	6.50	0.00%
WW Grainger Inc	GWW	0.07%	1.79	0.00%	12.47	0.01%
Halliburton Co	HAL	0.11%	2.35	0.00%	30.08	0.03%
Harley-Davidson Inc	HOG	0.02%	4.04	0.00%	10.30	0.00%
Harris Corp	HRS	0.08%	1.66	0.00%	7.00	0.01%
HCP Inc	HCP	0.06%	4.81	0.00%	3.23	0.00%
Helmerich & Payne Inc	HP	0.02%	5.24	0.00%	96.36	0.02%
Fortive Corp	FTV	0.11%	0.34	0.00%	13.89	0.02%
Hershey Co/The	HSY	0.07%	2.61	0.00%	8.00	0.01%
Synchrony Financial	SYF	0.10%	2.58	0.00%	1.55	0.00%
Hormel Foods Corp	HRL	0.10%	1.94	0.00%	5.80	0.01%
Arthur J Gallagher & Co	AJG	0.06%	2.14	0.00%	10.17	0.01%
Mondelez International Inc	MDLZ	0.28%	2.21	0.01%	7.33	0.02%
CenterPoint Energy Inc	CNP	0.06%	3.82	0.00%	6.92	0.00%
Humana Inc	HUM	0.16%	0.77	0.00%	14.11	0.02%
Willis Towers Watson PLC	WLTW	0.09%	1.51	0.00%	10.00	0.01%
Illinois Tool Works Inc	ITW	0.20%	2.78	0.01%	7.27	0.01%
Ingersoll-Rand PLC	IR	0.11%	2.01	0.00%	9.92	0.01%
Foot Locker Inc	FL	0.03%	2.55	0.00%	6.24	0.00%
Interpublic Group of Cos Inc/The	IPG	0.04%	4.08	0.00%	13.93	0.01%
International Flavors & Fragrances Inc	IFF	0.06%	2.29	0.00%	4.00	0.00%
Jacobs Engineering Group Inc	JEC	0.04%	0.92	0.00%	13.57	0.01%
Hanesbrands Inc	HBI	0.03%	3.23	0.00%	3.72	0.00%
Kellogg Co	K	0.08%	3.98	0.00%	3.68	0.00%
Broadridge Financial Solutions Inc	BR	0.05%	1.92	0.00%	10.00	0.00%
Perrigo Co PLC	PRGO	0.03%	1.56	0.00%	1.17	0.00%
Kimberly-Clark Corp	KMB	0.17%	3.53	0.01%	6.09	0.01%
Kimco Realty Corp	KIM	0.03%	6.37	0.00%	3.86	0.00%
Kohl's Corp	KSS	0.05%	3.61	0.00%	10.60	0.00%

Name	Ticker	[6] Weight in Index	[7] Estimated Dividend Yield	[8] Cap. Weighted Div. Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth Estimate
Oracle Corp	ORCL	0.77%	1.46	0.01%	7.54	0.06%
Kroger Co/The	KR	0.10%	1.91	0.00%	6.43	0.01%
Leggett & Platt Inc	LEG	0.02%	3.35	0.00%	10.00	0.00%
Lennar Corp	LEN	0.06%	0.33	0.00%	12.74	0.01%
Jefferies Financial Group Inc	JEF	0.03%	2.47	0.00%	n/a	n/a
Eli Lilly & Co	LLY	0.54%	2.04	0.01%	10.72	0.06%
L Brands Inc	LB	0.03%	4.59	0.00%	10.72	0.00%
Charter Communications Inc	CHTR	0.32%	n/a	n/a	41.16	0.13%
Lincoln National Corp	LNC	0.05%	2.37	0.00%	9.00	0.00%
Loews Corp	L	0.06%	0.53	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.35%	1.83	0.01%	15.80	0.06%
Host Hotels & Resorts Inc	HST	0.06%	4.08	0.00%	4.57	0.00%
Marsh & McLennan Cos Inc	MMC	0.19%	1.78	0.00%	11.80	0.02%
Masco Corp	MAS	0.05%	1.28	0.00%	12.50	0.01%
Mattel Inc	MAT	0.02%	n/a	n/a	10.00	0.00%
S&P Global Inc	SPGI	0.21%	1.14	0.00%	11.05	0.02%
Medtronic PLC	MDT	0.50%	2.21	0.01%	7.70	0.04%
CVS Health Corp	CVS	0.31%	3.46	0.01%	8.68	0.03%
DowDuPont Inc	DWDP	0.50%	2.86	0.01%	6.17	0.03%
Micron Technology Inc	MU	0.19%	n/a	n/a	-3.30	-0.01%
Motorola Solutions Inc	MSI	0.10%	1.59	0.00%	4.10	0.00%
Cboe Global Markets Inc	CBOE	0.04%	1.29	0.00%	13.46	0.01%
Mylan NV	MYL	0.06%	n/a	n/a	5.98	0.00%
Laboratory Corp of America Holdings	LH	0.06%	n/a	n/a	7.61	0.00%
Newmont Mining Corp	NEM	0.08%	1.64	0.00%	14.10	0.01%
Twenty-First Century Fox Inc	FOXA	0.22%	0.71	0.00%	2.66	0.01%
NIKE Inc	NKE	0.45%	1.03	0.00%	18.34	0.08%
NiSource Inc	NI	0.04%	2.97	0.00%	5.75	0.00%
Noble Energy Inc	NBL	0.04%	1.99	0.00%	14.55	0.01%
Norfolk Southern Corp	NSC	0.20%	1.92	0.00%	13.97	0.03%
Principal Financial Group Inc	PFG	0.06%	4.10	0.00%	4.16	0.00%
Eversource Energy	ES	0.09%	3.07	0.00%	5.62	0.01%
Northrop Grumman Corp	NOC	0.20%	1.66	0.00%	8.89	0.02%
Wells Fargo & Co	WFC	0.94%	3.61	0.03%	11.26	0.11%
Nucor Corp	NUE	0.08%	2.64	0.00%	0.85	0.00%
PVH Corp	PVH	0.04%	0.13	0.00%	11.03	0.00%
Occidental Petroleum Corp	OXY	0.21%	4.72	0.01%	-0.50	0.00%
Omnicom Group Inc	OMC	0.07%	3.43	0.00%	5.22	0.00%
ONEOK Inc	OKE	0.11%	5.35	0.01%	16.89	0.02%
Raymond James Financial Inc	RJF	0.05%	1.65	0.00%	12.30	0.01%
Parker-Hannifin Corp	PH	0.09%	1.73	0.00%	9.52	0.01%
Rollins Inc	ROL	0.05%	1.06	0.00%	10.00	0.01%
PPL Corp	PPL	0.10%	5.13	0.00%	6.17	0.01%
Exelon Corp	EXC	0.19%	2.98	0.01%	4.12	0.01%
ConocoPhillips	COP	0.32%	1.80	0.01%	6.00	0.02%
PulteGroup Inc	PHM	0.03%	1.63	0.00%	7.17	0.00%
Pinnacle West Capital Corp	PNW	0.04%	3.15	0.00%	5.18	0.00%
PNC Financial Services Group Inc/The	PNC	0.24%	3.02	0.01%	7.37	0.02%
PPG Industries Inc	PPG	0.11%	1.71	0.00%	7.49	0.01%
Progressive Corp/The	PGR	0.18%	0.55	0.00%	8.00	0.01%
Public Service Enterprise Group Inc	PEG	0.12%	3.20	0.00%	6.73	0.01%
Raytheon Co	RTN	0.22%	1.86	0.00%	10.03	0.02%
Robert Half International Inc	RHI	0.03%	1.82	0.00%	9.25	0.00%
Edison International	EIX	0.08%	4.09	0.00%	5.34	0.00%
Schlumberger Ltd	SLB	0.25%	4.54	0.01%	33.69	0.09%

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Charles Schwab Corp/The	SCHW	0.25%	1.48	0.00%	19.78	0.05%
Sherwin-Williams Co/The	SHW	0.17%	1.04	0.00%	10.74	0.02%
JM Smucker Co/The	SJM	0.05%	3.21	0.00%	3.20	0.00%
Snap-on Inc	SNA	0.04%	2.38	0.00%	7.93	0.00%
AMETEK Inc	AME	0.07%	0.70	0.00%	8.98	0.01%
Southern Co/The	SO	0.21%	4.83	0.01%	3.38	0.01%
BB&T Corp	BBT	0.16%	3.18	0.01%	9.85	0.02%
Southwest Airlines Co	LUV	0.13%	1.14	0.00%	10.01	0.01%
Stanley Black & Decker Inc	SWK	0.08%	1.99	0.00%	10.50	0.01%
Public Storage	PSA	0.15%	3.78	0.01%	5.26	0.01%
Arista Networks Inc	ANET	0.09%	n/a	n/a	21.64	0.02%
SunTrust Banks Inc	STI	0.12%	3.08	0.00%	8.04	0.01%
Sysco Corp	SYY	0.14%	2.31	0.00%	12.50	0.02%
Texas Instruments Inc	TXN	0.41%	2.91	0.01%	10.48	0.04%
Textron Inc	TXT	0.05%	0.15	0.00%	12.56	0.01%
Thermo Fisher Scientific Inc	TMO	0.43%	0.29	0.00%	12.00	0.05%
Tiffany & Co	TIF	0.05%	2.31	0.00%	10.53	0.01%
TJX Cos Inc/The	TJX	0.26%	1.79	0.00%	11.57	0.03%
Torchmark Corp	TMK	0.04%	0.78	0.00%	7.53	0.00%
Total System Services Inc	TSS	0.07%	0.55	0.00%	12.14	0.01%
Johnson Controls International plc	JCI	0.13%	2.95	0.00%	7.63	0.01%
Ulta Beauty Inc	ULTA	0.08%	n/a	n/a	21.00	0.02%
Union Pacific Corp	UNP	0.50%	2.10	0.01%	13.86	0.07%
Keysight Technologies Inc	KEYS	0.07%	n/a	n/a	17.00	0.01%
UnitedHealth Group Inc	UNH	0.96%	1.49	0.01%	13.73	0.13%
Unum Group	UNM	0.03%	2.78	0.00%	9.00	0.00%
Marathon Oil Corp	MRO	0.06%	1.20	0.00%	0.45	0.00%
Varian Medical Systems Inc	VAR	0.05%	n/a	n/a	16.10	0.01%
Ventas Inc	VTR	0.09%	5.05	0.00%	2.08	0.00%
VF Corp	VFC	0.14%	2.34	0.00%	-16.64	-0.02%
Vornado Realty Trust	VNO	0.05%	3.92	0.00%	0.74	0.00%
Vulcan Materials Co	VMC	0.06%	1.11	0.00%	15.34	0.01%
Weyerhaeuser Co	WY	0.08%	5.46	0.00%	8.70	0.01%
Whirlpool Corp	WHR	0.04%	3.25	0.00%	5.75	0.00%
Williams Cos Inc/The	WMB	0.13%	5.70	0.01%	3.90	0.01%
WEC Energy Group Inc	WEC	0.10%	3.09	0.00%	4.89	0.00%
Xerox Corp	XRX	0.03%	3.24	0.00%	-0.10	0.00%
Adobe Inc	ADBE	0.53%	n/a	n/a	17.16	0.09%
AES Corp/VA	AES	0.05%	3.17	0.00%	7.67	0.00%
Amgen Inc	AMGN	0.49%	3.05	0.01%	5.83	0.03%
Apple Inc	AAPL	3.38%	1.69	0.06%	9.40	0.32%
Autodesk Inc	ADSK	0.15%	n/a	n/a	54.78	0.08%
Cintas Corp	CTAS	0.09%	0.99	0.00%	12.02	0.01%
Comcast Corp	CMCSA	0.72%	2.17	0.02%	11.03	0.08%
Molson Coors Brewing Co	TAP	0.05%	2.66	0.00%	0.26	0.00%
KLA-Tencor Corp	KLAC	0.08%	2.60	0.00%	8.58	0.01%
Marriott International Inc/MD	MAR	0.18%	1.31	0.00%	12.10	0.02%
McCormick & Co Inc/MD	MKC	0.07%	1.68	0.00%	6.10	0.00%
Nordstrom Inc	JWN	0.03%	3.13	0.00%	10.55	0.00%
PACCAR Inc	PCAR	0.10%	1.89	0.00%	6.10	0.01%
Costco Wholesale Corp	COST	0.40%	1.04	0.00%	10.58	0.04%
First Republic Bank/CA	FRC	0.07%	0.69	0.00%	12.39	0.01%
Stryker Corp	SYK	0.29%	1.10	0.00%	8.72	0.03%
Tyson Foods Inc	TSN	0.08%	2.43	0.00%	-5.00	0.00%
Lamb Weston Holdings Inc	LW	0.04%	1.15	0.00%	11.02	0.00%

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Applied Materials Inc	AMAT	0.15%	2.09	0.00%	9.23	0.01%
American Airlines Group Inc	AAL	0.07%	1.12	0.00%	15.20	0.01%
Cardinal Health Inc	CAH	0.07%	3.51	0.00%	4.77	0.00%
Celgene Corp	CELG	0.24%	n/a	n/a	20.70	0.05%
Cerner Corp	CERN	0.08%	n/a	n/a	13.20	0.01%
Cincinnati Financial Corp	CINF	0.06%	2.58	0.00%	n/a	n/a
DR Horton Inc	DHI	0.06%	1.54	0.00%	11.80	0.01%
Flowserve Corp	FLS	0.02%	1.71	0.00%	13.05	0.00%
Electronic Arts Inc	EA	0.12%	n/a	n/a	11.87	0.01%
Expeditors International of Washington Inc	EXPD	0.05%	1.20	0.00%	7.70	0.00%
Fastenal Co	FAST	0.07%	2.73	0.00%	14.85	0.01%
M&T Bank Corp	MTB	0.10%	2.31	0.00%	7.98	0.01%
Xcel Energy Inc	XEL	0.12%	2.95	0.00%	5.89	0.01%
Fiserv Inc	FISV	0.14%	n/a	n/a	7.40	0.01%
Fifth Third Bancorp	FITB	0.08%	3.19	0.00%	3.95	0.00%
Gilead Sciences Inc	GILD	0.34%	3.88	0.01%	-1.48	-0.01%
Hasbro Inc	HAS	0.04%	3.20	0.00%	10.67	0.00%
Huntington Bancshares Inc/OH	HBAN	0.06%	3.89	0.00%	8.20	0.01%
Welltower Inc	WELL	0.12%	4.68	0.01%	6.74	0.01%
Biogen Inc	BIIB	0.27%	n/a	n/a	5.08	0.01%
Northern Trust Corp	NTRS	0.08%	2.58	0.00%	10.65	0.01%
Packaging Corp of America	PKG	0.04%	3.31	0.00%	8.25	0.00%
Paychex Inc	PAYX	0.11%	2.91	0.00%	9.25	0.01%
People's United Financial Inc	PBCT	0.03%	3.94	0.00%	2.00	0.00%
QUALCOMM Inc	QCOM	0.27%	4.65	0.01%	11.71	0.03%
Roper Technologies Inc	ROP	0.14%	0.57	0.00%	11.33	0.02%
Ross Stores Inc	ROST	0.15%	0.95	0.00%	10.50	0.02%
IDEXX Laboratories Inc	IDXX	0.08%	n/a	n/a	18.66	0.01%
Starbucks Corp	SBUX	0.36%	2.05	0.01%	13.22	0.05%
KeyCorp	KEY	0.07%	3.85	0.00%	13.17	0.01%
State Street Corp	STT	0.11%	2.62	0.00%	8.69	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	0.05%	n/a	n/a	12.53	0.01%
US Bancorp	USB	0.34%	2.86	0.01%	6.70	0.02%
AO Smith Corp	AOS	0.03%	1.69	0.00%	9.33	0.00%
Symantec Corp	SYMC	0.06%	1.33	0.00%	7.50	0.00%
T Rowe Price Group Inc	TROW	0.10%	3.03	0.00%	4.27	0.00%
Waste Management Inc	WM	0.18%	2.02	0.00%	8.03	0.01%
CBS Corp	CBS	0.07%	1.43	0.00%	14.79	0.01%
Allergan PLC	AGN	0.19%	2.15	0.00%	5.57	0.01%
Constellation Brands Inc	STZ	0.12%	1.75	0.00%	8.92	0.01%
Xilinx Inc	XLNX	0.13%	1.15	0.00%	9.33	0.01%
DENTSPLY SIRONA Inc	XRAY	0.04%	0.84	0.00%	6.90	0.00%
Zions Bancorp NA	ZION	0.04%	2.35	0.00%	6.78	0.00%
Alaska Air Group Inc	ALK	0.03%	2.27	0.00%	25.37	0.01%
Invesco Ltd	IVZ	0.03%	6.20	0.00%	4.30	0.00%
Linde PLC	LIN	0.39%	2.02	0.01%	19.10	0.07%
Intuit Inc	INTU	0.27%	0.76	0.00%	15.82	0.04%
Morgan Stanley	MS	0.30%	2.86	0.01%	13.50	0.04%
Microchip Technology Inc	MCHP	0.09%	1.68	0.00%	12.39	0.01%
Chubb Ltd	CB	0.25%	2.18	0.01%	10.00	0.03%
Hologic Inc	HOLX	0.06%	n/a	n/a	3.10	0.00%
Citizens Financial Group Inc	CFG	0.07%	3.47	0.00%	16.69	0.01%
O'Reilly Automotive Inc	ORLY	0.12%	n/a	n/a	15.58	0.02%
Allstate Corp/The	ALL	0.13%	2.12	0.00%	7.10	0.01%
FLIR Systems Inc	FLIR	0.03%	1.32	0.00%	n/a	n/a

