Exhibit No. MPG-1T
Dockets UE-170033 and UG-170034 (Cons.)
Witness: Michael P. Gorman

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-170033 and UG-170034 (Consolidated)**

RESPONSE TESTIMONY OF MICHAEL P. GORMAN

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 30, 2017

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. WHAT IS YOUR OCCUPATION?

A. I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. These are set forth in Exhibit No. MPG-2.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"), an association of large industrial businesses, some of whom are customers of Puget Sound Energy ("PSE" or the "Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony focuses on certain aspects of PSE's proposed rate of return, electric class cost of service and rate design. Specifically, my testimony addresses the following areas:

- PSE's proposed return on equity;
- PSE's electric revenue decoupling mechanism ("RDM");
- The classification and allocation of electric generation and transmission fixed costs;
- The appropriate distribution among rate schedules of any change in electric base rate revenues approved in this case;
- PSE's proposed changes to the earnings sharing band approved in its last rate case;
- PSE's proposal to implement a formalized, expedited rate filing process; and

- PSE's proposed electric cost recovery mechanism.

The fact that I am not addressing other issues in the Company's application in this proceeding should not be construed as an endorsement of the Company's position with regard to such issues.

I. PROPOSED RETURN ON EQUITY

Q. WHAT RETURN ON EQUITY IS PSE REQUESTING IN THIS PROCEEDING?

A. PSE is requesting an authorized return on equity of 9.8% in this proceeding. The Company's return on equity is supported by the Direct Testimony of Dr. Roger A. Morin. Dr. Morin has performed a Discounted Cash Flow ("DCF") analysis, a Capital Asset Pricing Model ("CAPM") and risk premium studies to support the Company's return on equity of 9.8%. (Direct Testimony of Dr. Morin, Exhibit No. ___ (RAM-1T) at 55).

Q. IS THE COMPANY'S REQUESTED RETURN ON EQUITY OF 9.8% REASONABLE?

A. No. On May 7, 2012, the Commission adopted a settlement agreement in PSE's rate case (Washington Utilities and Transportation Commission, Docket UE-111048) which included a return on equity of 9.80%. In 2012, industry average authorized returns on equity for electric and gas utilities were 10% and 9.94%, respectively. Since 2012, industry authorized returns on equity have declined by approximately 40 basis points. Currently, industry authorized returns on equity have been around 9.6%, approximately a 40 basis point reduction since the Washington Commission last approved a return on equity for PSE of 9.8%.

Bond yields are also additional observable evidence of declining capital market cost. This is illustrated by a comparison of bond yields in this case and the 2012 rate case. In Table 1 below, I show the change in utility bond yields.

TABLE 1

Capital Costs – PSE's Rate Cases

Description	**Current Case[1]**	**Docket UE-111048**	**Yield Change**
30-Year Treasury Yields	2.92%	3.18%	0.26%
"A" Rated Utility Bond Yields	4.09%	4.40%	0.31%
"Baa" Rated Utility Bond Yields	4.47%	5.08%	0.61%
13-Week Period Ending	06/16/2017	5/04/2012	

Source:
[1]Exhibit No. MPG-3.

As shown in the table above, the current market cost of debt for A and Baa-rated utility bond yields has decreased in this case relative to PSE's 2012 rate case. The current A rated utility yield is approximately 30 basis points lower than it was in PSE's 2012 rate case. The yield change is even more profound for Baa-rated utility yields. The current "Baa" rated utility bond yield is approximately 60 percentage points lower now than it was in PSE's 2012 rate case. Therefore, PSE's current authorized return on equity of 9.8% is excessive and should be reduced to reflect current market costs.

Also, I show evidence that since 2012 as authorized returns on equity have been declining, utilities' financial integrity has been preserved, their credit ratings have strengthened, and the utilities have supported very large capital programs under reasonable terms and conditions. This is clear observable evidence that the Commission should consider a much lower return on equity for PSE in this case.

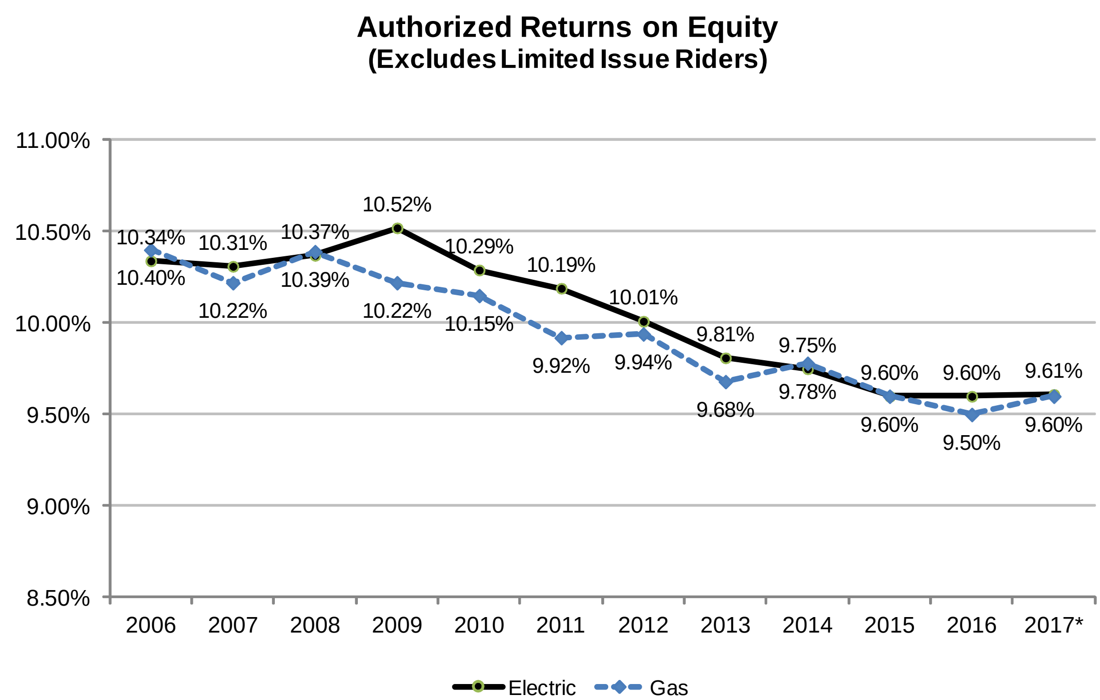
Finally, I comment on Dr. Morin's specific analyses supporting the Company's return on equity of 9.8%. Dr. Morin's analysis, with proper adjustments to his return on equity, shows the current market cost of equity is in the range of 8.6% to 9.6%. I will present these findings in rebuttal to Dr. Morin in this testimony.

<u>I.A. Lower Capital Market Cost and Supportive Regulatory Treatment</u>

Q. PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED RETURNS ON EQUITY FOR ELECTRIC AND GAS UTILITIES, UTILITIES' CREDIT STANDING, AND UTILITIES' ACCESS TO CAPITAL TO FUND INFRASTRUCTURE INVESTMENT.

A. Authorized returns on equity for both electric and gas utilities have been steadily declining over the last 10 years, as illustrated in Figure 1 below. More recent authorized returns on equity for electric utilities have declined down to about 9.60%, and local gas delivery utilities' returns on equity have declined to 9.60%. Further, authorized returns for gas delivery utilities have consistently trended at or below the returns authorized for electric utilities.

FIGURE 1



Source and Note:
Regulatory Research Associates, Inc., Regulatory Focus, Major Rate Case Decisions -- January - March 2017, April 20, 2017 at pages 5 and 6.
*January - March 2017

While the declines in authorized returns on equity are public knowledge, and align with declining capital market costs, utilities are maintaining stable investment grade credit standing, and have been able to attract large amounts of capital at low costs to fund very large capital programs.

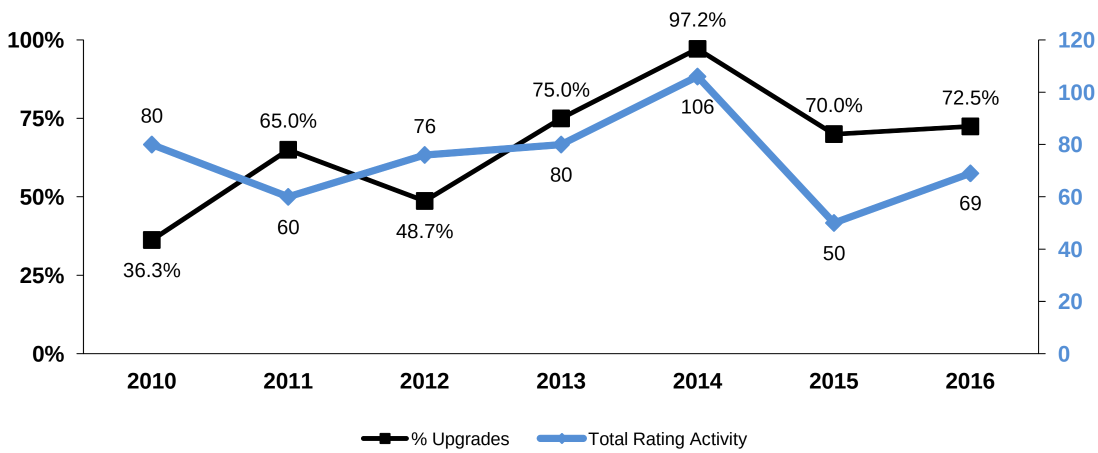
Q. PLEASE DESCRIBE THE TREND IN CREDIT RATING CHANGES IN THE ELECTRIC UTILITY INDUSTRY OVER THE LAST FIVE YEARS.

