

## **Exhibit JKL-5**

# **RMP Responses to Data Requests**

25-035-47 / Rocky Mountain Power

October 3, 2025

UTLCG Data Request 1.8

**UTLCG Data Request 1.8**

If Washington ratepayers are allocated 100 percent of Chehalis but non-Washington PacifiCorp states continue to take an allocated share of Chehalis:

- (a) Would PacifiCorp receive free allowances for 100 percent of Chehalis's output? Please explain your response.
- (b) Would PacifiCorp be required to purchase allowances associated with Chehalis's output? Please explain your response.
- (c) Please describe in detail the Company's Climate Commitment Act compliance strategy.

**Response to UTLCG Data Request 1.8**

Rocky Mountain Power objects to this request to the extent that it is requesting information that is prohibited from disclosure by Washington law and regulations. Without waiving any objection, the Company responds as follows:

- (a) The Washington Department of Ecology (Ecology) distributes no-cost allowances to utilities for the emissions associated energy that serves Washington retail load. On April 16, 2025, PacifiCorp petitioned the Washington Utilities Transportation Commission (WUTC) for a revised Climate Commitment Act (CCA) supply and demand forecast, reflecting the proposed resource allocations in the 2026 protocol. The revised forecast was approved by the WUTC on July 10, 2025. And, on October 1, 2025, Ecology published its schedule for 2026 no-cost allowance allocation, accepting the Company's request for no-cost allowances in anticipation of 100 percent allocation of Chehalis to Washington, consistent with the proposed 2026 protocol. It is unknown whether Ecology will adjust a future year distribution of no-cost allowances if the Chehalis facility is overallocated among the states.
- (b) PacifiCorp must purchase allowances to cover any portion of its obligation not associated with Washington retail load.
- (c) PacifiCorp is committed to complying with all state laws, including Washington state's Climate Commitment Act (CCA). Ecology's rules and guidelines prevent the disclosure of compliance strategy per Washington Administrative Code (WAC) 173-446-317 and 173-446-390.

25-035-47 / Rocky Mountain Power

October 28, 2025

UTLCG Data Request 2.3

### **UTLCG Data Request 2.3**

Provide the summary section of all Company Results of Operations (ROO) Reports for each of the six states in which PacifiCorp provides retail electric services from 2020 through 2024. Provide the unadjusted ROO for each year supporting these reports on a system-wide basis, six-state rolled-in allocated basis, and the Washington results on a comparable unadjusted Washington Inter-Jurisdictional Allocation Method basis.

### **Response to UTLCG Data Request 2.3**

Please refer to Attachment UTLCG 2.3 which provides the requested Results of Operations (ROO) data for calendar years 2020 through 2024. The requested information is organized by calendar year, with one workbook providing the requested data for Oregon, Washington, Utah, Idaho and Wyoming for each of the years in which data is being requested. Note: ROOs are not required and therefore not prepared or filed in California.

25-035-47 / Rocky Mountain Power

October 28, 2025

UTLCG Data Request 2.16

### **UTLCG Data Request 2.16**

Refer to the Direct Testimony of Cindy A. Crane, lines 122-123. Did the Company agree to the use of the Washington Western Control Area allocation method and Washington Inter-Jurisdictional Allocation Method? If not, please provide all documentation evidencing the Company's disagreement or objection.

### **Response to UTLCG Data Request 2.16**

PacifiCorp objects to this question as outside the scope of this proceeding and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving any objection, the Company responds as follows:

In 2006, the Washington Utilities and Transportation Commission (WUTC) rejected the Revised Protocol. As a result, the Company worked with the WUTC staff to develop the West Control Area (WCA) Methodology based on the WUTC's order and then worked with WUTC staff, Public Counsel, and Packaging Corporation of America to develop the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) which modifies the WCA.

Please refer to Attachment UTLCG 2.16 which provides a copy of the 2006 WUTC order.

25-035-47 / Rocky Mountain Power

October 28, 2025

UTLCG Data Request 2.34

**UTLCG Data Request 2.34**

Please provide all analysis, work papers, reports, or other documents related to or supporting the Company's proposed allocation method for generation that is based on a weighting of 75% 12 coincident peak and 25% energy.

