

**BEFORE THE**  
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFICORP d/b/a PACIFIC POWER  
AND LIGHT COMPANY,

Respondent.

DOCKET UE-230172  
(*Consolidated*)

In the Matter of

ALLIANCE OF WESTERN ENERGY  
CONSUMERS'

Petition for Order Approving Deferral of  
Increased Fly Ash Revenues

DOCKET UE-210852  
(*Consolidated*)

**RESPONSE TESTIMONY OF LANCE D. KAUFMAN**

**ON BEHALF OF**

**ALLIANCE OF WESTERN ENERGY CONSUMERS**

**(REDACTED)**

**September 14, 2023**

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Exhibit LDK-2:	Qualification Statement of Lance D. Kaufman
Exhibit LDK-3C:	Discovery Responses
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1 **I. INTRODUCTION AND SUMMARY**

2 **Q. PLEASE STATE YOUR NAME AND OCCUPATION.**

3 A. My name is Lance D. Kaufman. I am a consultant representing utility customers before state  
4 public utility commissions in the Northwest, Southwest, and Intermountain West. My witness  
5 qualification statement can be found at Exhibit LDK-2.

6 **Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.**

7 A. I am testifying on behalf of the Alliance of Western Energy Consumers.

8 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

9 A. I am providing testimony on Pacific Power's cost of capital, cost of service, rate spread, and  
10 wildfire expenses.

11 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

12 A. I make the following recommendations:

- 13 • The Commission should adopt (i) a 51 percent common equity, 0.01 percent preferred stock,  
14 and 48.99 percent long term debt capital structure, (ii) a 9.0 percent cost of equity, and (iii)  
15 4.77 percent cost of debt, and 6.927 percent weighted average cost of capital.
- 16 • Make the following changes to the cost of service study:
  - 17 ○ Allocate FERC Account 407, Amort of Prop Losses, Unrec Plant, functionalized to  
18 distribution plant, based on each schedule's allocation of distribution plant using  
19 Pacific Power's F102D factor.
  - 20 ○ Allocate FERC Accounts 561 and 581, load dispatching costs, based on each  
21 schedule's Load Complexity, calculated as the share of annual hourly load ramping.
  - 22 ○ Allocate FERC Account 904 Uncollectible Accounts using weighted customer counts,  
23 Pacific Power's F136 factor.

- 1           ○ Modify Pacific Power’s System Gross Miscellaneous Plant allocator, F102Co, such that
- 2                   when the allocator returns an error code, the backup allocator is an equal weighted
- 3                   average of F102, F136, Load Complexity, and Labor Allocation.
- 4           ○ Allocate FERC Account 926 Pensions and Benefits using Pacific Power’s allocation of
- 5                   labor expense to each schedule.
- 6           ● Increase rates for street and area lighting schedules by 125 percent of the average rate increase
- 7                   and increase all other schedules by an equal percentage.
- 8           ● Recover transmission and generation demand costs through the demand charge rather than the
- 9                   load size charge.
- 10          ● Limit individual rate changes to within 10 percent of the current rate after applying the
- 11                   schedule average increase.
- 12          ● Reduce Washington-allocated litigation and injuries and damages expense in Account 925 by
- 13                   \$545,054.

14 **Q. HOW DO YOUR RECOMMENDATIONS COMPARE TO CURRENT AND**  
15 **PROPOSED COST OF CAPITAL?**

16 A. Pacific Power’s current authorized rate of return is 9.5 percent and Pacific Power has requested  
17 this be increased to 10.3 percent in its initial application. My analysis shows that rather than an  
18 increase to PacifiCorp’s currently authorized ROE, a decrease is warranted for both ROE and  
19 overall rate of return.

20 **Q. WHY DO YOU RECOMMEND A COST OF EQUITY OF 9.0 PERCENT?**

21 A. This recommendation is based on the application of the Discounted Cash Flow (“DCF”)  
22 model, the Capital Asset Pricing Model (“CAPM”), and the Empirical CAPM (“ECAPM”). I  
23 found that after updating Pacific Power’s assumptions to reflect current data and modern

1 finance literature, these models support a reasonable ROE range from 8.5 percent to 9.5  
2 percent. I recommend 9.0 percent as the authorized ROE because it is the midpoint of the  
3 reasonable range, a reduction from the current authorized ROE is warranted due to investor  
4 behavior, and Pacific Power has a similar risk profile as the proxy group.

5 **Q. GIVEN CURRENT MARKET CONDITIONS, WHY DO YOU RECOMMEND A**  
6 **DECREASE IN THE COST OF EQUITY?**

7 A. The only market conditions that are relevant to evaluating cost of equity are those that are  
8 inputs to the ROE estimation models. Outside of these, Pacific Power's arguments about the  
9 condition of the market are speculative and irrelevant, in that the arguments are not  
10 theoretically or empirically linked to the models used to estimate ROE.

11 Rather than modify or weight ROE results based on market expectations, I suggest  
12 evaluating ROE results within the context of utility capital accumulation. The primary  
13 consideration in determining cost of equity is that it be commensurate with the returns on  
14 investments for other firms with similar risks and that it be sufficient to assure the financial  
15 integrity of the utility, to maintain credit, and to attract capital.<sup>1</sup> Pacific Power has not  
16 presented evidence that it has had any difficulties attracting capital on reasonable terms. This  
17 indicates that the current authorized returns are at or above the level required by investors.  
18 Thus, the required ROE can reasonably be expected to be below the current ROE.

19 Utility and investor behavior is also consistent with a finding that the current ROE is  
20 too high because utilities are accumulating excessive capital and equity. I discuss Ms.  
21 Bulkley's market analysis and my capital accumulation analysis in more detail in the section of  
22 my testimony directly evaluating return on equity.

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<sup>1</sup> *Federal Power Commission v. Hope Natural Gas Co.*, 320 US 591, 602 (1944).

1 **Q. WHAT ARE THE IMPACTS OF YOUR RECOMMENDATIONS ON PACIFIC**  
2 **POWER’S REVENUE REQUIREMENT?**

3 A. My recommendations reduce Pacific Power’s revenue requirement by \$10 million in Rate Year  
4 1 and \$2.3 million in Rate Year 2 relative to the initial filing.<sup>2</sup>

5 **II. COST OF EQUITY**

6 **Q. PLEASE SUMMARIZE YOUR COST OF EQUITY TESTIMONY.**

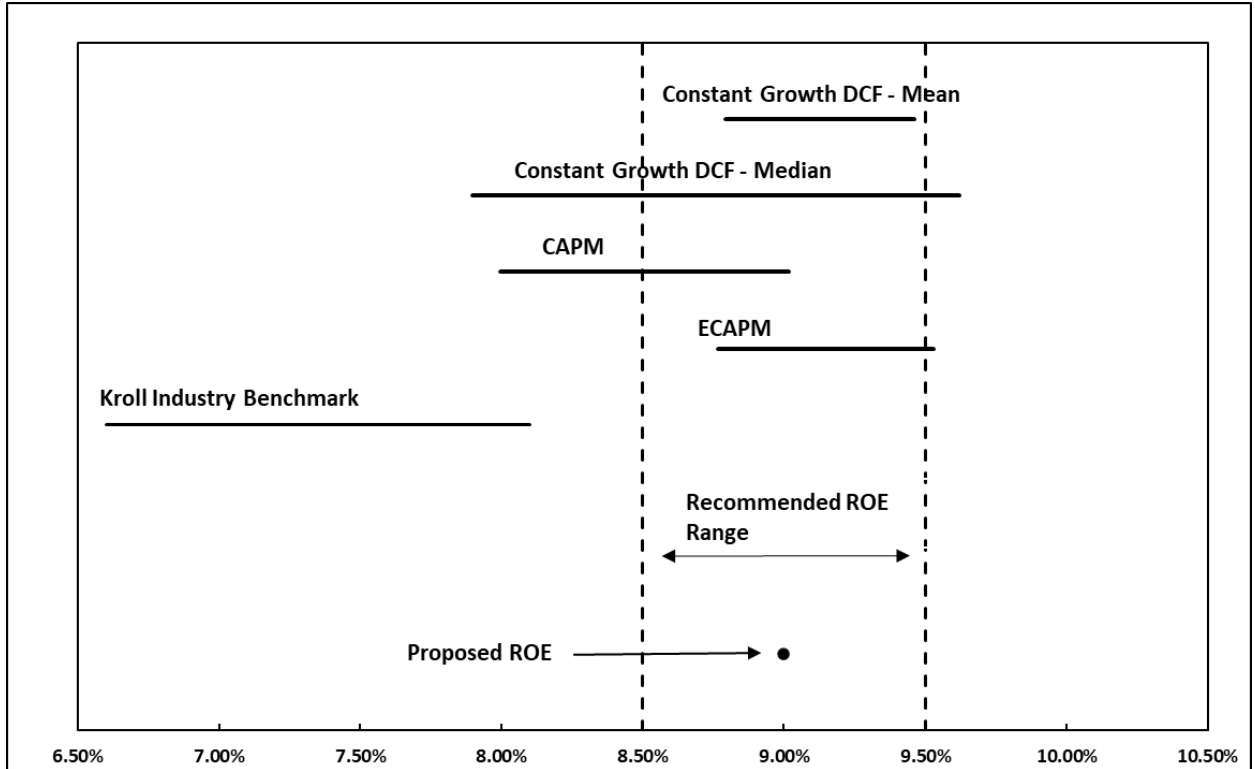
7 A. I analyzed Pacific Power’s cost of capital using constant growth discounted cash flows models,  
8 capital asset pricing models, and empirical capital asset pricing models. These models employ  
9 similar methodologies as those found in Pacific Power’s direct testimony. However, for each  
10 model I update inputs to reflect present market conditions, and I use alternate forecasts of  
11 growth rates and model parameters. For each model I examined a range of inputs, and I used  
12 this variation to establish that a reasonable range for Pacific Power’s ROE is 8.5 percent to 9.5  
13 percent. This range captures one or more variants of each ROE model that I evaluated. I  
14 recommend Pacific Power’s authorized ROE be set in the midpoint of this range, at 9.0  
15 percent. The figure below provides an update to Ms. Bulkley’s ROE estimations to illustrate  
16 my estimates, recommended range, and recommended ROE.

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<sup>2</sup> This change is approximate and may not include all revenue sensitive factors.

1

**Figure LK-1: Return on Equity Summary**



2 **Q.**  
3

**WHAT DRIVES THE DIFFERENCES BETWEEN YOUR ROE RESULTS AND PACIFIC POWER'S?**

4 **A.**

The primary difference between Pacific Power's approach to ROE and my approach to ROE is that I focus on the ROE required by the Company to attract capital and I favor data-driven forecasts. The key difference in my DCF models is that I model constant growth rates using historic growth rates, while Pacific Power relies on analyst forecasts of short-term growth, which is not appropriate for a constant growth model. The first key differences in my CAPM and ECAPM models is that I use an equity risk premium forecast that is consistent with professional surveys, historic data, and premiums implied by current equity prices, while Ms. Bulkley's premium is ad-hoc and inconsistent with financial and economic theory. The second key difference in my CAPM and ECAPM models is that I use unbiased estimates of beta, while

1 Ms. Bulkley uses estimates of beta that have been biased towards 1, which inflates ROE  
2 estimates and overrepresents the risk of utility equity investment.

3 **Q. HOW DOES YOUR FOCUS ON EXPECTED RETURN DIFFER FROM PACIFIC**  
4 **POWER'S?**

5 A. Many of Pacific Power's models focus on what returns analysts expect to realize in the market  
6 rather than on what capital investors require as compensation to incentivize them to invest  
7 capital in physical assets. Pacific Power's models rely heavily on analyst forecasts from Value  
8 Line, Yahoo, and Zachs. The use of analyst forecasts alone is not problematic. However,  
9 analyst forecasts have been found to be overly optimistic and statistically biased.<sup>3</sup> Pacific  
10 Power combines these forecasts in a manner that filters out a greater share of low forecasts,  
11 which exacerbates the bias inherent in analyst forecasts. In addition to filtering out low  
12 forecasts, Pacific Power presents "high" scenarios, which presumably represent the potential  
13 for market outcomes to exceed expectations.