A. As shown in Figure 2 below, over the period 2010-2016, the electric utility industry has experienced a significant number of upgrades in credit ratings by all of the major credit rating agencies (Fitch Ratings, Moody's, and Standard & Poor's).

FIGURE 2

Credit Rating Changes
(U.S. Shareholder-Owned Electric Utility Industry)

	2010	2011	2012	2013	2014	2015	2016
Upgrades	29	39	37	60	103	35	50
Downgrades	51	21	39	20	3	15	19
% Upgrades	36.3%	65.0%	48.7%	75.0%	97.2%	70.0%	72.5%
Total Rating Activity	**80**	**60**	**76**	**80**	**106**	**50**	**69**



Source: EEI 2016 Q4 Credit Ratings. Tab IV. Direction of Rating Action.

As noted above in Figure 2, the upgrades in utility credit ratings started outpacing downgrades in 2011, and more recently, the number of upgrades has substantially exceeded the number of downgrades. For example, in 2014, there were 103 upgrades and only three downgrades. In 2015, the number of upgrades was more than twice the number of downgrades (35 upgrades and 15 downgrades). This trend was even more profound in 2016.

Q. HOW DID THIS CREDIT RATING ACTIVITY IMPACT THE CREDIT RATING OF THE ELECTRIC UTILITY INDUSTRY?

A. The credit rating changes for the electric utility industry reflected a significant strengthening of the electric utility industry credit rating as shown below in Table 2. As shown in this table, in 2008, approximately 69% of the electric utility industry was rated from BBB- to BBB+, 18% had a bond rating better than BBB+, and around 13% of the industry was below investment grade. This industry rating improved steadily over the subsequent eight years. By 2016, only about 3% of the industry is below investment grade, around 65% continue to be in the range of BBB- to BBB+, and over 32% of the industry has a bond rating above BBB+. Overall, the improvement to the credit rating of the electric utility industry has been very significant.

TABLE 2

S&P Ratings by Category
(Year End)

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016
Regulated									
A or higher	8%	7%	9%	8%	6%	3%	3%	3%	5%
A-	10%	15%	14%	14%	17%	20%	21%	22%	27%
BBB+	23%	22%	17%	19%	14%	17%	32%	33%	35%
BBB	23%	27%	31%	35%	36%	49%	37%	33%	22%
BBB-	23%	20%	17%	14%	17%	6%	3%	3%	8%
Below BBB-	13%	10%	11%	11%	11%	6%	5%	6%	3%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: EEI 2016 Q4 Credit Ratings. Tab V. S&P Rating by Comp. Category.

Q. HAVE CREDIT RATING AGENCIES COMMENTED ON DECLINING AUTHORIZED RETURNS ON EQUITY?

A. Yes. Credit rating agencies recognize the declining trend in authorized returns and the expectation that regulators will continue lowering the returns for U.S. utilities while maintaining a stable credit profile. Specifically, Moody's states:

> **Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles**
>
> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to

> trim the sector's profitability by lowering its authorized returns on equity (ROE).[1/]

Further, in a recent report, Standard & Poor's ("S&P") states:

> **2. Earned returns will remain in line with authorized returns**
>
> Authorized returns on equity granted by U.S. utility regulators in rate cases this year have been steady at about 9.5%. Utilities have been adept at earning at or very near those authorized returns in today's economic and fiscal environment. A slowly recovering economy, natural gas and electric prices coming down and then stabilizing at fairly low levels, and the same experience with interest rates have led to a perfect "non-storm" for utility ratepayers and regulators, with utilities benefitting alongside those important constituencies. Utilities have largely used this protracted period of favorable circumstances to consolidate and institutionalize the regulatory practices that support earnings and cash flow stability. We have observed and we project continued use of credit-supportive policies such as short lags between rate filings and final decisions, up-to-date test years, flexible and dynamic tariff clauses for major expense items, and alternative ratemaking approaches that allow faster rate recognition for some new investments.[2/]

Q. HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT INFRASTRUCTURE CAPITAL PROGRAMS?

A. Yes. While cost of capital and authorized returns on equity were declining, the utility industry has been able to fund substantial increases in capital investments needed for infrastructure modernization and expansion. The Edison Electric Institute ("EEI") reported in a 2015 financial review of the electric industry financial performance that electric "industry-wide capex has more than doubled since 2005."[3/]

EEI also observed that, despite this significant increase in capital expenditures during the period 2005-2015, a majority of the funding for utilities' capital

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[1/] *Moody's Investors Service*, "US Regulated Utilities: Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

[2/] *Standard & Poor's Ratings Services*: "Corporate Industry Credit Research: Industry Top Trends 2016, Utilities," December 9, 2015, at 23, emphasis added.

[3/] Edison Electric Institute, *2015 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry*, page 17.

expenditures has been provided by internal funds. EEI reports that approximately 25% of funding needed to meet these increasing capital expenditures has been derived from external sources and 75% of these capital expenditures have been funded by internal cash. Further, despite nearly tripling capital expenditures and increases in the amount of outstanding debt, the electric utility industry's debt interest expense has declined by approximately 1.9%.[4/] This is clear proof that utilities have enjoyed access to large amounts of capital, and that the costs of capital have declined.

Similarly, in its March 21, 2017 Capital Expenditure Update report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several relevant comments about utility investments generally:

> Capital expenditures throughout the U.S. power and gas sectors in 2017 are projected to reach an all-time high of $117.5 billion. The nation's largest electric and gas utilities are investing in infrastructure to comply with sweeping environmental regulations, implement new technologies, build new natural gas, solar and wind generation and upgrade aging transmission and distribution systems. Moreover, their near-term capital spending forecasts continue to escalate — see below for individual examples. Total CapEx in 2016 for the companies in the RRA utility universe was $110.3 billion. We expect considerable levels of spending to serve as the basis for solid profit expansion for the foreseeable future, although our data indicates that CapEx in the industry may fall modestly in 2018 and 2019.[5/]

Indeed, historical versus projected outlooks for the electric and gas industries' capital investments are shown in Figure 3 below. As shown in this graph, electric industry investment outlooks are expected to be considerably higher relative to the last 10-year historical period. As noted by S&P Global Market Intelligence, this capital

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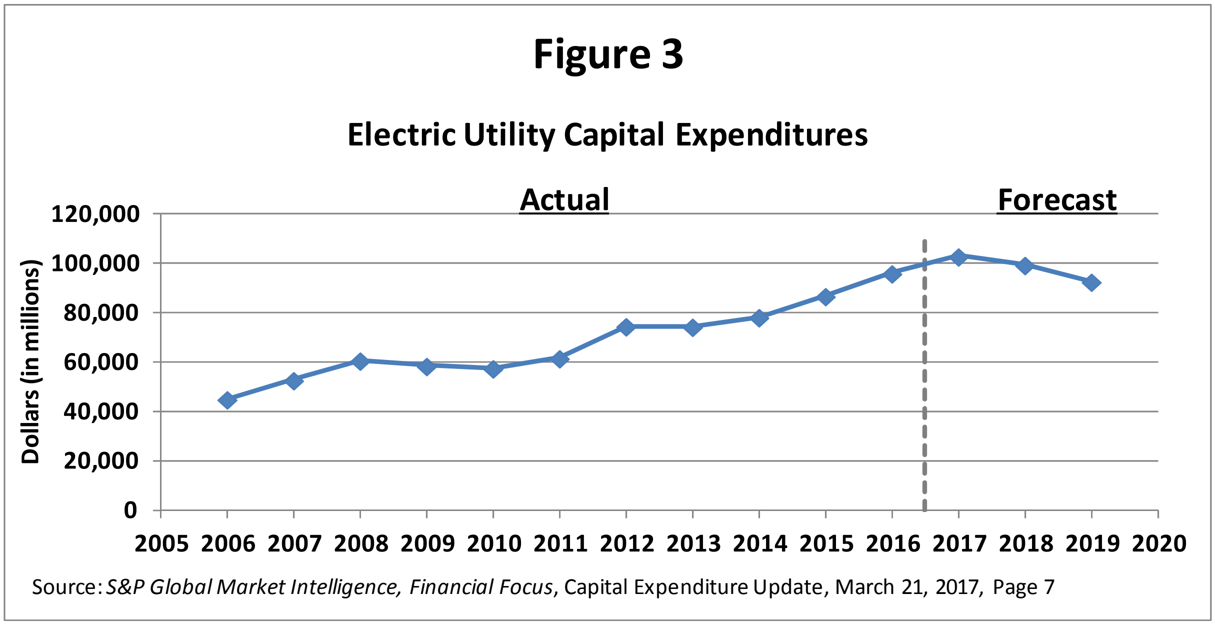
4/ *Id.*, pages 8 and 11.