**Response to UTLCG Data Request 2.34**

The Company is not proposing to change the 75 percent demand / 25 percent energy split for the calculation of the system generation (SG) allocation factor in the proposed 2026 Protocol. PacifiCorp has classified generation fixed costs as 75 percent demand / 25 percent energy using system coincident peak (CP) for all 12 months of the year for reporting and ratemaking since the merger between Pacific Power & Light and Utah Power & Light.

Attached is a discussion paper "Classification and Allocation of Generation Fixed Costs" by Dave Taylor and dated March 4, 2003 and filed as Exhibit 5A in Utah Docket No 04-035-42. This paper also reviews different methods such as Average and Excess method among others, the methodologies used by PacifiCorp and its predecessors in the past, some of the methods used by other utilities, and those proposed by participants in the Multi-State Process (MSP) forum, specifically around the classification and allocation of generation resources. On page 3 of the report, it concluded that, "The choice of the 75% demand 25% energy classification for generation . . . plant was the last allocation decision made by PITA after the merger. The PITA analysis indicated that a wide range of demand and energy classification could be supported on a technical basis. The demand energy classification was the swing issue employed to balance the sharing of merger benefits between all the states and 75% demand 25% energy was selected because it produced an overall cost allocation result that was acceptable to all the states. Following the conclusion documented in this discussion paper, a 75 percent demand/25 percent energy classification in the calculation of the SG factors was selected as an acceptable outcome in all states."

Absent a compelling reason to change, minimizing changes from current allocation practices will aid in implementation of the proposed 2026 Protocol and help reduce cost shifts among states.

Please refer to Attachment UTLCG 2.34 which provides a copy of the Exhibit 5A discussion paper referenced above.

Classification and Allocation of Generation Fixed Costs  
Discussion Paper  
By: Dave Taylor  
March 4, 2003

**Introduction**

One of the key questions to be resolved in the Multi State Process is that of classification and allocation of the fixed costs associated with generation resources. This is the case whether the final MSP resolution is based on a dynamic total system sharing of costs and resources as proposed by Utah, or whether the resolution is based on a control area approach where resources are first directly assigned to the east and west control areas with a sharing of costs and resources separately in each control area. Even a direct assignment of resources to individual states requires a decision on classification and allocation to determine the shares of plants to assign to each state.

All parties to MSP agree that any classification and allocation of generation costs need to be based on principle of cost causation. Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For generation resources, cost causation attempts to determine what influences a utility's production plant investment decisions. In this process, classification relates to separating the portion of generation costs that are expended to meet the Company's peak demand requirements from the portion of generation costs that are expended to meet the Company's energy requirements. Allocation relates to the methods applied to apportion the demand and energy related components of generation costs between the states we serve. Often times the classification and allocation process get combined into a set of composite allocation factors that perform both steps of the process.

A wide variety of classification and allocation options are currently used by utilities across the country and Utah Power, Pacific Power and PacifiCorp have used several different methods in the past. Many of these methods, as well as a number of new alternatives have been discussed during MSP. Of the total system allocation options, the classification of plant between demand and energy components seems to have the largest impact on state revenue requirements. Larger energy classifications assign more costs to high load factor states while larger demand classifications assign more cost to lower load factor states. The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger.

Several states use the same classification and allocation procedures for both jurisdictional allocation and allocation of costs between customer classes. The classification of plant has even greater impacts on the allocation of costs between customer classes, which makes this an issue of great concern for the intervening industrial customers.

This paper reviews the methodologies used by PacifiCorp and its predecessors in the past, some of the methods used by other utilities, and those proposed by the participants in MSP.