14 The optimism inherent in analyst forecasts, and the windfall returns that occur when  
15 market returns exceed expectations, do not accurately represent the return that is required by  
16 investors to attract equity. The return required for a regulated utility is not the one-year return  
17 that is expected by a group of stock analysts hoping to beat the market in spite of the efficient  
18 market hypothesis. Rather, it is a return that, when consistently earned from year to year,  
19 sufficiently compensates investors for the associated risks to attract capital.

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<sup>3</sup> Szakmary, Andrew; Conover, C. Mitchell; and Lancaster, Carol, "An Examination of Value Line's Long-term Projection" (2008). *Finance Faculty Publications*. 30. <https://scholarship.richmond.edu/finance-faculty-publications/30>.



1 **Q. AS AN ANALYST YOURSELF, HOW DO YOU AVOID THE RISK OF BIASED**  
2 **ESTIMATES?**

3 A. I avoid bias by placing greater weight on data. I also rely on modern finance and forecasting  
4 literature to support my methodologies. Finally, I vetted my results by comparing them against  
5 an independent third-party analysis of electric utility cost of capital.

6 **Q. HOW IS THIS SECTION ORGANIZED?**

7 A. I first present the results of the DCF, CAPM, and ECAPM models in sequence. The discussion  
8 of each model includes a description of the differences between my method and Pacific  
9 Power's method. After presenting the models I provide additional commentary on Ms.  
10 Bulkley's ROE testimony.

11 **a. Discounted Cash Flows**

12 **Q. WHAT ARE THE RESULTS OF YOUR DISCOUNTED CASH FLOW ANALYSIS?**

13 A. My discounted cash flow models estimate a mean ROE range from 8.79 percent to 9.46  
14 percent. The low value results from using earnings per share growth rates based on historical  
15 rates. The maximum value results from using earnings per share growth rates based on Value  
16 Line forecasts.

17 **Q. HOW DO YOUR DCF MODELS DIFFER FROM PACIFIC POWER'S DCF**  
18 **MODELS?**

19 A. I update prices and dividends to reflect information available as of August 26, 2023. This  
20 update modestly increases ROE estimates because dividend yields increased. The primary  
21 difference is our treatment of earnings per share ("EPS") growth rate. I modified the "high"  
22 scenario to reflect Value Line estimates, I introduced a "low" scenario based on historical  
23 earnings per share growth rates, and I used the average of these values to reflect the "mean"  
24 estimate. The median value produced a wider range of results than mean values.

1

**Table LK-1: Discounted Cash Flow ROE Estimates**

<i>Constant Growth DCF ROE Estimate</i>			
	Mean Monte Carlo	Mean	Mean ValueLine
30-Day Average	8.86%	9.36%	9.77%
90-Day Average	8.79%	9.17%	9.46%
180-Day Average	8.73%	9.10%	9.39%
Constant Growth Average	8.79%	9.21%	9.54%
	Median Monte Carlo	Median	Median ValueLine
30-Day Average	7.99%	8.84%	9.56%
90-Day Average	7.90%	8.51%	9.63%
180-Day Average	7.80%	8.44%	9.58%
Constant Growth Average	7.90%	8.59%	9.59%

2 **Q. WHY DO YOU TREAT THE VALUE LINE GROWTH FORECAST AS A HIGH**  
3 **FORECAST?**

4 A. The Value Line constitutes a high forecast for two reasons. First, the forecast is a five-year  
5 growth forecast, not a long-term forecast. It is only appropriate to apply it in a constant growth  
6 model if the 5-year growth rate is expected to continue. However, due to the current state of the  
7 economy, the near-term growth rates likely exceed the long-term growth rates. Bond yield  
8 curves are currently inverted. This is an indication that inflation is expected to decrease over  
9 the next five to ten years. In the long term, earnings growth rates are expected to converge to  
10 GDP growth rates. Constant growth equal to the Value Line forecast is a high scenario because  
11 after the five-year forecast horizon, growth is expected to decrease.

12 A second reason for treating Value Line estimates as “high” is that financial analysts  
13 tend to be optimistic and overestimate growth. Recent academic research finds “that Value  
14 Line’s long-term stock return projections are extremely overoptimistic and have no predictive

1 power.”<sup>4</sup> Constant growth equal to the Value Line forecast is a high scenario because they are  
2 overoptimistic forecasts.

3 **Q. HOW DO YOU FORECAST EARNINGS PER SHARE GROWTH WITHOUT**  
4 **RELYING ON ANALYST FORECASTS?**

5 A. I use historic, 28-year earnings-per-share growth rates of the proxy group to estimate long-term  
6 earnings per share growth.<sup>5</sup> For each company in the proxy group, I estimate the geometric  
7 mean return using a Monte Carlo simulation.

8 **Q. WHY DO YOU USE GEOMETRIC MEAN?**

A. The geometric mean provides a more accurate estimate of long-term growth, particularly when  
short-term growth can be both positive and negative. The table below provides a simple  
illustration of why arithmetic averages are misleading. In this table, \$100 is invested over two  
years. The first year’s return is a 50 percent loss, and the second year’s return is a 50 percent  
gain. The arithmetic mean incorrectly represents the two-year return of the portfolio as zero  
percent, when in fact the investment declined over two years. The use of mean return may be  
appropriate to evaluate expected values for single periods, but it is a biased measure of long  
run returns.

9 **Table LK-2 Arithmetic and Geometric Mean**

Year	Growth investment
1	100
2	-50% 50
3	50% 75
Arithmetic Mean	0%
Geometric Mean	-13%

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<sup>4</sup> Szakmary, Andrew; Conover, C. Mitchell; and Lancaster, Carol, “An Examination of Value Line’s Long-term Projection” (2008). *Finance Faculty Publications*. 30. <https://scholarship.richmond.edu/finance-faculty-publications/30>

<sup>5</sup> The 28-year period represents the full history of data available to me.

1 **Q. WHAT IS THE MONTE CARLO SIMULATION THAT YOU PERFORM?**

2 A. The Monte Carlo simulation involves performing repeated sampling in order to determine  
3 statistical characteristics of an estimator. I use the following steps for each proxy company:

- 4 1. Sample with replacement from historic annual growth of earnings per share.
- 5 2. Calculate 20-year geometric mean growth rate from sample.
- 6 3. Repeat steps 1 and 2 many times, recording each mean growth rate.<sup>6</sup>
- 7 4. Calculate the mean across all growth rates from step 3.

8 **Q. HOW DO THE RESULTS OF THE MONTE CARLO FORECAST COMPARE TO**  
9 **THE VALUE LINE EPS FORECAST?**

10 A. Generally, EPS growth rates from the Monte Carlo simulation were lower than the  
11 corresponding Value Line forecast. The table below summarizes the Monte Carlo results for  
12 different historic sampling periods, from the last ten years to the full 28 years available from  
13 my data source. All three time periods show mean and median growth rates are lower than the  
14 Value Line forecast. I recommend using all years of data to reflect long-term growth  
15 expectations. When calculating ROE in the DCF model, I replace negative EPS growth  
16 forecasts with zero growth forecasts. While this may bias the mean ROE upwards, it does not  
17 affect median results.

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<sup>6</sup> I conducted 290,000 iterations in this step.

1

**Table LK-3: Earnings Per Share Growth Forecasts**

Ticker	Monte Carlo Growth Rates by Historic Selection Period			Value Line
	10-Year	20-Year	All Years	Growth Rate
AEE	15.1%	5.0%	4.1%	6.5%
AEP	1.7%	16.8%	15.5%	6.5%
ALE	2.5%	-1.3%	1.2%	6.0%
AVA	2.2%	12.4%	-6.6%	3.5%
CMS	5.7%	6.5%	-3.8%	6.5%
DUK	-1.0%	-5.0%	-1.4%	5.0%
ETR	6.6%	7.9%	7.6%	4.0%
EVRG	5.1%	5.1%	5.1%	7.5%
IDA	3.7%	2.2%	3.4%	4.5%
LNT	6.5%	1.4%	1.7%	6.0%
NEE	5.9%	6.5%	6.6%	10.5%
NWE	2.3%	4.2%	4.2%	3.5%
OGE	1.5%	6.1%	3.9%	6.5%
OTTR	19.4%	4.5%	4.9%	4.5%
POR	2.8%	3.4%	3.4%	5.0%
SO	3.0%	3.2%	3.1%	6.5%
XEL	5.7%	4.1%	5.0%	6.0%
Mean	5.2%	4.9%	3.4%	5.8%
Median	3.7%	4.5%	3.9%	6.0%

2 **Q. WHY ARE SHORT-TERM VALUE LINE GROWTH FORECASTS NOT**  
3 **APROPRIATE FOR A CONSTANT GROWTH DCF MODEL?**

4 A. The constant growth DCF model reflects return on equity assuming a constant growth rate of  
5 earnings in perpetuity. Short-term growth rates are not typically representative of long-term  
6 growth rates. It is mathematically impossible for a single industry to grow perpetually faster  
7 than the overall economy. If an industry grows faster than the overall economy, the industry  
8 will become a larger share of the economy. If growth rates are perpetually higher than average,  
9 its share of the economy will eventually become 100 percent of the economy, at which point  
10 growth of the industry will equal growth of the economy. The U.S. Congressional Budget

1 Office's ("CBO") long-term growth forecast for the U.S. economy is 3.5 percent. This is  
2 slightly more than half of the Value Line long-term growth forecast. Note that the mean long-  
3 term earnings per share growth rate for the Monte Carlo simulation is nearly equal to the  
4 CBO's long term forecast for U.S. GDP.

5 **b. Capital Asset Pricing Model**

6 **Q. WHAT ARE THE RESULTS OF YOUR CAPITAL ASSET PRICING MODEL**  
7 **ANALYSIS?**

8 A. My CAPM models estimate an ROE range from 8.00 percent to 9.02 percent. The low value  
9 results from using the regression beta estimates and the mean of the current implied risk  
10 premium and the Value Line risk premium.<sup>7</sup> The maximum estimated ROE results from using  
11 the Bloomberg Unadjusted beta estimates and Pacific Power's proposed Value Line risk  
12 premium estimate. The table below summarizes my estimates.

13 **Table LK-4: CAPM ROE Estimates**

<i>CAPM ROE Estimate</i>		
	Regression Beta	Bloomberg Unadjusted Beta
Mean	8.00%	9.02%
Median	8.04%	8.85%

14 **Q. HOW DO YOUR CAPM MODELS DIFFER FROM PACIFIC POWER'S DCF**  
15 **MODELS?**

16 A. I use the risk-free rate to reflect the three-month average 30-year Treasury bond rate. This  
17 update increases the risk-free rate from 3.71 percent to 4.08 percent. I also update the estimates  
18 of beta for each stock. I estimate beta by performing linear regression on five years of monthly

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<sup>7</sup> Beta is a parameter unique to each stock that represents the relationship between the stock's return and the market return.

1 returns. I use S&P 500 as the basis for market returns. I also introduce an alternate measure of  
2 the equity risk premium based on modern finance research.

3 **Q. HOW DO YOUR ESTIMATES OF BETA DIFFER FROM PACIFIC POWER'S?**

4 A. Pacific Power selects beta from Bloomberg and Value Line. Bloomberg reports “adjusted” and  
5 “raw” betas. The coefficients used by Ms. Bulkley appear to be Bloomberg’s “adjusted” betas.  
6 Bloomberg’s “adjusted” beta “uses the historical data of the stock but assumes that a security’s  
7 beta moves toward the market average over time. It weights the historic raw beta and the  
8 market beta.” The weights appear to be 67 percent of the raw beta and 33 percent of the market  
9 beta, which is assumed to be 1.

10 Value Line beta is poorly documented, but it appears to use the New York Stock  
11 Exchange Composite Index as the basis for market return. This results in betas that are  
12 inconsistent with Pacific Power’s equity risk premium which is estimated based on S&P 500  
13 stocks. Value Line betas appear to be rounded to five percent and have some form of  
14 undisclosed upward adjustment. The table below compares my current beta estimate with that  
15 of Zach’s. My regression estimates of beta are generally smaller than the Company’s estimates,  
16 but more accurately reflect the relationship between utility stock returns and market returns  
17 than the Company’s adjusted betas.