5/ S&P Global Market Intelligence, RRA Financial Focus: "Capital Expenditure Update," March 21, 2017 at 1.

investment is exceeding internal sources of funds to the electric utilities, requiring them to seek external capital to fund capital investments.



Q. IS THERE EVIDENCE OF ROBUST VALUATIONS OF ELECTRIC UTILITY EQUITY SECURITIES?

A. Yes. On my Exhibit No. MPG-4, I show the historical valuation of the electric utility industry followed by *Value Line* based on price-to-earnings ratio, price-to-cash flow ratio and market price-to-book value ratio indicators. These electric utility industry security valuation metrics show that current electric utility stock valuations are very strong and robust relative to the last 10 to 15 years. These robust valuations are an indication that utilities can sell equity securities at high prices, which is a strong indication that they can access capital under reasonable terms and conditions, and at relatively low cost.

I.B. PSE Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF PSE.

A. The market's assessment of PSE's investment risk is described by credit rating analysts' reports. PSE's current corporate bond ratings from S&P and Moody's are BBB and Baa1, respectively.[6/] The Company's outlook from S&P and Moody's is "Stable."

I.C. Response to Dr. Morin

Q. WHAT RATE OF RETURN ON COMMON EQUITY IS PSE REQUESTING IN THIS PROCEEDING?

A. PSE is requesting a return on common equity of 9.8% based on the analysis and testimony sponsored by Dr. Roger Morin.

Q. PLEASE DESCRIBE HOW DR. MORIN DEVELOPED HIS MARKET COST OF EQUITY FOR PSE.

A. Dr. Morin used a DCF model, a CAPM, an Empirical CAPM ("ECAPM"), and a risk premium study to support his return on equity estimate for PSE. Dr. Morin employed these models to a group of utilities followed by *Value Line*.

His estimated return on equity results for PSE are shown below in Table 3 under Column 1. Under Column 2, I show adjustments to Dr. Morin's return estimates.

6/ SNL Financial, downloaded on June 29, 2017.

TABLE 3

Summary of Dr. Morin's Return on Equity Estimates

Description	**Morin Results (1)**	**Adjusted (2)**
Constant Growth DCF		
Value Line Growth	9.8%	9.4%
Analysts' Growth	9.4%	9.4%
Average Constant Growth DCF	**9.6%**	**9.4%**
CAPM		
Traditional CAPM	9.3%	8.6%
Empirical CAPM	9.8%	Reject
Average CAPM	**10.2%**	**8.6%**
Risk Premium		
Historical Risk Premium	10.5%	9.8%
Allowed Risk Premium	10.7%	9.3%
Average Risk Premium	**10.6%**	**9.6%**
Recommended Return on Equity	**9.8%**	**8.6% - 9.6%**
		9.1%

Source: Morin Direct Testimony at 55.

With reasonable adjustments described in detail below, Dr. Morin's analyses will support my recommended return of equity for PSE of 9.1%.

I.D. Dr. Morin's DCF Analyses

Q. PLEASE DESCRIBE DR. MORIN'S DCF ANALYSES.

A. Dr. Morin performed two constant growth DCF analyses on a group of combination electric and gas utilities followed by *Value Line*, using *Value Line*'s projected growth rates for the first one and consensus analysts' growth rate projections from Yahoo! Finance for the second one.

As shown on his Exhibit No. ___ (RAM-5) and (RAM-6), he relied on average growth rate estimates in the range of 6.03% to 5.46% from *Value Line* and *Zacks* to produce a DCF cost of equity in the range of 9.78% to 9.36%.[7/]

Q. PLEASE DESCRIBE THE ISSUES YOU TAKE WITH DR. MORIN'S DCF ANALYSES.

A. My major concern with Dr. Morin's DCF analysis is that, he failed to provide any evaluation of whether or not the proxy group three- to five-year growth rate estimates are reasonable estimates of long-term sustainable growth. Further, Dr. Morin's use of *Value Line* growth rates in his DCF analysis is not reasonable.

Q. DO YOU BELIEVE DR. MORIN'S DCF STUDY PRODUCES A FAIR ESTIMATE OF PSE'S CURRENT MARKET COST OF EQUITY?

A. No. Dr. Morin's proxy groups contain average growth rates of 6.03% and 5.46%, respectively. These growth rates are too high to be reasonable estimates of long-term sustainable growth.

Q. WHY ARE THE GROWTH RATE ESTIMATES USED IN DR. MORIN'S DCF STUDY NOT REASONABLE?

A. Dr. Morin's average growth rates from *Value Line* and *Yahoo! Finance* fall in the range of 5.27% to 6.00%. These growth rate estimates exceed the projected GDP growth rate of 4.20%[8/] for the next five to 10 years. As explained in detail earlier in my testimony, the GDP growth rate can be used as a proxy for a long-term sustainable growth rate because it represents the maximum growth rate of the U.S. economy. The growth rate estimates used in Dr. Morin's DCF study exceed the projected GDP

7/ Exhibit No. ___(RAM-1T) at 31.

8/ *Blue Chip Financial Forecasts*, June 1, 2017 at 14.

growth rate of 4.20% by approximately 107-180 basis points, and inflate the DCF return on equity results for PSE.

Q. WHY DO YOU BELIEVE THAT USING *VALUE LINE* GROWTH RATES IS NOT REASONABLE?

A. *The Value Line Investment Survey* provides growth rates from single professional analysts. Using *Value Line* growth rates contradicts Dr. Morin's own testimony:

> As proxies for expected growth, I examined the consensus growth estimate developed by professional analysts. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model.[9/]

I agree using consensus analysts' growth rates is more appropriate that using growth rates provided by a single analysts. Therefore, Dr. Morin's DCF using *Value Line* growth rates should be given minimum weight or completely disregarded.

Q. DO YOU HAVE ANY FURTHER COMMENTS IN REGARD TO DR. MORIN'S DCF MODEL?

A. Yes. The Commission should place primary weight to Dr. Morin's DCF result based on consensus analysts' growth rates of 9.4% and consider this result as high-end

9/ Exhibit No. ___(RAM-1T) at 22.

estimate of a fair return on equity for PSE because it is based on excessive growth rates.

I.E. Dr. Morin's CAPM Analysis

Q. PLEASE DESCRIBE DR. MORIN'S TRADITIONAL CAPM ANALYSIS.

A. Dr. Morin developed a CAPM return estimate of 9.3%% based on a group average beta of 0.70, a risk-free rate of 4.4% and a market risk premium of 7.0%.[10/]

Q. WHAT ISSUES DO YOU TAKE WITH DR. MORIN'S CAPM ANALYSIS?

A. My primary issues with Dr. Morin's CAPM study is that his risk-free rate of 4.4% significantly exceeds independent market participants' outlooks for Treasury bond yields. While I also disagree with Dr. Morin's methodology of applying the income return on Treasury yields in development of his historical market risk premium of 7.0%, I will not take issues with it, because it represents a reasonable market risk premium estimate.

Q. HOW DID DR. MORIN DEVELOP HIS RISK-FREE RATE ESTIMATE?

A. Dr. Morin developed his risk-free rate estimate using the projections made by the CBO, U.S. Department of Labor, U.S. EIA, *Global Insight*, and *Value Line.* At page 37 of his testimony, Dr. Morin states that the average forecast from these sources is 4.4%.

10/ Exhibit No. ___(RAM-1T) at 45.

Q. WHAT ISSUES DO YOU HAVE WITH DR. MORIN'S RISK-FREE RATE?

A. Dr. Morin used a projected risk-free rate of 4.4%, which is well in excess of the consensus economists' projected 30-year Treasury bond yield of 3.7%[11/] as published in *The Blue Chip Financial Forecasts*.

Dr. Morin's 4.4% projected Treasury bond yield exceeded consensus economists' outlooks by 70 basis points. Therefore, his CAPM return estimate is overstated.

Q. CAN DR. MORIN'S TRADITIONAL CAPM ANALYSIS BE CORRECTED TO PRODUCE MORE RELIABLE RESULTS?

A. Yes. Correcting Dr. Morin's traditional CAPM analysis by using a Duff & Phelps historical market risk premium of 7.0%, an estimated beta of 0.70, and using a consensus economists' projected risk-free rate (30-year Treasury bond yield) of 3.7%, produces a traditional CAPM cost estimate of approximately 8.6%.