## Historical Perspective

Prior to the Utah Pacific merger, Pacific Power classified generation fixed costs as 50% demand related and 50% energy related. The demand component was allocated to states using an allocation factor based on the summation of each state's contribution to the system coincident peak for each of the 60 preceding months (60 CP). The energy component was allocated using each state's energy usage for the previous 24 months. This is shown in the example below:

PP&L Historical Generation Plant Jurisdictional Allocation Factor								
	PPL- WA	PPL- OR	PPL- CA	PPL- WY	UPL- ID	UPL- WY	UPL- UT	MERGED TOTAL
Sum of 12 CP's								
1997	7,504	26,572	1,743	10,005	5,063	1,369	30,615	82,871
1998	8,099	27,733	1,815	9,977	5,112	1,791	31,936	86,463
1999	8,295	26,903	2,029	9,118	5,197	1,748	32,273	85,563
2000	8,135	27,679	1,719	9,567	5,146	1,760	34,786	88,791
2001	7,778	26,754	1,539	10,551	5,108	1,978	35,071	88,780
60 CP	39,811	135,640	8,845	49,218	25,626	8,646	164,680	432,468
60 CP Factor	9.2%	31.4%	2.0%	11.4%	5.9%	2.0%	38.1%	100.0%
Total Retail MWh								
2000	4,540,498	15,603,612	925,786	6,345,974	3,419,263	1,225,410	20,284,781	52,345,325
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	20,070,975	52,232,925
24 Months of Energy	8,954,016	30,628,972	1,791,438	13,429,725	6,826,133	2,592,210	40,355,756	104,578,250
24 Months Energy Factor	8.6%	29.3%	1.7%	12.8%	6.5%	2.5%	38.6%	100.0%
Composite Factor								
Generation Plant Factor	8.9%	30.3%	1.9%	12.1%	6.2%	2.2%	38.3%	100.0%
Allocation Factor = 60 CP Factor X 50% + 24 Month Energy Factor X 50%								

Prior to the merger, Utah Power classified all generation fixed costs as 100% demand related and allocated those costs using each states contributions to the system coincident peak for the eight critical months of the test period (8 CP) with March, April, May, and October being excluded.

Old Utah Power Generation Allocation Factor								
2001								
Month	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total System
January	723,744	2,739,428	142,784	888,677	370,179	175,778	2,652,253	7,692,843
February	687,411	2,689,629	146,431	901,580	341,777	175,579	2,652,713	7,595,120
March								
April								
May								
June	681,653	2,123,911	152,418	882,970	491,283	152,048	3,110,502	7,594,785
July	656,533	1,986,895	128,961	891,751	564,363	161,343	3,463,757	7,853,603
August	627,146	2,121,632	124,452	934,472	420,647	156,288	3,514,018	7,898,655
September	626,812	1,923,541	119,509	881,017	391,106	150,279	3,208,631	7,300,895
October								
November	670,076	2,169,395	118,765	897,491	410,725	170,314	2,981,676	7,418,442
December	691,537	2,346,343	131,577	900,452	422,902	178,549	3,017,000	7,688,360
8 CP	5,364,912	18,100,774	1,064,897	7,178,410	3,412,982	1,320,178	24,600,550	61,042,703
8 CP Factor	8.8%	29.7%	1.7%	11.8%	5.6%	2.2%	40.3%	100.0%

Since the merger PacifiCorp has classified generation fixed costs as 75% demand related and 25% energy related with the demand component being allocated using contributions to the system coincident peak all 12 months of the year. Because of the different cost basis of the Pacific Power and Utah Power fleet of plants, the investment in generation resources (Pre Merger Investment) that each company brought to the merger continued to be allocated separately to the Pacific Power and Utah Power states. All new investment in generation resources (Post Merger Investment) is allocated system wide. This is shown in the example below:

<b>Current PacifiCorp Generation Plant Allocation Factor (Modified Accord)</b>								
<b>Pre Merger Investment</b>								
	PPL-	PPL-	PPL-	PPL-	UPL-	UPL-	UPL-	
	WA	OR	CA	WY	ID	WY	UT	<b>TOTAL</b>
Sum of 12 CP's								
2001	7,778	26,754	1,539	10,551	5,108	1,978	35,071	88,780
Division Capacity Pacific (DC-P)	16.7%	57.4%	3.3%	22.6%				100.0%
Division Capacity Utah (DC-U)					12.1%	4.7%	83.2%	100.0%
Total Retail MWh								
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	20,070,975	52,232,925
Division Energy Pacific (DE-P)	16.1%	54.9%	3.2%	25.9%				100.0%
Division Energy Utah (DE-U)					13.7%	5.5%	80.8%	100.0%
Composite Factor								
Division Generation Pacific (DG-P)	16.5%	56.8%	3.3%	23.4%	0.0%	0.0%	0.0%	100.0%
Division Generation Utah (DG-U)	0.0%	0.0%	0.0%	0.0%	12.5%	4.9%	82.6%	100.0%
Allocation Factor = 12 CP Factor X 75% + Energy Factor X 25%								
<b>Post Merger Investment</b>								
	PPL-	PPL-	PPL-	PPL-	UPL-	UPL-	UPL-	<b>MERGED</b>
	WA	OR	CA	WY	ID	WY	UT	<b>TOTAL</b>
Sum of 12 CP's								
2001	7,778	26,754	1,539	10,551	5,108	1,978	35,071	88,780
System Capacity (SC)	8.8%	30.1%	1.7%	11.9%	5.8%	2.2%	39.5%	100.0%
Total Retail MWh								
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	20,070,975	52,232,925
System Energy Factor (SE)	8.4%	28.8%	1.7%	13.6%	6.5%	2.6%	38.4%	100.0%
Composite Factor								
System Generation Factor (SG)	8.7%	29.8%	1.7%	12.3%	5.9%	2.3%	39.2%	100.0%
Allocation Factor = 12 CP Factor X 75% + Energy Factor X 25%								

The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger. The PITA analysis indicated that a wide range of demand and energy classification could be supported on a technical basis. The demand energy classification was the swing issue employed to balance the sharing of merger benefits between all the states and 75% demand 25% energy was selected because it produced an overall cost allocation result that was acceptable to all the states.

## Methods used by other Utilities

The Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC) combines their discussion of classification and allocation alternatives for generation resources. The manual lists a range of alternatives, most of which are used by some utilities. While the Cost Allocation Manual was published as a guide for allocation of costs between customer classes, the cost causation principles discussed should also be applicable to jurisdictional allocation.

### Cost Accounting Approach

The cost accounting approach identifies all production costs as either fixed or variable. The assumption is that plant capacity is built to meet peak demand and once it is built it is fixed. Therefore all fixed costs are considered demand related and variable costs are considered energy related. The demand related costs are allocated using class, or state, contributions to system peak (CP). The allocation can use the single system annual peak, or it can use the monthly system peak from more than one month of the year. The three common methods are the single peak, summer winter average peak, and the sum of all 12 CPs. The use of all twelve monthly CPs has been adopted by FERC and seems to be the most common among electric utilities.

100% Demand Factors										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
1 CP Factor	100%	0%	8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
12 CP			8,067,405	27,115,372	1,746,245	9,824,030	5,190,516	1,812,264	34,259,181	88,015,012
12 CP Factor	100%	0%	9.17%	30.81%	1.98%	11.16%	5.90%	2.06%	38.92%	100.00%
Summer / Winter CP			1,443,622	4,672,892	309,461	1,689,646	957,261	322,124	6,509,073	15,904,079
Summer / Winter CP Factor	100%	0%	9.08%	29.38%	1.95%	10.62%	6.02%	2.03%	40.93%	100.00%

### Peak and Average

The Peak and Average method considers that average demand (or annual energy usage / 8760) is a significant cost driver along with coincident peak demand. Under the peak and average method, the demand related classification of fixed costs is calculated by dividing the system annual CP by the sum of the annual CP and the average demand (CP / (CP + average demand)). The demand component is allocated using each state's contribution to the system single coincident peak. For PacifiCorp, this method classifies 60% of fixed generation costs as demand related compared to the 75% used today.