1

**Table LK-5: Comparison of Betas Estimates**

	Regression	Zach's	Value Line	Bloomberg	
				Adjusted	Unadjusted
AEE	0.54	0.43	0.85	0.76	0.64
AEP	0.57	0.45	0.75	0.77	0.65
ALE	0.70	0.72	0.90	0.83	0.75
AVA	0.45	0.49	0.90	0.76	0.64
CMS	0.42	0.36	0.80	0.76	0.64
DUK	0.50	0.43	0.85	0.72	0.59
ETR	0.79	0.64	0.95	0.86	0.79
EVRG	0.58	N/A	0.90	0.79	0.68
IDA	0.57	0.60	0.80	0.80	0.71
LNT	0.61	0.55	0.85	0.80	0.70
NEE	0.57	0.46	0.95	0.82	0.73
NWE	0.47	0.43	0.90	0.86	0.80
OGE	0.72	0.72	1.00	0.93	0.89
OTTR	0.50	0.52	0.85	0.88	0.82
POR	0.51	0.55	0.85	0.79	0.69
SO	0.57	0.50	0.90	0.78	0.67
XEL	0.44	0.41	0.80	0.75	0.63
Average	0.56	0.52	0.87	0.80	0.71

2 **Q. IS IT APPROPRIATE TO ADJUST UTILITY BETAS TO THE MARKET AVERAGE?**

3 A. No, this adjustment is not appropriate. While it is correct that beta changes over time, adjusting  
4 betas for utility stocks towards the market average will overrepresent the risk of the utility  
5 industry. It is well known that utility stocks, after addressing diversifiable risk, are less risky  
6 than the market, on average. If anything, adjustment should be made to the industry average,  
7 not the market average. This position is supported by Nobel Laureate William F. Sharpe:

8 Information of the type shown in Table 13-4 [industry average betas] can be used to  
9 “adjust” historic beta values. For example, the knowledge that a corporation is in the air  
10 transport [\*68] industry suggests that a reasonable estimate of the beta value of its stock



1 is greater than 1.0. It thus makes more sense to adjust a historic beta value toward a  
2 value above 1.0 than to the average for all stocks.<sup>8</sup>

3 Furthermore, adjusting betas to an average is unnecessary when using proxy group analysis, as  
4 done by myself and Ms. Bulkley. In the context of this case, the “industry” is the group of  
5 proxy utilities and moving the beta of individual companies in the group towards the group  
6 average would not materially change the results. This is because the ROE results from the  
7 CAPM models ROE ranges are averages already.

8 **Q. WHAT HAVE OTHER COMMISSIONS DETERMINED REGARDING THE USE OF**  
9 **ADJUSTED BETAS?**

10 A. The Oregon Public Utility Commission (“OPUC”) has ruled against adjusting betas to the  
11 market average but has indicated support for adjusting betas towards the industry average.<sup>9</sup>

12 **Q. WHAT IS THE IMPACT OF ADJUSTING BETAS TOWARDS THE INDUSTRY**  
13 **AVERAGE?**

14 A. The current U.S. Electric Industry beta is 0.41.<sup>10</sup> This is below the average regression betas for  
15 the proxy group, and adjusting betas towards the industry average would lower the betas of the  
16 proxy group.

17 **Q. WHAT IS THE IMPACT OF A SMALLER ESTIMATE OF BETA ON ROE?**

18 A. All else equal, a smaller beta estimate for a company lowers the expected return for the  
19 company. If smaller betas are used for the proxy group in the CAPM and ECAPM models, the  
20 estimated cost of equity for Pacific Power’s would decrease.

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<sup>8</sup> *Investments*, 2d ed., Prentice-Hall, Inc., Englewood Cliffs, 1981, p. 344. As quoted in OPUC Docket Nos. UT 125/UT 80, Order No. 00-191 at ¶ 3, 2000 Ore. PUC LEXIS 401 at \*67-\*68 (Apr. 14, 2000).

<sup>9</sup> OPUC Docket Nos. UT 125/UT 80, Order No. 00-191, 2000 Ore. PUC LEXIS 401 (Apr. 14, 2000). The use of adjusted betas was disputed in this case. The Commission noted that “Thus, if any adjustment to the raw beta is appropriate, it should be toward the industry average rather than toward a generic average of all stocks.”

<sup>10</sup> Industry Betas - II Quarter 2023 (USA) Salvidio & Partners: <https://salvidio.com/en/documents-industry-betas/>

1 **Q. ARE YOUR ESTIMATES OF BETA CONSISTENT WITH OTHER FINANCE**  
2 **SOURCES?**

3 A. Yes, my estimates are consistent with Yahoo Finance, Zachs, and Stock Analysis.

4 **Q. SHOULD VALUE LINE OR BLOOMBERG ADJUSTED BETAS BE USED TO**  
5 **ESTIMATE PACIFIC POWER'S COST OF EQUITY?**

6 A. No, these betas do not accurately represent risk of equity investment in the electric industry.

7 **Q. WHAT ESTIMATES ARE AVAILABLE FOR THE EQUITY RISK PREMIUM?**

8 A. The table below summarizes estimates for the equity using a variety of methods. The Value  
9 Line approach in the first row of the table is the method proposed by Pacific Power. Notice that  
10 it is 30 to 100 percent higher than the other estimates.

11 **Table LK-6: Recent Equity Risk Premium Estimates**

<i>Approach Used</i>	<i>ERP</i>	<i>Additional information</i>
Valueline (With Assmetric Bounds)	8.31%	S&P Weighted Growth Forecast Between 0 and 20%
Survey: CFOs	4.42%	Campbell and Harvey survey of CFOs (2018); Average estimate. Median was 3.63%.
Survey: Global Fund Managers	4.60%	Merrill Lynch (January 2020) survey of global managers
Historical - US	5.06%	Geometric average - Stocks minus T.Bonds: 1928-2022
Historical - Multiple Equity Markets	5.00%	Average premium across 20 markets from 1900-2022: Dimson, Marsh and Staunton (2022)
Current Implied premium	5.94%	From S&P 500 - January 1, 2023
Average Implied premium (1960-2022)	4.21%	Average of implied equity risk premium
Average Implied premium (2012-2022)	5.37%	Average of implied equity risk premium
Default spread based premium	4.24%	Baa Default Spread on 1/1/23 * Median value of (ERP/ Default Spread)
Survey: Gobal Finance	5.60%	Finance and economics professors, analysts and managers of companies (2023)

1 **Q. WHAT IS THE CURRENT KROLL EQUITY RISK PREMIUM?**

2 A. The current Kroll-recommended Equity Risk Premium is 5.5 percent.<sup>11</sup> This is consistent with  
3 the current implied premium and 2023 survey of finance professionals.

4 **Q. DO YOU HAVE ANY CONCERNS ABOUT THE VALUE LINE ESTIMATED RISK**  
5 **PREMIUM OTHER THAN ITS STATUS AS AN OUTLIER COMPARED TO**  
6 **INDUSTRY STANDARDS FOR THE EQUITY RISK PREMIUM?**

7 A. Yes, this methodology is subject to the same optimism and subsequent bias as the Value Line  
8 EPS forecasts used in the DCF models. To illustrate the illogicality of the Value Line forecasts,  
9 the 5-year average annual growth for three stocks (Disney, Host Hotels & Resorts, and Fidelity  
10 National Information Services) exceed 50 percent per year, but all three of these stocks have  
11 declined in value since the forecast was produced. If the Value Line forecasts were reliable, an  
12 investor could invest in only stocks with high forecasted growth, and regularly earn returns  
13 several times larger than the market average. This is unreasonable and inconsistent with  
14 economic theory.

15 **Q. DOES PACIFIC POWER USE THE VALUE LINE FORECASTS DIRECTLY?**

16 A. No. Possibly due to the unrealistic nature of the forecasts, Pacific Power implements a 0%  
17 floor and 20% ceiling for stocks.<sup>12</sup> Those stocks with forecasts outside this band are excluded  
18 from the analysis. As a result, 20 percent of all S&P 500 stocks are excluded from the “S&P  
19 Expected Return” calculation. Conditional on using the Value Line forecast, it is reasonable to  
20 exclude or otherwise modify the forecasts to account for these abnormalities. However, it is  
21 unclear what the basis is for the 20% cap. Alternate caps, such as 10% or 30%, yield risk  
22 market returns of 9.57% and 13.47%, respectively. The Value Line equity risk premium is

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<sup>11</sup> <https://www.kroll.com/-/media/cost-of-capital/kroll-lowers-its-recommended-us-equity-risk-premium.pdf>  
(Accessed Sept. 7, 2023).

<sup>12</sup> Exhibit AEB-9 Column 11 reveals that companies outside this range are excluded.

1 sensitive to the arbitrary caps and greatly exceeds generally accepted equity risk premium  
2 estimates.

3 **Q. HOW DO YOU MOVE PACIFIC POWER’S EQUITY RISK PREMIUM TOWARDS A**  
4 **DATA-DRIVEN METHODOLOGY?**

5 A. I estimate an alternate model that averages Pacific Power’s risk premium with the current  
6 implied risk premium. The implied risk premium is a forward-looking risk premium based on  
7 current market prices, yields, and growth rates. This premium has been shown to be a strong  
8 predictor of the actual risk premium.<sup>13</sup> My proposed premium is summarized below.

9 **Table LK-7: Average Equity Risk Premium**

<u>Approach</u>	<u>ERP</u>
Valueline (With Assmetric Bounds)	8.03%
Current Implied premium (January 1, 2023)	5.94%
Average	6.98%

10 **Q THE AVERAGE THAT YOU PROPOSE REMAINS SIGNIFICANTLY HIGHER**  
11 **THAN THE OTHER RISK PREMIUMS IN TABLE LK-6. CAN YOU PROVIDE**  
12 **MORE DETAIL ON THE VARIOUS METHODS OF ESTIMATING THE EQUITY**  
13 **RISK PREMIUM?**

14 A There are three broad approaches to estimating the equity risk premium:

- 15 1) Survey of investors or other experts regarding expectations for future returns;  
16 2) Historical premium of equities over riskless investments; and  
17 3) Forward looking premiums based on current market prices.<sup>14</sup>

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<sup>13</sup> Damodaran, Aswath, Equity Risk Premiums (ERP): Determinants, Estimation and Implications - The 2023 Edition (March 23, 2023). Available at SSRN: <https://ssrn.com/abstract=4398884> or <http://dx.doi.org/10.2139/ssrn.4398884>

<sup>14</sup> Damodaran, Aswath, Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2022 Edition (March 23, 2022). Available at SSRN: <https://ssrn.com/abstract=4066060> or <http://dx.doi.org/10.2139/ssrn.4066060>

1 **Q WHAT DO SURVEYS OF INVESTORS OR OTHER EXPERTS REVEAL ABOUT**  
 2 **THE EQUITY RISK PREMIUM?**

3 A Recent survey-based estimates of the equity risk premium are available from institutional  
 4 investors, corporate management, and academics. The table below summarizes these data.

5 **Table LK-8: Summary of Investor and Finance Professional Surveys**

Date	Survey	Estimate
Feb-2007	Merryll Lynch survey of institutional investors <sup>15</sup>	3.5
Mar-2007	Merryll Lynch survey of institutional investors <sup>16</sup>	4.1
2010	Merryll Lynch survey of institutional investors <sup>17</sup>	3.76 to 3.9
Jan-2012	Merryll Lynch survey of institutional investors <sup>18</sup>	4.08
Feb-2014	Merryll Lynch survey of institutional investors <sup>19</sup>	4.6
June 2020	Merryll Lynch survey of institutional investors <sup>20</sup>	2.5
Dec-2017	Graham and Harvey survey of CFOs <sup>21</sup>	3.63
Jan-2016	Graham and Harvey survey of CFOs <sup>22</sup>	3.55
2000 to 2017	Graham and Harvey survey of CFOs <sup>23</sup>	2.42 to 4.56, 3.63 average
2011	Fernandes et al. survey of Academics <sup>24</sup>	5.6
2022	IESE Business School survey of Academics, investors, and executives <sup>25</sup>	5.5
2023	Kroll June, 2023 Recommended Equity Risk Premium <sup>26</sup>	5.5
2021	CFA Institute Research Foundation <sup>27</sup>	3 to 6

<sup>15</sup> Global Fund Manager Survey, cited in Damodaran (2022).

<sup>16</sup> Global Fund Manager Survey, cited in Damodaran (2022).

<sup>17</sup> Global Fund Manager Survey, cited in Damodaran (2022).

