Exhibit LDK-6T
Dockets UE-230172 & UE-210852
Witness: Lance D. Kaufman

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*)

CROSS-ANSWERING TESTIMONY OF LANCE D. KAUFMAN

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

October 27, 2023

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

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

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

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am providing cross-answering testimony on Pacific Power's ("PacifiCorp" or "Company") cost of capital, cost of service, and rate spread.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I make the following recommendations:

- The Commission should find that PacifiCorp is correct to include both the cost of demand and energy in the denominator when calculating demand and energy share of generation.
- The Commission should direct PacifiCorp to consider planning reserve margins and ELCC of storage in its cost study for the next general rate case.
- The Commission should spread rates consistent with the Response Testimony of Lance D. Kaufman, or if Dr. Dismukes or PacifiCorp's cost study is adopted the Commission should spread rates on an equal percentage increase basis for all classes.
- The Commission should not consider cost of equity estimates that rely on studying the risk premium approved in other proceedings.

II. COST OF SERVICE

Q. WHAT COST OF SERVICE TESTIMONY WAS SUBMITED BY OTHER INTERVENING PARTIES?

A. Dr. Dismukes provides cost of service testimony on behalf of Public Counsel. Dr. Dismukes claims that PacifiCorp's COSS incorrectly calculates the demand component of generation under the renewable future peak credit methodology. Dr. Dismukes' criticism and proposed amendment are both incorrect.

Q. HOW DOES PACIFICORP CALCULATE THE SHARE OF GENERATION COSTS DUE TO DEMAND?

A. PacifiCorp calculates demand share of generation by calculating the cost to serve PacifiCorp's demand and annual energy requirements, then calculating the share of demand and energy out of the total. PacifiCorp's approach is theoretically accurate because the total generation cost is the sum of capacity and energy cost. The cost to serve demand is calculated using a 12-hour battery. PacifiCorp calculates the levelized annual cost per kW-year of the battery including charging costs.

The cost to serve energy is somewhat more complicated because it includes adjustments to reflect PacifiCorp's system capacity factor to ensure that the ratio of energy to capacity is accurate. To do this, it isolates the energy and capacity costs of a single resource because all energy resources also provide some capacity, or demand, value.

PacifiCorp first calculates the amount of energy that is served each year per kW of peak demand. PacifiCorp's load factor is 65%. This means for every kilowatt of demand that PacifiCorp serves, PacifiCorp serves 5,694 kWh of energy per year (calculated as 65% load factor times 8,760, the number of hours in a year.)[1] PacifiCorp then determines the nameplate

[1] Exh. RMM-5, line 8.

capacity of a wind resource that is necessary to serve 5,694 kWh of energy each year. PacifiCorp's energy costs are based on a wind facility with a 46.3 percent capacity factor. One kilowatt of this resource will only produce 3,819 kWh of energy per year (calculated as 43.6 % capacity factor times 8,760).[2] PacifiCorp must build 1.49 kW of wind to generate a year's worth of energy associated with a kW of demand.[3]

The cost of serving this energy is the levelized cost of a kW of wind, or $120.28 per kW-year, times the number of kW necessary, 1.49 kW. This means the "raw" cost of serving a year's worth of energy is $179.32.[4] However, the wind facility that is used to model energy cost provides some capacity benefit. PacifiCorp isolates the capacity value of 1.49 kW of wind by multiplying the nameplate capacity by the capacity contribution, 30%. Thus, 1.49kW of wind provides enough capacity to serve 0.447 kW of demand. The value of this capacity, using the battery's cost of capacity, is $100.03 (0.447 kW * $224.72 per kW-Year). [5] The cost of a year's worth of energy when serving a single kW of demand is the cost of the wind facility ($179.32) minus the value of capacity for this facility ($100.03), or $79.29.[6] This represents the value of non-firm energy, i.e., energy with no capacity attributes.