Peak & Average (1 CP)										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
Average MW (MWh / 8760)			516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Demand Component										
Demand Allocation Factor Single CP / (CP + (MWh/8760))	58%		8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Energy Component										
Average MW Component Allocation Factor (1 - Demand)		42%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Total Allocation Factor	58%	42%	8.83%	28.27%	1.97%	11.27%	6.65%	2.10%	40.91%	100.00%

### Average and Excess

The Average and Excess method also considers that average demand to be a significant cost driver, and that excess demand (individual class or state NCP less average demand) drives the demand component. Under the average and excess method, the energy related component of fixed costs is determined to be equal to the system annual load factor. The demand component is allocated using each state's excess demand, annual non-coincident peak (NCP) less average annual demand (annual MWh / 8760). For PacifiCorp, this method would classify 70% to 75% of fixed generation costs as energy related compared to the 25% used today. This method was proposed by Utah Power in the 1980s and rejected by the three state commissions in favor of the 8 CP method.

Average & Excess										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual NCP			782,957	2,639,481	188,904	897,121	671,089	184,209	3,502,529	8,866,290
Average MW (MWh / 8760)			516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Excess MW			266,902	894,690	76,755	150,547	284,690	40,443	1,226,189	2,940,216
Average MW Component Allocation Factor (System Annual)		73%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Excess Demand Component Allocation Factor (1 - SALF)	27%		9.08%	30.43%	2.61%	5.12%	9.68%	1.38%	41.70%	100.00%
Total Allocation Factor	27%	73%	8.81%	29.71%	2.09%	10.58%	7.37%	2.14%	39.30%	100.00%

### Equivalent Peaker Method

The premises of this methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and base load units because of the additional energy loads they must serve. Thus, the cost of peaking capacity is regarded as peak demand-related and classified as demand-related. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related. The demand related component is generally allocated using the single system peak or the loads during the narrow peak period. The Company currently uses the equivalent peaker method in its avoided cost and marginal cost studies. Based on information in the current IRP, this method would classify about 40% of generation fixed cost as demand related and 60% as energy related.

Equivalent Peaker 1 CP										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
1 CP Factor	38%		8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Annual Energy		62%	4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Energy Factor			8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Composite Factor	38%	62%	8.79%	28.67%	1.94%	11.73%	6.60%	2.21%	40.05%	100.00%

### Base – Intermediate – Peak (BIP) Method

Under the BIP Method, base load plants are classified with a large energy component and allocated across all months of the year. Intermediate or Mid-range resources costs are assigned to individual months of the year based according to the operating hours in a given month and allocated using loads in each particular month. Peaking units are more heavily classified as demand related and allocated only to the months when the peaking resources are dispatched to meet retail load. The Oregon PUC Staff has proposed this method as one alternative in MSP.

Attachment 1 summarizes some of the available approaches for classification of generation fixed costs. Attachment 2 contains a summary of the methods used by a small sample of utilities. Attachment 3 shows examples of the allocation methods discussed in this paper applied to PacifiCorp loads.

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UTLCOG Data Request 2.44

**UTLCOG Data Request 2.44**

Refer to the Direct Testimony of Shelley E. McCoy, lines 125-132.

- (a) Please provide all analyses supporting the functionalization, classification, and allocation of transmission costs in the 2026 Protocol.
- (b) Please provide all analyses, workpapers, reports, or other documents related to or supporting an allocation method for transmission that is based on a weighting of 75% 12 coincident peak (CP) and 25% energy.
- (c) Did the company rely on any method to determine that 12 CP as opposed to 1 CP, 4 CP, 8 CP, or some other variation is appropriate to identify the appropriate cost causation for transmission for service provided in the State of Utah?
- (d) Was an Average and Excess method calculated or relied on to identify the appropriate cost causation for transmission for service provided in the State of Utah? If so, please provide such analysis.
- (e) Provide all Company analysis that supports the use of a 75% CP / 25% energy weighting in the development of the transmission allocation factors.
- (f) Did the Company analyze any capacity/energy weighting for transmission allocation factors other than 75% 12 coincident peak / 25% energy? If so, please provide such analyses.
- (g) Provide any analyses, reports, or other documentation upon which the Company relies to support its proposal regarding transmission allocation factors among non-Washington states, other than negotiated settlements.
- (h) Has the Company undertaken any analysis of the FERC allocation treatment of transmission costs using 1 CP based on annual coincident peak data? If so, please provide such data.
- (i) Please explain in detail the Company's rationale for using the 12 CP method for allocating transmission costs.
  - i. Further explain why the Company's allocation of transmission costs is weighted with energy.
  - ii. Further explain why the Company does not follow the same methodology as FERC for its retail jurisdictions.
- (j) Does the Company use a 1 CP or 12 CP method for allocating transmission costs in its FERC filings? Please explain why it is reasonable for the