<sup>18</sup> Global Fund Manager Survey, cited in Damodaran (2022).

<sup>19</sup> Global Fund Manager Survey, cited in Damodaran (2022).

<sup>20</sup> Global Fund Manager Survey, Bank of America Merrill Lynch, January 2022. Cited in Damodaran (2022).

<sup>21</sup> Graham, J.R. and C.R. Harvey, 2018, *The Equity Risk Premium in 2018*, Working paper, [https://papers.ssrn.com/sol3/papers.cfm?abstract\\_id=3151162](https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162). Cited in Damodaran (2022).

<sup>22</sup> Graham, J.R. and C.R. Harvey, 2018, *The Equity Risk Premium in 2018*, Working paper, [https://papers.ssrn.com/sol3/papers.cfm?abstract\\_id=3151162](https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162). Cited in Damodaran (2022).

<sup>23</sup> Graham, J.R. and C.R. Harvey, 2018, *The Equity Risk Premium in 2018*, Working paper, [https://papers.ssrn.com/sol3/papers.cfm?abstract\\_id=3151162](https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162). Cited in Damodaran (2022).

<sup>24</sup> Fernandez, P., J. Aguirreamalloa and L. Corres, 2011, Equity Premium used in 2011 for the USA by Analysts, Companies and Professors: A Survey, Working Paper, [http://papers.ssrn.com/sol3/papers.cfm?abstract\\_id=1805852&rec=1&srcabs=1822182](http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1805852&rec=1&srcabs=1822182). Cited in Damodaran (2022).

<sup>25</sup> Fernandez, Pablo and García de Santos, Teresa and Fernández Acín, Javier, Survey: Market Risk Premium and Risk-Free Rate Used for 95 Countries in 2022 (May 23, 2022). Available at SSRN: <https://ssrn.com/abstract=3803990> or <http://dx.doi.org/10.2139/ssrn.3803990>

<sup>26</sup> <https://www.kroll.com/-/media/cost-of-capital/kroll-lowers-its-recommended-us-equity-risk-premium.pdf>

<sup>27</sup> Laurence B. Siegel and Paul McCaffrey, Editors (2023) Revisiting the Equity Risk Premium. <https://www.cfainstitute.org/-/media/documents/article/rf-brief/Revisiting-the-Equity-Risk-Premium.pdf>.

1 Market surveys show that the average risk premium required by investors is materially lower  
2 than the forecast produced by Pacific Power.

3 **Q WHAT RISK PREMIUM EXISTS IN HISTORIC MARKET DATA?**

4 A The historical risk premium depends on the time period studied, method of averaging, and  
5 basis for risk free rate. Damodaran, a widely published and well-respected finance researcher,  
6 provides persuasive rationale for using an extended time horizon, geometric averaging, and  
7 Treasury bills as the risk-free rate.<sup>28</sup> This results in an equity risk premium of 4.47 to 5.13  
8 percent.<sup>29</sup> Historic risk premiums have an advantage over surveys in that they are market-  
9 driven, and thus are not subjective or exposed to other drawbacks of surveys. However, unlike  
10 surveys, historic risk premiums are not forward looking. Implied risk premiums provide a  
11 market-based approach to estimating a forward-looking risk premium.

12 **Q WHAT FORWARD RISK PREMIUMS CAN BE IMPLIED FROM MARKET DATA?**

13 A A forward-looking risk premium can be implied from current market prices and expected cash  
14 flows. The risk premium is implied by current market value for a representative index and the  
15 expected cash flows from that index. Damodaran finds that the implied equity premium of the  
16 trailing 12 months is the best predictor of the actual implied premium.<sup>30</sup> The January 2023  
17 trailing 12-month implied equity risk premium is 5.94 percent.<sup>31</sup>

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<sup>28</sup> Damodaran, Aswath, Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2022 Edition (March 23, 2022). Available at SSRN: <https://ssrn.com/abstract=4066060> or <http://dx.doi.org/10.2139/ssrn.4066060>.

<sup>29</sup> Damodaran (2022), page 38.

<sup>30</sup> Damodaran (2022).

<sup>31</sup> [https://pages.stern.nyu.edu/~adamodar/New\\_Home\\_Page/home.htm](https://pages.stern.nyu.edu/~adamodar/New_Home_Page/home.htm).

1 **Q WHAT DOES THE RANGE OF SURVEY RESULTS FOR THE EQUITY RISK**  
2 **PREMIUM SAY ABOUT THE USE OF GEOMETRIC VS. ARITHMETIC**  
3 **AVERAGING OF HISTORIC RATES?**

4 A The surveys of investors and finance professionals report that the equity risk premium is  
5 between 3 and 6 percent. This is consistent with the current implied risk premium of 5.94  
6 percent, but substantially less than the Value Line forecast of 8.03. The surveys are also  
7 consistent with historical risk premium when geometric averaging is used, but are well  
8 below historical risk premium when arithmetic averaging is used. This confirms that  
9 geometric averaging should be used when evaluating investor expectations.

10 **Q WHAT MEASURE OF THE EQUITY RISK PREMIUM IS RECOMMENDED FOR**  
11 **USE IN SETTING RATES?**

12 A There is no one approach to estimating equity risk premiums that is appropriate for all  
13 analyses. However, generally, the current trailing 12-month implied equity risk premium is  
14 more appropriate when equity markets are assumed to be functioning efficiently, when  
15 predictive power is important, or when current equity needs of investors are being considered.  
16 A historical risk premium or a long-term average of implied premiums is appropriate when  
17 evaluating long-term capital investment decisions or when there is reason to believe that  
18 current markets are over- or under-valued. Survey results are appropriate when markets are  
19 assumed to be functioning poorly over an extended time.

20 In setting utility rates, the primary function of estimating the cost of equity is to provide  
21 a fair return to equity investors that is sufficient to attract capital. However, utilities also use  
22 approved cost of capital in long-term planning and when making capital investment decisions.  
23 In an environment of well-functioning capital markets, greatest weight should be placed on the  
24 current implied equity risk premium. However, it is also appropriate to consider long-term  
25 average implied risk premium and the historic risk premium and current survey results due to

1 unstable equity market conditions and the capital planning functions of the authorized cost of  
2 equity.

3 In my models, I take a conservative approach by using the average of the current  
4 implied risk premium (5.94 percent), which has high forward-looking explanatory power, and  
5 the method used by Pacific Power (8.03 percent), which can be thought of as an upper bound  
6 on future risk premium because it exceeds all other forecasted risk premium estimates. This  
7 results in a risk premium of 6.98.

8 **c. Empirical CAPM**

9 **Q PLEASE SUMMARIZE THE RESULTS OF YOUR EMPIRICAL CAPM MODELS.**

10 A My ECAPM models estimate an ROE range from 8.77 percent to 9.53 percent. The low value  
11 results from using the regression beta estimates. The maximum estimated ROE results from  
12 using the unadjusted Bloomberg beta estimates. I recommend against placing material weight  
13 on this model because it contains questionable assumptions. The table below summarizes my  
14 estimates.

15 **Table LK-9: ECAPM ROE Estimates**

<i>ECAPM ROE Estimate</i>		
	Regression Beta	Bloomberg Unadjusted Beta
Mean	8.77%	9.53%
Median	8.79%	9.41%

16 **Q. HOW DO YOUR ESTIMATES OF BETA DIFFER FROM PACIFIC POWER'S?**

17 A. I apply the same updates to betas and equity risk premium performed for the CAPM model  
18 discussed above.



1 **Q. WHY DO YOU CHARACTERIZE THE ECAPM AS HAVING QUESTIONABLE**  
2 **ASSUMPTIONS?**

3 A. The formula Ms. Bulkley uses, and which I adopt, for the ECAPM relies on statistical analysis  
4 performed in 1989.<sup>32</sup> It is not clear that this relationship persists in the markets today.  
5 Furthermore, the analysis underlying the ECAPM model relies on industry averages, rather  
6 than utility averages. Thus, it is likely that the adjustment does not reflect any real  
7 characteristics of the utility industry. While I report ECAPM for informational purposes, I do  
8 not recommend giving the model results material weight or consideration because it over-  
9 represents the risk of utility companies. I also do not apply the excessive Value Line risk  
10 premium forecasts to this model because that would exacerbate the problems with the model.

11 **d. Market Analysis**

12 **Q. GIVEN CURRENT MARKET CONDITIONS, WHY DO YOU RECOMMEND A**  
13 **DECREASE IN THE COST OF EQUITY?**

14 A. The only market conditions that are relevant to evaluating cost of equity are those that are  
15 inputs to the ROE estimation models. Outside of these, Pacific Power's arguments about the  
16 condition of the market are speculative and irrelevant, in that the arguments are not  
17 theoretically or empirically linked to the models used to estimate ROE.

18 Furthermore, speculation about current market conditions does not directly address  
19 whether the currently approved ROE is too high or too low. The primary considerations in  
20 determining cost of equity are that it be commensurate with the returns on investments for  
21 other firms with similar risks and that it be sufficient to assure the financial integrity of the  
22 utility, to maintain credit, and to attract capital.<sup>33</sup> My recommendations are supported by

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<sup>32</sup> Morin, R. A (2006). *New Regulatory Finance*. Austria: Public Utilities Reports, page 190, footnote 12.

<sup>33</sup> *Federal Power Commission v. Hope Natural Gas Co.*, 320 US 591, 602 (1944).

1 various mathematical models that can be used to estimate a return on equity that meets these  
2 criteria. However, the judgement applied in evaluating these models is grounded in observing  
3 utility and investor behavior.

4 Pacific Power has not provided evidence that it has faced any difficulties in attracting  
5 capital, nor that it is aware of any other utilities that have been unable to.<sup>34</sup> In fact, not only has  
6 Pacific Power been able to attract capital, Pacific Power is seeking to increase its capital ratio  
7 above its historic levels. This indicates an investor appetite for Pacific Power's existing ROE.  
8 This investor appetite occurs when an investor's expected ROE exceeds that required by the  
9 investor, and the tendency for regulated utilities to over-capitalize is known academically as  
10 the Averch-Johnson effect, and informally, as "gold-plating." The Averch-Johnson effect is  
11 the tendency of regulated companies to engage in excessive capitalization in order to increase  
12 net income.

13 The cause of the Averch-Johnson effect is excessive ROE, and the symptoms of the  
14 Averch-Johnson effect are 1) actions that increase equity, and 2) market valuations of equity  
15 above the book value of equity. Examples of increasing equity include requesting an equity-  
16 heavy capital structure, discouraging competitive energy service, and acquiring owned  
17 generation rather than power purchase agreements. In most proceedings that I have participated  
18 in across the U.S., I have observed a utility actively arguing against actions that would  
19 decrease the utility's opportunity for increased investment.

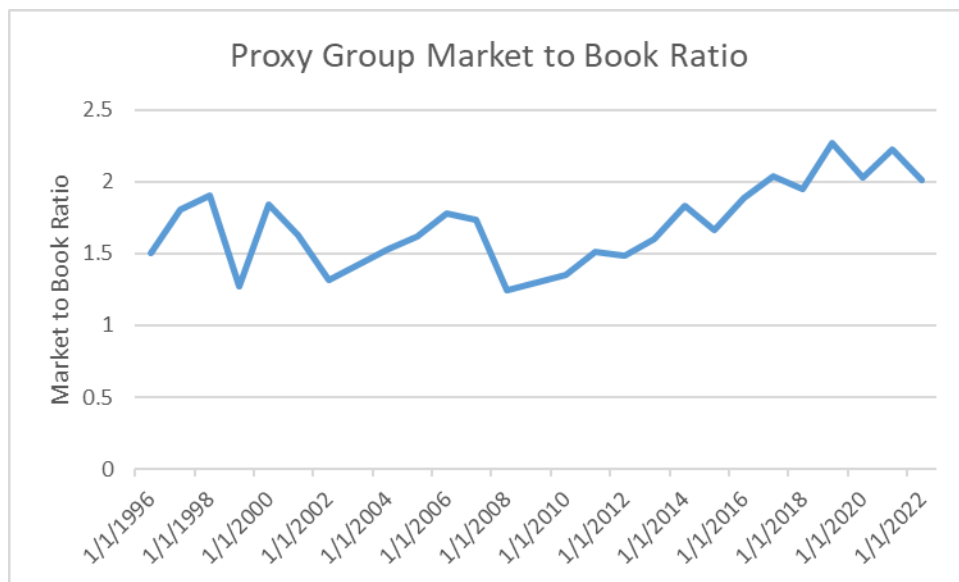
20 The second key factor indicating that current return on equity is excessive is that  
21 utilities are experiencing excessive market-to-book ratios. If return on equity for the utility

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<sup>34</sup> See Exh. LDK-3 (Pacific Power's response to AWEC Data Request 021).