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Equity Residential	EQR	0.11%	2.93	0.00%	6.28	0.01%
BorgWarner Inc	BWA	0.03%	1.67	0.00%	5.78	0.00%
Incyte Corp	INCY	0.08%	n/a	n/a	47.53	0.04%
Simon Property Group Inc	SPG	0.23%	4.53	0.01%	5.23	0.01%
Eastman Chemical Co	EMN	0.05%	3.00	0.00%	6.73	0.00%
Twitter Inc	TWTR	0.10%	n/a	n/a	37.35	0.04%
AvalonBay Communities Inc	AVB	0.11%	3.12	0.00%	6.01	0.01%
Prudential Financial Inc	PRU	0.16%	4.17	0.01%	9.00	0.01%
United Parcel Service Inc	UPS	0.32%	3.48	0.01%	8.96	0.03%
Apartment Investment & Management Co	AIV	0.03%	3.29	0.00%	5.75	0.00%
Walgreens Boots Alliance Inc	WBA	0.28%	2.47	0.01%	9.77	0.03%
McKesson Corp	MCK	0.10%	1.23	0.00%	8.08	0.01%
Lockheed Martin Corp	LMT	0.36%	2.84	0.01%	7.61	0.03%
AmerisourceBergen Corp	ABC	0.07%	1.92	0.00%	8.70	0.01%
Capital One Financial Corp	COF	0.16%	1.91	0.00%	4.77	0.01%
Waters Corp	WAT	0.07%	n/a	n/a	11.48	0.01%
Dollar Tree Inc	DLTR	0.09%	n/a	n/a	9.96	0.01%
Darden Restaurants Inc	DRI	0.06%	2.68	0.00%	10.31	0.01%
NetApp Inc	NTAP	0.07%	2.45	0.00%	13.23	0.01%
Citrix Systems Inc	CTXS	0.06%	1.33	0.00%	11.85	0.01%
DXC Technology Co	DXC	0.07%	1.15	0.00%	6.70	0.00%
DaVita Inc	DVA	0.04%	n/a	n/a	19.15	0.01%
Hartford Financial Services Group Inc/The	HIG	0.07%	2.43	0.00%	9.50	0.01%
Iron Mountain Inc	IRM	0.04%	6.90	0.00%	7.16	0.00%
Estee Lauder Cos Inc/The	EL	0.14%	1.10	0.00%	12.38	0.02%
Cadence Design Systems Inc	CDNS	0.07%	n/a	n/a	10.35	0.01%
Universal Health Services Inc	UHS	0.05%	0.29	0.00%	9.54	0.00%
E*TRADE Financial Corp	ETFC	0.05%	1.14	0.00%	12.08	0.01%
Skyworks Solutions Inc	SWKS	0.06%	1.86	0.00%	8.87	0.01%
National Oilwell Varco Inc	NOV	0.04%	0.71	0.00%	77.76	0.03%
Quest Diagnostics Inc	DGX	0.05%	2.45	0.00%	6.92	0.00%
Activision Blizzard Inc	ATVI	0.13%	0.88	0.00%	6.65	0.01%
Rockwell Automation Inc	ROK	0.09%	2.17	0.00%	8.94	0.01%
Kraft Heinz Co/The	KHC	0.17%	4.82	0.01%	2.60	0.00%
American Tower Corp	AMT	0.32%	1.91	0.01%	15.31	0.05%
HollyFrontier Corp	HFC	0.04%	2.58	0.00%	7.07	0.00%
Regeneron Pharmaceuticals Inc	REGN	0.19%	n/a	n/a	13.88	0.03%
Amazon.com Inc	AMZN	3.34%	n/a	n/a	37.60	1.25%
Jack Henry & Associates Inc	JKHY	0.04%	1.21	0.00%	11.00	0.00%
Ralph Lauren Corp	RL	0.03%	2.00	0.00%	6.84	0.00%
Boston Properties Inc	BXP	0.08%	2.86	0.00%	6.24	0.01%
Amphenol Corp	APH	0.12%	0.98	0.00%	10.64	0.01%
Arconic Inc	ARNC	0.04%	0.43	0.00%	14.35	0.01%
Pioneer Natural Resources Co	PXD	0.10%	0.45	0.00%	26.85	0.03%
Valero Energy Corp	VLO	0.14%	4.41	0.01%	19.17	0.03%
Synopsys Inc	SNPS	0.06%	n/a	n/a	14.50	0.01%
L3 Technologies Inc	LLL	0.07%	1.61	0.00%	5.00	0.00%
Western Union Co/The	WU	0.03%	4.48	0.00%	5.00	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.21	0.00%	9.07	0.00%
Accenture PLC	ACN	0.43%	1.81	0.01%	10.27	0.04%
TransDigm Group Inc	TDG	0.10%	n/a	n/a	11.07	0.01%
Yum! Brands Inc	YUM	0.12%	1.78	0.00%	13.12	0.02%
Prologis Inc	PLD	0.18%	3.03	0.01%	6.87	0.01%
FirstEnergy Corp	FE	0.09%	3.73	0.00%	-0.02	0.00%
VeriSign Inc	VRSN	0.09%	n/a	n/a	8.80	0.01%

Name	Ticker	[6] Weight in Index	[7] Estimated Dividend Yield	[8] Cap. Weighted Div. Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth Estimate
Quanta Services Inc	PWR	0.02%	0.45	0.00%	25.00	0.01%
Henry Schein Inc	HSIC	0.04%	n/a	n/a	7.11	0.00%
Ameren Corp	AEE	0.07%	2.67	0.00%	6.70	0.00%
ANSYS Inc	ANSS	0.06%	n/a	n/a	10.37	0.01%
NVIDIA Corp	NVDA	0.39%	0.41	0.00%	7.86	0.03%
Sealed Air Corp	SEE	0.03%	1.47	0.00%	6.04	0.00%
Cognizant Technology Solutions Corp	CTSH	0.17%	1.13	0.00%	11.40	0.02%
SVB Financial Group	SIVB	0.05%	n/a	n/a	11.00	0.01%
Intuitive Surgical Inc	ISRG	0.26%	n/a	n/a	12.62	0.03%
Affiliated Managers Group Inc	AMG	0.02%	1.17	0.00%	4.37	0.00%
Take-Two Interactive Software Inc	TTWO	0.04%	n/a	n/a	10.30	0.00%
Republic Services Inc	RSG	0.10%	1.91	0.00%	13.01	0.01%
eBay Inc	EBAY	0.14%	1.51	0.00%	10.67	0.02%
Goldman Sachs Group Inc/The	GS	0.30%	1.63	0.00%	7.27	0.02%
SBA Communications Corp	SBAC	0.08%	n/a	n/a	27.95	0.02%
Sempra Energy	SRE	0.14%	3.21	0.00%	10.10	0.01%
Moody's Corp	MCO	0.14%	1.16	0.00%	12.80	0.02%
Booking Holdings Inc	BKNG	0.32%	n/a	n/a	12.50	0.04%
F5 Networks Inc	FFIV	0.04%	n/a	n/a	9.39	0.00%
Akamai Technologies Inc	AKAM	0.05%	n/a	n/a	14.50	0.01%
Devon Energy Corp	DVN	0.05%	1.22	0.00%	1.15	0.00%
Alphabet Inc	GOOGL	1.40%	n/a	n/a	15.22	0.21%
Red Hat Inc	RHT	0.13%	n/a	n/a	18.40	0.02%
Teleflex Inc	TFX	0.06%	0.47	0.00%	12.45	0.01%
Allegion PLC	ALLE	0.04%	1.20	0.00%	11.24	0.00%
Netflix Inc	NFLX	0.65%	n/a	n/a	32.07	0.21%
Agilent Technologies Inc	A	0.10%	0.83	0.00%	9.50	0.01%
Anthem Inc	ANTM	0.32%	1.06	0.00%	11.14	0.04%
CME Group Inc	CME	0.27%	1.65	0.00%	13.40	0.04%
Juniper Networks Inc	JNPR	0.04%	2.81	0.00%	8.63	0.00%
BlackRock Inc	BLK	0.29%	2.98	0.01%	9.69	0.03%
DTE Energy Co	DTE	0.09%	3.06	0.00%	5.53	0.01%
Celanese Corp	CE	0.05%	2.11	0.00%	7.05	0.00%
Nasdaq Inc	NDAQ	0.06%	1.92	0.00%	9.11	0.01%
Philip Morris International Inc	PM	0.56%	5.25	0.03%	9.06	0.05%
salesforce.com Inc	CRM	0.52%	n/a	n/a	23.98	0.12%
Huntington Ingalls Industries Inc	HII	0.04%	1.64	0.00%	40.00	0.01%
MetLife Inc	MET	0.18%	3.72	0.01%	8.46	0.02%
Under Armour Inc	UA	0.02%	n/a	n/a	37.34	0.01%
Tapestry Inc	TPR	0.04%	3.86	0.00%	11.75	0.00%
Fluor Corp	FLR	0.02%	2.23	0.00%	17.99	0.00%
CSX Corp	CSX	0.25%	1.32	0.00%	10.47	0.03%
Edwards Lifesciences Corp	EW	0.15%	n/a	n/a	14.00	0.02%
Ameriprise Financial Inc	AMP	0.07%	2.73	0.00%	11.80	0.01%
TechnipFMC PLC	FTI	0.04%	2.33	0.00%	15.43	0.01%
Zimmer Biomet Holdings Inc	ZBH	0.11%	0.77	0.00%	4.74	0.00%
CBRE Group Inc	CBRE	0.07%	n/a	n/a	8.55	0.01%
Mastercard Inc	MA	0.94%	0.59	0.01%	19.66	0.19%
CarMax Inc	KMX	0.04%	n/a	n/a	12.92	0.01%
Intercontinental Exchange Inc	ICE	0.18%	1.43	0.00%	8.02	0.01%
Fidelity National Information Services Inc	FIS	0.14%	1.29	0.00%	12.00	0.02%
Chipotle Mexican Grill Inc	CMG	0.07%	n/a	n/a	20.31	0.01%
Wynn Resorts Ltd	WYNN	0.06%	2.37	0.00%	31.10	0.02%
Assurant Inc	AIZ	0.03%	2.33	0.00%	n/a	n/a
NRG Energy Inc	NRG	0.05%	0.29	0.00%	46.03	0.02%

Name	Ticker	[6] Weight in Index	[7] Estimated Dividend Yield	[8] Cap. Weighted Div. Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth Estimate
Monster Beverage Corp	MNST	0.14%	n/a	n/a	15.00	0.02%
Regions Financial Corp	RF	0.07%	3.41	0.00%	10.88	0.01%
Mosaic Co/The	MOS	0.05%	0.32	0.00%	8.40	0.00%
Expedia Group Inc	EXPE	0.07%	1.04	0.00%	17.20	0.01%
Evergy Inc	EVRG	0.06%	3.40	0.00%	7.43	0.00%
Discovery Inc	DISCA	0.02%	n/a	n/a	12.30	0.00%
CF Industries Holdings Inc	CF	0.04%	2.84	0.00%	19.75	0.01%
Viacom Inc	VIAB	0.04%	2.74	0.00%	4.93	0.00%
Alphabet Inc	GOOG	1.62%	n/a	n/a	15.22	0.25%
TE Connectivity Ltd	TEL	0.12%	2.14	0.00%	11.18	0.01%
Cooper Cos Inc/The	COO	0.06%	0.02	0.00%	4.70	0.00%
Discover Financial Services	DFS	0.10%	2.23	0.00%	8.80	0.01%
TripAdvisor Inc	TRIP	0.03%	n/a	n/a	11.39	0.00%
Visa Inc	V	1.07%	0.68	0.01%	15.59	0.17%
Mid-America Apartment Communities Inc	MAA	0.05%	3.71	0.00%	7.00	0.00%
Xylem Inc/NY	XYL	0.06%	1.27	0.00%	14.00	0.01%
Marathon Petroleum Corp	MPC	0.17%	3.42	0.01%	16.14	0.03%
Advanced Micro Devices Inc	AMD	0.10%	n/a	n/a	15.67	0.02%
Tractor Supply Co	TSCO	0.05%	1.30	0.00%	12.09	0.01%
ResMed Inc	RMD	0.06%	1.44	0.00%	12.50	0.01%
Mettler-Toledo International Inc	MTD	0.07%	n/a	n/a	12.66	0.01%
Copart Inc	CPRT	0.06%	n/a	n/a	20.00	0.01%
Fortinet Inc	FTNT	0.06%	n/a	n/a	22.10	0.01%
Albemarle Corp	ALB	0.04%	1.61	0.00%	11.41	0.00%
Essex Property Trust Inc	ESS	0.08%	2.79	0.00%	6.06	0.00%
Realty Income Corp	O	0.09%	3.91	0.00%	4.39	0.00%
Seagate Technology PLC	STX	0.05%	5.41	0.00%	3.37	0.00%
Westrock Co	WRK	0.04%	4.87	0.00%	4.73	0.00%
IHS Markit Ltd	INFO	0.09%	n/a	n/a	11.21	0.01%
Wabtec Corp	WAB	0.03%	0.66	0.00%	14.00	0.00%
Western Digital Corp	WDC	0.06%	3.98	0.00%	2.72	0.00%
PepsiCo Inc	PEP	0.67%	3.21	0.02%	5.48	0.04%
Diamondback Energy Inc	FANG	0.07%	0.49	0.00%	17.55	0.01%
Nektar Therapeutics	NKTR	0.03%	n/a	n/a	n/a	n/a
Maxim Integrated Products Inc	MXIM	0.06%	3.38	0.00%	8.93	0.01%
Church & Dwight Co Inc	CHD	0.07%	1.38	0.00%	8.21	0.01%
Duke Realty Corp	DRE	0.04%	2.91	0.00%	4.50	0.00%
Federal Realty Investment Trust	FRT	0.04%	3.05	0.00%	6.15	0.00%
MGM Resorts International	MGM	0.06%	1.94	0.00%	3.32	0.00%
Twenty-First Century Fox Inc	FOX	0.17%	0.72	0.00%	2.66	0.00%
JB Hunt Transport Services Inc	JBHT	0.05%	0.97	0.00%	18.78	0.01%
Lam Research Corp	LRCX	0.11%	2.50	0.00%	-0.42	0.00%
Mohawk Industries Inc	MHK	0.04%	n/a	n/a	7.59	0.00%
Pentair PLC	PNR	0.03%	1.69	0.00%	10.29	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.20%	n/a	n/a	49.41	0.10%
Facebook Inc	FB	1.59%	n/a	n/a	21.88	0.35%
United Rentals Inc	URI	0.04%	n/a	n/a	17.76	0.01%
Alexandria Real Estate Equities Inc	ARE	0.06%	2.86	0.00%	4.80	0.00%
ABIOMED Inc	ABMD	0.06%	n/a	n/a	29.00	0.02%
Delta Air Lines Inc	DAL	0.14%	2.82	0.00%	13.07	0.02%
United Continental Holdings Inc	UAL	0.10%	n/a	n/a	14.17	0.01%
News Corp	NWS	0.01%	1.50	0.00%	-9.13	0.00%
Centene Corp	CNC	0.10%	n/a	n/a	13.68	0.01%
Macerich Co/The	MAC	0.03%	6.88	0.00%	-0.12	0.00%
Martin Marietta Materials Inc	MLM	0.05%	1.02	0.00%	13.29	0.01%

Name	Ticker	[6] Weight in Index	[7] Estimated Dividend Yield	[8] Cap. Weighted Div. Yield	[9] Long-Term Growth Estimate	[10] Cap. Weighted Long-Term Growth Estimate
PayPal Holdings Inc	PYPL	0.48%	n/a	n/a	22.12	0.11%
Coty Inc	COTY	0.03%	4.55	0.00%	8.76	0.00%
DISH Network Corp	DISH	0.03%	n/a	n/a	-20.68	-0.01%
Alexion Pharmaceuticals Inc	ALXN	0.13%	n/a	n/a	15.94	0.02%
Everest Re Group Ltd	RE	0.04%	2.48	0.00%	10.00	0.00%
WellCare Health Plans Inc	WCG	0.05%	n/a	n/a	17.08	0.01%
News Corp	NWSA	0.02%	1.54	0.00%	-9.13	0.00%
Global Payments Inc	GPN	0.09%	0.03	0.00%	14.67	0.01%
Crown Castle International Corp	CCI	0.20%	3.79	0.01%	15.50	0.03%
Aptiv PLC	APTV	0.09%	1.06	0.00%	10.66	0.01%
Advance Auto Parts Inc	AAP	0.05%	0.15	0.00%	16.17	0.01%
Capri Holdings Ltd	CPRI	0.03%	n/a	n/a	6.73	0.00%
Align Technology Inc	ALGN	0.09%	n/a	n/a	23.19	0.02%
Illumina Inc	ILMN	0.19%	n/a	n/a	25.16	0.05%
Alliance Data Systems Corp	ADS	0.04%	1.46	0.00%	2.54	0.00%
LKQ Corp	LKQ	0.04%	n/a	n/a	13.85	0.01%
Nielsen Holdings PLC	NLSN	0.04%	5.34	0.00%	n/a	n/a
Garmin Ltd	GRMN	0.07%	2.72	0.00%	7.28	0.00%
Cimarex Energy Co	XEC	0.03%	1.11	0.00%	66.37	0.02%
Zoetis Inc	ZTS	0.19%	0.70	0.00%	15.36	0.03%
Digital Realty Trust Inc	DLR	0.10%	3.82	0.00%	18.00	0.02%
Equinix Inc	EQIX	0.15%	2.32	0.00%	20.00	0.03%
Discovery Inc	DISCK	0.04%	n/a	n/a	12.30	0.00%

Notes:
[1] Equals sum of Col. [7]
[2] Equals sum of Col. [10]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Exhibit KWO-4
[5] Equals [3] – [4]
[6] Equals weight in S&P 500 based on market capitalization
[7] Source: Bloomberg Professional, as of February 28, 2019
[8] Equals [6] x [7]
[9] Source: Bloomberg Professional, as of February 28, 2019
[10] Equals [6] x [9]

PSEG
Energy Strong II
CAPM Results

Combination Utility Group

	[1] Risk Free Rate	[2] Beta	[3] Est. Market Required Return	[4] Equity Risk Premium	[5] Equity Cost Rate
Treasury - Maximum	3.46%	0.591	13.77%	10.31%	9.55%
Treasury - Average	3.12%	0.591	13.77%	10.65%	9.41%
Treasury - Minimum	2.92%	0.591	13.77%	10.85%	9.33%
				Mean	9.43%

Public Service Enterprise Group

	Risk Free Rate	Beta	Est. Market Required Return	Equity Risk Premium	Equity Cost Rate
Treasury - Maximum	3.46%	0.65	13.77%	10.31%	10.16%
Treasury - Average	3.12%	0.65	13.77%	10.65%	10.04%
Treasury - Minimum	2.92%	0.65	13.77%	10.85%	9.97%
				Mean	10.06%

[1] Exhibit KWO-4
[2] Exhibit KWO-4
[3] Exhibit AEB-5
[4] Column [3] minus Column [1]
[5] Column [1] plus column [2] multiplied by column [4]

Value Line Beta

Alliant Energy	LNT	0.6
Ameren	AEE	0.55
Avista	AVA	0.65
Black Hills	BKH	0.75
CMS Energy	CMS	0.55
Consolidated Edison	ED	0.45
Dominion Resources	D	0.55
DTE Energy	DTE	0.55
Duke Energy	DUK	0.5
Entergy Corp	ETR	0.6
Exelon Corp.	EXC	0.7
Fortis	FTS	0.65
MGE Energy	MGEE	0.6
Sempra Energy	SRE	0.75
Southern	SO	0.5
Xcel	XEL	0.5
Average		0.591
PSEG	PEG	0.65

PSEG
Energy Strong II
CAPM Results

Combination Utility Group

	[1] Risk Free Rate	[2] Beta	[3] Est. Market Required Return	[4] Equity Risk Premium	[5] Equity Cost Rate
Treasury - KWO-4	3.46%	0.591	13.77%	10.31%	9.55%
Treasury - KWO-4	3.12%	0.591	13.77%	10.65%	9.41%
Treasury - KWO-4	2.92%	0.591	13.77%	10.85%	9.33%
				Mean	9.43%

Public Service Enterprise Group

	Risk Free Rate	Beta	Est. Market Required Return	Equity Risk Premium	Equity Cost Rate
Treasury - KWO-4	3.46%	0.59	13.77%	10.31%	9.55%
Treasury - KWO-4	3.12%	0.59	13.77%	10.65%	9.41%
Treasury - KWO-4	2.92%	0.59	13.77%	10.85%	9.33%
				Mean	9.43%