I.F. Dr. Morin's Empirical CAPM ("ECAPM")

Q. PLEASE DESCRIBE DR. MORIN'S ECAPM ANALYSIS.

A. The ECAPM analysis modifies the traditional CAPM equation by including a risk premium weighted by the utility beta, and the overall market beta of 1.0. The original ECAPM analysis was designed to use unadjusted regression betas. In Dr. Morin's ECAPM analysis, he adds two weighted risk premiums to a risk-free rate: a 75% weighted risk premium based on a 0.70 utility beta, and a 25% weighted risk premium based on a beta equal to the overall market beta of 1.0. The theory of the ECAPM is that a beta of less than 1.0 will increase toward the market beta of 1.0 over time, which is necessary because the risk of securities will be increasing over time.

11/ *Blue Chip Financial Forecasts*, June 1, 2017 at 2.

Q. WHAT ISSUES DO YOU TAKE WITH DR. MORIN'S ECAPM ANALYSIS?

A. The ECAPM analysis should be rejected for several reasons. First, the practical result of Dr. Morin's ECAPM is that the CAPM return is based on a beta estimate of 0.78,[12/] instead of his actual *Value Line* utility beta of 0.70. The ECAPM analysis significantly overstates a utility company-specific risk premium for use in a risk premium analysis.

Dr. Morin included an adjusted beta within her ECAPM study. I believe this is inconsistent with the academic research supporting the development of an ECAPM methodology.[13/] Bottom line, using adjusted betas within an ECAPM study double counts the purpose of the ECAPM study – that is, to flatten the security market line and increase a CAPM return estimate for companies with betas less than 1, and decrease the CAPM return estimate for betas greater than 1. Dr. Morin goes over the objective of the ECAPM at pages 45-49 of his direct testimony. As shown in Dr. Morin's CAPM figure on page 46, the ECAPM will raise the intercept point of the security market line and flatten the slope. Again, this has the effect of increasing CAPM return estimates for companies with betas less than 1, and decreasing the CAPM return estimates for companies with betas greater than 1. Importantly, however, the use of an adjusted beta such as those published by *Value Line*, produces comparable adjustments to the security market line and CAPM return estimate. For all these reasons, Dr. Morin's ECAPM analysis should be rejected.

12/ 75% x 0.70 + 25% x 1 = 0.78.

13/ See Black, Fischer, "Beta and Return," *The Journal of Portfolio Management*, Fall 1993, 8-18; and Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," 1972.

Q. DOES DR. MORIN ATTEMPT TO JUSTIFY THE USE OF AN ADJUSTED BETA IN AN ECAPM ANALYSIS?

A. Yes, he does. At pages 48-49 of his testimony, Dr. Morin makes the argument that an adjusted beta is a horizontal axis adjustment and the ECAPM is a vertical axis adjustment.

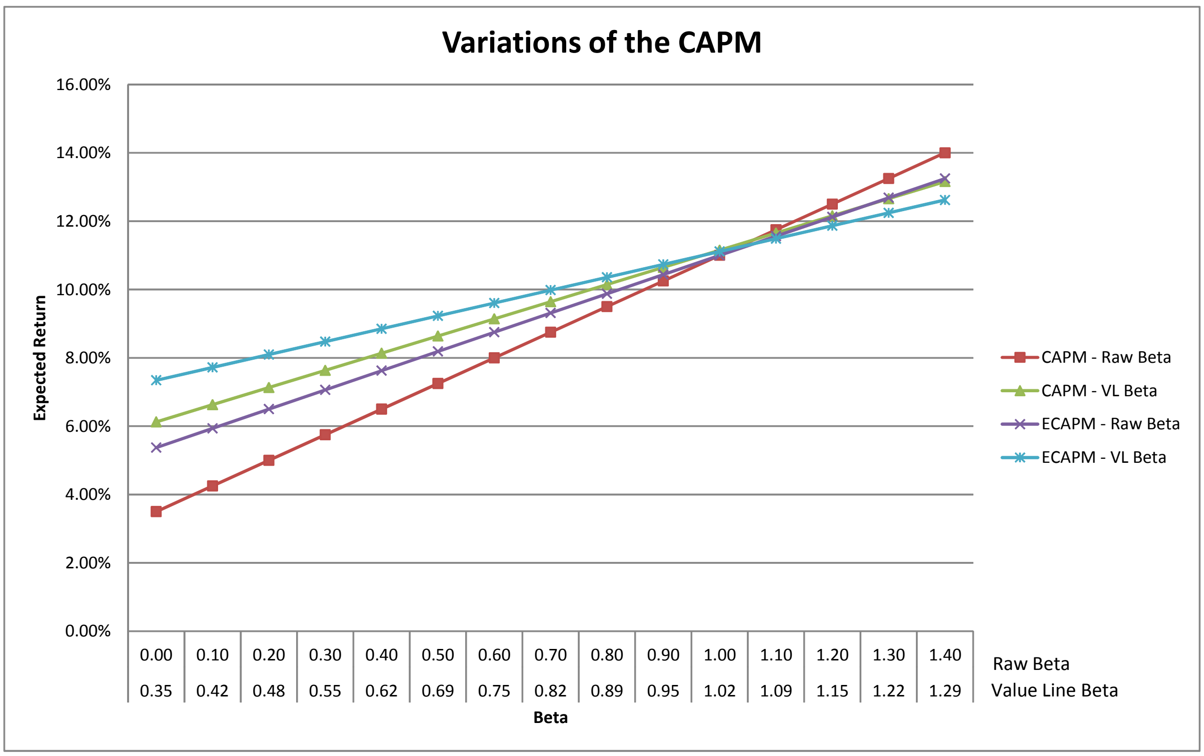
Q. PLEASE RESPOND TO DR. MORIN'S ASSERTION.

A. Dr. Morin's assertion that an adjustment to beta is only a horizontal axis adjustment is not true. The *Value Line* beta adjustment alters the CAPM return at both the vertical axis (the intercept point) and the horizontal axis, the slope of the CAPM return line (along the horizontal axis). This is depicted in Figure 4 below.

As shown in Figure 4, I have modeled the expected returns at various levels of raw beta using both the traditional CAPM and ECAPM methodologies assuming a risk-free rate of 3.50%, and a market risk premium of 7.50%. I also show the expected CAPM and ECAPM returns using the associated adjusted *Value Line* beta estimates for each raw beta estimate. As shown in Figure 4 below, the impact on the traditional CAPM return using an unadjusted beta and a traditional CAPM using an adjusted beta has the effect of increasing the intercept point at a zero raw beta (y axis) from: (1) risk-free rate, to (2) the combination of the risk-free rate plus 35% of the market risk premium. Further, as the unadjusted beta is increased above zero, the adjusted beta increases the CAPM return when the unadjusted beta is less than one, and decreases the CAPM return when the unadjusted beta is greater than one. In other words, the beta adjustment raises the CAPM return at the vertical axis point and flattens the security market across the horizontal axis as the unadjusted beta increases above zero.

The ECAPM using unadjusted betas has the same impact on the traditional CAPM using an unadjusted beta: the ECAPM increases the CAPM return at a zero unadjusted beta from: (1) the risk-free rate, to (2) the risk-free rate plus 25% of the market risk premium. Further, the ECAPM using unadjusted betas flattens the traditional CAPM return line across the horizontal axis as the unadjusted betas increase above zero.

Figure 4



Assumptions:
Market Risk Premium is 7.50%
Risk-Free Rate is 3.50%

As shown in Figure 4 above, the CAPM using a *Value Line* beta, versus a CAPM using a raw beta shows that the *Value Line* beta raises the intercept slope and flattens the security market line. Further, the ECAPM using a raw beta, and an ECAPM using a *Value Line* beta, have a magnified effect of increasing the intercept slope and further flattening the security market line. There is simply no legitimate basis to use an adjusted beta within an ECAPM because they are designed to produce the same effect on the CAPM return estimate.

Q. IS THERE ANY ACADEMIC SUPPORT FOR DR. MORIN'S PROPOSED USE OF AN ADJUSTED BETA IN AN ECAPM STUDY?

A. No. I am unaware of any peer reviewed academic study showing that the ECAPM is more accurate using adjusted betas. To my knowledge, the ECAPM has been tested and published with raw beta estimates. Further, Dr. Morin has not provided any academic research that was subjected to academic peer review, which supports her proposed use of an adjusted beta in an ECAPM study. As such, the practice of using an adjusted beta in an ECAPM study is simply not supported by academic research. While I have encountered the ECAPM analysis in many proceedings over the last 10 years, I have failed to find any utility witness in support of this methodology that can provide academic support for use of an ECAPM analysis with an adjusted beta such as a *Value Line* published beta. Rather, the ECAPM is designed to accommodate an unadjusted beta. Support for this academic study is identified above. For the reasons outlined above, Dr. Morin's proposal to use adjusted betas in an ECAPM study should be rejected.