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UTLCOG Data Request 2.44

Company to use its approved allocation methodology.

- (k) Please provide any Company testimony at FERC in the last five years supporting the Company's transmission cost allocation methodology.
- (l) For the analyses in the Company's 2025 Integrated Resource Plan, did the Company rely on the average annual system peak or the average of 12 monthly system peaks for the development of new transmission capacity?
- (m) Has the Company functionalized all transmission costs per FERC Order 888 and only included high-voltage bulk transmission costs in any inputs in the results of operations that are allocated on a system basis?

### **Response to UTLCOG Data Request 2.44**

- (a) The Company continues to support the proposed 2026 Protocol allocation of transmission assets remain under the system generation (SG) allocation factor. This treatment is consistent with the allocation factor used and approved in many past cost allocation agreements, including the most recently approved 2020 Inter-Jurisdictional Cost Allocation Methodology (2020 Protocol) as filed in Docket No. 19-035-42. Note: transmission was also considered a resolved issue as identified in Section 5.2 in the 2020 Protocol and would continue to be allocated using the System Transmission (ST) allocation factor, which is calculated the same as the SG allocation factor as proposed in Phase I of the proposed 2026 Protocol. Absent a compelling reason to change, minimizing changes from current allocation practices will aid in implementation of the proposed 2026 Protocol and help reduce cost shifts among states. No additional analysis is available.
- (b) Please refer to the Company's response to subpart (a) above. Transmission assets typically deliver generation level voltage to lower level distribution system assets. As such, transmission assets have been based on allocation factor characteristics similar to that of generation assets as discussed further in the Company's response to UTLCOG Data Request 2.34.
- (c) Please refer to the Company's response to subpart (b) above.
- (d) Please refer to the Company's response to subpart (b) above.
- (e) Please refer to the Company's response to subparts (a) and (b) above. No additional analysis is available.
- (f) No other weighted of capacity/energy other than 75 percent demand and 25 percent energy were analyzed as part of this proposed 2026 Protocol proceeding.

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UTLCOG Data Request 2.44

- (g) No additional analysis or reports have been completed.
- (h) No. The Company has not analyzed using a single coincident peak (CP) for the purpose of allocated transmission assets in this proposed 2026 Protocol proceeding.
- (i) Please refer to the Company's responses to subparts (a) and (h) above.
- (j) The Federal Energy Regulatory Commission (FERC) transmission formula rate uses a 12 CP for allocating transmission costs to customers with network load service, which is the defined FERC methodology of using a load ratio share on a monthly basis (12 CP) and as a result PacifiCorp utilizes this method to charge customers and it is the method approved in the transmission formula rate.
- (k) The Company has not filed any testimony with FERC in the last five years as the approved formula is being followed.
- (l) In the 2025 Integrated Resource Plan (IRP), PacifiCorp allowed endogenous selection of transmission projects in the long-term (LT) capacity expansion model. The LT model used four blocks of hours per month over the 21-year horizon. Thus, transmission selections were based on four blocks-per-month granularity for load, not the average annual system peak or the average of 12 monthly system peaks.
- (m) Rocky Mountain Power objects to this request as vague, overly broad, outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving any objection, the Company responds as follows:

The Company functionalizes transmission facilities consistent with FERC requirements. These facilities include some 46kV and 69kV transmission lines, as well as assets that serve a transmission function but which are not defined by voltage level, such as meters, transformers, breakers, and rights-of-way. A list of the Company's transmission assets is provided in PacifiCorp's FERC Form 1.