1 industry is sufficient but not excessive, the market-to-book ratio for the utility industry should  
2 be at or near one.<sup>35</sup> A market-to-book ratio above one indicates that return on equity exceeds  
3 that which is necessary for an investment of comparable risk.<sup>36</sup> The figure below presents the  
4 mean market-to-book ratio for the proxy utilities. The average market-to-book ratios have  
5 exceeded one since 1996 and are currently at their highest levels. These data indicate that the  
6 proxy group, on average, earns returns on equity substantially higher than necessary.

7 **Figure LK-2: Market-to-Book Ratio**



8 **Q. OTHER THAN GENERAL INDUSTRY OBSERVATIONS, WHAT SPECIFIC**  
9 **BEHAVIOR OF PACIFIC POWER INDICATES THAT THE CURRENT**  
10 **AUTHORIZED ROE OF 9.5 PERCENT IS EXCESSIVE?**

11 A. Pacific Power's effort to increase its equity ratio indicates the current ROE is excessive. Pacific  
12 Power's advocacy in direct access proceedings in Oregon has prevented material competition  
13 for energy service. This indicates a preference for owned generation, which is consistent with  
14 the Averch-Johnson effect.

<sup>35</sup> Morin, R. A (2006). New Regulatory Finance. Austria: Public Utilities Reports, page 360.

<sup>36</sup> Morin, R. A (2006). New Regulatory Finance. Austria: Public Utilities Reports, page 360.

1 **Q WHAT MARKET COMMENTARY DOES MS. BULKLEY OFFER?**

2 A Ms. Bulkley makes the following assertions:

- 3 • Interest rates may remain at the current rates.<sup>37</sup>
- 4 • Utility share prices are inversely correlated with interest rates.<sup>38</sup>
- 5 • Utilities are expected to underperform in current market conditions.<sup>39</sup>
- 6 • Washington authorized ROE is below average relative to other states.<sup>40</sup>

7 **Q WHAT IS YOUR RESPONSE TO MS. BULKLEY'S MARKET OBSERVATIONS?**

8 A These observations are flawed and do not inform ROE estimates, other than through the impact  
9 of inputs to the return on equity models. Ms. Bulkley did not analyze the correlation of utility  
10 stock prices with interest rates, and a closer examination shows that there is no fixed  
11 relationship. Decreasing stock prices can reflect decreased expected earnings, and thus it is  
12 incorrect to conclude that decreasing stock prices imply increased ROE requirements. Finally,  
13 to the extent that utilities are expected to underperform, and that this expectation is public, the  
14 efficient market hypothesis demonstrates that current market prices will reflect this  
15 underperformance.

16 Ms. Bulkley accurately notes that Washington authorized ROE has been below average  
17 relative to other states in recent years. However, Ms. Bulkley incorrectly concludes that this  
18 increases the overall cost of equity<sup>41</sup> and inhibits Pacific Power's ability to attract capital.<sup>42</sup> If  
19 Ms. Bulkley's assertions were accurate, states with below average ROE could reduce their cost

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<sup>37</sup> Exh. AEB-1Tr at 6.

<sup>38</sup> Exh. AEB-1Tr at 6, 12, and 19.

<sup>39</sup> Exh. AEB-1Tr at 6, 19, and 21.

<sup>40</sup> Exh. AEB-1Tr at 58.

<sup>41</sup> Exh. AEB-1Tr at 58.

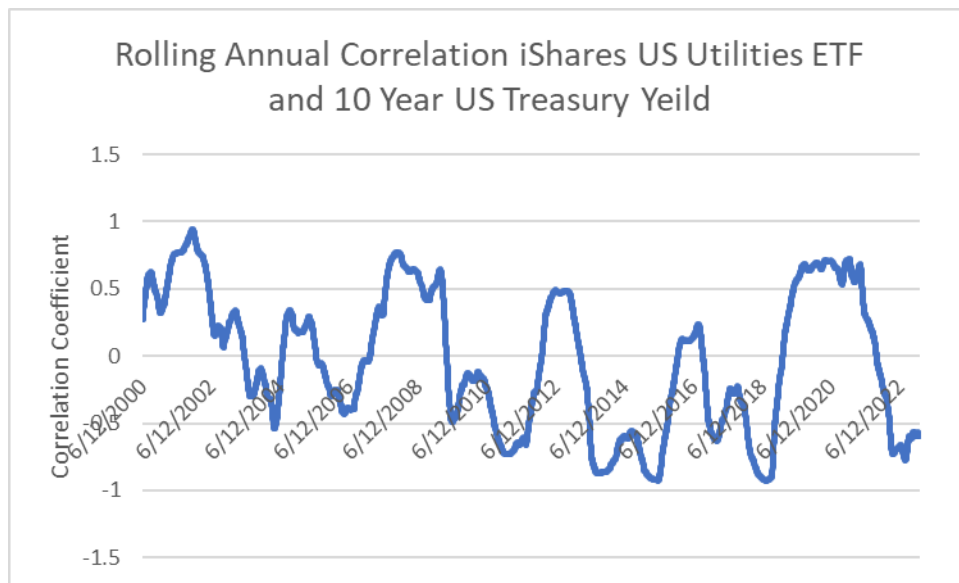
<sup>42</sup> Exh. AEB-1Tr at 9.

1 of equity by increasing their authorized ROE to an above average level. However, this would  
2 cause other states to be below average, affording an opportunity for the new below average  
3 states to lower their cost of equity. This logic results in a circular process that would lead to a  
4 constant growth of ROE over time, regardless of the actual needs of investors.

5 **Q WHY DO YOU CLAIM THAT THERE IS NO FIXED RELATIONSHIP BETWEEN**  
6 **UTILITY STOCK PRICE AND INTEREST RATES?**

7 A I analyzed the correlation of utility stock prices with Treasury yields, and utility stock price  
8 growth with Treasury yields. I used the iShares U.S. Utilities ETF to measure utility prices.  
9 Neither measure shows a consistent inverse correlation. The figure below shows that the  
10 rolling one-year correlation between utility stock price and 10-year Treasury yield is cyclical  
11 and varies from negative to positive.

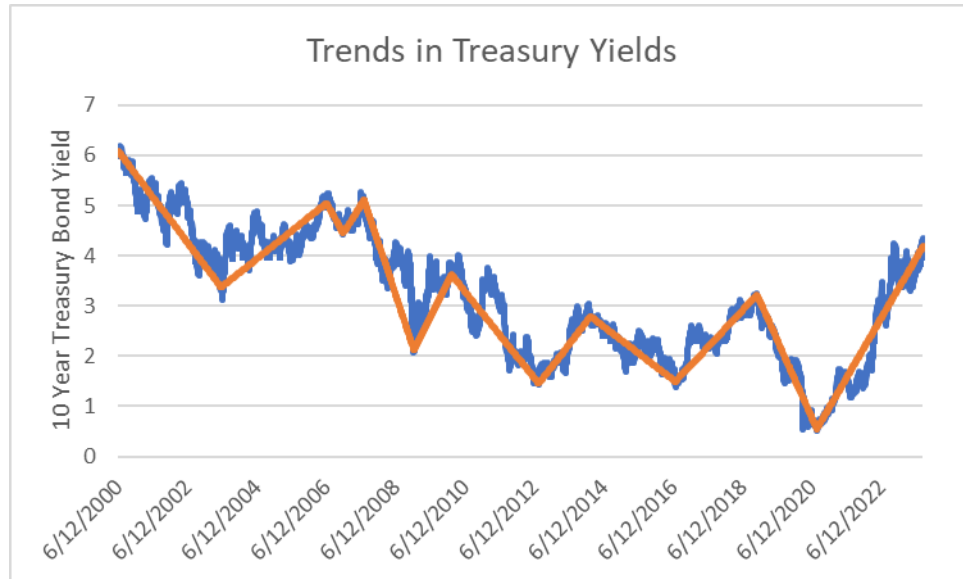
12 **Figure LK-3: Rolling Annual Correlation Between Utility Share Price and Treasury Yield**



13 In addition to evaluating rolling annual correlation, I investigated whether the correlation is  
14 affected by whether Treasury yields are declining or increasing. The figure below identifies my  
15 determination of whether yields are decreasing or increasing.

1

**Figure LK-4: Break Points in Treasury Trends**



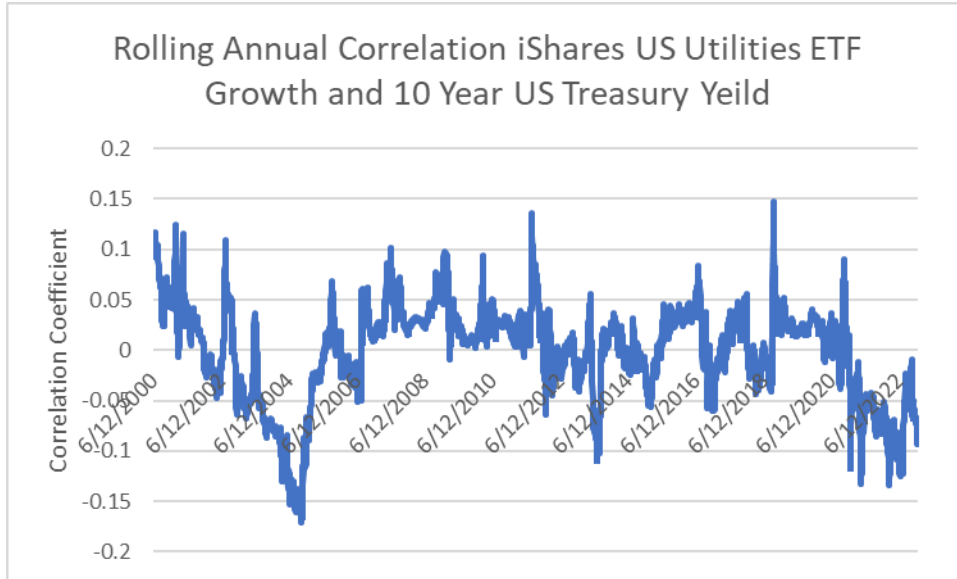
2 I calculated the correlation between the utility index price and Treasury yields within each straight-  
 3 line segment of the figure above. I found the correlation to be positive in eight of 12 segments, as  
 4 shown in the table below.

5 **Table LK-10: Correlation Between Stock Price and 10-year Treasury Bond Yields**

Start Date	End Date	Correlation
6/12/2000	5/30/2003	0.81
5/30/2003	6/14/2006	0.33
6/14/2006	12/5/2006	-0.87
12/5/2006	7/13/2007	0.22
7/13/2007	12/19/2008	0.54
12/19/2008	1/21/2010	0.44
1/21/2010	7/26/2012	-0.77
7/26/2012	1/23/2014	0.47
1/23/2014	6/30/2016	-0.82
6/30/2016	11/7/2018	0.21
11/7/2018	7/30/2020	-0.13
7/30/2020	8/23/2023	0.48

6 I also investigated the one-year rolling correlation between utility price growth and Treasury yields.  
 7 There is no consistent relationship, as shown in the figure below.

1 **Figure LK-5: Rolling Annual Correlation Between Stock Price Growth and Treasury Yield**



2 **Q EVEN IF A NEGATIVE RELATIONSHIP IS ASSUMED BETWEEN TREASURY**  
3 **YIELDS AND UTILITY SHARE PRICE, HOW IS THIS RELEVANT TO ROE**  
4 **ESTIMATES?**

5 **A** Ms. Bulkley incorrectly concludes that a negative relationship between share price and  
6 Treasury yields implies a negative relationship between ROE and equity. While investor ROE  
7 requirements can drive stock price, so can investor expectations. For example, in the  
8 discounted cash flow model, if ROE is held constant but earnings expectations are decreased,  
9 the stock price will decrease.