The total annual cost of generation for one kW is the cost of serving both capacity ($224.72 per year) and non-firm energy ($79.29 per year), or $304.01 per year. The demand share of generation is the cost of capacity ($224.72 per year) divided by the cost of generation, ($304.01 per year), or 74%.

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2 Exh. RMM-5, line 9.
3 Exh. RMM-5, line 10.
4 Exh. RMM-5, line 11.
5 Exh. RMM-5, line 12.
6 Exh. RMM-5, line 13.

Q. WHAT IS DR. DISMUKES' ALLEGATION REGARDING PACIFICORP'S MODEL?

A. Dr. Dismukes alleges that including both capacity cost and generation cost in the denominator of the final step is not logical.[7] The denominator that Dr. Dismukes refers to is the $304.01 per year cost to serve the annual energy and capacity needs of 1 kW of load. The basis for Dr. Dismukes' assertion is that he is not aware of the logical purpose of including both energy and capacity costs in the denominator of the formula.[8]

Q. WHAT IS THE LOGICAL PURPOSE OF INCLUDING BOTH CAPACITY AND ENERGY IN THE DENOMINATOR?

A. The first step in understanding the logic behind including both costs is understanding how the resulting percentages are used in the cost-of-service model. The percentages are used to split PacifiCorp's actual generation costs into demand components and energy components. The demand components are allocated to each schedule based on share of demand. The energy components are allocated to each schedule based on share of energy.

Because the demand percentage is ultimately multiplied by total generation costs, which serve both demand and energy, it is logical for the denominator of the demand percentage to also include total generation cost. The logic of this can be easily proven. Suppose that the cost assumptions in PacifiCorp's model were correct, and a new system were built from scratch using these costs to avoid the complexities that the ravages of time work on revenue requirement.

If this were the case, PacifiCorp's actual cost of generation would be the modeled cost of generation, or $304.01 per kW. If PacifiCorp's demand and energy percentages are used, we would find that the demand component is $224.97 ($304.01 times 0.74) while the energy

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7 Exh. DED-1T at 17:1-3.

8 Exh. DED-1T at 17:10-11.

component is $79.02 ($304.01 times 0.26). These are very close to the modeled demand and energy components, with the slight difference due to rounding error of the percentages. Thus, using PacifiCorp's numbers properly returns the actual cost of capacity and energy.

However, if Dr. Dismukes' demand and energy percentages are used, the demand component is $197.61 ($304.01 times 0.74) while the energy component is $106.4 ($304.01 times 0.26). Dr. Dismukes' method deviates substantially from the modeled cost of capacity and energy. Dr. Dismukes' method is to use only the cost of capacity, or $224.97, in the denominator. This is only appropriate if the resource used to estimate the cost of capacity also provides a year's worth of energy at no cost, which a battery simply cannot do.

Q. WHAT ARE THE IMPLICATIONS OF CORRECTING DR. DISMUKES' CHANGES TO THE COSS?

A. Dr. Dismukes' changes increase the energy component of generation costs, which has some impact on each rate class's parity ratio. However, as explained below, because these changes do not result in any rate class being more than 10% from parity, under Commission precedent Dr. Dismukes' changes do not materially impact my recommendation to apply an equal percentage rate increase to most rate schedules even if the Commission agrees with Dr. Dismukes.

Q. DR. DISMUKES ARGUES THAT PACIFICORP'S APPLICATION OF THE RENEWABLE FUTURE PEAK CREDIT IS NOT CONSISTENT WITH THE THERMAL PEAK METHOD.[9] IS THIS CORRECT?

A. No, Dr. Dismukes is incorrect. The thermal peak formula that Dr. Dismukes uses is of the form Demand = (1/2 of CT Fixed Cost) / (CCT Fixed Cost). A CT is a capacity unit that also serves energy needs when power prices are high. Therefore, ½ of the CT fixed cost can reasonably be

[9] Exh. DED-1T at 16:7-9.

attributed to capacity value.[10] A CCT unit is a baseload unit that serves capacity and energy, and thus the fixed cost of the baseload unit represents the cost of both capacity and energy. When the conceptual components of the formula are replaced, the formula becomes Demand = Capacity Cost / (Capacity plus Energy Cost), which is effectively what PacifiCorp's model does.