Combination Utility Group

	[1] Risk Free Rate	[2] Beta	[3] Est. Market Required Return	[4] Equity Risk Premium	[5] Equity Cost Rate
Treasury - Average	3.12%	0.591	13.77%	10.65%	9.41%
Treasury - Projection (2019-2020)	3.28%	0.591	13.77%	10.49%	9.47%
Treasury - Projection (2020-2024)	3.90%	0.591	13.77%	9.87%	9.73%
				Mean	9.54%

Public Service Enterprise Group

	Risk Free Rate	Beta	Est. Market Required Return	Equity Risk Premium	Equity Cost Rate
Treasury - Maximum	3.12%	0.65	13.77%	10.65%	10.04%
Treasury - Projection (2019-2020)	3.28%	0.65	13.77%	10.49%	10.10%
Treasury - Projection (2020-2024)	3.90%	0.65	13.77%	9.87%	10.31%
				Mean	10.15%

[1] Exhibit KWO-4 and Blue Chip Financial Forecast
[2] Schedule KWO-4
[3] Exhibit AEB-5
[4] Column [3] minus Column [1]
[5] Column [1] plus column [2] multiplied by column [4]

COMPARISON OF PSEG AND PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

						Decoupling		New Capital	
Proxy Group Company	Operation State	Operation		Test Year	Rate Base	Full	Partial	Generation Capacity	Generic Infrastructure
Alliant Energy Corporation	Iowa	Electric	1	Historical	Average				
	Iowa	Gas	1	Historical	Average				
	Wisconsin	Electric	1	Fully Forecast	Average				
	Wisconsin	Gas	1	Fully Forecast	Average				
Ameren Corporation	Illinois	Electric	1	Historical	Year End				
	Illinois	Gas	1	Fully Forecast	Average	x			x
	Missouri	Electric	1	Historical	Year End		x		x
	Missouri	Gas	1	Historical	Year End				x
Avista	Alaska	Electric	1	Historical	Average				
	Idaho	Electric	1	Historical	Average	x			
	Idaho	Gas	1	Historical	Average	x			
	Oregon	Gas	1	Fully Forecast	Average	x			
	Washington	Electric	1	Historical	Average		x		
	Washington	Gas	1	Historical	Average		x		
Black Hills Corporation	Arkansas	Gas	1	Partially Forecast	Year End	x			x
	Colorado	Electric	1	Historical	Average			x	x
	Colorado	Gas	1	Historical	Average				
	Iowa	Gas	1	Historical	Average				x
	Kansas	Gas	1	Historical	Year End		x		x
	Nebraska	Gas	1	Fully Forecast	Year End				x
	South Dakota	Electric	1	Historical	Average		x		
	Wyoming	Electric	1	Historical	Year End		x		
	Wyoming	Gas	1	Historical	Year End		x		
CMS Energy Corporation	Michigan	Electric	1	Fully Forecast	Average				
	Michigan	Gas	1	Fully Forecast	Average		x		x
Consolidated Edison, Inc.	New York	Electric	1	Fully Forecast	Average	x			
	New York	Gas	1	Fully Forecast	Average	x			x
	New Jersey	Electric	1	Partially Forecast	Year End				x
Dominion	North Carolina	Electric	1	Historical	Year End				
	Ohio	Gas	1	Partially Forecast	Year End				x
	Utah	Gas	1	Fully Forecast	Average	x			x
	Virginia	Electric	1	Fully Forecast	Year End			x	x
	West Virginia	Gas	1	Historical	Average				x
DTE Energy Company	Michigan	Electric	1	Fully Forecast	Average				
	Michigan	Gas	1	Fully Forecast	Average		x		x
Duke Energy	Florida	Electric	1	Fully Forecast	Average			x	
	Indiana	Electric	1	Historical	Year End		x	x	x
	Kentucky	Electric	1	Historical	Year End		x		
	Kentucky	Gas	1	Historical	Year End		x		x
	North Carolina	Electric	1	Historical	Year End				
	North Carolina	Gas	1	Historical	Year End	x			x
	Ohio	Electric	1	Partially Forecast	Year End		x		x

COMPARISON OF PSEG AND PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

						Decoupling		New Capital	
Proxy Group Company	Operation State	Operation		Test Year	Rate Base	Full	Partial	Generation Capacity	Generic Infrastructure
	Ohio	Gas	1	Partially Forecast	Year End				x
	South Carolina	Electric	1	Historical	N/A				
	South Carolina	Gas	1	Historical	N/A		x		
	Tennessee	Gas	1	Fully Forecast	Average		x		x
Entergy	Arkansas	Electric	1	Fully Forecast	Year End		x	x	x
	Louisiana NOCC	Electric	1	Partially Forecast	Average		x	x	
	Louisiana NOCC	Gas	1	Partially Forecast	Average				
	Louisiana PSC	Electric	1	Historical	Average		x	x	x
	Louisiana PSC	Gas	1	Historical	Average		x		x
	Mississippi	Electric	1	Partially Forecast	Average		x		
	Texas PUC	Electric	1	Historical	Year End				x
Exelon	Delaware	Electric	1	Historical	Average				
	Delaware	Gas	1	Historical	Average				
	District of Columbia	Electric	1	Partially Forecast	Average		x		x
	Illinois	Electric	1	Historical	Year End				x
	Maryland	Electric	1	Historical	Average		x		x
	Maryland	Gas	1	Historical	Average		x		x
	New Jersey	Electric	1	Partially Forecast	Year End				x
	Pennsylvania	Electric	1	Fully Forecast	Year End				x
	Pennsylvania	Gas	1	Fully Forecast	Year End				x
Fortis	Arizona	Electric	1	Historical	Year End		x		
	Arizona	Gas	1	Historical	Year End		x		
	New York	Electric	1	Fully Forecast	Average	x			
	New York	Gas	1	Fully Forecast	Average	x			x
MGE Energy	Wisconsin	Electric	1	Fully Forecast	Average				
	Wisconsin	Gas	1	Fully Forecast	Average				
Sempra Energy	California	Electric	1	Fully Forecast	Average	x			
	California	Gas	1	Fully Forecast	Average	x			
	Texas PUC	Electric	1	Historical	Year End				x
Southern	Alabama	Electric	1	Historical	Average			x	
	Florida	Electric	1	Fully Forecast	Average			x	
	Florida	Gas	1	Fully Forecast	Average				x
	Georgia	Electric	1	Partially Forecast	Average				x
	Georgia	Gas	1	Partially Forecast	Average			x	
	Illinois	Gas	1	Historical	Year End				x
	Mississippi	Electric	1	Partially Forecast	Average		x		
	Tennessee	Gas	1	Fully Forecast	Average	x			
	Virginia	Gas	1	Fully Forecast	Year End		x		x
Xcel Energy Inc.	Colorado	Electric	1	Historical	Average			x	x
	Colorado	Gas	1	Historical	Average		x		x
	Minnesota	Electric	1	Partially Forecast	Average		x		
	Minnesota	Gas	1	Partially Forecast	Average				x
	New Mexico	Electric	1	Historical	Year End				
	North Dakota	Electric	1	Fully Forecast	Average				x
	North Dakota	Gas	1	Fully Forecast	Average				
	South Dakota	Electric	1	Historical	Average		x	x	x
	Texas (PUC)	Electric	1	Historical	Year End				x
	Wisconsin	Electric	1	Fully Forecast	Average				
	Wisconsin	Gas	1	Fully Forecast	Average				
Proxy Companies				Historical: 44 Forecast: 47	Average: 57 Year End: 32	14	30	12	45
Total Jurisdictions	91								
Percent of Jurisdictions				Forecast: 52%	Year End: 35%	15.4%	33.0%	13.2%	49.5%
Public Service Enterprise Group	New Jersey			Partially Forecast	Year End		x		x

Notes:
[1] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 28, 2018. Operating subsidiaries not covered in this report were excluded from this exhibit.
[2] This exhibit includes the adjustment mechanisms for the electric and gas distribution companies.

CAPITAL STRUCTURE ANALYSIS

		COMMON EQUITY RATIO [1]								
Electric Proxy Group Company	Ticker	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
Alliant Energy Corporation	LNT	49.88%	49.85%	48.68%	48.74%	50.81%	49.94%	49.51%	49.41%	49.60%
Ameren Corporation	AEE	52.72%	51.43%	52.38%	52.02%	52.80%	52.35%	52.01%	51.93%	52.20%
Avista Corporation	AVA	50.21%	50.37%	51.71%	51.28%	50.47%	52.00%	51.96%	51.40%	51.17%
Black Hills Corporation	BKH	53.22%	53.92%	53.86%	54.49%	55.34%	53.96%	53.19%	52.72%	53.84%
CMS Energy Corporation	CMS	52.86%	52.71%	52.97%	52.10%	53.09%	52.81%	51.93%	51.07%	52.44%
Consolidated Edison, Inc.	ED	48.85%	47.42%	49.27%	48.83%	50.02%	49.16%	50.18%	49.83%	49.20%
DTE Energy Company	DTE	49.97%	49.23%	51.12%	51.02%	50.50%	50.63%	50.50%	50.50%	50.43%
Duke Energy Corporation	DUK	52.85%	53.04%	52.88%	53.01%	53.02%	53.20%	52.92%	53.10%	53.00%
Entergy Corporation	ETR	48.44%	48.14%	46.14%	47.56%	48.05%	47.10%	48.21%	47.84%	47.68%
Exelon Corporation	EXC	53.02%	53.78%	53.56%	53.38%	53.04%	53.56%	53.48%	52.99%	53.35%
Fortis Inc.	FTS	54.34%	53.71%	53.25%	52.80%	52.81%	52.62%	51.91%	51.51%	52.87%
MGE Energy, Inc.	MGEE	57.36%	60.66%	60.20%	59.73%	60.49%	60.07%	60.02%	60.66%	59.90%
Sempra Energy	SRE	58.18%	60.06%	59.11%	57.84%	57.46%	57.73%	58.12%	57.63%	58.27%
Southern Company	SO	52.81%	51.20%	51.11%	48.17%	48.70%	49.24%	48.91%	49.35%	49.94%
Xcel Energy Inc.	XEL	54.29%	53.51%	54.40%	54.23%	53.76%	54.01%	54.75%	54.22%	54.15%
MEAN		52.60%	52.60%	52.71%	52.35%	52.69%	52.56%	52.51%	52.28%	52.54%
LOW		48.44%	47.42%	46.14%	47.56%	48.05%	47.10%	48.21%	47.84%	47.68%
HIGH		58.18%	60.66%	60.20%	59.73%	60.49%	60.07%	60.02%	60.66%	59.90%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
Interstate Power and Light Company	LNT	47.96%	48.62%	48.01%	48.37%	49.68%	48.78%	48.08%	48.09%	48.45%
Wisconsin Power and Light Company	LNT	52.62%	51.52%	49.57%	49.23%	52.39%	51.56%	51.45%	51.22%	51.19%
Ameren Illinois Company	AEE	52.69%	52.25%	53.71%	52.84%	54.40%	53.96%	53.50%	52.85%	53.28%
Union Electric Company	AEE	52.73%	50.77%	51.30%	51.38%	51.61%	51.14%	50.92%	51.27%	51.39%
Avista Corporation	AVA	49.55%	49.74%	51.16%	50.75%	49.89%	51.50%	51.48%	50.93%	50.62%
Alaska Electric Light and Power Company	AVA	61.94%	61.78%	61.53%	60.77%	60.67%	60.58%	60.23%	59.65%	60.89%
Black Hills Colorado Electric, Inc.	BKH	53.04%	54.85%	54.68%	55.69%	54.96%	55.01%	53.08%	52.20%	54.19%
Black Hills Power, Inc.	BKH	53.51%	53.30%	53.22%	53.49%	56.14%	53.26%	53.24%	52.88%	53.63%
Cheyenne Light, Fuel and Power Company	BKH	53.04%	53.32%	53.46%	54.01%	53.16%	53.27%	53.29%	53.35%	53.36%
Consumers Energy Company	BKH	52.86%	52.71%	52.97%	52.10%	53.09%	52.81%	51.93%	51.07%	52.44%
Consolidated Edison Company of New York, Inc.	CNP	48.33%	46.72%	48.66%	48.22%	49.47%	48.58%	49.65%	49.31%	48.62%
Orange and Rockland Utilities, Inc.	CMS	48.44%	50.74%	50.83%	50.25%	50.27%	49.81%	50.00%	49.46%	49.98%
Rockland Electric Company	ED	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
DTE Electric Company	ED	49.97%	49.23%	51.12%	51.02%	50.50%	50.63%	50.50%	50.50%	50.43%
Duke Energy Carolinas, LLC	DTE	52.64%	52.10%	51.70%	52.98%	53.98%	53.49%	53.32%	52.81%	52.88%
Duke Energy Indiana, LLC	DUK	52.79%	52.64%	52.54%	51.94%	51.71%	51.89%	52.15%	51.59%	52.16%
Duke Energy Kentucky, Inc.	DUK	56.58%	55.79%	53.72%	53.11%	50.69%	55.74%	55.43%	54.74%	54.48%
Duke Energy Ohio, Inc.	DUK	67.73%	67.10%	66.06%	66.24%	65.79%	65.38%	65.36%	66.39%	66.25%
Duke Energy Progress, LLC	DUK	50.76%	53.22%	52.82%	52.27%	51.06%	53.61%	52.99%	51.58%	52.28%
Entergy Arkansas, LLC	DUK	49.13%	48.03%	45.60%	45.67%	45.42%	44.45%	46.05%	45.90%	46.28%
Entergy Louisiana, LLC	DUK	46.77%	46.97%	44.58%	47.43%	47.83%	46.77%	48.38%	47.87%	47.07%
Entergy Mississippi, LLC	ETR	49.70%	48.71%	47.93%	47.45%	50.45%	49.68%	49.05%	48.67%	48.95%
Entergy New Orleans, LLC	ETR	50.93%	54.02%	53.43%	53.16%	52.82%	52.46%	52.30%	52.39%	52.69%
Entergy Texas, Inc.	ETR	52.61%	51.38%	50.79%	50.45%	51.18%	50.30%	49.82%	49.56%	50.76%
Atlantic City Electric Company	ETR	50.38%	49.46%	49.14%	49.19%	49.37%	49.11%	49.06%	48.37%	49.26%
Baltimore Gas and Electric Company	ETR	52.85%	55.34%	55.36%	54.77%	53.70%	53.33%	53.37%	52.54%	53.91%
Commonwealth Edison Company	EXC	54.72%	55.36%	54.96%	54.85%	54.60%	55.22%	54.90%	54.52%	54.89%
Delmarva Power & Light Company	EXC	50.11%	49.86%	50.35%	50.38%	50.18%	50.13%	50.22%	49.43%	50.08%
PECO Energy Company	EXC	52.82%	54.28%	53.77%	53.54%	53.30%	55.64%	55.53%	55.13%	54.25%
Potomac Electric Power Company	EXC	50.24%	50.08%	49.94%	49.89%	49.71%	49.60%	49.86%	49.57%	49.86%
Central Hudson Gas & Electric Corporation	EXC	51.91%	51.26%	51.82%	51.15%	50.42%	51.22%	51.14%	50.58%	51.18%
CH Energy Group, Inc.	EXC	51.91%	51.26%	51.82%	51.15%	50.42%	51.22%	51.14%	50.58%	51.18%
ITC Interconnection LLC	FTS	59.62%	59.34%	60.37%	60.60%	61.79%	62.45%	59.82%	58.06%	60.26%
Tucson Electric Power Company	FTS	55.16%	54.39%	53.56%	53.20%	53.56%	52.86%	51.91%	51.58%	53.28%
UNS Electric, Inc.	FTS	55.47%	55.89%	55.20%	54.59%	53.99%	54.77%	54.09%	53.62%	54.70%
UNS Energy Corporation	FTS	55.20%	54.56%	53.74%	53.36%	53.61%	53.08%	52.16%	51.81%	53.44%
Madison Gas and Electric Company	FTS	57.36%	60.66%	60.20%	59.73%	60.49%	60.07%	60.02%	60.66%	59.90%
Energy Future Holdings Corp	MGEE	59.29%	62.31%	60.34%	58.86%	58.56%	58.49%	58.41%	58.04%	59.29%
Oncor Electric Delivery Company LLC	PCG	59.29%	62.31%	60.34%	58.86%	58.56%	58.49%	58.41%	58.04%	59.29%
San Diego Gas & Electric Company	PPL	55.17%	54.47%	55.92%	55.09%	54.51%	55.75%	57.35%	56.52%	55.60%
Alabama Power Company	PPL	47.24%	46.62%	47.91%	46.12%	46.20%	46.32%	46.07%	46.00%	46.56%
Georgia Power Company	PPL	57.27%	54.97%	53.81%	50.06%	49.78%	50.94%	49.77%	51.01%	52.20%
Gulf Power Company	SO	55.34%	54.90%	54.27%	54.19%	54.97%	54.41%	55.63%	52.94%	54.58%
Mississippi Power Company	SO	44.81%	43.41%	42.54%	38.96%	46.93%	46.37%	49.22%	49.34%	45.20%
Northern States Power Company - MN	SO	52.64%	52.61%	52.59%	52.38%	52.22%	52.78%	52.62%	52.31%	52.52%
Northern States Power Company - WI	SO	48.45%	53.85%	53.79%	53.36%	55.57%	55.22%	55.66%	54.93%	53.85%
Public Service Company of Colorado	WC	56.08%	54.17%	56.67%	56.50%	55.64%	54.88%	57.00%	56.32%	55.91%
Southwestern Public Service Company	XEL	56.29%	53.88%	53.54%	53.55%	52.29%	54.61%	54.48%	53.93%	54.07%