Q. IS THERE A WAY TO MORE ACCURATELY MEASURE THE COST OF EQUITY FOR PSE USING THE ECAPM?

A. Because the makeup of the ECAPM model is based on a raw or regression beta, if the appropriate beta is used in the ECAPM it would produce a reasonable return estimate. As such, if the adjusted *Value Line* betas are modified to remove *Value Line*'s adjustment to the regression beta for the long-term tendency to converge on the market beta of 1, the *Value Line* unadjusted beta can be properly used in the ECAPM study.

Removing the beta adjustment to reflect a raw beta for an ECAPM will generally produce a more accurate ECAPM result. For example, as shown on page 49 of Dr. Morin's testimony an average CAPM cost for his proxy group of 9.3%, and an ECAPM return of 9.8%. The average proxy group adjusted *Value Line* beta to produce a 9.3% CAPM return is 0.70. This would equate to an unadjusted/raw beta estimate of 0.52.[14/] Using a raw beta of 0.52 and Dr. Morin's ECAPM methodology produces an ECAPM estimate of approximately 8.90%.[15/]

I.G. Dr. Morin's Historical Risk Premium

Q. PLEASE DESCRIBE DR. MORIN'S HISTORICAL RISK PREMIUM.

A. Dr. Morin estimates the actual achieved return on electric utility stocks relative to that of long-term Treasury bond securities over the period 1931 through 2015. This produced an achieved return on electric utility stocks above the achieved return on Treasury bonds of 5.5% and 6.1% only on the income return of the Treasury bonds.[16/]

Then he adds the estimated electric equity risk premium of 6.1% to his projected yield on Treasury bonds of 4.4%, to arrive at a risk premium estimate of 10.5%.[17/]

Q. WHAT ISSUE DO YOU TAKE WITH DR. MORIN'S RISK PREMIUM?

A. My main concern with Dr. Morin's analysis is his reliance on unrealistic and overstated projected Treasury bond yields. As described above, Dr. Morin's Treasury bond projection is substantially out of line with consensus economists' outlooks that

[14/] (Adj. Beta - 0.35)/0.67 = Raw Bea. (0.70 – 0.35)/0.67 = 0.52.
[15/] ECAPM (Raw Beta) = RF + 0.25 x MRP + 0.75 x MRP x Raw Beta.
ECAPM (0.52) = 4.4% + 0.25 x 7.0% + 0.75 x 7.0% x 0.52 = 8.9%.
[16/] Exhibit No. ___(RAM-9).
[17/] Exhibit No. ___(RAM-1T) at 50.

are published by independent sources. I believe the consensus economists' published Treasury bond projections are far more reasonable estimates of consensus investor and market participants than are Dr. Morin's subjective projections.

Q. HOW WOULD THE RISK PREMIUM METHODOLOGY USED BY DR. MORIN CHANGE IF IT IS UPDATED TO INCLUDE MORE REALISTIC TREASURY BOND YIELDS?

A. Adding a more reasonable projected Treasury yield of 3.7% to his risk premium of 6.1% produces a cost estimate of 9.8%.

I.H. Dr. Morin's Allowed Risk Premium

Q. PLEASE DESCRIBE DR. MORIN'S ALLOWED RISK PREMIUM.

A. Dr. Morin measures the indicated risk premium of authorized electric returns over Treasury bond yields over the period 1986 through 2015. The average indicated risk premium that Dr. Morin calculates is 5.6%.[18/] Dr. Morin then performs a linear regression analysis in an attempt to capture a simple inverse relationship between interest rates and authorized electric return risk premiums. Dr. Morin then plugs in his projected Treasury bond yields of 4.4% in the regression formula to calculate a projected risk premium of 6.3%. Adding the risk premium estimate of 6.3% to his projected 4.4% Treasury bond yield implies a cost of equity estimate of 10.7%.[19/]

Q. WHAT ISSUES DO YOU HAVE WITH DR. MORIN'S ALLOWED RISK PREMIUM ANALYSES?

A. My two main concerns with Dr. Morin's allowed risk premium analysis are his continued reliance on unrealistic long-term Treasury bond yields and his use of a simple inverse relationship to estimate a risk premium.

18/ Exhibit No. ___(RAM-10).

19/ Exhibit No. ___(RAM-1T) at 53.

Q. WHY IS DR. MORIN'S USE OF A SIMPLE INVERSE RELATIONSHIP BETWEEN INTEREST RATES AND EQUITY RISK PREMIUMS NOT REASONABLE?

A. Dr. Morin's belief that current risk premiums can be gauged by a simplistic inverse relationship between equity risk premiums and interest rates is not supported by academic research. While academic studies have shown that, in the past, there has been an inverse relationship with these variables, academics have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to the investment risks of equity investments.[20] The relative risk of equity investments versus the risk of bond investments changes based on investors' perceptions of risk, risk tolerance, and market factors. While the interest rate is certainly one component that helps describe an appropriate equity risk premium, it is not the only factor. A more broader assessment of perceptions of equity versus bond risk is necessary to properly determine an appropriate equity risk premium in the current market.

Q. PLEASE SUMMARIZE SOME OF THE ACADEMIC STUDIES ON EQUITY RISK PREMIUM MEASUREMENTS.

A. In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. As such, when interest rates were more volatile, the relative perception of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

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[20] "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001 and "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985.

In today's marketplace, interest rate volatility is not as extreme as it was during the 1980s.[21] Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing changes to nominal interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, not simply changes to interest rates.

Importantly, Dr. Morin's analysis simply ignores investment risk differentials. His projected equity risk premium is based exclusively on changes in nominal interest rates. This is a flawed methodology and does not produce accurate or reliable risk premium estimates. His results should be rejected by the Board.

Q. CAN DR. MORIN'S RISK PREMIUM ANALYSES BASED ON PROJECTED YIELDS BE MODIFIED TO PRODUCE MORE REASONABLE RESULTS?

A. Yes. Eliminating the reliance on a regression formula to estimate the equity risk premium and relying on an updated consensus economists' projection of Treasury bond yield of 3.7% and Dr. Morin's risk premium of 5.6% will result in a return on equity of 9.3% for PSE.

Q. DO YOU HAVE ANY COMMENTS CONCERNING DR. MORIN'S RELIANCE ON PROJECTED INTEREST RATES?

A. Yes. First, it is simply not known how much, if any, long-term interest rates will increase from current levels or whether they have already fully accounted for the

[21] "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985, at 44.

termination of the Federal Reserve's Quantitative Easing program and the increase in the Federal Funds Rate. Nevertheless, I do agree that this Federal Reserve program introduced risk or uncertainty in long-term interest rate markets. Because of this uncertainty, caution should be taken in estimating PSE's current return on common equity in this case. However, as noted in the EEI quote above, the increase in short-term interest rates had no impact on longer-term yields that "remain at historically low levels and are influenced more by the level of inflation and economic strength than by the Fed's short-term rate policy."[22/]

Second, I would note PSE is largely shielded from significant changes in capital market costs. To the extent interest rates ultimately increase above current levels, which may have an impact on required returns on common equity, at that point in time, PSE, like all other utilities, can file to change rates to restate its authorized rate of return at the prevailing market levels.

. Finally, while current observable interest rates are actual market data that provides a measure of the current cost of capital, the accuracy of forecasted interest rates is problematic at best.

Q. WHY DO YOU BELIEVE THAT THE ACCURACY OF FORECASTED INTEREST RATES IS HIGHLY PROBLEMATIC?

A. Over the last several years, observable current interest rates have been a more accurate predictor of future interest rates than economists' consensus projections. Exhibit No. MPG-5 illustrates this point. On this exhibit, under Columns 1 and 2, I show the actual market yield at the time a projection is made for Treasury bond yields two years

[22/] *EEI Q4 2015 Financial Update*: "Stock Performance" at 6.

in the future. In Column 1, I show the actual Treasury yield. In Column 2, I show the projected yield two years out.

As shown in Columns 1 and 2, over the last several years, Treasury yields were projected to increase relative to the actual Treasury yields at the time of the projection. In Column 4, I show what the Treasury yield actually turned out to be two years after the forecast. In Column 5, I show the actual yield change at the time of the projections relative to the projected yield change.

As shown in this exhibit, economists consistently have been projecting that interest rates will increase over several years. However, as shown in Column 5, those yield projections have turned out to be overstated in almost every case. Indeed, actual Treasury yields have decreased or remained flat over the last several years rather than increased as the economists' projections indicated. As such, current observable interest rates are just as likely to accurately predict future interest rates as are economists' projections.

II. PROPOSED REVENUE SPREAD AND COST OF SERVICE

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVENUE SPREAD IN THIS PROCEEDING.