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UTLCOG Data Request 2.45

**UTLCOG Data Request 2.45**

Refer to the Direct Testimony of Shelley E. McCoy, lines 141-146. Provide the 2024 timesheets or default profiles for Company employees holding positions of vice-president and above that reflect the work orders, projects, or other accounting data element that is used to assign costs for allocation purposes. Provide the names of all projects, work orders, or other data elements identified so that a determination can be made that the costs were properly functionalized, classified, and allocated.

**Response to UTLCOG Data Request 2.45**

The Company objects to this request as it is seeking information well outside the scope of this proposed 2026 Protocol proceeding and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving any objection, the Company responds as follows:

The Company is not proposing to change any existing allocation factor associated with administrative and general (A&G) costs, nor seeking ratemaking treatment of these costs in this proposed 2026 Protocol proceeding. For a listing of A&G costs incurred for calendar year 2024, including the applicable allocation factor assignment, please refer to the data listed in tab "YE 2024 BW" of non-confidential work paper "25-035-47 2026 Protocol Estimated Revenue Requirement Impact Workpaper McCoy" and filter column A "JARS Reporting Structure" by 920 through 935.

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November 10, 2025

UTLCG Data Request 4.5

**UTLCG Data Request 4.5**

Refer to the Direct Testimony of Shelley E. McCoy, Lines 90-91.

- (a) Will Washinton's divisional allocation under the Washington Inter-Jurisdictional Allocation Method of Jim Bridger Units 3 and 4 and Colstrip Unit 4 be fully depreciated by December 31, 2025?
- (b) If not, please provide the remaining balances for these facilities and provide a detailed explanation of the actions the Company will take to ensure other customers do not pay for Washington's share that would be reassigned and dynamically allocated beginning in 2026 under the Company's proposal.

**Response to UTLCG Data Request 4.5**

- (a) Please refer to the Company's response to UTLCG Data Request 3.30, specifically subpart (b), which provides the net rate base balance under the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) of Jim Bridger Unit 3, Jim Bridger Unit 4 and Colstrip Unit 4 reflected in rate year two rates which became effective April 2025, through Docket UE-230172 (2023 Multi-Year Rate Plan (MYRP)).

Depreciation expense and accumulated depreciation are not recorded on the Company's accounting books based on what is included in rates but rather based on approved depreciation rates. Therefore, the accumulated depreciation is not recorded by state, but rather in total for the Company. Accordingly, a WIJAM net book balance of Jim Bridger Unit 3, Jim Bridger Unit 4 and Colstrip Unit 4 projected through December 31, 2025 is not readily available.

- (b) Please refer to the Company's response to subpart (a) above, and the Company's responses to UTLCG Data Request 3.1 and UTLCG Data Request 3.26 (subparts (b) and (c)).

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January 22, 2026

UTLCG Data Request 7.2

**UTLCG Data Request 7.2**

Refer to the Company's response to UTLCG Data Request 2.12. The Company identified Washington as an example where an allocation method is different from other states and "has limited PacifiCorp's opportunity to recover all of its prudently incurred costs because the aggregate system-wide cost-allocation factors across all states does not always sum to 100 percent."

- (a) For each year from 2020 through 2024, please provide the allocation shortfall (in total dollars and percent of total-Company costs) caused by Washington being on a different allocation method where the Company's system-wide cost-allocation does not sum to 100 percent.
- (b) Provide all studies, analysis, and management reports that have been produced or in the Company's possession that identify any shortfall and support the Company's response to subpart (a).
- (c) If the Company claims that no information is available in subparts (a) or (b) above, please explain how and to what extent the Company knows that a different cost allocation methodology in Washington than PacifiCorp's other five states "has limited PacifiCorp's opportunity to recover all of its prudently incurred costs".