Q. IF THE COMMISSION FINDS THAT PACIFICORP'S MODEL IS NOT CONSISTENT WITH THE THERMAL PEAK CREDIT METHOD, SHOULD DR. DISMUKES' METHOD BE ADDOPTED?

A. No. While I believe the models are consistent, the method as understood and explained in the rulemaking adopting the Renewable Future Peak Credit method should be used. While the rules do not provide detail on the Renewable Future Peak Credit method, the rulemaking documents contain the original Renewable Future Peak Credit method. General Order R-599 notes that, in an April 25, 2019 notice, electric companies were directed to model costs using the Renewable Future Peak Credit method.[11] The notice directs readers to a presentation filed in the docket on February 21, 2019.[12] Page 6 of the presentation contains a table specifying the Renewable Future Peak Credit method.[13] The method used by PacifiCorp in this case is consistent with the method presented in the rulemaking; however, there are some differences.

Q. WHAT DIFFERENCES DO YOU SEE BETWEEN THE RULEMAKING METHODOLOGY AND PACIFICORP'S FILED METHODOLOGY?

A. There are several input updates, such as capital costs, capacity factor, and load factor. These updates are reasonable and based on IRP values. However, there is a material change in the

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10 Some jurisdictions would argue that all of the CT cost reflects capacity value.

11 Dockets UE-170002/UG-170003, General Order R-599, Order Amending and Adopting Rules Permanently, ¶¶ 19-20.

12 Dockets UE-170002/UG-170003, Revised Notice of Informal Draft Rules and Opportunity to File Written Comments at 3, fn. 1.

13 *See* Exh. LDK-7.

operation of the battery. The rulemaking models the battery as operating for 200 hours while PacifiCorp's filed model shows only 12 hours of operation. This is concerning because 12 hours of operation may not be sufficient to provide 100 percent capacity contribution. PacifiCorp's IRP does not appear to report on the effective load carrying capacity ("ELCC") of a 12-hour storage resource. However, PSE reports an ELCC of 37.2 percent for 8-hour storage in the base scenario for 2027,[14] Avista reports an ELCC of 80 percent in 2027 for 12-hour storage, but indicates that ELCC will decline rapidly over time,[15] and Portland General Electric has found that 10-hour storage resources only have an ELCC of 80%, and that this level declines rapidly with greater degrees of storage penetration.[16]

Q. WHAT UPDATES DO YOU RECOMMEND TO PACIFICORP'S RENEWABLE FUTURE PEAK CREDIT METHOD TO ACCOUNT FOR THE LIMITED LOAD CARRYING CAPACITY OF BATTERIES?

A. I recommend that the method be modified to account for the ELCC of the storage resource being modeled. I also recommend that demand costs be grossed up by the planning reserve margin. These changes should be made in PacifiCorp's next general rate case.

Q. WHAT ARE THE IMPLICATIONS OF REVISING THE DEMAND AND ENERGY ALLOCATIONS TO REFLECT ELCC AND PLANNING RESERVE MARGINS?

A. These changes would increase demand's share of generation. If PacifiCorp's model is modified to account for a 15% planning reserve margin and 80% battery ELCC, the demand share of generation costs increases from 74% to 80%, as seen in the table below.

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14 Docket No. UE-200304, Puget Sound Energy 2021 Final Integrated Resource Plan, Figure 7-34: Effective Load Carrying Capability for model years 2027 and 2031, Base Scenario and Temperature Sensitivity, at 7-47 (April 1, 2021).

15 Docket No. UE-200301, Avista Corporation d/b/a Avista Utilities 2023 Final Electric IRP, Figure 6.4 QCC Forecast for VER and Energy Storage at 6-23 (June 1, 2023).