10 **Q IF STOCK PRICES ARE EXPECTED TO UNDERPERFORM, IS THAT A BASIS**  
11 **FOR PLACING LESS WEIGHT ON DISCOUNTED CASH FLOW RESULTS?**

12 **A** No. Reliable ROE models such as the DCF and CAPM models assume efficient markets. This  
13 means that current market prices reflect all known information about the respective companies  
14 and markets. Ms. Bulkley makes a key assertion that is inconsistent with this, specifically that  
15 “the share prices of utilities are likely to decline.”<sup>43</sup> Ms. Bulkley makes this assertion by

<sup>43</sup> Exhibit No. AE B-1Tr page 6 line 15.

1 isolating a single market factor (Treasury yields), forecasting the factor to remain constant, and  
2 assuming the relationship between that factor and utility prices (that utility stock yields must  
3 exceed Treasury yields.) This approach to forecasting stock prices is not academically rigorous  
4 because it essentially assumes the result. Furthermore, if the relationships are real, market  
5 traders would short sell utility stock in the current market, driving down the stock price until  
6 there is no opportunity for inter-temporal arbitrage.

7 **Q HOW DO CURRENT MARKET CONDITIONS FACTOR INTO ROE ESTIMATES?**

8 A. Current market conditions are inputs to the DCF and CAPM models. These models  
9 automatically account for the impact of current and expected market conditions. It is  
10 unnecessary to make further adjustments.

11 **Q. PLEASE SUMMARIZE YOUR COST OF EQUITY ANALYSIS AND**  
12 **RECOMMENDATION.**

13 A. The DCF, CAPM, and ECAPM models result in a broad range of ROE estimates. However, all  
14 models overlap with some portion of the range of 8.5 to 9.5 percent, which I recommend as a  
15 reasonable ROE range. I recommend an ROE of 9.0 percent. This provides a return on equity  
16 sufficient to attract capital given the risk and returns of Pacific Power and the proxy group.

17 **Q. WHAT ARE INDEPENDENT, THIRD-PARTY ESTIMATES OF THE UNITED**  
18 **STATES ELECTRIC UTILITY INDUSTRY COST OF EQUITY?**

19 A. Cost of capital estimates rely in part on assumptions and judgements about model inputs. These  
20 assumptions and judgements may be influenced by the incentives of the analyst making  
21 estimates. In rate setting proceedings, utilities are incentivized to recommend higher cost of  
22 equity and ratepayer advocates are incentivized to recommend lower cost of equity. Even if  
23 individual analyst and experts sponsored by participants are free of bias and incentives,  
24 participants may select experts whose assumptions and judgements align with the participant's



incentives. Cost of equity estimates produced by third parties without vested interests in the outcome of rate proceedings can avoid both incentive bias and selection bias.

The Kroll Cost of Capital Navigator is a third-party tool produced by a third party without a direct vested interest in the outcome of this rate proceeding. This tool includes an industry benchmarking tool that reports current industry cost of equity under multiple models. The only user input to the Kroll Cost of Capital Industry Benchmark Study is the reporting date, making the model results for this study free of user bias and selection bias. The table below summarizes the results of the Kroll Cost of Capital Industry Benchmark Cost of Equity. Results are provided for the median firm, all firms in the industry, the five largest firms and the five smallest firms. The mean and median values for every sub-group are well below Pacific Power’s requested ROE.

**Table LK-11:Kroll Cost of Capital Industry Benchmark**

**Kroll Industry Cost of Equity Capital (%): GICS 551010: Electric Utilities**

	CAPM + Size		Build-Up		Discounted Cash Flow		Fama-French	Mean	Median	
	CAPM	Prem	CRSP	KRPR	1-Stage	3-Stage	5-Factor			
		CRSP	KRPR	CRSP	KRPR					
Median	6.90	7.40	9.90	7.40	12.10	10.80	7.90	8.10	8.81	8.00
SIC/GICS Composite	6.90	6.90	9.50	7.00	11.20	10.70	7.20	6.90	8.29	7.10
Large Composite	6.80	6.60	9.20	6.80	10.80	10.60	7.00	N/A	8.26	7.00
Small Composite	7.10	7.80	10.70	7.60	13.60	10.60	7.70	7.60	9.09	7.75

Sourced from the Cost of Capital Navigator: U.S. Industry Benchmarking Module on 09/10/2023

Three of eight models in the benchmark study, identified by strike through, contain assumptions that render them inappropriate for a rate setting context. These three models are discussed in more detail in the Cost of Equity section of this testimony. The table below illustrates the Cost of Equity results when these models are removed from the mean and median. Every relevant independent third-party model result is more consistent with my cost of equity recommendations than Pacific Power’s cost of equity recommendations.

**Table LK-12: Kroll Cost of Capital Industry Benchmark Excluding Inapplicable Models**

**Kroll Industry Cost of Equity Capital (%): GICS 551010: Electric Utilities**

	<b>CAPM +</b>	<b>3-Stage</b>	<b>FF 5-</b>				
	<b>CAPM</b>	<b>Size Prem</b>	<b>Build-Up</b>	<b>DCF</b>	<b>Factor</b>	<b>Mean</b>	<b>Median</b>
Median	6.90	7.40	7.40	7.90	8.10	7.54	7.40
SIC/GICS Composite	6.90	6.90	7.00	7.20	6.90	6.98	6.90
Large Composite	6.80	6.60	6.80	7.00	N/A	6.80	6.80
Small Composite	7.10	7.80	7.60	7.70	7.60	7.56	7.60

Sourced from the Cost of Capital Navigator: U.S. Industry Benchmarking Module on 09/10/2023

**Q. WHAT KROLL MODELS DO YOU CONSIDER INAPPROPRIATE FOR RATE SETTING PURPOSES?**

A. The Kroll Risk Premium Report “KRPR” CAPM + Size Premium and Build-Up models only utilize size measures that are not tuned to the capital-intensive utility industry, such as number of employees. The single stage discounted cash flow model relies on short-term industry growth forecasts rather than long-term forecasts.

**Q. HOW DO YOU RECOMMEND THE COMMISSION USE THE KROLL ELECTRIC UTILITY INDUSTRY BENCHMARK STUDY?**

A. This study should be used to validate whether my recommendations are reasonable. The Commission should view the mean and median results of five applicable models as a reasonable lower bound for this case. My models produce ROE estimates that exceed all applicable Kroll models because I intentionally selected model inputs that result in conservatively high cost of equity. For example, I include Value Line growth estimates in all three of my models. I made conservatively high ROE recommendations in order to promote gradualism in ROE changes, and to provide investors with a buffer against unexpected increases in the market ROE after rates are set.

1 To the extent that the Commission chooses to place weight on the three models that I  
2 characterize as inappropriate, the Commission should limit this to evaluating the eight models  
3 in aggregate, by considering the mean and median values across all eight models. My  
4 recommended ROE of 9 percent is consistent with Kroll's Small Composite mean ROE  
5 estimate of 9.09 percent.

### 6 III. CAPITAL STRUCTURE

7 **Q. PLEASE SUMMARIZE YOUR CAPITAL STRUCTURE TESTIMONY.**

8 A. I recommend the use of a 51 percent common equity, 0.01 percent preferred stock, and 48.99  
9 percent long-term debt capital structure. This structure is based on Pacific Power's forecasted  
10 capital structure with short-term debt replaced by long-term debt. Pacific Power has argued  
11 that its short-term debt is transitory and has a *de minimis* impact on weighted average cost of  
12 capital.<sup>44</sup> Pacific Power recommends removing short-term debt from its forecasted capital  
13 structure and replacing with a proportionate share of equity and long-term debt.

14 Given the *de minimis* impact of short-term debt, I recommend modeling short-term debt  
15 as long-term debt rather than a share of short-term and long-term debt. This has the effect of  
16 mitigating some of Pacific Power's requested increase in its share of equity.

17 **Q. WHY HAS PACIFIC POWER'S REQUESTED SHARE OF EQUITY INCREASED?**

18 A. Pacific Power claims that it needed to increase its equity share to above 51 percent to maintain  
19 a "single A" credit rating, and that this will result in an optimal capital structure.<sup>45</sup>

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<sup>44</sup> Exh. NLK-1Tr at 3.

<sup>45</sup> Exh. NLK-1Tr at 4-5.

1 **Q. WHAT DOES PACIFIC POWER PROPOSE TO BE USED AS THE BASIS FOR ITS**  
2 **CAPITAL STRUCTURE?**

3 A. Pacific Power proposes using its pro-forma 2024 capital structure, with short-term debt  
4 replaced by a proportionate share of long-term debt and equity.<sup>46</sup> This recommendation inflates  
5 the weighted average cost of capital above that necessary to maintain its alleged optimal bond  
6 rating, or 51percent. I recommend modeling short term debt be replaced by a mixture of long  
7 term debt and equity such that the equity ratio equals the optimal amount asserted by Pacific  
8 Power, or 51 percent. This approach will moderate the impact of Pacific Power's recent  
9 increases in equity and will result in a 51 percent common equity, 0.01 percent preferred stock,  
10 and 48.99 percent long term debt capital structure.

11 **Q. CAN PACIFIC POWER ACHIEVE YOUR RECOMMENDED CAPITAL**  
12 **STRUCTURE?**

13 A. Yes. Pacific Power manages its capital structure through its issuance of dividends to its parent,  
14 BHE.<sup>47</sup> I model Pacific Power achieving my recommended capital structure by maintaining  
15 Pacific Power's proposed level of long-term debt and issuing dividends to draw down Pacific  
16 Power's equity from Pacific Power's proposed level to the recommended level of 51 percent.

17 **Q. WHAT COST OF DEBT AND PREFERRED STOCK DO YOU USE TO CALCULATE**  
18 **THE WEIGHTED AVERAGE COST OF CAPITAL?**

19 A. I use Pacific Power's proposed rates of 4.77 percent and 6.75 percent, respectively. This  
20 reduces Pacific Power's weighted average cost of capital from 7.60 to 6.927 percent.

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<sup>46</sup> Exh. NLK-1Tr at 3.

<sup>47</sup> Exh. NLK-1Tr at 6.

1 **IV. COST OF SERVICE**

2 **Q. WHAT ARE YOUR COST-OF-SERVICE RECOMMENDATIONS?**

3 A. I recommend five changes to Pacific Power’s filed cost of service study:

- 4 1. Allocate FERC Account 407, Amort of Prop Losses, Unrec Plant, functionalized to distribution  
5 plant, based on each schedule’s allocation of distribution plant using Pacific Power’s F102D  
6 factor. The proposed allocation reflects the relationship between distribution plant and property  
7 losses for distribution plant.
- 8 2. Allocate FERC Accounts 561 and 581, load dispatching costs, based on each schedule’s Load  
9 Complexity, calculated as the share of annual hourly load ramping. The proposed allocation  
10 reflects that load variability drives load dispatching costs.
- 11 3. Allocate FERC Account 904 Uncollectible Accounts using weighted customer counts, Pacific  
12 Power’s F136 factor. The proposed allocation reflects the WAC 480-85-060 requirement that  
13 costs functionalized to customer costs be allocated based on customer counts.
- 14 4. Modify Pacific Power’s System Gross Miscellaneous Plant allocator, F102Co, such that when  
15 the allocator returns an error code, the backup allocator is an equal weighted average of F102,  
16 F136, Load Complexity, and Labor Allocation. This factor allocates a large number of non-  
17 plant related common costs, such as pensions. It is therefore appropriate that the allocation  
18 reflects a broad range of cost drivers, including labor costs, customer service costs, and  
19 operational costs.
- 20 5. Allocate FERC Account 926 Pensions and Benefits using Pacific Power’s allocation of labor  
21 expense to each schedule. Pensions and benefits are directly related to labor expense.

1 **a. Allocation of FERC Account 407**

2 **Q. WHAT COSTS ARE RECORDED TO FERC ACCOUNT 407?**

3 A. According to the FERC uniform system of accounts, “This account shall be charged with  
4 amounts credited to account 182.1, Extraordinary Property Losses, and account 182.2,  
5 Unrecovered Plant and Regulatory Study Costs, when the Commission has authorized the  
6 amount in the latter account to be amortized by charges to electric operations.”<sup>48</sup> More than 99  
7 percent of Washington’s allocation of system costs in this account are functionalized based on  
8 distribution poles and wires, indicating that these costs are primarily driven by distribution  
9 poles and wires.<sup>49</sup>

10 **Q. HOW DOES PACIFIC POWER ALLOCATE THESE COSTS TO CUSTOMER**  
11 **SCHEDULES?**

12 A. Pacific Power allocates these costs using the F110, System Intangible Plant allocation factor.  
13 This factor reflects each schedule’s allocation of intangible plant, which is primarily software.