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Electric Proxy Group Company	Ticker	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
Alliant Energy Corporation	LNT	48.13%	48.04%	49.13%	49.06%	46.81%	47.64%	48.02%	48.12%	48.12%
Ameren Corporation	AEE	46.33%	47.61%	46.61%	46.95%	46.16%	46.60%	46.93%	47.01%	46.77%
Avista Corporation	AVA	49.79%	49.63%	48.29%	48.72%	49.53%	48.00%	48.04%	48.60%	48.83%
Black Hills Corporation	BKH	46.78%	46.08%	46.14%	45.51%	44.66%	46.04%	46.81%	47.28%	46.16%
CMS Energy Corporation	CMS	46.85%	47.01%	46.73%	47.60%	46.60%	46.88%	47.75%	48.61%	47.25%
Consolidated Edison, Inc.	ED	51.15%	52.58%	50.73%	51.17%	49.98%	50.84%	49.82%	50.17%	50.80%
DTE Energy Company	DTE	50.03%	50.77%	48.88%	48.98%	49.50%	49.37%	49.50%	49.50%	49.57%
Duke Energy Corporation	DUK	47.15%	46.96%	47.12%	46.99%	46.98%	46.80%	47.08%	46.90%	47.00%
Entergy Corporation	ETR	51.35%	51.64%	53.63%	52.21%	51.62%	52.57%	51.45%	51.81%	52.04%
Exelon Corporation	EXC	46.98%	46.22%	46.44%	46.62%	46.96%	46.44%	46.52%	47.01%	46.65%
Fortis Inc.	FTS	45.66%	46.29%	46.75%	47.20%	47.19%	47.38%	48.09%	48.49%	47.13%
MGE Energy, Inc.	MGEE	42.64%	39.34%	39.80%	40.27%	39.51%	39.93%	39.98%	39.34%	40.10%
Sempra Energy	SRE	41.82%	39.94%	40.89%	42.16%	42.54%	42.27%	41.88%	42.37%	41.73%
Southern Company	SO	46.48%	48.06%	48.17%	51.10%	49.47%	49.43%	49.50%	48.99%	48.90%
Xcel Energy Inc.	XEL	45.71%	46.49%	45.60%	45.77%	46.24%	45.99%	45.25%	45.78%	45.85%
MEAN		47.12%	47.11%	46.99%	47.35%	46.92%	47.08%	47.11%	47.33%	47.13%
LOW		41.82%	39.34%	39.80%	40.27%	39.51%	39.93%	39.98%	39.34%	40.10%
HIGH		51.35%	52.58%	53.63%	52.21%	51.62%	52.57%	51.45%	51.81%	52.04%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
Interstate Power and Light Company	LNT	48.66%	47.72%	48.17%	47.78%	46.24%	47.07%	47.64%	47.64%	47.62%
Wisconsin Power and Light Company	LNT	47.38%	48.48%	50.43%	50.77%	47.61%	48.44%	48.55%	48.78%	48.81%
Ameren Illinois Company	AEE	46.39%	46.83%	45.31%	46.15%	44.54%	44.97%	45.41%	46.05%	45.71%
Union Electric Company	AEE	46.27%	48.24%	47.66%	47.58%	47.36%	47.81%	48.04%	47.70%	47.58%
Avista Corporation	AVA	50.45%	50.26%	48.84%	49.25%	50.11%	48.50%	48.52%	49.07%	49.38%
Alaska Electric Light and Power Company	AVA	38.06%	38.22%	38.47%	39.23%	39.33%	39.42%	39.77%	40.35%	39.11%
Black Hills Colorado Electric, Inc.	BKH	46.96%	45.15%	45.32%	44.31%	45.04%	44.99%	46.92%	47.80%	45.81%
Black Hills Power, Inc.	BKH	46.49%	46.70%	46.78%	46.51%	43.86%	46.74%	46.76%	47.12%	46.37%
Cheyenne Light, Fuel and Power Company	BKH	46.96%	46.68%	46.54%	45.99%	46.84%	46.73%	46.71%	46.65%	46.64%
Consumers Energy Company	BKH	46.85%	47.01%	46.73%	47.60%	46.60%	46.88%	47.75%	48.61%	47.25%
Consolidated Edison Company of New York, Inc.	CNP	51.67%	53.28%	51.34%	51.78%	50.53%	51.42%	50.35%	50.69%	51.38%
Orange and Rockland Utilities, Inc.	CMS	51.56%	49.26%	49.17%	49.75%	49.73%	50.19%	50.00%	50.54%	50.02%
Rockland Electric Company	ED	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Electric Company	ED	50.03%	50.77%	48.88%	48.98%	49.50%	49.37%	49.50%	49.50%	49.57%
Duke Energy Carolinas, LLC	DTE	47.36%	47.90%	48.30%	47.02%	46.02%	46.51%	46.68%	47.19%	47.12%
Duke Energy Indiana, LLC	DUK	47.21%	47.36%	47.46%	48.06%	48.29%	48.11%	47.85%	48.41%	47.84%
Duke Energy Kentucky, Inc.	DUK	43.42%	44.21%	46.28%	46.89%	49.31%	44.26%	44.57%	45.26%	45.52%
Duke Energy Ohio, Inc.	DUK	32.27%	32.90%	33.94%	33.76%	34.21%	34.62%	34.64%	33.61%	33.75%
Duke Energy Progress, LLC	DUK	49.24%	46.78%	47.18%	47.73%	48.94%	46.49%	47.01%	48.42%	47.72%
Entergy Arkansas, LLC	DUK	50.35%	51.44%	53.80%	53.73%	53.99%	54.95%	53.31%	53.46%	53.13%
Entergy Louisiana, LLC	DUK	53.23%	53.03%	55.42%	52.57%	52.17%	53.23%	51.62%	52.13%	52.93%
Entergy Mississippi, LLC	ETR	49.51%	50.49%	51.26%	51.72%	48.68%	49.44%	50.05%	50.42%	50.20%
Entergy New Orleans, LLC	ETR	49.07%	45.98%	46.57%	46.84%	44.77%	45.12%	45.27%	45.19%	46.10%
Entergy Texas, Inc.	ETR	47.39%	48.62%	49.21%	49.55%	48.82%	49.70%	50.18%	50.44%	49.24%
Atlantic City Electric Company	ETR	49.62%	50.54%	50.86%	50.81%	50.63%	50.89%	50.94%	51.63%	50.74%
Baltimore Gas and Electric Company	ETR	47.15%	44.66%	44.64%	45.23%	46.30%	46.67%	46.63%	47.46%	46.09%
Commonwealth Edison Company	EXC	45.28%	44.64%	45.04%	45.15%	45.40%	44.78%	45.10%	45.48%	45.11%
Delmarva Power & Light Company	EXC	49.89%	50.14%	49.65%	49.62%	49.82%	49.87%	49.78%	50.57%	49.92%
PECO Energy Company	EXC	47.18%	45.72%	46.23%	46.46%	46.70%	44.36%	44.47%	44.87%	45.75%
Potomac Electric Power Company	EXC	49.76%	49.92%	50.06%	50.11%	50.29%	50.40%	50.14%	50.43%	50.14%
Central Hudson Gas & Electric Corporation	EXC	48.09%	48.74%	48.18%	48.85%	49.58%	48.78%	48.86%	49.42%	48.82%
CH Energy Group, Inc.	EXC	48.09%	48.74%	48.18%	48.85%	49.58%	48.78%	48.86%	49.42%	48.82%
ITC Interconnection LLC	FTS	40.38%	40.66%	39.63%	39.40%	38.21%	37.55%	40.18%	41.94%	39.74%
Tucson Electric Power Company	FTS	44.84%	45.61%	46.44%	46.80%	46.44%	47.14%	48.09%	48.42%	46.72%
UNS Electric, Inc.	FTS	44.53%	44.11%	44.80%	45.41%	46.01%	45.23%	45.91%	46.38%	45.30%
UNS Energy Corporation	FTS	44.80%	45.44%	46.26%	46.64%	46.39%	46.92%	47.84%	48.19%	46.56%
Madison Gas and Electric Company	FTS	42.64%	39.34%	39.80%	40.27%	39.51%	39.93%	39.98%	39.34%	40.10%
Energy Future Holdings Corp	MGEE	40.71%	37.69%	39.66%	41.14%	41.44%	41.51%	41.59%	41.96%	40.71%
Oncor Electric Delivery Company LLC	PCG	40.71%	37.69%	39.66%	41.14%	41.44%	41.51%	41.59%	41.96%	40.71%
San Diego Gas & Electric Company	PPL	44.83%	45.53%	44.08%	44.91%	45.49%	44.25%	42.65%	43.48%	44.40%
Alabama Power Company	PPL	50.91%	51.50%	50.15%	51.86%	50.19%	51.71%	51.95%	51.93%	51.27%
Georgia Power Company	PPL	42.73%	45.03%	46.19%	49.94%	49.10%	47.88%	49.07%	47.78%	47.22%
Gulf Power Company	SO	44.66%	45.10%	45.73%	45.81%	45.03%	45.59%	38.99%	41.32%	44.03%
Mississippi Power Company	SO	54.16%	55.55%	56.40%	60.08%	52.25%	52.80%	50.22%	50.10%	53.94%
Northern States Power Company - MN	SO	47.36%	47.39%	47.41%	47.62%	47.78%	47.22%	47.38%	47.69%	47.48%
Northern States Power Company - WI	SO	51.55%	46.15%	46.21%	46.64%	44.43%	44.78%	44.34%	45.07%	46.15%
Public Service Company of Colorado	WC	43.92%	45.83%	43.33%	43.50%	44.36%	45.12%	43.00%	43.68%	44.09%
Southwestern Public Service Company	XEL	43.71%	46.12%	46.46%	46.45%	47.71%	45.39%	45.52%	46.07%	45.93%

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

PREFERRED RATIO [1]

Electric Proxy Group Company	Ticker	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
Alliant Energy Corporation	LNT	1.99%	2.11%	2.19%	2.21%	2.38%	2.42%	2.47%	2.47%	2.28%
Ameren Corporation	AEE	0.96%	0.96%	1.01%	1.02%	1.04%	1.05%	1.06%	1.06%	1.02%
Avista Corporation	AVA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Black Hills Corporation	BKH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CMS Energy Corporation	CMS	0.29%	0.29%	0.30%	0.30%	0.31%	0.31%	0.31%	0.32%	0.30%
Consolidated Edison, Inc.	ED	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Energy Company	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Corporation	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Corporation	ETR	0.21%	0.22%	0.22%	0.23%	0.33%	0.33%	0.34%	0.34%	0.28%
Exelon Corporation	EXC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Fortis Inc.	FTS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MGE Energy, Inc.	MGEE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Sempra Energy	SRE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southern Company	SO	0.71%	0.73%	0.72%	0.74%	1.83%	1.33%	1.59%	1.66%	1.16%
Xcel Energy Inc.	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MEAN		0.28%	0.29%	0.30%	0.30%	0.39%	0.36%	0.38%	0.39%	0.34%
LOW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
HIGH		1.99%	2.11%	2.19%	2.21%	2.38%	2.42%	2.47%	2.47%	2.28%

Company Name	Ticker	PREFERRED RATIO [1] 2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
Interstate Power and Light Company	LNT	3.37%	3.66%	3.81%	3.85%	4.08%	4.15%	4.28%	4.28%	3.93%
Wisconsin Power and Light Company	LNT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ameren Illinois Company	AEE	0.92%	0.92%	0.98%	1.00%	1.06%	1.07%	1.08%	1.10%	1.02%
Union Electric Company	AEE	1.00%	0.99%	1.04%	1.04%	1.03%	1.04%	1.04%	1.03%	1.03%
Avista Corporation	AVA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Alaska Electric Light and Power Company	AVA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Black Hills Colorado Electric, Inc.	BKH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Black Hills Power, Inc.	BKH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cheyenne Light, Fuel and Power Company	BKH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Consumers Energy Company	BKH	0.29%	0.29%	0.30%	0.30%	0.31%	0.31%	0.31%	0.32%	0.30%
Consolidated Edison Company of New York, Inc.	CNP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Orange and Rockland Utilities, Inc.	CMS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rockland Electric Company	ED	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Electric Company	ED	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Carolinas, LLC	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Indiana, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Kentucky, Inc.	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Ohio, Inc.	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Progress, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Arkansas, LLC	DUK	0.52%	0.53%	0.59%	0.60%	0.59%	0.60%	0.64%	0.64%	0.59%
Entergy Louisiana, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Mississippi, LLC	ETR	0.79%	0.80%	0.81%	0.82%	0.87%	0.89%	0.90%	0.91%	0.85%
Entergy New Orleans, LLC	ETR	0.00%	0.00%	0.00%	0.00%	2.40%	2.42%	2.43%	2.43%	1.21%
Entergy Texas, Inc.	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Atlantic City Electric Company	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Baltimore Gas and Electric Company	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Commonwealth Edison Company	EXC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Delmarva Power & Light Company	EXC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PECO Energy Company	EXC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Potomac Electric Power Company	EXC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Central Hudson Gas & Electric Corporation	EXC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CH Energy Group, Inc.	EXC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ITC Interconnection LLC	FTS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tucson Electric Power Company	FTS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UNS Electric, Inc.	FTS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
UNS Energy Corporation	FTS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Madison Gas and Electric Company	FTS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Energy Future Holdings Corp	MGEE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Oncor Electric Delivery Company LLC	PCG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
San Diego Gas & Electric Company	PPL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Alabama Power Company	PPL	1.85%	1.88%	1.94%	2.01%	3.61%	1.97%	1.98%	2.08%	2.17%
Georgia Power Company	PPL	0.00%	0.00%	0.00%	0.00%	1.12%	1.17%	1.15%	1.21%	0.58%
Gulf Power Company	SO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	5.38%	5.73%	1.39%
Mississippi Power Company	SO	1.04%	1.04%	1.05%	0.96%	0.82%	0.83%	0.56%	0.56%	0.86%
Northern States Power Company - MN	SO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Northern States Power Company - WI	SO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of Colorado	VVC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southwestern Public Service Company	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF THE SECOND ENERGY STRONG PROGRAM (ENERGY STRONG II)

BPU Docket Nos. EO18060629 and GO18060630

PUBLIC SERVICE ELECTRIC AND GAS COMPANY REBUTTAL TESTIMONY OF THE COST-BENEFIT ANALYSIS PANEL

April 18, 2019

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
REBUTTAL TESTIMONY
OF THE
COST-BENEFIT ANALYSIS PANEL
ENERGY STRONG II PROGRAM

I. INTRODUCTION

Q. Please introduce the members of the Cost-Benefit Panel, Energy Strong II Program (the "ESII-CBA Panel" or "Panel").

A. The witnesses comprising the ESII-CBA Panel are Russell A. Feingold, Krystal R. Richart and Andrew L. Trump.

Q. Mr. Feingold, please state your name and business address.

A. My name is Russell A. Feingold, and my business address is 2525 Lindenwood Drive Wexford, Pennsylvania 15090.

Q. By whom are you employed and in what capacity?

A. I am a Vice President at Black & Veatch Management Consulting, LLC ("Black & Veatch") and lead its Rates & Regulatory Practice.

Q. Have you testified previously in this proceeding?

A. Yes. On June 8, 2018, on behalf of Public Service Electric & Gas Company ("PSE&G" or "Company"), I submitted direct testimony in support of PSE&G's Petition requesting that the New Jersey Board of Public Utilities ("PBU" or "Board") approve PSE&G's Energy Strong II Program ("ESII" or "Program").

Q. Ms. Richart, please state your name and business address.

A. My name is Krystal R. Richart, and my business address is 11401 Lamar Avenue

Overland Park, KS 66211.

Q. By whom are you employed and in what capacity?

A. I am a Manager employed by Black & Veatch.

Q. Have you testified previously in this proceeding?

A. Yes. On June 8, 2018, on behalf of PSE&G, I submitted direct testimony in support of PSE&G's Petition requesting that the Board approve PSE&G's ESII.

Q. Mr. Trump, please state your name and business address.

A. My name is Andrew L. Trump, and my business address is 832 Media Line Road, Newtown Square, Pennsylvania.

Q. By whom are you employed and in what capacity?

A. I am currently an independent consultant and was a Director employed by Black & Veatch at the time my direct testimony was submitted to the Board.

Q. Have you testified previously in this proceeding?

A. Yes. On June 8, 2018, on behalf of PSE&G, I submitted direct testimony in support of PSE&G's Petition requesting that the Board approve PSE&G's ESII.

Q. What was the purpose of the Panel's direct testimony in this proceeding?

A. In our direct testimony, we sponsored the cost-benefit analyses ("CBAs") of the electric and gas portions of PSE&G's ESII.

Q. What is the purpose of the Panel's rebuttal testimony?

A. In our rebuttal testimony, we respond to the criticisms raised by the New Jersey Division of Rate Counsel in the direct testimony of Dr. David E. Dismukes concerning the

CBAs for the electric and gas portions of ESII submitted by PSE&G in this proceeding.

II. IDENTIFICATION OF EXHIBITS

Q. Do you sponsor any exhibits in support of your rebuttal testimony?

A. Yes. We have attached the following three (3) exhibits:

1. Exhibit BV-ESII-1 is a diagram of the specification of benefits.
2. Exhibit BV-ESII-2 is a chart of monetary benefits for the Company's electric CBA under less conservative assumptions.
3. Exhibit BV-ESII-3 is a listing of principal reference sources for electric Value of Lost Load ("VoLL") research efforts.

III. SUMMARY

Q. Please summarize your rebuttal testimony.

A. The recommendation of Dr. Dismukes that the Board deny PSE&G's ESII Petition should be rejected. Contrary to the assertions made by Rate Counsel's witness, the Company's CBAs were conducted in a reasonable and acceptable manner that properly describe and estimate the total monetized costs and benefits, and other quantitative and qualitative benefits, of PSE&G's ESII investment plans. The Company's CBAs provide meaningful and acceptable results to the Board for purposes of examining the value these investments will provide to PSE&G's customers.

In addition, contrary to the claims made by Dr. Dismukes, the outage event scenarios identified in the Company's CBAs are well-conceived and accurately parameterize the risks the Company will mitigate through the proposed ESII infrastructure investment plan.

Finally, the reasonableness and acceptability of the Company's CBAs is also supported by the fact that the monetization of benefits in the Company's CBAs is conservative in its estimation of VoLL and other benefits.

The Board should reject Dr. Dismukes' criticisms of the Company's CBA for the following reasons:

1) Dr. Dismukes' use of a benefit-to-cost ratio (BCR) test of 1.0 as a strict "pass" or "fail" measure to evaluate the viability of the Company's proposed ESII investments fails to acknowledge the existence of important quantified, but not monetized and qualitative benefits that can be realized under the Company's proposed ESII.

2) Dr. Dismukes' recommendation to exclude the benefits of the Company's ESII from its CBAs unless there are specific performance metrics and guarantees associated with the future achievement of these benefits is unsound because whether or not performance metrics are imposed has no impact on the reasonableness, quality, comprehensiveness, or results of the CBAs, which stand on their own merits.

3) Dr. Dismukes' claim that the Company's quantification of VoLL-derived benefits is seriously flawed and should either be excluded or highly discounted when used in the Company's electric CBA should be rejected; his criticisms of the VoLL factors (derived by the Lawrence Berkeley National Laboratory in its 2015 Report) and their use in the Company's CBA are incorrect.

4) Dr. Dismukes' claim that the Company's VoLL-derived benefits should be excluded from the Company's gas CBA should be rejected; his criticisms of the methodology used by the Company to derive its residential and commercial and industrial ("C&I") VoLL factors are incorrect.

5) Dr. Dismukes' claim that the Company's quantification of other avoided costs (benefits) is deficient and should be excluded from its gas CBA fails to acknowledge that these costs will be avoided under the types of outage events the Company's ESII investments are meant to mitigate.

6) Dr. Dismukes' claim that the Company's electric outage event scenario that underpins our calculation of outage benefits is unrealistic, leading to exaggerated benefit claims, should also be dismissed; in essence, Dr. Dismukes is simply arguing that the Company should not have relied on outage data from real historical storm events.

The Board should also reject Dr. Dismukes' "alternative CBAs" because of the following deficiencies in how he utilized the IMPLAN Model as the basis of his analysis:

1) Dr. Dismukes' "alternative CBAs" are strictly limited to the consideration and measurement of a narrow set of monetary impacts, and completely ignore any other decision criteria.

2) Dr. Dismukes' use of the IMPLAN Model as a CBA is an incomplete analysis and, therefore, insufficient to support his conclusions because it fails to accept and include any outage-related benefits which constitute the primary purpose of the Company's ESII investments and is a requirement in a properly structured CBA.

3) Certain input assumptions made by Dr. Dismukes for purposes of performing his IMPLAN Model analysis overstate the negative economic activity impacts found in his "alternative CBAs."