A. The Company's proposed cost of service relative to current revenue is shown on my attached Exhibit No. MPG-6, under Columns 2 and 3. The Company's proposed revenue spread is shown in the Direct Testimony of Jon Piliaris.

Q. DO YOU BELIEVE THAT THE COMPANY'S COST OF SERVICE STUDY IS REASONABLE FOR SETTING RATES?

A. No, but it is consistent with the agreement reached in Docket No. UE-141368. Therefore, I do not take issue with the Company's cost of service study in this proceeding, but I must express my concern that I believe it over-allocates production and transmission capacity costs to high load factor classes, and understates PSE's costs to low load factor customers.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLASSIFICATION PROPOSAL?

A. PSE bases its cost classification proposal on the rate design settlement in Docket No. UE-141368. Paragraph 10 of that settlement agreement specifies that, in the Company's next general rate case, "PSE will adjust demand/energy cost allocation percentages to 25% demand and 75% energy."

Q. PSE OPINES IN TESTIMONY THAT IT WOULD BE APPROPRIATE TO UPDATE THE PEAK CREDIT ANALYSIS. DO YOU AGREE?

A. No. PSE's proposal to update its peak credit analysis would change the classification of production and transmission fixed costs from 25% to 18%. The energy-related classification of these costs would increase from 75% to 82%.[23/]

This is inappropriate because Paragraph 10 of the settlement agreement explicitly requires that the demand and energy classification percentages be set at 25% demand and 75% energy in this proceeding. Adjusting these classification percentages in this case would violate the compromise agreed to by the parties to the settlement agreement.

The Commission should reject PSE's proposal to deviate from the results required by the settlement agreement in Docket UE-141368 by updating the peak credit classification assumptions and modifying the demand and energy classification percentages specified in the agreement.

[23/] Exhibit No. ___(JAP-1T) at 29.

Q. DO YOU BELIEVE THE COMPANY'S PROPOSED SPREAD OF THE INCREASE ACROSS RATE CLASSES IS REASONABLE?

A. I only comment on the Schedule 40 customer class because I believe the Company's spread for this class is not reasonable. I reached this conclusion based on the following facts:

1. The Company's own cost of service study demonstrates that the prices for production and transmission capacity costs in Schedules 46 and 49 are already priced above cost of service.
2. The Company's own evidence shows that the capacity and energy pricing for production and transmission for Schedule 40 is tied to Schedule 49 prices. These prices are adjusted for high delivery voltage down to primary delivery voltage.[24/]
3. Because the Company's rate recovery of production and transmission capacity costs in Schedule 49 are already priced above cost of service, I believe these prices should not be increased.
4. Because Schedule 40 production capacity and energy prices are based on Schedule 49 prices, these prices should not be increased because Schedule 49 prices should not be increased.
5. Therefore, in my proposed spread I recommend no increase for Schedule 49 and Schedule 46 rate schedule, and a 2.24% increase for Schedule 40.
6. The Schedule 40 increase reflects the full increase in distribution costs proposed by the Company but no increase for demand and energy pricing for production and transmission consistent with Schedule 40's tie to Schedule 49 and Schedule 46.

The results of my proposed cost of service study are shown in my Exhibit No. MPG-6, under Columns 4 and 5.

Q. IS YOUR PROPOSAL TO KEEP THE PRODUCTION AND TRANSMISSION CHARGES FOR SCHEDULE 40 EQUAL TO CHANGES FOR SCHEDULES 46 AND 49 CONSISTENT WITH PSE'S POSITION CONCERNING THE INTERACTION BETWEEN THESE RATE SCHEDULES?

A. Yes. PSE witness Jon Piliaris states at page 71 of his Direct Testimony (Exhibit No. ___(JAP-1T) that the production and transmission capacity rates for Schedule 40 are tied to these charges for Schedule 49, but adjust for lower delivery voltage losses.

24/ *Id*. at 53-54.

Because Schedule 40 is a lower delivery voltage rate, the demand charges and energy charges are adjusted for primary level voltage losses as opposed to transmission level voltage losses that apply to Schedules 46 and 49. Because the Company is not proposing adjustments to loss factors, and its cost of service study states that Schedules 46 and 49 charges should not change, I am recommending that the demand charge and non-fuel energy charges associated with Schedule 40 remain intact, and tied to Schedule 49 adjusted for losses. The only change in Schedule 40 would relate to appropriate changes for distribution costs.

III. ELECTRIC DECOUPLING MECHANISM

Q. PLEASE DESCRIBE PSE'S DECOUPLING MECHANISM.

A. PSE's decoupling mechanism is called RDM. The RDM allows PSE to recover its allowed delivery service revenue from customers. PSE defers the difference between its monthly allowed and actual delivery service revenues collected from customers and performs a true-up of these differences in its annual Schedule 142 filing.[25]

Q. PLEASE DESCRIBE PSE'S PROPOSAL FOR RDM IN THIS PROCEEDING.

A. The Company proposes that its current decoupling mechanisms actually become permanent until they are approved by the Commission to be either discontinued or modified.[26]

Q. SHOULD THE COMMISSION APPROVE PSE'S PROPOSAL TO CONTINUE RDM?

A. No. The Commission should reject PSE's proposal for RDM in this proceeding.

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[25] *Id*. at 107 and 109.
[26] *Id*. at 146.

Q. IS REVENUE DECOUPLING APPROPRIATE FOR A UTILITY?

A. No. Revenue decoupling is inappropriate and inconsistent with traditional ratemaking principles.

Q. PLEASE EXPLAIN WHY REVENUE DECOUPLING IS INCONSISTENT WITH TRADITIONAL RATEMAKING.

A. Revenue decoupling allows the Company to automatically adjust its base rates outside of a base rate case for revenue inputs resulting from fluctuations in sales levels. Revenue decoupling essentially insulates utility shareholders from the impact of fluctuations in sales levels.

Q. SHOULD THE COMMISSION ADJUST PSE'S RETURN ON EQUITY IN THE EVENT REVENUE DECOUPLING IS CONTINUED?

A. Yes. If the Commission approves to continue revenue decoupling, PSE's lower operating risk would appropriately justify a lower return on equity. Investors' risk would decline because the revenue decoupling takes sales-related risk and transfers it from investors to customers based on the implementation of the decoupling surcharge. Because investors would no longer be assuming sales risk, the return on equity should be reduced to reflect this lower operating risk. Conversely, since customers would have a larger amount of risk associated with PSE's rates and surcharges, the rates should be adjusted downward to reflect this greater variability and uncertainty of utility service bills from PSE.

Q. IF THE COMMISSION DOES APPROVE A DECOUPLING MECHANISM FOR PSE, SHOULD THERE ANY LIMITATIONS?

A. Yes. A decoupling mechanism should only apply to PSE's weather-sensitive classes. For PSE's large volume classes, whose load is largely driven by process requirements or operating requirements, rather than heating, ventilation and air conditioning, the decoupling mechanism is not needed and should not be allowed. Specifically, PSE's Schedule 40, Schedule 46 and Schedule 49 are largely high volume industrial rate designs. These rate structures are largely already based on a fixed and variable rate design. Therefore, the revenues from these classes will not vary based on factors such as weather and other unpredictable factors to the extent the lower load factor classes which have greater weather-sensitive demands.

Therefore, the rate design of Schedules 40, 46 and 49 already provides a stable revenue source to cover PSE's fixed costs without a decoupling mechanism. For this reason, the Company's proposal for a decoupling mechanism should not be approved, but if it is it should not apply to rate Schedules 40, 46 and 49.

Q. DO THE RATE DESIGNS FOR SCHEDULE 40, SCHEDULE 46 AND SCHEDULE 49 CREATE EFFICIENT INCENTIVES FOR CONSERVATION?

A. Yes. These rate designs provide price signals to customers to reduce demands during peak periods and/or shift energy consumption from high cost periods to low cost periods. Cost-based rates will provide customers with utility bill savings if they reduce peak period demands and/or change energy usage in a way that reduces PSE's cost of providing service. Hence, customers can receive utility bill savings by changing consumption between peak and off-peak periods or reduce peak period demands in ways that allow PSE to reduce its cost to provide utility service.

For example, if a large customer reduces peak demands, its bill would decline but also PSE would need less production and transmission capacity resources to serve the customer's peak period demands. Further, reducing energy consumption during peak periods can result in declines to the customer's utility bill, but also PSE's energy cost would decline. All stakeholders benefit if tariff rate designs produce pricing signals that reasonably reflect the utility's cost of providing service.

Further, demand and energy based pricing such as that used in PSE Schedules 40, 46 and 49, recover fixed cost in demand charges and variable costs in energy charges. This pricing structure stabilizes fixed cost recovery much the same as decoupling does for smaller customers that have only energy based pricing. Because demand billing units are more stable than energy billing units, the demand charge revenue collection is more stable and reliably supports PSE's ability to recover its fixed cost. On the other hand, Schedules 40, 46 and 49 energy prices largely reflect variable costs which increase/decline when energy sales increase/decline. Decoupling is not needed for these rate schedules because the pricing structure already stabilizes revenue collection that supports PSE's ability to recover fixed cost.