**Response to UTLCG Data Request 7.2**

- (a) The Company objects to this request as overly broad and burdensome, seeking information well outside the scope in this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving any objection, the Company responds as follows:

For calendar years 2020 through 2024, the Company has not performed or maintained analysis to calculate what the total Company earnings shortfall by year would have been for the Washington Western Control Area Allocation Methodology (WCA) and Washington Inter-Jurisdictional Allocation Methodology (WIJAM) used in Washington as a result of not having a common six-state allocation method. Such analysis would require Washington's earnings to be assessed both on WCA/WIJAM and the 2020 Inter-Jurisdictional Cost Allocation Methodology (2020 Protocol) in order to have a relative comparison, and the Company has never calculated Washington's result of operations (ROO) under the 2020 Protocol since it is not an approved allocation methodology for the purposes of ratemaking in Washington.

- (b) Please refer to the Company's response to subpart (a) above.

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UTLCG Data Request 7.2

- (c) As discussed in the Company's response to UTLCG Data Request 2.12, having a cost allocation in one state (i.e., Washington) that differs from the other remaining states (i.e., California, Idaho, Oregon, Utah and Wyoming) has limited PacifiCorp's opportunity to recover all of its prudently incurred costs because the aggregate system-wide cost-allocation factors across all states does not always sum to 100 percent. For example, a generation facility that is actually allocated 0 percent to Washington under the WIJAM but assumed to be allocated at 8 percent to Washington under the 2020 Protocol, will inherently create limited opportunities to recover the prudently incurred costs associated with this generation facility. The proposed 2026 Protocol uses the objective of having a cost allocation agreement where all states sum to 100 percent.

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January 22, 2026

UTLCG Data Request 7.4

**UTLCG Data Request 7.4**

Refer to the Company's response to UTLCG Data Request 2.28. Does the Company assign any costs related to the Hermiston Gas Plant to Washington after December 31, 2025, including but not limited to deferred taxes, decommissioning, or removal costs for the period that Washington used the plant? Provide all studies and analysis to demonstrate that Washington has paid for their use of the facility while in their rates for any future liabilities.

**Response to UTLCG Data Request 7.4**

With the adoption of the Washington 2026 Protocol, there will no longer be operating costs (capital and expenses) allocated to Washington after December 31, 2025 for the Hermiston Gas Plant. Up until then, decommissioning and removal costs are collected through depreciation expenses embedded as part of depreciation rates. However, the allocation of on-going decommissioning and removal costs and final true-up of these costs remains an issue still to be fully addressed in Phase 2 of the 2026 Protocol filings. Accordingly, the requested analyses or studies have not yet been prepared.

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January 22, 2026

UTLCG Data Request 7.6

### **UTLCG Data Request 7.6**

UTLCG Data Request 2.45 requested the following:

Refer to the Direct Testimony of Shelley E. McCoy, lines 141-146. Provide the 2024 timesheets or default profiles for Company employees holding positions of vice-president and above that reflect the work orders, projects, or other accounting data element that is used to assign costs for allocation purposes. Provide the names of all projects, work orders, or other data elements identified in the timesheets so that a determination can be made that the costs were properly functionalized, classified, and allocated.

Provide the information as requested in UTLCG Data Request 2.45 with management time sheets, including those for Rick Link and Joelle Steward.

### **Response to UTLCG Data Request 7.6**

PacifiCorp objects to this request on the grounds that it seeks information well outside the scope of the proposed 2026 Protocol proceeding and is not reasonably calculated to lead to the discovery of admissible evidence. Based on the foregoing objection, the Company responds as follows:

PacifiCorp employs established internal accounting processes to ensure that work orders associated with time entries are appropriately allocated. The Company is not proposing any changes to existing allocation factors for administrative and general (A&G) costs, nor is it seeking ratemaking treatment of these costs in this proceeding. For a listing of A&G costs incurred during calendar year 2024, along with the corresponding allocation factor assignments, please refer to the information provided in the “YE 2024 BW” tab of work paper “25-035-47 2026 Protocol Estimated Revenue Requirement Impact Workpaper McCoy”. To view the relevant data, filter column A (“JARS Reporting Structure”) for FERC Account 920 through FERC Account 935.