14 **Q. WHY DOES PACIFIC POWER’S ALLOCATION PRESENT AN ISSUE?**

15 A. Factor F110 does not appear to be related to property losses, unrecovered plant, or regulatory  
16 study costs. It is also unrelated to distribution poles and wires.

17 **Q. HOW DO YOU RECOMMEND ALLOCATING THESE COSTS?**

18 A. I recommend these costs be allocated based on each schedule’s allocation of distribution plant  
19 using Pacific Power’s F102D factor. The F102D factor reflects each schedule’s share of system  
20 gross distribution plant. This factor is more directly related to property losses than the  
21 intangible plant allocation factor.

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<sup>48</sup> Code of Federal Regulations Title 18, Chapter I Subchapter C Part 101.

<sup>49</sup> Exh. RMM-4 at 21. Line 741 Column D divided by Line 744 Column D.

1 **b. Allocation of FERC Accounts 561 and 581**

2 **Q. WHAT COSTS ARE RECORDED TO FERC ACCOUNTS 561 AND 581?**

3 A. These accounts reflect labor, materials, and expense incurred to monitor current and next day  
4 load dispatching.<sup>50</sup> Such costs include direct switching, voltage control, current and next day  
5 load forecasting, and monitoring real-time flows of energy.<sup>51</sup>

6 **Q. HOW DOES PACIFIC POWER ALLOCATE THESE COSTS TO CUSTOMER**  
7 **SCHEDULES?**

8 A. Pacific Power allocates these costs using the F12 “12 Coincident Peak” and F20 allocation  
9 factor, “Maximum Schedule Peak.”<sup>52</sup> The 12 CP and maximum schedule peak factors do not  
10 reflect the impact of inter hour or inter day load changes on the system.

11 **Q. WHY NOT?**

12 A. The 12 CP factor reflects each schedule’s share of the monthly system coincident peaks in all  
13 12 months. The Maximum Schedule Peak factor reflects the maximum load within each  
14 schedule. Both of these measures relate to peak load, not variability of load. A schedule with a  
15 single hour of energy use, and no energy in all other hours of the day, may have a high peak,  
16 but will not drive the costs recorded in this account because it will have very little impact on  
17 current and next day load dispatching, which occurs in all hours of the year, not only the peak  
18 hours. Similarly, a customer with flat load in all hours of the day could have a high peak, but  
19 will have minimal impact on the complexity of maintaining voltage control, forecasting load,  
20 and switching to manage load dispatch.

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<sup>50</sup> Code of Federal Regulations Title 18 Chapter I Subchapter C Part 101.

<sup>51</sup> Code of Federal Regulations Title 18 Chapter I Subchapter C Part 101.

<sup>52</sup> Exh. RMM-4 at 17, lines 446 and 498.

1 **Q. HOW DO YOU RECOMMEND ALLOCATING THESE COSTS?**

2 A. I recommend these costs be allocated using a factor that reflects load variability. I constructed  
3 this factor by calculating the absolute value of inter-hour load changes for each schedule across  
4 the year, summing this difference for all hours in the year, and calculating each schedule's  
5 share of total hourly load changes. This allocation factor is summarized in the table below.

6 **Table LK-13: Annual inter-hour load change by schedule**

	Residential Schedule 16	Small General Service Schedule 24	Large General Service <1,000 kW Schedule 36	Large General Service >1,000 kW Schedule 48	Large General Dedicated Facilities Schedule 48	Agricultural Pumping Schedule 40	Street & Area Lighting Sch. 15, 51- 54, 57	Total
Inter Hour Load Change (MWh)	156,875	25,423	29,174	483	4,497	6,291	1,459	4,913
Share of Total	68.1%	11.0%	12.9%	3.4%	2.0%	2.1%	0.5%	100%

7 **c. Allocation of FERC Account 904**

8 **Q. WHAT COSTS ARE RECORDED TO FERC ACCOUNT 904?**

9 A. According to the FERC uniform system of accounts, "This account shall be charged with  
10 amounts sufficient to provide for losses from uncollectible utility revenues. Concurrent credits  
11 shall be made to account 144, Accumulated Provision for Uncollectible Accounts—Cr. Losses  
12 from uncollectible accounts shall be charged to account 144."<sup>53</sup>

13 **Q. HOW DOES PACIFIC POWER ALLOCATE THESE COSTS TO CUSTOMER**  
14 **SCHEDULES?**

15 A. Pacific Power allocates these costs using the F80 factor.

16 **Q. WHY DOES PACIFIC POWER'S ALLOCATION PRESENT AN ISSUE?**

17 A. The F80 factor directly assigns residential write-offs and recoveries to residential schedules,  
18 but allocates commercial, industrial, and irrigation write-offs and recoveries based on revenue.

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<sup>53</sup> Code of Federal Regulations Title 18 Chapter I Subchapter C Part 101.



1 This allocation is inconsistent with WAC 480-85-060(3)'s requirement that costs  
2 functionalized to customer costs be allocated based on customer counts.

3 **Q. HOW DO YOU RECOMMEND ALLOCATING THESE COSTS?**

4 A. I recommend these costs be allocated using PacifiCorp's weighted customer count factor F136,  
5 which reflects both the weighted customer count factor F41 and F42. I make this  
6 recommendation to be consistent with WAC 480-85-060(3) described above. WAC 480-85-  
7 060(3) Table 2 indicates that Customer Service and Billing functionalized costs are to be  
8 allocated using weighted customer counts. Uncollectible accounts are appropriately considered  
9 part of the billing function. Therefore, these costs are appropriately allocated using weighted  
10 customer counts. Alternatively, if the Commission does not agree that the treatment of  
11 uncollectibles is governed by WAC 480-85-060(3), then it should allocate uncollectible costs  
12 using the average uncollectible by schedule, rather than using revenue as Pacific Power's filed  
13 model does.

14 **d. Modification of PacifiCorp's Allocation Allocator F102CO**

15 **Q. WHAT IS PACIFIC POWER'S SYSTEM GROSS MISCELLANEOUS PLANT**  
16 **ALLOCATOR, F102CO?**

17 A. The F102 factor is calculated as each schedule's allocated share of generation, transmission,  
18 and distribution gross plant.<sup>54</sup> This factor is calculated using the following process:

- 19 1. Functionalize plant to Generation, Transmission, Distribution, Customer, and Common.
- 20 2. Within each function, allocate costs to customer classes. (AWEC does not dispute the  
21 allocations Pacific Power makes in this step.)

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<sup>54</sup> 230172-PAC-RMM-COSWA-FINAL.xlsx sheet "COS Factor Table" row 49.

1           3. Sum each schedule's allocated costs across all functions.

2           4. Calculate each schedule's share of allocated costs.

3           The F102Co factor is similar to the F102, but limited to plant that has been functionalized as  
4           common costs. This factor is calculated by modifying step 3 above to only sum costs  
5           functionalized as common costs. Because no generation, transmission, or distribution costs are  
6           functionalized as common costs, this results in an undefined number.

7   **Q.   HOW IS THE F102CO FACTOR USED IN PACIFIC POWER'S COST MODEL?**

8   A.   This factor is used to allocate several accounts functionalized to common:

- 9           • 920 Administrative and General Salaries
- 10          • 921 Office Supplies and Expenses
- 11          • 922 Administrative and General Expenses
- 12          • 923 Outside Services
- 13          • 925 Injuries and Damages
- 14          • 931 Rents

15          These accounts are not directly related to generation, distribution, and transmission costs.

16   **Q.   WHY DOES PACIFIC POWER'S ALLOCATOR PRESENT AN ISSUE?**

17   A.   Pacific Power's cost model does not functionalize any generation, transmission, or distribution  
18          plant as common. This results in an undefined calculation with zero in the denominator. Pacific  
19          Power's model defaults the F102Co factor to the F102 factor in the event of a calculation error  
20          such as an undefined number.

21   **Q.   WHAT IS YOUR RECOMMENDED CHANGE TO THIS FACTOR?**

22   A.   I recommend that this factor be changed to default to a broader factor that more accurately  
23          reflects administrative burden. The FERC accounts that this allocator is applied to do not relate

1 only to plant costs. In addition to plant investment, labor costs, load complexity, and customer  
2 service all add to administrative burden. I recommend that F102Co default to an average of  
3 these four factors:

- 4 • Plant investment, using Pacific Power’s F102 factor,
- 5 • Customer costs, using Pacific Power’s F136 factor,
- 6 • Load complexity, using the hourly load change factor described in this testimony, and
- 7 • Labor costs, calculated as the weighted average of each schedule’s total allocated labor  
8 costs, as summarized in Exhibit LDK-5.

9 **e. Allocation of FERC Account 926**

10 **Q. WHAT COSTS ARE RECORDED TO FERC ACCOUNT 926?**

11 A. According to the FERC uniform system of accounts, “This account shall include pensions paid  
12 to or on behalf of retired employees, or accruals to provide for pensions, or payments for the  
13 purchase of annuities for this purpose, when the utility has definitely, by contract, committed  
14 itself to a pension plan under which the pension funds are irrevocably devoted to pension  
15 purposes, and payments for employee accident, sickness, hospital, and death benefits, or  
16 insurance therefor. Include, also, expenses incurred in medical, educational or recreational  
17 activities for the benefit of employees, and administrative expenses in connection with  
18 employee pensions and benefits.”<sup>55</sup>

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<sup>55</sup> Code of Federal Regulations Title 18 Chapter I Subchapter C Part 101.

1 **Q. HOW DOES PACIFIC POWER ALLOCATE THESE COSTS TO CUSTOMER**  
2 **SCHEDULES?**

3 A. Pacific Power allocates these costs using the overall allocation of common costs F138Co. This  
4 factor reflects each schedule's total allocation of costs functionalized to common.

5 **Q. WHY DOES PACIFIC POWER'S ALLOCATION PRESENT AN ISSUE?**

6 A. Pension and benefit costs are directly related to labor costs. It is therefore more appropriate to  
7 allocate these costs using labor rather than the more general F138Co allocator. F138Co has  
8 many non-labor costs embedded in it, such as plant allocations and regulatory fee allocations,  
9 which are clearly unrelated to pensions and benefits.

10 **Q. HOW DO YOU RECOMMEND ALLOCATING THESE COSTS?**

11 A. I recommend these costs be allocated using each schedule's allocation of labor, as calculated in  
12 Exhibit LDK-5.

13 **Q. WHAT IS THE IMPACT OF YOUR COST OF SERVICE RECOMMENDATIONS?**

14 A. Under my recommended cost study, all schedules except for street lighting are within a  
15 reasonable range of rate parity. Parity ratio is calculated as a revenue divided by cost. If the  
16 parity ratio is 1, the schedule's revenue equals the cost to serve the schedule. This is a desired  
17 outcome because it indicates that rates are cost based. A parity ratio of 1.05 indicates that the  
18 schedule's revenues are five percent above the cost to serve the schedule, while a parity ratio of  
19 0.95 indicates that the schedule's revenues are 5 percent below the cost to serve the schedule.  
20 The table below compares rate parity under my cost study with that of Pacific Power's.