16 Docket No. LC 80, Public Utility Commission of Oregon, Portland General Electric 2023 Clean Energy Plan and IRP, Figure 148. Winter storage ELCC at 553.

TABLE LDK-1

	Lithium-Ion Battery, 50 MW, 200 MWh		
1	Fixed Cost per kW-year	$223.65	
2	Cost per MWh to Charge	$75.83	
3	Hours of Operation	12	
4	Storage Efficiency	85%	
5	Total Cost of Charging	$1.07	Line 2 / 1000 / Line 4 X Line 3
6	Total Cost 1 kW-year, 12 Hours	$224.72	Line 1 + Line 5
7	Planning Reserve Margin	15%	
8	ELCC 12 Hour Storage	80%	
9	Cost of 1 kW Demand	$323.04	Line 6 * (1+Line 7) / Line 8
	Medicine Bow, WY, 200 MW Wind, CF: 43.6% (100% PTC)		
7	Fixed Cost per kW-year	$120.28	
8	Average Output Requirement @ 65.0% Load Factor	5,694	8,760 X 65.0%
9	Output @ 43.6% Capacity Factor	3,819	8,760 X 43.6%
10	Total kW Capacity Required	1.49	Line 8 / Line 9
11	Total Fixed Costs	$179.32	Line 7 X Line 10
12	Demand Related Cost @ 30% Capacity Contribution	$100.03	Line 10 X 30% X Line 1
13	Total Energy Related Cost	$79.29	Line 11 - Line 12
14	Demand Component	80%	Line 9 / (Line 9 + Line 13)
15	Energy Component	20%	100% - Line 14

Q. HAS YOUR RECOMMENDATION TO IMPLEMENT AN EQUAL PERCENTAGE INCREASE FOR ALL RATE SCHEDULES OTHER THAN STREET AND AREA LIGHTING CHANGED UPON REVIEW OF OTHER PARTIES' TESTIMONY?

A. No. The evidence continues to demonstrate that all rate schedules are within 10% of parity and, therefore, an equal percentage approach to spreading the rate increase is appropriate and consistent with Commission precedent.

III. RATE SPREAD

Q. WHAT RATE SPREAD ISSUES DO PARTIES RAISE IN RESPONSE TESTIMONY?

A. Dr. Dismukes recommends a multistage method of rate spread that effectively spreads rates equal to 115 percent of the average increase for all schedules except small general service. Dr.

Dismukes' method increases small general service by 10 percent of the average rate increase.[17] Andrew D. Teague provides testimony on behalf of Walmart that any reduction to revenue requirement should be allocated proportionately to Column M of RMM-2, p. 17.

Q. HAS YOUR RECOMMENDATION TO IMPLEMENT AN EQUAL PERCENTAGE INCREASE FOR ALL RATE SCHEDULES OTHER THAN STREET AND AREA LIGHTING CHANGED UPON REVIEW OF OTHER PARTIES' TESTIMONY?

A. No. The evidence continues to demonstrate that all rate schedules are within 10% of parity and, therefore, an equal percentage approach to spreading the rate increase is appropriate and consistent with Commission precedent.

Q. IF THE COMMISSION ADOPTS DR. DISMUKES' GENERATION MARGINAL COST ADJUSTMENTS, WOULD THAT AFFECT YOUR RATE SPREAD RECOMMENDATION?

A. No. If Dr. Dismukes' study were adopted, all customer classes would still have parity ratios within 10 percent of parity. Current rates are within Staff's historic range of reasonableness and all rate schedules warrant an equal percentage increase.[18] This is a relatively minor deviation from the results of my cost-of-service study, which indicates that lighting schedules warrant an above average rate increase. The table below compares parity ratios under PacifiCorp's filed study, my study, and Dr. Dismukes' study. The results of all three studies have similar parity ratios, with the only material difference among the studies being the result for Street and Area Lighting.

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17 Exh. DED-8 at 1.