Q. WOULD PSE'S PROPOSED DECOUPLING MECHANISM ENCOURAGE LARGE VOLUME CUSTOMERS TO INVEST IN CONSERVATION?

A. No, it would not. As background, the State of Washington and this Commission have long supported policies and initiatives that encourage the development of conservation resources. The state's conservation objectives have since been codified in the Energy Independence Act.[27/] I believe that large volume customers, such as those represented by ICNU, would be discouraged from making further investments in conservation should PSE's decoupling mechanism be approved for their rate schedules.

Decoupling is intended to make the company indifferent to conservation investments made by customers. The company's "indifference" is tied directly to the recovery of revenues "lost" as a result of conservation and other influences on sales.

[27/] RCW 19.285

In other words, customers pay a "surcharge" to the company for kilowatt hours avoided due to conservation.

Large volume customers make conservation investments only after thorough analysis of the future financial benefits provided by the investment. Customers benefit by making conservation investment that reduce or shift (from high cost periods to low cost periods) their energy consumption and lower their cost of utility service. Decoupling eliminates or reduces the utility cost savings expected by customers in justifying conservations programs or investments. It is the utility bill savings that provide customers with recovery of conservation costs and produces a return of and on customer-funded conservation investments. Hence, eliminating these conservation bill savings or customer benefits, eliminates the economic justification that customers rely on to justify conservation program costs.

The additional charges imposed by PSE's decoupling proposal makes conservation investments less financially attractive, as the customers' cost recovery period is lengthened, or eliminated, by decoupling's surcharges. Since most conservation investments made by large volume users are specific projects designed to improve energy consumption for specific industrial processes or programs, the cost-effectiveness margin for such investments are critically important to a decision to move forward with the investment. Conservation projects on the "margin" or those with more limited energy needs will likely be shelved.

In the end, I believe that PSE's decoupling mechanism will detrimentally impact the conservation investment decisions of large volume customers. This result is diametrically opposed to the Commission's long-standing support for conservation and the requirement of the Energy Independence Act to secure all cost-effective conservation.[28/] Should the Commission adopt my recommendation to protect Schedules 40, 46, and 49 from PSE's proposed decoupling mechanism, this result can be avoided.

Q. IS ICNU OPEN TO DISCUSSING ALTERNATIVES TO DECOUPLING WITH PSE?

A. Yes. ICNU is willing to work with PSE to discuss alternatives to decoupling that would be more practical for large volume customers, while still satisfying the policy objectives of the Commission.

IV. EARNINGS SHARING BAND

Q. HAS PSE PROPOSED CHANGES TO THE EARNINGS SHARING BAND APPROVED IN ITS LAST RATE CASE

A. Yes. PSE witness Daniel Doyle proposed to alter the earnings sharing band in several respects**:**

1. He proposes to include a 25 basis point band above the authorized return on equity where PSE does not share earnings. For earnings in excess of the 25 basis point band, he proposes a 50/50 sharing of excess earnings with customers.
2. He proposes to adjust actual earnings to reflect conforming and normalizing adjustments before the equity return subject to an earnings band is established.
3. If the 25 basis point band is not approved, he requests the Commission increase PSE's authorized equity return by 14 basis points.[29/]

Q. ARE PSE'S PROPOSED EARNINGS BAND CHANGES APPROPRIATE?

A. No. PSE's existing earnings band should remain in effect. If the Commission adjusts the earnings mechanism, it should require PSE to retain all earnings within the 25

[28/] RCW 19.285.040(1).
[29/] Daniel Doyle Direct at 14-20.

basis points dead band but refund to customers 100% of all earnings above the 25 basis points dead band (excess earnings).

This will accomplish PSE's objective of symmetrical earnings around the authorized equity return over time while also mitigating rate impacts on customers. In effect, PSE can earn less than its authorized returns in some years, and make up the under earnings in other years with the 25 basis point dead band. This corrects the asymmetrical aspect of the current earnings sharing mechanism that was a concern expressed by Mr. Doyle. However, requiring 100% of excess earnings to be refunded to customers will mitigate the rate impacts on PSE's customers while still providing PSE with fair and reasonable compensation.

The proposed conforming and normalization adjustments as outlined by Mr. Doyle are material components of PSE's operating income and revenue requirements. If these adjustments are reflected in the earnings adjustment bands, then PSE earnings subject to the sharing bands will be mitigated in a material way. This further supports giving customers 100% of all excess earnings to customers.

However, the normalization adjustments should not be approved if PSE's proposed decoupling surcharge is approved. Indeed, decoupling surcharge revenue should be included in the development of operating income subject to the earnings test. This is particularly appropriate if the Commission approves a decoupling mechanism that applies to Schedules 40, 46 and 49 customers.

V. EXPEDITED RATE FILING PROCESS

Q. PLEASE DESCRIBE PSE'S PROPOSAL FOR ERF IN THIS PROCEEDING.

A. PSE requests that formal procedures be established that would allow the Company to submit limited issue rate filings for review on an expedited basis. In its proposal, the Company requests that expedited rate filings be considered within an extraordinarily condensed time period of 60 to 90 days.

Under the Company's proposed ERF, it would be allowed to update costs with the exception of power and purchased gas costs. Furthermore, PSE would not include any changes to its rate spread, rate design or rate of return relative to its most recent general rate case. The only allowed adjustments to PSE's cost of capital would be to update debt costs for known changes.[30/]

Q. IS THE ESTABLISHMENT OF ERF APPROPRIATE?

A. No. PSE is asking the Commission to authorize a new rate change mechanism that would allow what is effectively single-issue ratemaking. PSE would select certain costs for ERF review, and hold back on other aspects of its cost of service. Arguably, the Company's ERF would include only those costs where it can demonstrate a short-term deficiency in support of a rate increase. Notably excluded will be cost areas where the Company experienced efficiencies or cost reductions, and could support a rate decrease.

In other words, PSE's ERF will not allow the Commission to review and consider all changes in the Company's cost of service, and determine if existing rates are reasonable. This is precisely why the ERF results in single-issue ratemaking, or an incomplete assessment of the adequacy and reasonableness of current approved rates.

30/ Exhibit No. ___(KJB-1T) at 68-72.

Q. HAS THIS COMMISSION ADDRESSED SINGLE ISSUE RATEMAKING IN PREVIOUS PROCEEDINGS?

A. Yes. It is my understanding that this Commission has gone so far as to declare that such single issue or limited rate making is against the public interest.[31/] The Commission has also commented on how single issue ratemaking has the potential to produce rates and charges that are not fair, just, reasonable, and sufficient, concluding that this problem is best "resolved by a comprehensive review of [a] company's" rate base, charges, and expenses.[32/] In this order, the Commission clearly understood the risks to ratepayers that accompany single issue ratemaking. Therefore, the Commission should only venture into this territory when absolutely compelled to do so, and only when there are no other options available to achieve its regulatory objective. PSE presents no such compelling reasons.

Q. HAS THE COMMISSION APPROVED AN ERF FOR PSE PREVIOUSLY?

A. Yes. In Docket Nos. UE-121697/UG-121705 and UE-130137/UG-130138, the Commission approved an ERF as part of a suite of innovative ratemaking mechanisms in part to address what the Commission found to be the problem of serial rate case filings.[33/] The ERF was originally proposed by Commission Staff based on the Company's need for unusually high levels of capital investment to replace aging infrastructure and meet the State's renewable portfolio standard. These circumstances

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31/ See Re US West Commc'ns., Inc., Docket No. UT-920085, Third Supplemental Order pg. 8 (April 15, 1993) (concluding that "authorization of the ELG method for computing intrastate depreciation is not in the public interest, as it amounts to single issue ratemaking.").

32/ MCI Telecomm. Corp. v. GTE Nw. Inc., Docket No. UT-970653, Second Supplemental Order pg. 6 (Oct. 22, 1997).

33/ WUTC v. PSE, Docket Nos. UE-121697/UG-121705 and UE-130137/UG-130138, Order 07 (June 25, 2013).

allegedly resulted in the Company persistently failing to earn its authorized rate of return.

Q. ARE THE SAME CIRCUMSTANCES THAT LED THE COMMISSION TO APPROVE AN ERF PREVIOUSLY STILL APPLICABLE TODAY?

A. No. According to the Company's most recent Integrated Resource Plan, it has no immediate need for any new resources to meet the RPS.[34/] Additionally, it is not evident that the Company needs extraordinary regulatory mechanisms to replace aging infrastructure. However, if new regulatory mechanisms are needed, the Company is also proposing the Electric Cost Recovery Mechanism ("ECRM") precisely to support infrastructure replacement, as discussed below. It would certainly be unfair to customers to approve both an ERF and the ECRM to address the same infrastructure replacement issue.