1

**Table LK-14: AWEC and Pacific Power Parity Ratios**

Schedule	AWEC Parity Ratio	PAC Parity Ratio
Residential Schedule 16	0.971	0.988
Small General Service Schedule 24	1.060	1.070
Large General Service < 1,000 kW Schedule 36 & 29	1.058	1.037
Large General Service > 1,000 kW Schedule 48	1.001	0.977
Large General Dedicated Facilities Schedule 48	0.961	0.925
Agricultural Pumping Schedule 40	0.941	0.944
Street & Area Lighting Sch. 15, 51-54, 57	0.865	0.961
Total	1.000	1.000

**V. RATE SPREAD**

2 **Q. WHAT RATE SPREAD DID PACIFIC POWER PROPOSE?**

3 A. Pacific Power proposed a lower than average rate increase for Schedules 24, 29, and 36, and a  
4 higher than average rate increase for all other schedules, as summarized in the table below.<sup>56</sup>

5 **Table LK-15: Pacific Power Proposed Revenue Increase by Schedule**

A	B	C	D	E	F
Schedule	Description	Change Required per Adjusted Target Cost of Service	Present Revenue as a Percent of of Earned Cost of Service	Proposed Price Change	Proposed Revenue as a Percent of Adjusted Target Cost of Service
16,17,19	Residential	15.5%	98.8%	16.2%	100.6%
24	General - Small	6.3%	107.0%	6.5%	100.2%
29,36	General	8.8%	103.7%	10.0%	101.1%
47,48T	General - Large	15.4%	97.8%	16.2%	100.7%
48T-DF*	General - Large	21.3%	92.5%	16.3%	95.8%
40	Agricultural Pumping	20.8%	94.4%	16.2%	96.2%
15,51,53,54	Lighting	20.4%	96.1%	16.2%	96.6%
All		13.5%	100.0%	13.5%	100.0%

\*Dedicated Facilities (DF)

6 **Q. IS PACIFIC POWER’S RATE SPREAD SUPPORTED BY EITHER PACIFIC**  
7 **POWER’S COST STUDY OR YOUR COST STUDY?**

8 A. No, neither Pacific Power’s cost study nor my cost study supports Pacific Power’s  
9 recommendations. Commission Staff has previously recommended treating parity ratios within

<sup>56</sup> Reproduced from Exh. RMM-1T at 10.

1 5 percent of parity, or 1, as within the margin of error for cost studies, and parity ratios within  
2 10 percent of parity as reasonable.<sup>57</sup> Under both Staff's test and Pacific Power's cost study  
3 parity ratios, reproduced in Table LK-14 above, all schedules are within the margin of error or  
4 within a reasonable range of 1. This means that if none of my recommended cost study changes  
5 are implemented, all rate schedules should receive the same percentage increase. Under my  
6 cost study, street and area lighting are the only schedules outside the reasonable range. The  
7 parity ratio for street and area lighting is 0.865, which is more than ten percent from parity.  
8 Therefore the street and area lighting schedules warrant a larger than average rate increase.

9 **Q. WHAT IS YOUR RECOMMENDED RATE SPREAD?**

10 A. I recommend street and area lighting be increased by 125 percent of the average rate increase,  
11 with all other schedules increased by an equal percentage.

12 **VI. RATE DESIGN**

13 **Q. WHAT RATE DESIGN CHANGES DOES PACIFIC POWER PROPOSE FOR**  
14 **INDUSTRIAL SCHEDULES?**

15 A. Pacific Power makes four recommendations regarding Schedule 48T:

- 16 • Ten percent movement towards cost of service for rate components,<sup>58</sup>
- 17 • Treat transmission costs and 11.5 percent of generation costs as load size costs rather than  
18 on peak demand costs,<sup>59</sup>
- 19 • Add a transmission pricing option,<sup>60</sup> and

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<sup>57</sup> Dockets UE-200900, UG-200901, UE-200894, Exh. ELJ-1T at 10, Table 1.

<sup>58</sup> Exh. RMM-1T at 34:5.

<sup>59</sup> Exh. RMM-1T at 34:6-35:4.

<sup>60</sup> Exh. RMM-1T at 35:11-20.

1 • Clarify language for the load size charge.<sup>61</sup>

2 Pacific Power also recommends that Schedule 47T continue to be based on Schedule 48T  
3 rates.<sup>62</sup>

4 **Q. WHICH OF THESE CHANGES DO YOU SUPPORT?**

5 A. I support transmission pricing options, language clarification, and treatment of Schedule 47T. I  
6 do not support Pacific Power's proposed treatment of transmission and generation costs. I  
7 partially support the ten percent movement towards cost of service; however, I recommend that  
8 the percent movement be a percent change from current rates, rather than percent change of the  
9 difference between cost of service and current rates.

10 **Q. WHY IS IT NOT APPROPRIATE TO TREAT TRANSMISSION AND GENERATION**  
11 **COSTS AS LOAD SIZE COSTS?**

12 A. Load size costs should be limited to costs that are directly impacted by the peak load of a  
13 facility. These costs should also be consistent with the cost model used to allocate costs.  
14 Transmission and generation costs are driven by, and allocated, using peak demand, not facility  
15 size or non-coincident peak.

16 **Q. WHAT IS THE IMPACT OF PACIFIC POWER'S RECOMMENDED CHANGE?**

17 A. Pacific Power's proposal increases the load size charge by 1,058 percent, from \$0.29 per kW to  
18 \$3.01 per kW.<sup>63</sup> This is an unreasonably large change in rates over just two years.

19 **Q. WHAT RATIONALE DOES PACIFIC POWER OFFER FOR THE PROPOSED**  
20 **CHANGE TO FACITLITY CHARGES?**

21 A. Pacific Power offers no compelling rationale for treating transmission cost as load size costs.  
22 Pacific Power argues that 11.5 percent of demand-related generation costs are load size costs

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<sup>61</sup> Exh. RMM-1T at 36:12-21.

<sup>62</sup> Exh. RMM-1T at 37:5-7.

<sup>63</sup> Exh. RMM-11r at 19.

1 because they relate to the planning reserve margin to account for uncertain events and  
2 operating reserve requirements.<sup>64</sup> Pacific Power asserts that because unknown events can occur  
3 off peak, and the load size charge is not bound to on peak periods, reserve margin costs should  
4 be recovered through the load size charge.<sup>65</sup>

5 **Q. WHAT IS YOUR RESPONSE TO PACIFIC POWER'S RATIONALE?**

6 A. There are several problems with Pacific Power's rationale. First, while operating reserve  
7 margins must be held in every hour, these are more appropriately considered generation costs  
8 than demand costs because they are a cost of serving energy in every hour of the year, rather  
9 than a cost for meeting peak demand. Second, there is no evidence or reason to believe that any  
10 individual customer's maximum historic facility load correlates to system outages or  
11 unexpected system stresses. Third, the facility load charge is a persistent measure over the  
12 previous 12 months. In actual operations, Pacific Power can monetize excess capacity by  
13 selling to the market or dispatching less expensive resources. Thus the persistence of the load  
14 size charge will cause customers to pay for a cost that Pacific Power does not incur. Finally, if  
15 Pacific Power's rationale were accurate, then it would be appropriate to allocate demand costs  
16 using the sum of facility size for all customers. This would likely shift costs away from  
17 Schedule 48T because of the relatively large variability of small customer loads.

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<sup>64</sup> Exh. RMM-1T at 34:14-19.

<sup>65</sup> Exh. RMM-1T at 35:1-4.



1 **Q. WHY DO YOU RECOMMEND THAT PRICE CHANGES BE LIMITED TO 10**  
2 **PERCENT CHANGES FROM CURRENT PRICES RATHER THAN 10 PERCENT OF**  
3 **THE DIFFERENCE BETWEEN THE COST OF SERVICE AND CURRENT PRICES?**

4 A. Under Pacific Power's approach to limiting price changes, unreasonably large changes can still  
5 occur. For example, Pacific Power increases the facility charge by 1,058 percent over two  
6 years. Under my recommendation this increase would be closer to 20 percent.

7 **Q. HOW WOULD YOUR RECOMMENDED LIMIT BE IMPLEMENTED WHILE STILL**  
8 **ACCOMODATING THE OVERAL SCHEDULE REVENUE REQUIREMENT**  
9 **CHANGE?**

10 A. I recommend that the 10 percent change be applied as a cap to present rates after applying the  
11 schedule's average increase. For example, if a current rate is \$1.00 per kW, and the schedule's  
12 revenue requirement increase is 20 percent, the final rate limit would be \$1.20 plus or minus  
13 ten percent, or \$0.12, depending on whether prices are above or below the component's cost of  
14 service.

15 **VII. WILDFIRE**

16 **Q. PLEASE SUMMARIZE PACIFIC POWER'S PROPOSED TREATMENT OF WILD**  
17 **FIRE EXPENSES.**

18 A. Pacific Power has proposed not seeking recovery of specific wildfire expenses.<sup>66</sup> To  
19 accomplish this, Pacific Power has removed \$224 million in wildfire repair capital costs,<sup>67</sup> and  
20 adjusted injuries and damages expense to a three-year average.<sup>68</sup> However, Pacific Power has  
21 not proposed adjustments to wildfire litigation expense and is including 2022 wildfire litigation  
22 costs in its requested revenue requirement.<sup>69</sup>

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<sup>66</sup> Exh. LDK-3 (Response to AWEC Data Request 8).

<sup>67</sup> Exh. SLC-4 at 339.

<sup>68</sup> Exh. SLC-4 at 113

<sup>69</sup> Exh. LDK-3 (Response to AWEC Data Request 8).

1 **Q. DO 2022 WILDFIRE LITIGATION COSTS INCLUDE COSTS ASSOCIATED WITH**  
 2 **THE LABOR DAY FIRES?**

3 A. [REDACTED]  
 4 [REDACTED]  
 5 [REDACTED]  
 6 [REDACTED]  
 7 [REDACTED]

8 **Q. DOES PACIFIC POWER’S 3 YEAR INJURIES REPRESENT A REASONABLE**  
 9 **AVERAGE LEVEL OF INJURIES AND DAMAGES?**

10 A. No, Pacific Power’s three-year average includes an abnormal level of injuries in 2019. I  
 11 recommend modifying the three year average to a two year average. The table below identifies  
 12 injuries and damages by year and compares the three year and two year average.

13 **Table LK-16: Two Year Average Injuries and Damages Expense**

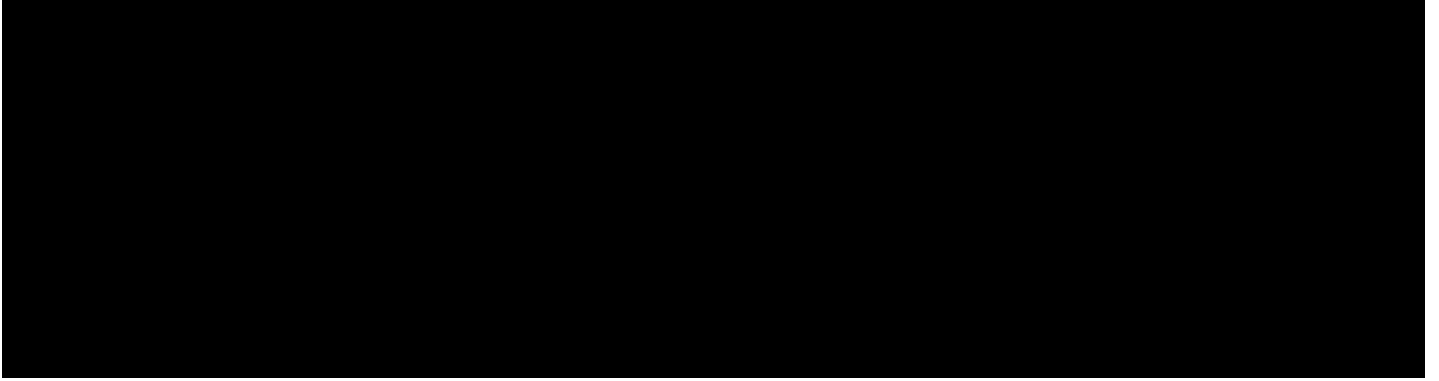
	July 19 - June 20	July 20 - June 21	July 21 - June 22	Total
	Cash	Cash	Cash	Cash
Cash paid on claims	11,469,351	2,929,134	2,576,288	16,974,772
Remove amounts not requested	-	-	-	0
Net Paid	11,469,351	2,929,134	2,576,288	16,974,772
Third Party Insurance Claim Proceeds	-	-	-	-
Remove amounts not requested	-	-	-	-
Net Reimbursement from Commercial Insurance	-	-	-	-
Net Paid				16,974,772
Three-Year Average				5,658,257
Two-Year Average				2,752,711
AWEC Adjustment				(2,905,547)

14 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON WASHINGTON**  
 15 **EXPENSES?**

16 A. The table below summarizes the Washington allocation of my expense adjustment. My  
 17 adjustment reduces expense in Account 925 by \$545,054.

1

**Confidential Table LK-17: AWEC Wildfire Adjustment**



2 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

3 A. Yes.