18 Dockets UE-200900, UG-200901, UE-200894, Exh. ELJ-1T at 10, Table 1.

TABLE LDK-2

Schedule	AWEC Parity Ratio	PC Parity Ratio	PAC Parity Ratio
Residential Schedule 16	0.970	0.991	0.988
Small General Service Schedule 24	1.067	1.068	1.070
Large General Service < 1,000 kW Schedule 36 & 28	1.056	1.035	1.037
Large General Service > 1,000 kW Schedule 48	1.000	0.975	0.977
Large General Dedicated Facilities Schedule 48	0.958	0.921	0.925
Agricultural Pumping Schedule 40	0.948	0.944	0.944
Street & Area Lighting Sch. 15, 51-54, 57	0.893	0.956	0.961
Total	1.000	1.000	1.000

Q. WHAT IS YOUR RESPONSE TO MR TEAGUE'S RECOMMENDED RATE SPREAD?

A. Mr. Teague recommends that "If the Commission awards a lower revenue requirement than what is proposed by the Company, then the Commission should use the revenue reduction to move each class closer to cost of service by allocating the difference between the Company's requested revenue requirement and the awarded revenue requirement proportionately based on the Company's COSS, RMM-2, p. 17, Column M"[19]

I noted several minor discrepancies with this recommendation. The table produced in Mr. Teague's testimony reflects page 18 rather than page 17. Column M on both of these pages represents the "Increase or Decrease Required to Move from Annual Revenue to Full Cost of Service Percent."[20] Allocating a revenue reduction using this column will generally benefit Schedule 48T customers. However, this may not be Mr. Teague's intended effect because it does not necessarily cause greater movement towards PacifiCorp's cost of service study.

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19 Exh. ADT-1 at 12:12-17.

20 Footnote for Column M, RMM-2, p. 17.

Regardless of these discrepancies. The differences in rate parity across rate classes is not sufficient to warrant different rate increases for different classes other than Street and Area Lighting under my revisions to the COSS.

IV. COST OF CAPITAL

Q. DO YOU DISAGREE WITH ANY SPECIFIC ASPECTS OF MR. PARCELL'S TESTIMONY?

A. Yes, I disagree with Mr. Parcell's use of the Risk Premium model because this model does not adhere to the *Hope* and *Bluefield* standard.

Q. WHY DO YOU THINK THE RISK PREMIUM MODEL DOES NOT ADHERE TO THE *HOPE* AND *BLUEFIELD* STANDARD?

A. This method does not have a theoretical basis and does not reflect what investors expect to earn for investments of comparable risk. The Risk Premium model relies on Commission rulings rather than market data or outcomes. As a result, there are a number of assumptions that must be made for the Risk Premium model to be considered to reflect returns required by investors:

1. Commissioners must be assumed to be free from regulatory or political capture. This means that one must assume that Commission decisions are not unduly biased in favor of either utilities or consumers. There is no practical or feasible method of testing this assumption.
2. The historical risk premium must be assumed to be the current risk premium. This assumption is clearly incorrect because the risks of investing in the utility industry change over time. In addition investor expectations change over time.
3. Prior Commission decisions must be assumed to be based on something other than the Risk Premium model. If prior Commission decisions are based upon the Risk Premium model, the model becomes a circular model with no basis. Therefore, for the Risk Premium model to reflect capital costs, there must be an assumption that at least one prior Commission decision

was based on something other than the Risk Premium model, such as a DCF, CAPM or other market based estimate.

If all three of these assumptions hold true, then it is possible for the Risk Premium model to reflect the return expected by investors for investments of comparable risk. However, if all these assumptions hold true, it becomes evident that the risk premium model adds no information to a cost of capital analysis, because the only information that it contains is historical market information. Under the second assumption risk premiums do not change over time, thus current and historic market information reflect the same risk premium, and therefore DCF and CAPM models based on current market data would offer the same insight as Risk Premium models.

Q. DOES THIS CONCLUDE YOUR CROSS-ANSWERING TESTIMONY?

A. Yes.