IV. THE COMPANY'S CBAs PROVIDE MEANINGFUL, ACCEPTABLE AND CONSERVATIVE RESULTS

Q. Rate Counsel Witness Dismukes claims that the Company's CBA suffers from a number of deficiencies that cause the Company's ESII Proposal to "fail" the CBA. Do you agree with his assertions?

A. No. The Company's electric and gas CBA were conducted in a reasonable and acceptable manner that properly yield estimates and descriptions of the total monetized costs and benefits, and other quantitative but not monetized and qualitative benefits, of PSE&G's ESII investment plans. The CBAs are structured in a manner consistent with industry practice standards. The Company's electric and gas CBA reports are highly transparent and include detailed descriptions of the underlying methodologies, definitions, pertinent industry and academic literature, structural issues in constructing a CBA, conceptual valuation issues surrounding outage damage costs, evaluation of results, sensitivity analyses, an extensive narrative on each ESII subprogram and its benefits, and careful and comprehensive benefit inventories. Both of the Company's CBA reports also include detailed and comprehensive identification and description of all essential study assumptions.

The Company's CBAs provide meaningful and acceptable results to the Board for purposes of examining the value these investments will provide to PSE&G's electric and gas customers. Based on a close review of the *complete* results of the Company's CBA (i.e., the monetized costs and benefits, the associated BCRs, the non-monetized quantitative and qualitative benefits of the ESII investments and related sensitivities), the Company's ESII investments will provide significant value to its electric and gas customers and should be approved as necessary and prudent by the Board.

Q. To help frame your discussion of the benefit components of a CBA, have you prepared a diagram which provides a specification of the benefits that are relevant when evaluating the value of electric and gas infrastructure investments such as those included in the Company's ESII?

A. Yes. Exhibit BV-ESII-1 to this testimony presents a diagram of the specification of benefits associated with an electric or gas outage event. There are three dimensions to identifying and explaining these benefits: (1) the type of cost avoided (direct or indirect); (2) the type of benefit (monetary, quantified but not monetized, and qualitative); and (3) the timeframe of the outage event. Each of these dimensions and the resulting benefits under the Company's ESII will be discussed in detail in conjunction with our responses to Dr. Dismukes' claims and related arguments presented in his direct testimony. Most importantly, benefits from each of these dimensions should be included in a properly conducted CBA.

Q. A recurring theme in Dr. Dismukes' direct testimony is his claim that the benefits reflected in the Company's CBA results are upwardly biased. How do you respond to his claim?

A. Dr. Dismukes is mistaken for a number of reasons. We will respond specifically to each of Dr. Dismukes' arguments in the next section of our rebuttal testimony. However, as we will describe below, there are a number of reasons why the benefits and the CBA results of the ESII infrastructure investments are not upwardly biased but are, in fact, conservative in nature.

Q. How are the results of the Company's electric CBA conservative?

A. The results of the Company's electric CBA are conservative because a wide range of benefits have been carefully inventoried, the monetized benefits have been conservatively estimated, and the monetary CBA results are not weighted to incorporate the additional contribution of quantified but not monetized and qualitative benefits within the monetary CBA results.

Furthermore, the Company has rigorously and thoroughly identified the engineering basis of each of the electric ESII subprogram's potential effects on the Company's costs, and on reliability and resiliency improvements. This is evidenced in part in Appendix A of the electric CBA report, the Benefits Matrix, which documents forty (40) separate subprogram impacts and eighty-four (84) specific benefits. Each subprogram's functional dependencies are identified, and the benefit by type is indicated. Furthermore, Appendix B of the report provides extensive documentation on assumptions that drive each of these benefits.

Q. What makes the monetary benefits in the Company's electric CBA conservatively estimated?

A. The Company's electric CBA adopts several conservative assumptions that result in conservative estimates of the monetary benefits:

- Monetary benefits are delayed until the end of the ESII 5-year construction period, even though benefits accrue immediately as each substation or circuit improvement is completed. As a result, only fifteen (15) years of monetary benefits are included in the CBA results.

- The electric CBA assumes that for any outages lasting 16 hours or more the VoLL factors remain static at the 16-hour threshold level. This assumption ignores the fact that VoLL benefits increase as outage duration increases. This choice in assumptions reduces the VoLL benefits for outages that are greater than 16 hours in duration.
- The estimate of benefits in the electric CBA uses a 20-year forecast period for costs and benefits and takes no account of the fact that many of the assets have very long expected in-service lives of 55 or 60 years.
- The CBA ignores the largest storm event that has occurred in the recent past, namely Superstorm Sandy.

Q. How would the monetary results of the Company's electric CBA change if a less conservative approach was applied to these assumptions?

A. Using less conservative assumptions would have a dramatic effect on the total monetary benefits estimated to result from the Company's electric ESII. Exhibit BV-ESII-2 to this testimony displays the results graphically. The impacts to the net present value ("NPV") result in the Company's electric CBA are as follows:

- Recognizing the monetary benefits as the construction is completed increases the VoLL-related benefits, increasing the NPV result by $330 million.
- Recognizing the long-life of the ESII assets over a 40-year period increases the NPV result by $1.025 billion. This includes additional avoided costs of $94 million and VoLL-related benefits of $931 million.
- Including the effects of Superstorm Sandy within the Company's electric CBA increases the NPV result by approximately $1.087 billion.

Q. How else is the Company's electric CBA conservative in nature?

A. The electric CBA is deliberate and detailed in identifying many specific qualitative benefits. For example, there are fifteen (15) qualitative benefits identified in Appendix A related to outage improvement. These benefits, though difficult to monetarily estimate, represent further improvements in the Company's system reliability and resiliency benefits.

In addition, as explained in the Company's electric CBA report, while the VoLL factors provide monetary estimates of the direct damage costs private parties may incur resulting from outages, they do not account for many other direct and indirect costs. These other costs can be very extensive and are not estimated as part of the monetary results in the Company's electric CBA. The "Additional Outage-Related Impacts" section of the Company's electric CBA report explains these facts and supporting Table 7 lists many examples of these costs.[1] Many of these costs are identified as "indirect" and long-term costs.

Q. Can you further describe the nature of these indirect costs?

A. Yes. In a recent study performed by the FSC Group, indirect costs are explained within the context of electric utility long duration power outage studies:

> "Indirect costs to commercial and industrial customers result from the chain reaction of economic losses stemming from direct costs: interactions between business (e.g., changes in quantities of inputs bought or outputs sold, changes in relative prices) and interactions between consumers and business (e.g., lost wages and reduced spending). Indirect costs are thus incurred not only by people and firms subject to an outage, but also to people and firms outside of the affected areas. Additionally, outage costs associated with public expenditures (e.g., assistance programs, emergency services, loss of taxes), public goods, (e.g., water treatment and injury or loss of life can be considered a part of indirect costs."[2]

Q. What is the potential magnitude of these costs?

A. There are many industry studies that provide *ranges* of estimates for indirect benefits. Many of these studies fall within the literature associated with resiliency effects. The FSC Group provided these estimates of ranges that are possible for indirect costs of long-term

[1] Attachment 5 Schedule-BV-ESII-Elec-4, page 31.
[2] FSC Group, Downtown San Francisco Long Duration Outage Cost Study, Prepared for Pacific Gas & Electric Company, March 27, 2013, page 12A-9.

electric power outages:

- Researchers estimate that the indirect costs of the 1977 NYC outage were more than 5 times the direct cost estimate.[3]
- For an extensive San Francisco electric power outage study, the FSC Group concluded that indirect outage costs ranged between 0.5 times and 2.0 times the value of direct outage costs.

This area of estimation can be very complex because of the highly diverse nature of impacts that are evidenced in long-term power outage circumstances.

Q. How are the results of the Company's gas CBA conservative in nature?

A. The results of the gas CBA are conservative for several reasons. As with the electric CBA, a careful inventory of benefits has been included in the gas CBA.[4] Additionally, several assumptions add conservatism to the resulting benefit estimates, including:

- The gas CBA is based on a limited forecast period of 20 years and does not reflect the long-lived nature of the assets. Both the resiliency improvements and the M&R station upgrades will provide benefits for 50-60 years.
- The outage event that is the basis of the resiliency benefit evaluation represents a single event over the long life of the assets. More than one avoided outage incident is possible, thereby increasing the benefits that would be realized.
- The outage event assumed a rapid repair and restoration of the upstream gas transmission system of not more than 10 days. A longer repair period would increase the outage-related benefits.
- The outage duration assumes a period of 30 days to restore service to most of the Company's gas customers. There are many factors that could increase the duration of this restoration period, including the availability of mutual aid crews.
- The residential VoLL factor applied in the gas CBA is conservative by design and is based on customers simply valuing the loss of gas service at the currently effective price charged by the Company under its residential gas tariff.

[3] Ibid, page 12A-5.
[4] See Attachment 6 Schedule-BV-ESII-Gas-5, pages 48-51, 64-65 and Appendix G.

Q. How else is the gas CBA conservative?

A. As with the Company's electric CBA, the gas CBA is deliberate and detailed in identifying many specific qualitative benefits, such as those identified for the Company's M&R stations in Appendix G of the gas CBA report.

In addition, as explained in the Company's gas CBA report, the VoLL factors provide monetary estimates of the direct damage costs private parties may incur resulting from outages. The VoLL excludes many other direct and indirect costs. These other costs can be very extensive and are not estimated as part of the monetary results in the Company's gas CBA. The gas CBA report describes these other costs at page 43:

> For outages, it is also relevant to expand the impacts to beyond just observable costs. Some of the impacts of a gas outage are quantifiable in monetary terms, and hence, economic in nature; whereas other impacts reflect broad, social impacts tied to convenience, personal safety, pain and suffering, security and other less tangible, but very real, values to the customer. Outage impacts are also characterized by *externalities*, which can be either positive or negative; externalities are impacts incurred by others not party to the economic transaction. For example, an outage event may disrupt a harbor or airport and cause supply chain disruptions for manufacturers far outside the immediate region. This is a form of negative "network externalities," -- it is beyond the influence of the manufacturer suffering the damage.[5]

Q. Are these indirect costs of gas system outages like the indirect costs described earlier?

A. Yes, they are similar in many respects in terms of their impact. However, the specific nature of the causes of these losses would be specific to the loss of gas service.

[5] Attachment 6 Schedule-BV-ESII-Gas-5, page 43.

Q. Does the gas CBA attempt to capture the monetary impacts of these long-term indirect costs?

A. No. The gas CBA attempts to capture estimates of the private and direct costs to residents and businesses. The long-term indirect costs explained here are in addition to the private and direct costs that were estimated.

V. RESPONSE TO SPECIFIC ISSUES RAISED BY RATE COUNSEL

A strict "Pass/Fail" test ignores risk reduction and other benefits

Q. At page 17 of his direct testimony, Dr. Dismukes claims that a "pass/fail" test should be applied to the Company's CBA to evaluate the acceptability of PSE&G's proposed infrastructure investment programs under its ESII. Do you believe that such a test is appropriate?

A. No. Dr. Dismukes' use of a BCR test of 1.0 as a strict "pass" or "fail" measure to evaluate the viability of the Company's proposed ESII is deficient because it fails to acknowledge the existence of important quantified, but not monetized and qualitative benefits that can be realized due to the Company's proposed ESII. The simplistic and absolute nature of Dr. Dismukes' approach ignores the value - indeed, the whole point - of conducting a CBA, and obscures the purpose and full value of the utility infrastructure investments being evaluated.

As discussed in the Company's electric CBA report, the strictly monetary BCR, by its very nature, ignores consideration of many significant and important qualitative benefits, such as reduction in risk and safety enhancements that will be created through the Company's electric and gas program investments. Black & Veatch believes that the CBA, and especially the discrete estimate of a specific monetary BCR, is one of several inputs to decision makers about the merits of the Company's electric and gas programs, but it is not dispositive by itself. For example, a significant portion of PSE&G's proposed investment was chosen based on asset risk management analysis that was guided by a range of criteria, including safety and environmental performance, which help address the chronic and long-term effects of aging equipment and run-to-failure conditions.

Q. Is it feasible to monetize in a CBA all the impacts associated with an infrastructure investment plan such as the Company's ESII?

A. No. While it is true that one of the goals of a CBA is to monetize as many impacts as possible, it is not required that, and rarely possible for, all impacts to be monetized.[6] However, by establishing the proposed monetary-based "pass/fail" test as a strict "bright line" measure, Dr. Dismukes either ignores our observations or fails to acknowledge certain technical limitations inherent in a CBA that make it impossible to monetize all relevant impacts (benefits). He also ignores the role of alternative analytical approaches related to risk evaluation that compliment a formal monetary CBA when the benefit effects cannot be monetized.

Q. How were these technical limitations treated in relationship to the Company's CBA?

A. As explained in Black & Veatch's electric and gas CBA reports, significant attention was devoted to identifying a wide range of cost and benefit impacts of the Company's proposed ESII investments. Creating an "impact inventory" is a very important early step in conducting a proper CBA.[7] The Company's inventory of cost and benefit impacts includes those that cannot reasonably be quantified and/or monetized. This does not mean, however,

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[6] See Attachment 5 Schedule-BV-ESII-Elec-4, page 14.

[7] Anthony E. Boardman, David H. Greenberg, Aidan R. Vining, and David L. Weimer, Cost-Benefit Analysis, Concepts and Practice, (Cambridge: Cambridge University Press, 2018), page 8.

that their impacts are not tangible, direct, and reasonably inferable; they certainly cannot be casually dismissed.

Q. Can you provide a reference to this inventory and the classification effort?

A. Yes. We provide extensive details concerning this inventory and classification effort. For example, in Appendix B, Subprogram B-4, we explain the logic for the benefit classification for this specific subprogram: "The reliability of the multiprotocol label switching ("MPLS") circuits is known as compared to the existing fiber network from eight (8) months of available data, but unlike the recloser, plain old telephone service ("POTS") lines, the costs associated with MPLS outages are not specifically quantified due to limited repair data. This benefit is therefore qualitative."[8] This is part of one of the 84 detailed benefit descriptions discussed earlier.

Q. How should we refer to these impacts that are not monetized?

A. The literature on cost-benefit analysis is extensive and provides ample evidence that practitioners consider three types of benefits: (1) monetary benefits; (2) benefits that can be quantified, but not monetized; and (3) qualitative benefits. Furthermore, benefits that can be quantified but not monetized can in some cases be evaluated in terms of cost-effectiveness.

Useful guidance on this concept is provided by the U.S. Federal Government in its direction to federal regulatory agencies, with the purpose of "standardizing the way benefits and costs of Federal regulatory actions are measured and reported." See Circular A-4 issued

[8] Attachment 5 Schedule-BV-ESII-Elec-4, page 92.

by the United States Government's Office of Management and Budget ("OMB").[9]

Q. Can you please provide an example of each type of benefit described above?

A. Yes. An example of a monetary benefit of ESII is the value customers attribute to the Company's ability to avoid or minimize the extent of electric and gas outages (as monetized with the VoLL factors used in the Company's CBA). An example of a benefit that is quantified but not monetized is the reduction in the risk associated with aging electrical substations and circuits through the Company's proposed substation upgrades under its electric ESII. In this case the risk reduction is quantified through a risk score developed by evaluating candidate replacement electric assets, which we discuss further below. Finally, an example of a qualitative benefit is the reduction in the potential for methane releases at M&R stations as these stations are upgraded[10] or the example provided above for the MPLS circuits.

Q. Earlier you mentioned that Dr. Dismukes ignores technical limitations and alternative analytical approaches that are required when performing a CBA. What did you mean by "alternative analytical approaches"?

A. The term "alternative analytical approaches" refers specifically here to the risk-based modeling of PSE&G's electric and gas distribution assets undertaken by Black & Veatch using asset-level Risk Models. Black & Veatch conducted a risk-based assessment of many of the electric and gas distribution system assets to help PSE&G identify and prioritize assets for end-of-life replacement, including the life cycle substation upgrade aspects of the

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[9] Office of Management and Budget, Circular A-4, Washington, D.C. 2003. In October 2010 OMB published an agency checklist for regulatory impact analyses required by Executive Order 12866 and OMB Circular A-4. For Circular A-4 see: https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4. For a description of federal requirements related to cost benefit see: Congressional Research Service. Cost-Benefit and Other Analysis Requirements in the Rulemaking Process, 7-5700 www.crs.gov R41974, December 2014.

[10] See Appendix G to the Company's gas CBA report (Attachment 6, Schedule BV-ESII-GAS-5) for a complete listing of these qualitative benefits.

Company's ES II.[11] The risk scores resulting from this modeling efforts help to quantify the relative benefits (i.e., the quantified, but not monetized benefits) associated with the assets proposed by the Company for end-of-life replacement.

The risk scoring approach that the Company has applied to these assets includes numerous "consequence criteria" in categories such as safety and environmental performance. It is inherently difficult to monetize the value of reductions for each of these risks. Rather, the consequence criteria are scored using ordinal scales that denote ranges of impacts from high to low. Improving safety and environmental performance are beneficial even if a specific monetary value cannot be reasonably assigned to them for purposes of conducting the CBA. In both his direct testimony and numeric analysis presented in Schedules DED-6 and DED-7, Dr. Dismukes completely ignores the benefits of risk reduction created by the Company's proposed ESII.

Q. How does the BCR threshold requirement of 1.0 imposed by Dr. Dismukes influence the claims he makes concerning the appropriateness and reasonableness of the Company's ESII?

A. Dr. Dismukes asserts that "[t]wo large subprograms fail even under the Company's own analysis."[12] He cites the separate and individual CBA results for the electric substation and gas M&R station subprograms, which each have separate monetized BCR results less than 1.0. Dr. Dismukes also applies the 1.0 threshold requirement as a fundamental evaluation criterion in his Schedules DED-6 and DED-7, which report the results of the alternative CBAs he prepared. We respond to his use of the 1.0 threshold requirement within

[11] See the direct testimony of William D. Williams (Attachment 4) for a complete explanation of the process used to conduct the risk-based modeling of PSE&G's electric distribution assets.
[12] Page 19, line 12 of David E. Dismukes' direct testimony.

that context later in our rebuttal testimony.

Q. How should non-monetary benefits be treated within the structure of a CBA?

A. Non-monetary benefits (i.e., quantified, but not monetized and qualitative benefits) should be carefully identified, discussed, summarized, and, if meritorious, ultimately included as part of the overall results of the CBA, even if this is done on qualitative terms. As previously stated, this classification process occurs early in the process of conducting the CBA.

Governmental agencies, utility regulators, researchers and utilities have each acknowledged the role of qualitative and non-monetized quantified benefits as part of utility infrastructure investments decision making:

- The OMB provides the following guidance - "A complete regulatory analysis includes a discussion of non-quantified as well as quantified benefits and costs. A non-quantified outcome is a benefit or cost that has not been quantified or monetized in the analysis. When there are important non-monetary values at stake, you should also identify them in your analysis so policymakers can compare them with the monetary benefits and costs. You should categorize or rank the qualitative effects in terms of their importance (e.g., certainty, likely magnitude, and reversibility). You should distinguish the effects that are likely to be significant enough to warrant serious consideration by decision makers from those that are likely to be minor."[13]

- The New York State Public Service Commission ("NYPSC") has promulgated detailed rules on the treatment of costs and benefits for utility energy investments that must be followed by jurisdictional electric utilities when evaluating certain kinds of large grid investments. The resulting guidance includes specific allowances for qualitative benefits.[14]

- Consistent with the NYPSC requirements, Consolidated Edison's Benefit Cost Analysis ("BCA") Handbook identifies, "net non-energy costs" in the following way: "In cases where non-energy impacts are attributable to the specific project or program,

[13] OMB Circular A-4.