Meanwhile, the Commission's prior approval of the ERF, along with decoupling and a rate plan for PSE resolved the issue of the Company's claims of persistent underearning, as PSE has now over-earned for two consecutive years.[35/] The appropriate action for the Commission now is to treat the ERF as the "experimental" mechanism it was originally designed to be by prohibiting PSE from using it again in order to determine whether the ERF truly did have the impact for which it was designed, or whether these impacts are more appropriately attributed to other causes.

Q. WOULD AN ERF ENCOURAGE EFFICIENT COMPANY OPERATIONS?

A. No, just the opposite. PSE's proposed ERF provides the Company a regulatory mechanism that may allow for expedited rate changes to reflect costs that may not

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34/ *See* Puget Sound Energy's 2015 Integrated Resource Plan at 1-10.

35/ Exh. No. DAD-1T at 4:1-11.

have been efficiently managed, may reflect inefficient procurement practices, and may have included cost overruns that could have been avoided by more efficient management of capital programs. Under an ERF, parties to the case and the Commission will not have time to identify inefficient costs before they are reflected in retail rates. Further, if the ERF is allowed, the Company will lose the financial incentive to be an efficient and effective manager of its resources. For, if costs go over those anticipated during the rate case, then PSE would simply bring these costs to the Commission to "true up" in the ERF. Regulation should promote efficient practices and spending. PSE's ERF fails in this important ratepayer protection.

Q. ARE THE PROCEDURAL TIMELINES INCLUDED IN THE PROPOSED ERF SUFFICIENT TO ALLOW REASONABLE REVIEW OF AN ERF FILING?

A. No. PSE proposes that the Commission limit itself to a very constricted review period. Specifically, PSE proposes that the ERF review period be limited to 60 to 90 days. Without question, such an extremely compressed schedule would impede the thorough review of PSE's filing by Commission Staff, ICNU, and other parties. To produce a record sufficient to support a Commission decision, more time will be needed to thoroughly review PSE's application, conduct appropriate discovery, and prepare responsive pleadings. PSE's proposed review period would effectively restrain these pursuits. By doing so, PSE's ERF would inappropriately remove important regulatory safeguards in the ratemaking process, to the detriment of ratepayers.

Q. IF THE COMMISSION SHOULD AUTHORIZE PSE's USE OF AN ERF, WHAT OTHER COSTS SHOULD BE INCLUDED IN THE FILING?

A. I recommend that PSE be required to include its power costs in all ERF filings. PSE proposes that power costs be excluded from an ERF filing, arguing that such costs are both forward looking and subject to the effects of other regulatory mechanisms such as Power Cost Only Rate Case ("PCORC"). I disagree with PSE on this issue and explain below.

Without question, PSE's power costs materially impact its overall rates. Given the dynamics of the region's energy market, the Commission has approved the use of a PCORC in conjunction with a Power Cost Adjustment Mechanism ("PCA") for PSE. For the PCA to function properly, and to avoid large deferral balances, power costs must be revisited to ensure that rates and costs are reasonably tracking. Generally, PSE's power costs are reset during general rate cases, with the Company filing its forecasts late in the review process, again to ensure that the most accurate forecasts are used to set rates. Importantly, the Commission's intent is to use the most accurate information to set rates, when the Company's rates are under review.

PSE's ERF proposal, no matter how it is being cast by PSE, will place PSE's general rates under review by the Commission. For this reason, the Commission should require the Company to file a power cost update at the time the ERF is filed. This requirement will ensure that rates are tracking PSE's actual costs. Further, this practice will prevent misalignment of the sharing bands within the PCA.

Finally, PSE's power cost forecasts for this rate case assume a $18.5 million cost to conform to the requirements of the Clean Air Rule (CAR).[36] At this time, the

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[36] Exhibit No. ___(PKW-1CT) at page 75.

CAR is under judicial review, and the rule may not be enforceable during the rate year. PSE itself is one of the parties challenging the CAR. Should the Commission approve PSE's power costs as filed and the rule is found to be unenforceable, then PSE's power costs will be $18.5 million higher than necessary and PSE's rates will include this overpayment.

It would be particularly inappropriate to allow PSE to continue to collect this overpayment by excluding power costs from an ERF when the Company itself apparently does not believe these costs are lawfully incurred. To deal with this possibility in a practical manner, I believe PSE should be required to file a new power cost study with any rate filing during the rate year, including an ERF. This will protect ratepayers and maintain a reasonable alignment of the balances in the PCA.

Q. WHAT IT IS YOU RECOMMENDATION WITH RESPECT TO THE COMPANY'S ERF PROPOSAL?

A. For the reasons above, I recommend that the Commission reject PSE's proposal for an ERF. The Commission should only allow PSE to adjust its base rates in a full general rate case proceeding. This will allow for adequate review time for all aspects of the Company's revenue requirement.

VI. ELECTRIC COST RECOVERY MECHANISM ("ECRM")

Q. PLEASE DESCRIBE PSE'S PROPOSAL FOR ITS ECRM.

A. PSE'S ECRM is a new proposed rider that would be used to recover the costs of replacing facilities that are needed for targeted reliability improvements on the PSE system. These improvements are intended to reduce the number and the length of power outages on the PSE system.

Q. WHAT IS THE ESTIMATED FIRST YEAR ECRM REVENUE REQUIREMENT?

A. The first year revenue requirement for the ECRM is estimated at $10.5 million.[37/]

Q. HOW WILL THE ECRM REVENUE REQUIREMENT BE ALLOCATED TO CLASSES?

A. The overall revenue requirement for the ECRM would be allocated between overhead and underground investments based on the ECRM capital investment in these two cost categories. The resulting overhead and underground related revenue requirements would each be allocated to customers based on the load weighted line miles associated with each type of distribution feeder. The ECRM rate design would be based on a single, schedule-specific rate per kWh.

Q. IS THE ESTABLISHMENT OF THE ECRM APPROPRIATE?

A. No, it is not appropriate. These costs should be collected in PSE's base rates. Base rates consider all relevant investments and costs of the utility in combination. An increase in one component could be offset by a decrease in another component of the Company's base rates, negating the need for a base rate increase. Riders, however, are designed to track changes in only a single cost item. This results in single-issue ratemaking. Recovery of costs in a rider are appropriate when those costs are significant, volatile, and beyond the utility's control. Costs that do not meet these three criteria should not be collected via a rider.

ICNU supports the Company's efforts to modernize its delivery system and improve its system reliability. However, as with all other aspects of the utility system, the Company needs to weigh improvements in system reliability with costs to retail customers. The Company's use of System Average Interruption Duration Index

[37/] Exhibit No. ___(KJB-1T) at 81.

("SAIDI") and System Average Interruption Frequency Index ("SAIFI") metrics to prioritize circuit identification needed for system improvements is of course reasonable. However, the Company must still manage its capital expenditure program to mitigate and manage impact on retail rates, while improving system reliability.

PSE has strong access to capital, as do all regulated utilities with strong investment grade bond ratings like PSE, so managing a capital program to improve system reliability and modernize PSE's infrastructure should be pursued, but also with a mind toward managing impacts on retail customers.

Implementing a new regulatory mechanism which will disregard other cost of service items and not reflect capital improvements in balance with PSE's overall cost of service does not emphasize the need for rate management, or cost to customers, as an important component of system modernization. As such, the Company's proposal would not affect the program to modernize its infrastructure and improve its system reliability, without the necessary component of managing its cost to retail customers. For these additional reasons, the Company's proposed ECRM should be rejected.

Q. WHY DO YOU BELIEVE THAT THE COMPANY'S PROPOSED COSTS TO BE RECOVERED THROUGH THE ECRM DO NOT JUSTIFY THE USE OF A NEW RIDER?

A. These infrastructure replacement costs do not appear to meet the traditional criteria for recovery via a rider. Specifically, riders are typically used for significant costs which are beyond the utility management's control. The Company's capital costs related to infrastructure replacement are not beyond the utility management's control, and therefore should not be subject to recovery through a new rider.

For example, when PSE has determined that an area of its system should be targeted for reliability improvements, the costs to improve this area are known and the utility can take action in order to plan the needed improvements and recover those costs accordingly from customers. Costs such as fuel and purchased power which can be significant, volatile and beyond the utility's control are examples of costs that are deemed appropriate for rider recovery. The costs to improve reliability on PSE's system with planned upgrades are not beyond the utility's control.

Q. WHAT IS THE RESULT OF THE COMPANY'S PROPOSAL TO RECOVER ECRM COSTS FROM CUSTOMERS VIA A RIDER?

A. The result of the Company's proposal to recover ECRM costs via a rider, is to shift the risk of cost recovery for these investments away from PSE and onto customers. This is inappropriate and these costs should be recovered via the Company's base rates.

Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?

A. Yes, it does.

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