[14] New York Public Service Commission, Case No. 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, issued and effective: January 21, 2016.

they may be assessed qualitatively."[15]

- The Electric Power Research Institute ("EPRI") Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects, in its definition of benefits, states as follows: defines benefits as follows: "Difficult-to-monetize or difficult-to-quantify impacts may be referred to as benefits, which may be included in a qualitative scoring portion of a cost/benefit analysis."[16]

Q. In your opinion, why do you believe the industry literature on conducting a CBA places emphasis on the accommodation of qualitative benefits?

A. The industry literature places emphasis on this issue because qualitative benefits resulting from infrastructure investments are often very important even though they may be difficult to measure and monetize. Moreover, a CBA "can be thought of as providing a framework for assessing the relative efficiency of policy alternatives."[17] This means that setting policy commonly must address questions concerning non-monetary pursuits involving social welfare considerations, such as quality of life, and the degree of risk associated with our physical environment.

Q. What is the impact of limiting the scope of possible benefits considered in a CBA in a case like this?

A. Limiting the scope of benefits to those that can be monetized undermines the rigorous and comprehensive discovery and evaluation of the impacts of investments under an infrastructure program such as the Company's ESII. If the focus of the CBA is limited to monetary benefits, the stepwise process beginning with the development of the impact inventory would ignore many relevant impacts.[18] This would introduce a harmful bias in the

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[15] Benefit Cost Analysis Handbook, ConEdison, New York, N.Y., (2016), page 47.
[16] EPRI, Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects, Revision 1, Measuring Impacts and Monetizing Benefits (1025734) Technical Update, (December 2012), page A-2 - Definitions.
[17] Boardman et al. Ibid, page 28.
[18] In the Company's electric CBA report, (Attachment 5 Schedule-BV-ESII-Elec-4), the impacts inventory is provided as an integral part of both Appendix A – Benefit Matrix and Appendix B, ESII Electric Subprogram Details.

determination of benefits associated with any infrastructure program. This limited focus would also fail to satisfy the requirements of N.J.A.C. 14:3 2A.5(b) that "descriptions of project objectives - including specific expected resilience benefits" be included in the Company's petition.

Q. In your practice of conducting CBAs, have you observed the existence of this type of benefits bias?

A. Yes. Often an electric utility's benefits discovery process for a grid investment will narrow too quickly to those benefits that are strictly monetary in nature. As a facilitator in these discussions, we must challenge the participants to think more expansively about the impacts and hold in abeyance considerations on whether we can quantify and/or monetize them.

Q. Do you believe the structure of the Company's CBA is consistent with industry and governmental standards regarding the recognition of qualitative benefits?

A. Yes, the Company's CBA is consistent with the requirements and guidance of the OMB, NYPSC, EPRI, and other industry guidance on the recognition of qualitative benefits. The Company's CBAs provide itemizations and detailed explanations of both monetary benefits and costs <u>and</u> non-monetized and qualitatively considered impacts. In fact, this observation applies to all the Company's subprograms - not just the two ESII subprograms questioned by Dr. Dismukes.

Moreover, the Company applied professional judgement in determining the nature and magnitude of non-quantifiable benefits. For its Electric Substation subprogram, for example, the Company carefully identified and delineated for purposes of the electric CBA twenty-eight (28) separate major benefits. Ten (10) of these benefits represent approximately $663 million of monetary benefits. Another eighteen (18) of these benefits are specifically identified as qualitative in nature and difficult to monetize. These benefits are identified in Appendix A – Benefits Matrix, contained in the Black & Veatch electric CBA Report,[19] with the reference rows labeled "SF" and "SU." However, the BCR of 0.7 – which is the monetary CBA component and measure -- does not reflect the additional and substantial value that these eighteen qualitative benefits provide to the Company and its customers.[20]

Q. What are examples of quantified but non-monetized and qualitative benefits for the Company's gas M&R subprogram?

A. As with the electric CBA, the Company's Gas CBA report identifies many qualitative benefits for its M&R Upgrade Subprogram. They include the stations being brought into conformance with PSE&G's current design standards, improving their operating and environmental performance, and reducing noise levels through improved layout, equipment, and building structural materials. These qualitative benefits are also identified on pages 6-7 of our direct testimony discussing the Company's gas CBA.[21] In all, ten (10) major qualitative benefit areas are classified and identified by specific station.[22]

Q. Do you believe the Board's regulations on Infrastructure Investment Programs ("IIP"), N.J.A.C. 14:3-2A, contemplates a strict BCR threshold of 1.0 when conducting a CBA to determine the viability of a utility's proposed infrastructure investments?

A. No. The IIP's CBA requirement is one of several evaluation considerations by the Board. It is part of the engineering and evaluation report criteria requiring the submission of

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[19] Attachment 5, Schedule BV-ESII-ELEC-4.

[20] See Appendix A – Benefits Matrix, of the Black & Veatch Electric CBA report (Attachment 5, Schedule BV-ESII-ELEC-4) for a detailed description of the beneficial impacts of the electric ESII categorized as cost-related impacts (i.e., avoided costs), Customer Minutes of Interruption or CMI-related impacts and other impacts (i.e., qualitative benefits).

[21] Direct testimony of the Cost Benefit Analysis Panel Energy Strong II Program – Gas, Attachment 6.

[22] Attachment 6, Schedule BV-ESII-GAS-5, Appendix G, page 93.

"descriptions of project objectives-including the specific expected resilience benefits, detailed cost estimates, in service dates, and any applicable cost-benefit analysis for each project." Additionally, the core purpose of the IIP regulations is to support enhancement of the reliability, safety and/or resiliency of the grid. These regulations provide no instruction or limitations that the relative importance or acceptance of each utility's infrastructure program, subprogram or project should be determined through the application of a strict monetary BCR of 1.0 threshold test.

Q. Do you believe the Board's IIP regulations contemplates a broader consideration of benefits than permitted under a strictly monetary-based BCR of 1.0 threshold test as utilized by Dr. Dismukes?

A. Yes. As noted above, the CBA requirement in the IIP regulations includes the language, "any applicable cost benefit analysis." This language implicitly recognizes there are a variety of forms of a CBA, and a potential variety of important benefits. We also believe the "any applicable" wording is inconsistent with attempts to limit the scope and discovery of meaningful benefits.

Q. What is your overall conclusion concerning the Company's CBA results for the Electric Substation and M&R Upgrade Subprograms in relation to Dr. Dismukes' claims that a strict BCR of 1.0 threshold test is required?

A. Dr. Dismukes' application of a strict BCR of 1.0 threshold test (that is defined without compromise in monetary terms) is not appropriate, does not meet the norms of practice for properly conducting a CBA, and is inconsistent with a reasonable interpretation of the guiding IIP regulations. Rather, the Board should consider the entirety of the CBA results including the role of quantified, but not monetized and qualitative results. The quantified, but not monetized and qualitative benefits - together with the approximately $698 million of monetary benefits – for these two subprograms provide cumulative benefits that can outweigh the subprograms' direct costs when including the proper and full consideration of benefits.

CBA benefits stand on their own with or without performance metrics and guarantees

Q. Dr. Dismukes claims (at pp. 19, 21-22) that PSE&G's CBAs are flawed because they do not "tie estimated benefits to . . . performance metrics," and that "PSE&G overstates the benefits of its program since, without "performance standards", those future benefits "cannot be verified with any reasonable degree of certainty." Do you agree with these claims?

A. No. First, Dr. Dismukes' proposal to require a benefits performance guarantee should not prejudice the evaluation of benefits in the Company's CBAs. The CBAs should be evaluated on their own merits. Additionally, we understand that PSE&G will adhere to any performance metrics and reporting requirements the Board deems appropriate to measure the effectiveness of the Program. Therefore, it is not true that the Company's results will not be verified. Moreover, it is not necessarily true that the creation of "performance metrics" can or will ensure achievement of future benefits.

Q. From your work in conducting the Company's CBAs, did you identify any bias in the input assumptions and, if so, was it attributable to the lack of performance measures?

A. No. The Black & Veatch team conducting the Company's CBA is not aware of any input assumptions that are biased-upward due to the *lack* of some type of performance accountability. Rather, we specifically focused on ensuring that the Company's CBAs were based on conservative assumptions to enhance the reasonableness of the results.

Q. At page 50 of his direct testimony, Dr. Dismukes claims that, "the omission of any meaningful performance metrics shifts ESII program performance risk away from the Company and onto ratepayers." How do you respond to his claim?

A. This claim is incorrect because it ignores mitigation of the risks customers face today, which will remain unmitigated and will grow without the ESII investments. Today, the Company's electric and gas distribution systems face outage risks and, therefore, its customers also face these risks. These risks are "always present", "24 x 7." ESII is intended to shift these risks away from customers through the proposed resiliency and system hardening investments, lessening customer risks associated with electric and gas outage events.

Q. Why do you believe Dr. Dismukes makes this claim?

A. Because he ignores consideration of any quantified but not monetized reliability and resiliency benefits in his "alternative CBAs," it is our belief that Dr. Dismukes fails to acknowledge the insurance-like aspect of the Company's ESII investments.

In essence, Rate Counsel's approach to calculating benefits in this case ignores the fact that the proper comparison to the investment program under ESII, if it were available, is a financially and legally sound insurance policy available in the market that the Company could purchase and that would cover PSE&G's customers from a wide range of risks related to the system resiliency hazards described in the Company's CBA reports and its direct testimony. This insurance product would have to cover the PSE&G system and its customers for 60 years or more. In the event both minor and major outages are experienced, this insurance policy would have to provide immediate compensation to the Company's customers in a manner and at a level that is acceptable, making them whole on their losses. We know of no such insurance product.

The VoLL benefits used in the Company's CBAs are appropriate

Dr. Dismukes' criticisms of the 2015 LBNL Report are incorrect

Q. Dr. Dismukes also claims that the Company's quantification of VoLL benefits is seriously flawed and should either be highly discounted or excluded when used in the Company's CBA. Specifically, he claims (at page 27) that the VoLL factors used by PSE&G, which are from a well-known 2015 Lawrence Berkeley National Laboratory ("LBNL") Report, are too "unreliable", "variable", and "upwardly biased", and are "inappropriate for use in this part of the United States." Is he correct?

A. Absolutely not. For its electric ESII, the Company applies VoLL factors from a detailed research effort and study conducted by LBNL. Simply stated, Dr. Dismukes has either greatly undervalued or simply ignored the degree of effort, rigor and peer review that has gone into the research supporting the VoLL factors presented in the 2015 LBNL Report and utilized in the Company's electric CBA. The 2015 Report was built on and superseded a prior study published in 2009.[23] It is instructive to cite from the 2015 LBNL Report's abstract explaining the study effort:

> "This report updates the 2009 meta-analysis that provides estimates of the value of service reliability for electricity customers in the United States (U.S.). The meta-dataset now includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012. Because these studies used nearly identical interruption cost estimation or willingness-to- pay/accept methods, it was possible to integrate their results into a single meta-dataset describing the value of electric service reliability observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers."[24]

[23] Michael J. Sullivan, Matthew Mercurio and Josh Schellenberg, Estimated Value of Service Reliability for Electric Utility Customers in the United States, Prepared for Office of Electricity Delivery and Energy Reliability U.S. Department of Energy, Ernesto Orlando Lawrence Berkeley National Laboratory, June 2009.

[24] Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, Ernesto Orlando Lawrence Berkeley National Laboratory, January 2015.

Q. Is this research work related to the VoLL valuation methods progressive?

A. Yes. By several indicators this research effort is an on-going, progressive initiative focused on building upon the body of research, analytical methods and models supporting the estimation of interruption costs. In fact, Nexant, Inc. and LBNL recently published a Guidebook[25] for estimating power system interruption costs that relies on the progression of work associated with the 2009 and 2015 studies sponsored by LBNL. The Guidebook reflects the extensiveness of this effort and the significant level of researcher participation from the United States government (Department of Energy, LBNL) and the energy industry.

Q. Are VoLL estimates used in other important ways within the utility industry?

A. Yes. Several organized electric wholesale energy markets within the United States -- including ERCOT and MISO -- rely on VoLL estimates for the determination of certain components of electricity market prices related to ancillary energy products. In fact, according to a study in which it inspected shortage pricing throughout the United States, the Brattle Group concluded that every electric wholesale energy market jurisdiction within the United States "reflect some measure of VoLL in its administrative shortage pricing."[26]

Q. Dr. Dismukes claims that the study limitations cited in the 2015 LBNL report associated with the specific electric VoLL factors used in the Company's electric CBA justify their exclusion from the Company's analysis. Do you agree with his claim?

A. No. Dr. Dismukes has taken several comments made by the study authors out of context and is, thereby, misrepresenting the nature of the VoLL factors – and the

[25] Michael J. Sullivan, Myles T. Collins, Josh Schellenberg and Peter H. Larsen, Estimating Power System Interruption Costs – A Guidebook for Electric Utilities, Nexant, Inc. and Lawrence Berkeley National Laboratory, July 2018.

[26] The Brattle Group, Shortage Pricing in North American Wholesale Electricity Markets, page 2. Also, some literature refers to Value of Service, or VOS instead of VoLL.

mathematical regression model the factors are based upon. The fact is that the VoLL factors used by the Company are based on the best and most complete data available. As the LBNL study authors explain in the 2015 Report, "[to] the knowledge of the authors, this dataset includes nearly all large power interruption cost studies that have been conducted in the U.S."[27]

Q. Does Dr. Dismukes recommend alternative VoLL factors for use in the Company's CBAs or in the "alternative CBAs" he has prepared?

A. No. Throughout his direct testimony and discovery responses, Dr. Dismukes dismisses the reliability and resiliency benefits that comprise the Company's electric CBA, and he offers no alternative factors for use in his "alternative CBAs." In effect, he dismisses completely both the purposes of the statutory IIP requirements and the body of knowledge concerning value-based reliability and resiliency planning. In fact, the VoLL factors the Company has cited and relied upon represent a major contribution to the U.S. electricity industry's significant, long-term research and policy analysis effort to improve value-based reliability and resiliency planning for the power industry.

Q. How does Dr. Dismukes dismiss the reliability of the electric VoLL factors used by the Company?

A. Dr. Dismukes' direct testimony implies that the LBNL 2015 Report represents a minor update of a 2009 study, omitting that these studies form part of a significant and progressive effort stretching several decades as reflected in past EPRI studies (1995, 2015), LBNL studies (2001, 2004, 2009, 2015, 2017, 2018), numerous utility studies and rate cases,

[27] Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, Ernesto Orlando Lawrence Berkeley National Laboratory, January 2015, page 16 (footnote 7).

and sponsored work by the U.S. DOE. We have provided a list of reference sources for the principal works associated with this effort in Exhibit BV-ESII-3. Dr. Dismukes ignores that this body of work is supporting value-based reliability planning throughout the U.S. for multiple purposes including: estimating reliability costs to the U.S. economy, establishing the marginal costs of generation capacity to set rates, assessing the economic costs of electric transmission and distribution system and smart grid investments, and improving the design of demand response programs, to name several specific uses.[28]

Q. Does Dr. Dismukes fail to acknowledge some of the improvements included in the 2015 LBNL Report compared to its 2009 Report?

A. Yes. Dr. Dismukes' criticizes the lack of data as a reason why the VoLL factors should be dismissed, whereas the LBNL researchers claim the regression model has evolved with greater explanatory power (2015 versus 2009) leveraging the data that is in fact available, making it more useful to U.S. electric utilities for value-based reliability and resiliency planning purposes. In addition, Dr. Dismukes ignores the fact that users can now access and use the regression model via web access. This speaks to the confidence that DOE, LBNL and the study authors have in the efficacy and usefulness of the regression model and the VoLL factors it generates for value-based reliability and resiliency planning for utility planners throughout the United States.

Q. Does Dr. Dismukes unfairly represent the nature of the 2015 LBNL Report update in other ways?

A. Yes. Dr. Dismukes improperly challenges two new studies incorporated into the

[28] Sullivan, Mercurio, Schellenberg. Estimated Value of Service Reliability for Electric Utility Customers in the United States (LBNL-2132E), Ernest Orlando Lawrence Berkeley Laboratory, June 2009, page xiv.

research reflected in the 2015 Report. In fact, he highlights these two studies on a separate schedule: These two new studies, "highlighted in Schedule DED-5," according to Dr. Dismukes "are from utilities already included in the original meta-dataset."[29] Notwithstanding the fact that the two new studies add explanatory value to the regression model (the output of which are the VoLL factors he criticizes), Dr. Dismukes criticizes the 2015 Report on the simple grounds that the original dataset already includes outage data from the same utilities.

Q. Could the new survey data be useful even if it is associated with utilities that have performed prior studies?

A. Yes. The LBNL researchers point out that these two new studies provide new and original data from "two large interruption cost surveys," with one featuring "several noteworthy methodological improvements" in survey design. Moreover, based on the inclusion of these new studies the LBNL researchers observe that, "for interruptions from 8 to 16 hours, the new model produces estimates that are more reasonable and show gradually increasing costs up to 16 hours."[30] Within the context of explaining the usefulness of these new studies, the authors observe that the resulting complete data base, "now includes 34 different datasets from surveys fielded by 10 different utility companies between 1989 and 2012, totaling over 105,000 observations."

Contrary to Dr. Dismukes' claims that the new studies add no value in improving the VoLL-based estimates, the LBNL authors clearly believe the addition of these studies are important, have substantial and significant merit, were worth the effort to expend public

[29] Direct testimony of David E. Dismukes, page 23, Lines 15-16.
[30] LBNL 2015 Report, page 17.

funds to include and analyze, and enhance the database upon which the Company's electric VoLL factors are based.

Q. Dr. Dismukes appears to take issue (page 24) with the fact that study sponsors were, "interested in measuring interruption costs for conditions that were important for planning their specific systems" and that the interruption conditions described in the surveys for a specific region tended to focus on periods of time when interruptions were more problematical for that region." Should this point be a concern in utilizing the VoLL factors in the Company's electric CBA?

A. No. It is quite reasonable that high quality outage survey data would come from utilities that focused on their specific circumstances and needs. Moreover, in considering this alleged limitation, it is important to appreciate that each study that is drawn upon "measured the same basic underlying concepts"[31] and these involved attributes of the interruption (e.g. duration, frequency, season, time of day), summary of costs, and customer characteristics. In this instance, Dr. Dismukes ignores the study authors' explanation that most of the studies we examined included a summer afternoon interruption, so we could compare that condition among studies."[32] Notably, summer afternoon interruption costs tend to be higher than other periods.[33] Therefore, a portion of Dr. Dismukes' concern is mitigated.

The VoLL factors from the LBNL Report are appropriate to use in New Jersey

Q. Dr. Dismukes points out that the authors of the LBNL Report express concerns about variables in the data being confounded. Should this be a consideration in making the decision to utilize these VoLL factors in the Company's CBA?

A. No. The study authors explain that the region and year of the study variables are

[31] LBNL 2009 Report, page 6.
[32] LBNL 2015 Report, page 48.
[33] LBNL 2015 Report, Table ES-2, page xiii.

correlated in the underlying study data in such a way that it is impossible to separate the effects of these variables on interruption costs. Confounding of independent and dependent variables is a problem commonly encountered when building a regression model. If variables are confounded and this is not identified or recognized it can bias the regression model and lead to the masking of, or the over- or under-estimating of, the strength of an effect. When this "omitted variable bias" is identified, specific steps are recommended to address it to create a regression model of improved statistical power. These include adding the omitted (confounded) variables to the regression or adding proxy variables. We believe that in identifying this effect, the LBNL researchers have addressed it as part of the regression model specification through their use of rigorous statistical techniques.

Q. For this concern raised by Dr. Dismukes to be significant, what do you believe he would have to demonstrate?

A. He would have to demonstrate that this "omitted variable bias" related to the region and year of study variables has not been accounted for or corrected as part of the regression model, or if accounted for, that it has been done in a way that leads to a model of significantly less statistical precision and explanatory power. Dr. Dismukes has not provided this type of demonstration.

Q. At page 25 of his direct testimony, Dr. Dismukes points out that the surveys that formed the basis of the studies were limited to certain regions of the country. Should this be a concern in utilizing the VoLL factors in the Company's CBA?

A. No. The LBNL authors observe that the under-representation of survey data for mid-Atlantic customers is a study limit, but the authors do not suggest that this limit should restrict use of the regression model to any geographical area. Rather, the 2015 Report is clear that, "[o]nce the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week and geographical regions within the U.S for industrial, commercial and residential customer."[34]

Q. At pages 25-26 of his direct testimony, Dr. Dismukes points out that the customer surveys used to form the meta-analysis database are over 15 years old. Should this be a concern in utilizing the VoLL factors in the Company's electric CBA?

A. No. Dr. Dismukes cites language in the LBNL 2015 Report concerning the "outdated vintage of the data." Presumably, he uses this observation in support of his later observation that the LBNL estimates are unreliable and likely suffer from a considerable upward bias. Dr. Dismukes has it backwards. A more meaningful and accurate citation addressing this issue, however, appears on page 18 of the LBNL 2015 Report where the study authors state that the newer data will show that there are increases, not decreases, to interruption costs due to the energy demands of the current economy.

> "[A]nother caveat is that this meta-analysis may not accurately reflect current interruption costs, given that around half of the data in the meta-database is from surveys that are 15 or more years old. To address this issue, the 2009 study included an intertemporal analysis, which suggested that interruption costs did not change significantly throughout the 1990s and early 2000s. However, during the past decade in particular, technology trends may have led to an increase in interruption costs. For example, home and business life has become increasingly reliant on data centers and "cloud" computing, which may have led to an increase in interruption costs for both producers and consumers of these services.

[34] LBNL 2015 Report, page iv.

Dr. Dismukes' criticism of the WTP estimates is overstated

Q. At page 26 of his direct testimony, Dr. Dismukes claims that the LBNL customer surveys are based on Willingness to Pay ("WTP") estimates that are often overstated due to an inherent bias in survey responses (where customers indicate they are willing to pay more than they actually would pay). Should his claim be a concern in using the VoLL factors in the Company's CBA?

A. No, for the reasons we explain below. We do acknowledge that it is a fair observation that WTP surveys can be affected by response bias. However, Dr. Dismukes' claims concerning bias within the WTP survey methods are grossly overstated.

Dr. Dismukes indicates that the utility surveys the LBNL Report relies upon are based on WTP estimates.[35] However, contrary to his belief, the studies that underpin the regression model to derive VoLL factors are a mix of direct interruption cost estimation and willingness-to-pay/accept study types. While both study types use survey-based instruments, interruption cost estimate surveys involve direct cost estimation, as distinct from surveys using WTP estimation techniques, which involve asking customers what they would pay to avoid electric service interruptions. The WTP-based argument made by Dr. Dismukes simply does not apply to both survey approaches.

Q. Are the two survey methods you just discussed applied uniquely to an electric utility's specific customer classes?

A. Yes. Experts agree that there are preferred survey methods based on the specific customer class that you are examining. "Several types of survey-based valuation methods are available for [customer interruption cost] study teams to use. The preferred method depends on which customer class will be the subject of the survey."[36]

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[35] See the direct testimony of David E. Dismukes, page 26 (footnote 63) which cites the LBNL 2015 Report, page iv.
[36] Nexant and LBNL Guidebook, 2018, page 18.

Q. In the case of the LBNL meta-analysis and the underlying customer surveys that are related to this bias argument made by Dr. Dismukes, do the WTP and direct cost estimation methods apply to specific customer types?

A. Yes. The interruption cost estimates provided for residential customers in the LBNL Report, that comprise the meta-analysis data, are based on WTP survey methods, whereas the interruption cost estimates provided for C&I customers in the meta-analysis data are based on direct cost estimation surveys.

Q. If Dr. Dismukes' claim that there is upward bias in the WTP-based estimates used to derive the VoLL factors has merit, what proportion of the VoLL reflected in the Company's electric CBA is influenced by this bias?

A. Since only a small percentage (less than 5%) of the VoLL is contributed by residential customers in the Company electric CBA, only a small percentage can be similarly influenced by Dr. Dismukes' claim of upward bias within WTP-based interruption cost estimates.

Q. Is Dr. Dismukes accurate in his claims of WTP bias as it relates specifically to the LBNL regression models and the resulting VoLL factors used by the Company?

A. No. Dr. Dismukes' claims are incorrect for the VoLL factors used for the Company's C&I customers and too speculative in nature for the VoLL factors for residential customers to influence the consideration of the quality of the VoLL factors presented in the LBNL Report for use in the Company's electric CBA. A more reliable discussion on the bias inherent in customer interruption cost ("CIC") studies is offered in the recent Guidebook from Nexant and LBNL to guide survey development in this area. This Guidebook identifies the eight (8) main sources of potential bias in CIC studies: hypothetical, strategic response, utility benefit, status quo, anchoring, survey fatigue, nonresponse, and measurement error.[37] Moreover, as explained in the Guidebook, two (2) of these potential biases can increase estimates, two (2)

[37] Nexant and LBNL Guidebook, 2018, Table 5-1, page 60.

potential biases can decrease estimates, and four (4) potential biases can either increase or decrease the estimates. Several of the biases can potentially affect survey-based methodologies including WTP information solicitation techniques.

Q. Can we determine if the LBNL researchers were able to determine if the underlying CIC studies suffered from these potential biases, or if they were able to solicit information that was not unduly influenced by them?

A. No. On reaching a definitive conclusion on this question, the LBNL researchers noted, "We cannot determine, prime facie, the biases inherent in such self-reports of cost estimates associated with the hypothetical interruption scenarios."[38] However, they did acknowledge that, "there is concern that cost estimates based on hypothetical circumstances *may over or under estimate* the costs that occur under real conditions. There is no empirical evidence one way or another as to whether this concern is justified.[39]

Q. Is Dr. Dismukes accurate in his claims of WTP bias in any form, magnitude and direction?

A. No. Dr. Dismukes' offers claims of bias concerning WTP surveys generally but implicates the LBNL research specifically. We are not aware that he has inspected the specific surveys in question. Furthermore, as explained in the Guidebook, there are many forms of bias specifically relevant to cost estimation related to value of service attributes, not all which pertain to WTP surveys, and not all have an upward direction. Moreover, the Guidebook explains that each form of bias is associated with specific and practical methodologies that can be used to minimize bias: "The previous sections of this Guidebook discussed each of these sources of bias and how to mitigate them while designing and

[38] 2009 LBNL Report, page 6.
[39] 2009 LBNL Report, page xviii.

conducting the study."[40]

In summary, Dr. Dismukes apparently has not inspected the surveys and data in question, nor has he determined whether researchers involved in these surveys addressed specific forms of bias as part of their solicitations. The Board must reject his claims that the survey data nonetheless exhibits specific forms of bias, that it is of a specific direction and magnitude, and that it therefore disqualifies the LBNL research from consideration.

The Residential VoLL factor used in the gas CBA is appropriate

Q. At pages 29 of his direct testimony, Dr. Dismukes criticizes the methodology used by the Company to derive its residential VoLL factor used in its gas CBA, and on that basis, recommends that the VoLL-derived benefits should be disregarded. Do you agree with his criticisms and resulting recommendation?

A. No. Dr. Dismukes criticizes the use of the residential tariff price as the basis for the residential gas VoLL estimates. He argues that, "This approach, however, has nothing to do with the theoretical determinants of a customer's willingness-to-pay and should be dismissed by the Board. In fact, the method used by the Company in the ESII filing differs considerably from that used in its ESI filing which had more theoretic appeal despite several faulty calculation errors."

In making his claim, Dr. Dismukes presumably ignores a fair reading of the Company's gas CBA report. The report makes specific deference to valuation approaches, but also recognizes that the final valuation also depends on many other factors. Its appeal is that it is highly conservative and allows due emphasis to be placed on these other factors. The relevant section is quoted in its entirety:

[40] Nexant/LBNL Guidebook, page 59.

Black & Veatch offers that there are different approaches to measuring VoLL for residential customers facing costs of power interruption. Black & Veatch has noted arguments based on "contingent valuation" WTP arguments, consumer surplus-based arguments, and household income-based arguments. Black & Veatch notes that there are many variables impacting the outage scenario, such as duration, temperature, and restoration duration, all of which also impact the VoLL determination. For all of these reasons, and to provide a reasonable, yet conservative, view of VoLL, the cost-benefit analysis assumes that the customers simply value the loss of gas service at the currently effective price charged under PSE&G's residential gas tariff. The VoLL is, therefore, strictly proportionate to the foregone gas consumption during the outage period.

The assumptions and detailed calculations are presented in Appendix F - VoLL Calculations for PSE&G's Curtailment Resiliency Subprogram. The resulting VoLL during the outage period for PSE&G's residential customers is approximately $25M. On a per customer per day basis, this equates to $6.23. Black & Veatch notes that the VoLL analysis conducted for the ES I Gas Program resulted in a residential VoLL equal to $53 per day per customer, which is many times higher than this current estimate. Black & Veatch's approach to computing VoLL utilizes PSE&G's current gas commodity prices, which have declined over the ensuing 4-year period since the last VoLL analysis was conducted. Higher commodity prices would thus raise this estimate of VoLL.

The Black & Veatch approach makes no claim to limit prices (as part of consumer surplus-based assumptions) and other determinations of foregone gas consumption outside of assuming that in the absence of the outage event the customers would have continued to enjoy the use of the product in an uninterrupted fashion during this period. Most studies indicate, in fact, that a consumer values continued uninterrupted service at a level much higher than tariff prices for the service, recognizing as they do the significant direct and indirect costs and loss of welfare that results in a large and catastrophic event. As such, the Black & Veatch analysis approach is conservative.[41]

Q. How important is the benefit component associated with the residential VoLL to the overall gas CBA result?

A. We recognized that the residential VoLL estimate – even if utilizing a much higher value such as that offered by the Company in its ESI filing of $53/day – yields a very small contribution to the total VoLL benefits associated with the gas outage event.

[41] Attachment 6, Schedule BV-ESII-GAS-5, page 46.

Q. Why is the choice of such a conservative value appropriate?

A. The approach taken – as documented in the Company's gas CBA report -- provides the Board with a meaningful context about different valuation approaches. Furthermore, it explains that, "there are many variables impacting the outage scenario, such as duration, temperature, and restoration duration, all of which also impact the VoLL determination." Therefore, it provides meaningful guidance to the Board about how to weigh and consider the contribution of effects to the overall CBA results. Significant debates about various valuation methods would, in this instance, not yield significant benefit since the greater and more dispositive assumptions compared to the residential VoLL factors are the assumptions used to specify the characteristics of the gas outage event.

The C&I VoLL factor used in the gas CBA is appropriate

Q. At pages 30-32 of his direct testimony, Dr. Dismukes criticizes the methodology used by the Company to derive its C&I VoLL factor used in its gas CBA, and on that basis, recommends that the VoLL-derived benefits should be disregarded. Do you agree with his criticisms and resulting recommendation?

A. No. The gas CBA and its related VoLL for C&I customers does in fact recognize the concern with the assumption that 100 percent of the value added for the C&I customers impacted by a gas outage is permanently lost. For this reason, a downward adjustment was made to the VoLL as the gas CBA report explains:

> Black & Veatch agrees that the "Value Added" concept utilized in PSE&G's ES I proceeding for evaluating the VoLL for C&I customers is a reasonable approach. This is intuitive and assumes that C&I customers will face losses due to their inability to generate economic output if they cannot conduct business during the outage. **Black & Veatch also notes an adjustment that it believes is appropriate. At least one study recognizes differentials amongst customers for their sensitivity to gas use.** These differences implicitly address a wide range of differences associated with these businesses and their actions and recourse in an event of an outage of their gas service. In this study, it was determined that most of the small and medium businesses either

> valued strongly or very strongly continued gas service, but some did not. The cost-benefit analysis relies on specific assumptions concerning intensity of use, thus adjusting the Value Add to recognize that not all customers will be equally affected by the outage. As with residential VoLL estimates, Black & Veatch believes this is conservative and reasonable [42] (emphasis added).

Appendix F – VoLL Calculations for PSE&G Curtailment Resiliency Subprogram[43] – then proceeds to adjust downward the output value by over approximately 20% to "address a wide range of differences associated with these businesses and their actions and recourse in an event of an outage of their gas service."[44] The adjustment corresponds to the proportion of firm and non-firm gas customers served from PSE&G's gas distribution system. In certain respects, this adjustment also recognizes that the Company's gas C&I customers exhibit varying levels of economic resiliency to avoid potential losses from the gas outage event assumed under the Company's gas ESII.

Q. At pages 31-32 of his direct testimony, Dr. Dismukes provides references to academic literature which address the concept of economic resiliency in support of his claim that the Company's gas C&I VoLL estimates are unreasonable. Do you believe these literature references support Dr. Dismukes' claim?

A. No. We believe a closer inspection of the Adam Rose et. al. research on the economic resiliency of businesses during exogenous disasters shows that Dr. Dismukes' reliance on the reported findings is misplaced.

Dr. Dismukes cites the Rose research, and the findings related to the business losses and subsequent recovery in the aftermath of the World Trade Center ("WTC") disaster on September 11, 2001 as support for his need to significantly discount the direct costs estimated using the Company's gas C&I VoLL (for the C&I segment, these direct costs are estimated as

[42] Attachment 6 Schedule-BV-ESII-Gas-5, page 46.
[43] Attachment 6 Schedule-BV-ESII-Gas-5, page 91.
[44] Attachment 6 Schedule-BV-ESII-Gas-5, page 46

$894 million in Appendix F of the Company's gas CBA report). Dr. Dismukes suggests that this severe discount is proper due to the "direct economic resilience" effects estimated by Rose in the literature. Dr. Dismukes explains that the direct business interruption losses related to the WTC tragedy were 72 percent lower than what they would have been if all the WTC tenants had gone out of business. While we are not disputing Rose' findings which Dr. Dismukes is citing, Rose also provides a more thorough explanation of this 72 percent estimate in an article published in 2015:

> "We illustrate the application of the definition with the following case study by Rose et al. (2009), who estimated the national and regional economic impact of the September 11, 2001, terrorist attack on the World Trade Center. The researchers refined available data indicating that more than 95 percent of the businesses and government offices operating in the WTC area survived by relocating, primarily to Mid-town Manhattan or across the river in Northern New Jersey. Had all of these firms gone out of business, the potential direct economic loss in terms of GDP would have been $43 billion. However, relocation was not immediate, taking anywhere from a few days to as long as eight months for the vast majority of firms. Rose et al. (2009) calculated this loss in GDP at $11 billion. They were then able to apply the resilience definition to estimate that the effectiveness of relocation as a resilience tactic in the aftermath of the 9/11 attacks was 72 percent ($43 billion minus $11 billion, divided by $43 billion). In other words, Rose found that there were direct economic losses of $11 billion compared to the hypothetical losses of $43 billion had they gone out of business."[45]

Q. Why is this further commentary of the WTC disaster relevant to the gas C&I VoLL issue?

A. It reveals that Dr. Dismukes offers a faulty comparison with the Company's gas CBA, which makes no claim about hypothetical losses to the total Gross State Product ("GSP") of the effected C&I customers caused by these businesses going out of business. The Company's gas C&I VoLL estimate assumes the temporary loss of business over a gas curtailment event lasting about 45 days over which time these businesses will gradually resume operation.

[45] Rose, Adam, Measuring Economic Resilience: Recent Advances and Future Priorities, Center (CREATE) University of Southern California, September 27, 2015, pages 3-4.

Q. If you were making a claim that the Company's C&I gas customers would all go out of business because of the ESII gas outage event, how would that impact the gas C&I VoLL?

A. We would start with the contribution to the GSP made by all the Company's C&I gas customers within the gas outage event "footprint." This figure can be derived from Appendix F by multiplying $205.7 billion (i.e., the total state product of all the Company's C&I gas customers) by 8.1% (i.e., the percent of the Company's firm C&I gas customers curtailed during the gas outage). This yields an amount of $16.6 billion per year. This amount represents the lost value added if all the Company's C&I gas customers went out of business within the gas outage scenario "footprint." The estimated direct cost (the gas C&I VoLL) of $894 million used in the Company's gas CBA, as presented in Appendix F, is about 5 percent of the total loss in economic value of $16.6 billion.

Q. How should we interpret the Company's measure of direct cost impacts (the gas C&I VoLL) in comparison to this hypothetical "going out of business" loss estimate?

A. For the WTC business tenants, they lost about 28% of their yearly output in the aftermath of 9/11 according to the literature cited. In sharp contrast, for the Company's gas outage event occurring over a 45-day period, we estimate that the Company's C&I gas customers would lose only about 5% of their yearly output ($894 million divided by $16.6 billion) - which is a much more modest claim than that suggested by Dr. Dismukes in citing the ETC figures. This computation demonstrates that the Company's estimate of direct costs of $894 million is a small percentage (5%) of the total GSP for the affected region (PSE&G's service territory). We have not claimed that the direct costs for the Company's C&I gas customers are anywhere near the full value of their business output of $16.6 billion. Yet, this was the implication from Dr. Dismukes' argument based on his cited measure of resiliency (72%). The more appropriate way to discuss this resiliency measure in conjunction with the Company's CBA results is to simply note that under the Company's gas CBA, 5% of the subject firms' yearly output is lost, whereas in the resiliency literature example the cited amount of 28% (100% – 72% = 28%) was lost. This is the more appropriate way to view the Company's CBA result in relation to the specifically cited literature.

The inclusion of other gas outage-related avoided costs is appropriate

Q. At pages 28-29 of his direct testimony, Dr. Dismukes disputes the manner in which the Company estimates the other outage-related avoided costs associated with a gas outage event. How do you respond to his claim?

A. Dr. Dismukes observes that there is no supporting documentation for several technical factors that the gas CBA has used to support avoided cost estimates pertaining to space heating, temporary housing, and lost wages due to an extended gas outage. However, he ignores the purpose of these estimates and the all-important context in which they are offered. Moreover, his critique is of three avoided cost examples out of numerous other ones that are provided in the Company's gas CBA report. The following is an excerpt from the gas CBA report that explains the purposes of these and other avoided cost estimates that are addressed in the report:

> Care is needed when agglomerating all potential avoided costs and benefits to reach a total benefit value. Notwithstanding this caution, there are additional beneficial impacts beyond the VoLL estimates that are important to consider in the full accounting of cost and benefit effects. Some of these are alluded to briefly in the previous section. Some of these benefits represent costs excluded from the VoLL consideration. Others are public or social costs. Still others represent specific externalities (e.g., costs incurred by other entities should a major outage event occur). Together with VoLL, they reinforce the tremendous scale of impacts and costs businesses and consumers will face in the event of a major outage event. Some of the

> additional benefits identified below have been further estimated and are explicitly included in the benefit-to-cost ratio shown in Figure 1. Others are noted as qualitative benefits as part of Figure 1.[46]

The report then continues by itemizing in a series of bullet points the avoided costs of: construction period impacts, restoration costs, customer costs due to heating, housing and damages, lost wages, long-term business impacts, delays in utility programs, delays in other construction programs, impacts to local government services, additional transportation related costs, costs associated with education and day care, government fees and tax impacts, cascading economic impacts outside the region, loss of gas revenues, public safety impacts, loss of public confidence, and general welfare impacts.

Q. Are the three avoided costs Dr. Dismukes criticizes intended to serve as definitive benefit estimates?

A. No. Dr. Dismukes appears to ignore the explanation that is offered in the gas CBA report specifically concerning these three (and other) cost estimates:

> Black & Veatch acknowledges that the monetary estimates of these impacts are illustrative as some assumptions are speculative. For example, there is no research we are aware of to indicate how many electric space heaters might be purchased by customers facing an extended outage during 30-degree temperatures, or how man will seek temporary housing. (Certainly, many customers would find this to be a financial burden). However, while illustrative in nature, Black & Veatch also believes it is irrefutable that 435,500 customers facing a loss of gas services for an extended, multi-week period will make specific accommodations to secure their personal needs, which in turn will drive these types of costs.[47]

Q. What is the effect of Dr. Dismukes criticism?

A. Dr. Dismukes is effectively broadening his criticism concerning these three avoided costs to suggest to the Board that it should disregard the entirety of the benefits associated

[46] Attachment 6 Schedule-BV-ESII-Gas-5, page 48.
[47] Attachment 6 Schedule-BV-ESII-Gas-5, page 48.

with the Company's Gas subprogram. In doing so, Dr. Dismukes is obscuring the nature of the Company's evidence and its purposes. The purposes are stated explicitly within the gas CBA report, but they appear to be completely ignored by Dr. Dismukes. First, "There are additional beneficial impacts beyond the VoLL estimates that are important to consider in the full accounting of cost and benefit effects." Second, "Together with VoLL, they reinforce the tremendous scale of impacts and costs businesses and consumers will face in the event of a major outage event." Third, the illustrations are offered as evidence, "that 435,500 customers facing a loss of gas services for an extended, multi- week period will make specific accommodations to secure their personal needs, which in turn will drive these types of costs."[48]

Q. Are these impacts similar to the indirect avoided costs you cited earlier?

A. Yes, many are similar, and some are examples of direct costs that would be borne by private individuals. For the indirect costs, however, it is useful for the Board to appreciate that these costs can easily exceed direct and privately borne costs. The three costs criticized by Dr. Dismukes may be very small in comparison to the scale of long-term indirect effects of the gas outage.

The historic time period used for the electric CBA is appropriate

Q. At page 34 of his direct testimony, Dr. Dismukes claims it is unreasonable to include certain years in defining the weather-related outage events used in the Company's electric CBA because it "upwardly biases" the number of outages from major weather events. How do you respond to Dr. Dismukes' claim?

A. We strongly disagree with Dr. Dismukes' claim. The weather has a natural variability

[48] Attachment 6 Schedule-BV-ESII-Gas-5, pages 47 and 50.

and volatility that is difficult to predict. Including the additional years that were of concern to Dr. Dismukes results in a larger, more robust data set of outage-related information due to periodic storms and captures more of the natural variability and volatility. The result is a more reliable estimate of how the Company's electric distribution system is exposed to storm-related hazards.

Q. Why then did you limit the outage event data to a period of seven (7) years for purposes of conducting the Company's electric CBA?

A. We understand that the Company does not have a robust and reliable data set on electric outage conditions by specific circuit suitable to be used in the Company's electric CBA for the years before 2010.

Q. Would use of the last 5 years of outage event data, as argued by Dr. Dismukes, improve the quality of the Company's electric CBA?

A. No. The use of a shorter timeframe would ignore the occurrences of certain storm events, and by doing so would not provide sufficient information about how storms effect the Company's electric distribution system. By including more years of data which encompassed more outage events, the Company is able to evaluate the effects of storms on a larger set of substations, circuits, poles and other assets that are by nature more geographically dispersed, (since storm events have distinct geographic patterns as they move across the service territory).

There are issues with Dr. Dismukes' "alternative CBAs"

Q. Did you examine the IMPLAN Model used by Dr. Dismukes to conduct his "alternative CBAs"?

A. Yes. The Company requested Dr. Dismukes' workpapers for the IMPLAN Model and submitted data requests to solicit further information on the input assumptions he made. Our examination of this information did provide us with a general understanding of how Dr. Dismukes conducted his IMPLAN modeling activities and structured the multiple Excel spreadsheets which provided the input assumptions and results of his "alternative CBAs."

Q. Please provide your understanding of the "alternative CBAs" discussed by Dr. Dismukes in his direct testimony and summarized in Schedules DED-6 and DED-7.

A. We were able to determine that Dr. Dismukes used the IMPLAN Model to estimate the net economic impacts of the Company's ESII. He first estimated the direct, indirect and induced impacts of the expenditures associated with the Company's proposed investments under ESII. His analysis indicated that the ESII capital outlays and net O&M changes ($1.89B on a NPV basis) will produce jobs and result in multiplier benefits for the New Jersey economy (and presumably elsewhere). Next, Dr. Dismukes estimated the direct, indirect and induced economic impacts that a rate increase associated with the Company's ESII would have on the New Jersey economy. The rate increases are assumed to be recovered from residential, commercial, and industrial consumers and produce a negative economic impact. Based on the resulting economic impacts from the IMPLAN Model, Dr. Dismukes concluded that the long-term negative economic impact from the Company's rate increase would be greater than the positive long-term economic impact from the ESII investments, resulting in an overall or net negative economic impact on the State.

Q. At page 39 of his direct testimony, Dr. Dismukes explains that the IMPLAN Model is a well-respected model for examining regional economic impacts, particularly those associated with energy industries. How do you respond to his characterization?

A. While the IMPLAN Model is recognized as one of several useful input-output models, it does have limits in that it is unable to capture all the benefits associated with infrastructure investments, such as those proposed by the Company under ESII. In fact, the IMPLAN Model cannot compute the very benefits that are the motivation for the Company's ESII—system reliability and resiliency benefits. As a result, any CBA that does not reflect all the benefits of the Company's ESII creates biased results and understated estimates of value.

The limits of the IMPLAN-based CBAs performed by Dr. Dismukes are clearly revealed in his response to the Company's data requests. In his response to PSE&G-RC-DED-3, Dr. Dismukes acknowledged that the IMPLAN-based CBA: a) "excludes the inclusion of risk reduction benefits as identified for PSE&G's substation subprograms."; b) "excludes qualitative benefits"; and c) "...only includes benefits that have an identified monetary benefit." Therefore, the CBA resulting from the IMPLAN analysis prepared by Dr. Dismukes does not include all ESII benefits and, therefore, the resulting BCRs underestimate the true ESII benefits.

Dr. Dismukes' "alternative CBAs" are strictly limited to the consideration and measurement of a narrow set of identified monetary impacts included and parameterized within the IMPLAN Model, which ignores any other decision criteria. For that reason alone, his "alternative CBAs" should be given no weight by the Board.

Q. Are there other ways in which the IMPLAN Model fails to account for these important economic effects?

A. Yes. Dr. Dismukes' evaluation – by dismissing all reliability and resiliency benefits – fails to additionally account for the way a more reliable and resilient electrical grid supports and attracts economic activity. In fact, just as there are negative effects of power outages, including indirect effects, so too are there positive direct and indirect and long-lasting effects of improved electric system reliability and resiliency. For example, businesses will avoid long-term costs for such mitigations as back-up power generation, for example, or will choose to expand operations with the confidence that the power grid can provide reliable service. The IMPLAN Model has no way of capturing these indirect and long-term benefits of improved regional electrical system reliability and resiliency. In contrast, the Company's CBAs estimate the direct reliability and resiliency benefits through the application of the VoLL-based factors.

Q. Do you have any examples of other investments with reliability and resiliency benefits that would not be appropriately valued based on the IMPLAN Model?

A. Yes. One example would be the replacement of cast iron mains. A strict comparison of the cost of installing new plastic main versus the benefit of lower O&M costs from replacement of older cast iron mains would show the replacement as not being cost-beneficial. However, the safety risk of maintaining cast iron mains has been significant enough to result in a national call to action to replace cast iron mains. There is clearly a significant risk reduction-related benefit to replacing cast iron main that is not captured in the IMPLAN Model.

Further, Company witness Wade Miller compared the Company's proposed gas Curtailment Resiliency subprogram to a building installing a sprinkler system. A strict look at the cost of installing a sprinkler system versus the benefits to the economy from the investment would almost certainly result in a net economic loss. Does that mean sprinkler systems should not be installed in office buildings? Of course not. They are not being installed to result in net economic benefits. They are installed as a safety precaution and are undervalued if looked at strictly from a net economic impact perspective.

Q. **Are there additional factors or assumptions that contribute to the negative net benefit estimates derived by Dr. Dismukes?**

A. Yes. Any estimate of program benefits made using the IMPLAN Model would require an assumption as to the portion of program expenditures that occur within the region of study (New Jersey) or that involve purchases originating outside the study region that constitute "leakages" from the regional economy. It is not readily apparent in the supporting information provided by Dr. Dismukes the percentage of the $1.89 billion in ESII expenditures that he assumed would occur within New Jersey, but it is clear that this was assumed to be a relatively small percentage given that his estimated total output benefits are only $2.85 billion. This is a 1.51 ratio of benefits-to-program cost. On the other hand, the $1.89 billion in program expenditures that are assumed to be recovered through the Company's electric and gas rates are projected by Dr. Dismukes to have a negative economic impact of $5.40 billion, an impact-to-program cost ratio of 2.86.

This unexpected disparity in the resulting multipliers raises important questions on what Dr. Dismukes assumed when establishing his set of inputs for use in the IMPLAN

Model and whether those assumptions caused his results to be skewed to the extent described above.

Q. Based on Dr. Dismukes' above-described treatment of the ESII investments and the related rate impacts in the IMPLAN Model, and the exclusion of any other benefits besides the increased economic activity caused by the ESII investments, do you believe any utility investment evaluated in a similar manner would be able to show a positive economic benefit?

A. No. As Dr. Dismukes explained in his response to PSE&G-RC-DED-2, he "cannot identify any prior testimony addressing the economic impacts of energy infrastructure development that would lead to positive net economic benefits..." for utility programs. This raises the question of whether *__any__* utility expenditure would be recommended based on the "alternative CBA" method used by Dr. Dismukes. Moreover, it underscores the reality that utility investments are often supported on a range of evaluation decision criteria, including at times through the results of a CBA. These criteria include whether the investment promotes the provision of a safe, adequate, and reliable supply of electricity or natural gas supply to utility customers at the lowest reasonable cost and in an environmentally acceptable manner.

Q. Do you have any response to the assumption made by Dr. Dismukes related to the rate impact associated with ESII?

A. Yes. Dr. Dismukes' assumption appears to be faulty because it assumes within the IMPLAN Model that the Company's C&I customers reduce their services or physical productive output provided to and for their customers by the total amount of the net rate increase for ESII. We do not believe this is a fair assumption about the way the economy works in practice. In reality, these customers will engage in adaptive behaviors by attempting to adjust their prices for products and services to account for the increases experienced in the electric and gas rates they are charged, absorb the increase in their costs of doing business and accept a reduced level of financial performance (and to retain market share), or some combination of these two options. In each of these cases, the level of products and services provided by these C&I customers may not decline and may not cause a decrease in economic activity in the State. This means that Dr. Dismukes has overstated in his "alternative CBAs" the negative economic activity he has attributed to ESII.

Q. Does this complete the Panel's rebuttal testimony?

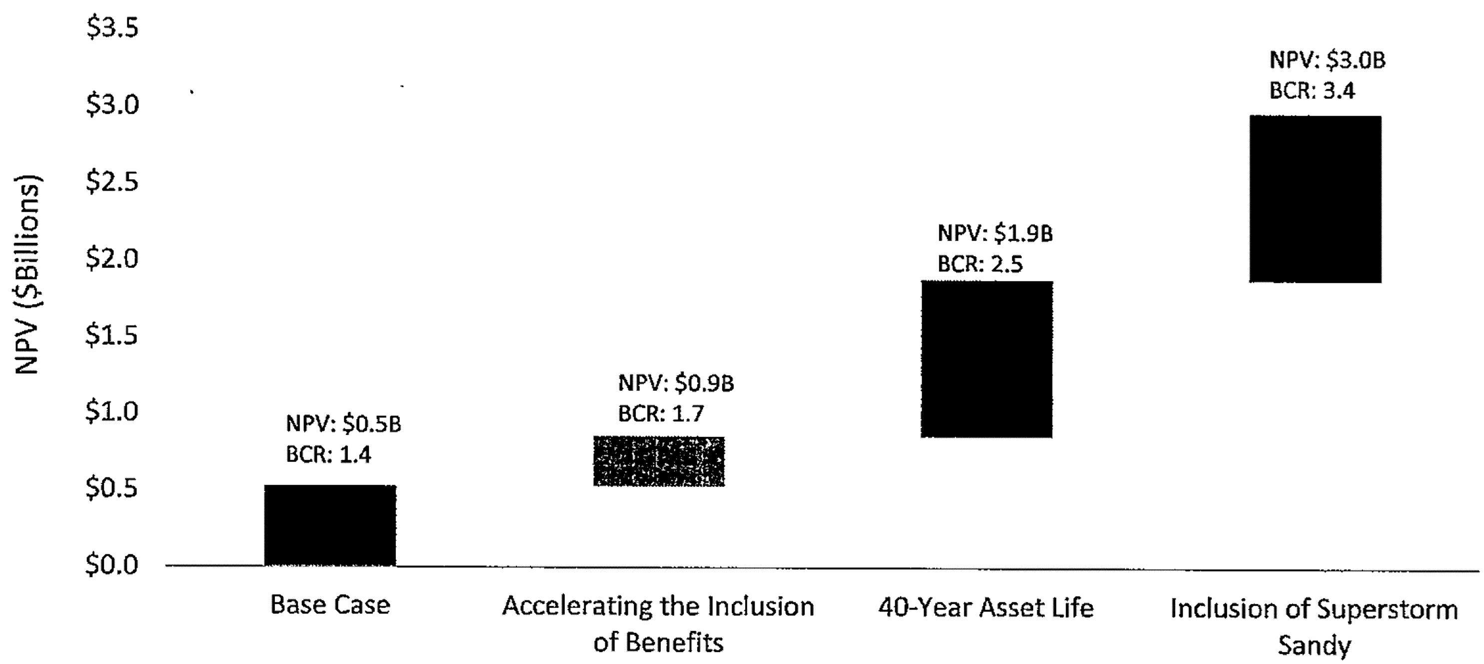
A. Yes.

Benefit Types

	Column A	Column B	Column C	
	Cost Type →	Direct Costs (immediate consequences of outage)	Indirect Costs (provoked by consequences of outage; represent the chain reaction of economic losses stemming from direct costs)	Time
Beneficiary (if costs avoided)	Whose costs are considered?	Those subject to the direct outage effects	Costs incurred by people and firms subject to outage and people and firms outside the affected areas	
Benefit Type	Monetary (e.g., VoLL)	Included ($) Captured in Residential and C&I VoLL, and avoided Capital and O&M expenses	Monetary estimates cited as range of possible effects, per resiliency literature (0.5 - 2.0 of direct costs)	
	Quantified (not monetized) - e.g., risk reduction	Included: Captured in narrative terms in benefits such as risk reduction	Included: Captured in narrative terms in benefits such as risk reduction	
	Qualitative	Included: Captured in narrative terms in benefits such as risk reduction	Included: Captured in narrative terms in benefits such as risk reduction	

- Definitions and typecasting of direct and indirect benefits related to outages taken from Sullivan, M., The FSC Group. Downtown San Francisco Long Duration Outage Cost Study. March 2013. Appendix B, Literature Review. This dichotomy is offered in relation to resiliency scale outage events lasting over 12 hours. Typecasting of monetary, quantified and qualitative taken from Electric and Gas CBA reports.
- The dimension of time is suggested by the authors of the CBA report. This provides an additional dimension of explanatory value about the nature of the direct and indirect cost occurrences. Indirect costs will incur over long periods of time. They are also influenced by adaptive behaviors as outage durations increase.

Monetary Benefits for the Company's Electric CBA
Under Less Conservative Assumptions



BCR = Present value benefit-to-cost ratio

LISTING OF PRINCIPAL REFERENCE SOURCES FOR ELECTRIC VALUE OF LOST LOAD (VOLL) RESEARCH EFFORTS

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4. Sullivan, M., Mercurio, M., Schellenberg, J., "Estimated Value of Service Reliability for Electric Utility Customers in the United States," Ernest Orlando Lawrence Berkeley National Laboratory. LBNL Research Project. LBNL-2132E. June 2009.
5. Sullivan, M., Schellenberg, J., Blundell, M. *Nexant*, Inc. "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States", (Prepared for the Office of Electricity Delivery and Energy Reliability, a Division U.S. Department of Energy). Ernest Orlando Lawrence Berkeley National Laboratory. LBNL Research Project LBNL-6941E. Berkeley, CA, January 2015.
6. Electric Power Research Institute. "Electric Power System Resiliency, Challenges and Opportunities". White Paper. 3002007376. Palo Alto, CA, February 2016.
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8. Sullivan, M., Collins, M., Schellenberg, J., *Nexant*, Inc., and Larsen, Peter. "Estimating Power System Interruption Costs: A Guidebook for Electric Utilities," (Prepared for the Office of Electricity Transmission Permitting and Technical Assistance Division U.S. Department of Energy.). Ernest Orlando Lawrence Berkeley National Laboratory. Berkeley, CA, July 2018.
9. Frontiers in the Economics of Widespread, Long-Duration Power Interruptions: Proceedings from an Expert Workshop. Editors Larsen, P., Sanstad, A., LaCommare, K., Eto, J. (Prepared for the Office of Electricity Transmission Permitting and Technical Assistance Division U.S. Department of Energy.). Ernest Orlando Lawrence Berkeley National Laboratory. Berkeley Berkeley, CA, January 2019.