SOMACH SIMMONS & DUNN
A PROFESSIONAL CORPORATION
ATTORNEYS AT LAW

500 CAPITOL MALL, SUITE 1000, SACRAMENTO, CA 95814
OFFICE: 916-446-7979 FAX: 916-446-8199
SOMACHLAW.COM

June 22, 2022

Via Electronic Filing

Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301

RE: In the Matter of PACIFICORP d/b/a PACIFIC POWER
Request for a General Rate Revision
Docket No. UE 399

Dear Filing Center:

Please find enclosed the Opening Testimony and Exhibits of Lloyd C. Reed (KWUA-OFBF/100-103) on behalf of the Klamath Water Users Association and Oregon Farm Bureau Federation in the above-referenced docket.

Thank you. If you have any questions, please contact the undersigned.

Very truly yours,

Crystal Rivera, Secretary to
Paul S. Simmons

Encs.

Docket No. UE 399
Exhibit KWUA-OFBF/100
Witness: Lloyd C. Reed

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

KLAMATH WATER USERS ASSOCIATION
AND THE OREGON FARM BUREAU FEDERATION

OPENING TESTIMONY OF

LLOYD C. REED

June 22, 2022

TABLE OF CONTENTS

ATTACHED EXHIBITS

KWUA-OFBF/101: Resume of Lloyd C. Reed

KWUA-OFBF/102: Ariel views of three major irrigated agricultural areas in Oregon

KWUA-OFBF/103: Adjusted 12-month weighted average distribution peak loads

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, occupation, position, and business address.

A. My name is Lloyd C. Reed. My business address is 10025 Heatherwood Lane, Highlands Ranch, Colorado 80126. I am President of Reed Consulting.

Q. Briefly describe your educational background and work experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Washington. I have been involved in the electric utility industry for 40 years and I previously held several positions of increasing responsibility at two Pacific Northwest based investor-owned utilities including the Director of Power Supply Operations for Puget Sound Energy. I also held several positions of increasing responsibility at two power marketing companies including the Vice President of Power Marketing for e-prime. Since 2001, I have been an energy consultant and have provided a wide range of professional services to multiple clients including investor-owned and publicly-owned electric utilities, irrigation districts, and law firms in such areas as wholesale and retail ratemaking, short-term power systems operation, power marketing and trading, long-term utility load/resource planning, wind plant integration analyses, hydroelectric systems operations, and energy risk management. A copy of my resume is included in Exhibit KWUA-OFBF/101.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I previously submitted testimony to the Oregon Public Utilities Commission (“OPUC”) in PacifiCorp’s 2021 General Rate Case in Docket No. UE 374. I have also testified in multiple wholesale power proceedings before the Federal Energy Regulatory Commission (“FERC”) on behalf of several different clients.

Q. On whose behalf are you submitting testimony in this proceeding?

A. I am submitting testimony on behalf of the Klamath Water Users Association ("KWUA") and the Oregon Farm Bureau Federation ("OFBF"). KWUA is a non-profit, mutual benefit with members such as irrigation districts, drainage districts, improvement districts, and similar water distribution entities ("Districts") that deliver water to thousands of irrigation/water users in Klamath County. These entities and their landowner patrons: (1) receive water through the U.S. Bureau of Reclamation's ("Reclamation") Klamath Irrigation Project ("Klamath Project" or "Project") in southern Oregon and northern California, and (2) purchase electricity from PacifiCorp ("PAC" or the "Company") under retail rate tariffs. The OFBF is a voluntary, grassroots, nonprofit organization representing Oregon's farmers and ranchers in the public and policymaking arenas. As Oregon's largest general farm organization, its primary goal is to promote educational improvement, economic opportunity, and social advancement for its members and the farming, ranching, and natural resources industry. Today, OFBF represents nearly 6,500 member farm families professionally engaged in the industry. In particular, the OFBF works to assist agricultural power users across Oregon to help these individuals lower their overall irrigation and/or drainage costs by supporting funding for water efficiency upgrades and advocating for lower power purchase costs.

KWUA's members and their patrons and agricultural power users supported by the OFBF purchase electricity for irrigation pumping and drainage purposes primarily under PacifiCorp's Schedule 41 Rate Tariff. In addition, some of KWUA's members and their patrons have previously participated in PAC's Irrigation Time of Use Pilot Program, which the Company recently made permanent under the Schedule 741 Rate Tariff.

KWUA's membership includes the Districts who deliver water to nearly all of the Klamath Project lands in Oregon that use water diverted from Upper Klamath Lake and the Klamath River, which is in excess of 100,000 acres. In addition, KWUA does not represent, but has certain information regarding, other water users in the Upper Klamath Basin who are PacifiCorp retail tariff customers. This includes the two Districts in the Klamath Project that receive water exclusively from the Lost River system, and so-called "off-Project" users who are generally located adjacent to, or on tributaries of, Upper Klamath Lake.

Irrigation water users in the Klamath Project can incur costs for power in three ways. First, Reclamation owns and operates certain large pumping facilities, including for drainage, which the Districts provide advance funds to cover the cost of. Second, the Districts own and operate pumps and other facilities for various purposes and pass on their costs, as well as the costs charged by Reclamation, to the individual water users. Third, the individual water users own and operate pumps of various types, for diversion, pressurizing systems, recirculation and drainage, and groundwater pumping, with the specifics depending on the individual operation.[1] The Klamath Project is considered to be extremely efficient in its use of water, and a significant reason is the recycling and reuse of water that occurs throughout the Project.

From 1917 through 2006, water users in the Klamath Project received power at favorable rates under contracts entered into between Reclamation and PacifiCorp's predecessors-in-

[1] It should be noted that PacifiCorp's proposed +13.2% increase to the Schedule 41 Irrigation Rate impacts all three levels of pumping costs (i.e., Reclamation, Districts, and individual water users) in an additive fashion. Since all three levels of electricity/pumping costs are ultimately passed along to individual water users, even relatively small increases in PAC's power rates end up having a much larger multiplying effect on farmer's overall cost of production.

interest. Water users in the "off-Project" area similarly received power at favorable rates under a separate contract that went into effect in 1956. These contract-based power rates were reflected in a separate tariff until the contracts terminated in 2006 and were not extended or renewed. In accordance with state legislation intended to mitigate rate increase shock,[2] the Commission adopted in Order 06-172 a schedule for a stair-step increase in rates to the Schedule 41 irrigation tariff.

Outside of the Klamath Basin, OFBF represents farmers and ranchers who are also part of Reclamation projects and incur pumping costs as patrons of irrigation districts who pump and deliver water throughout the state, on their own as water is delivered to their farms and ranches and must be pumped onto fields, as well as through direct appropriations of water from rivers and streams across the state, where pumps are placed directly in rivers and streams to deliver water.

OFBF is interested in the viability and success of these producers in Klamath County as well as producers throughout the State of Oregon who are Schedule 41 PAC customers.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. Please state the purpose of your testimony.

A. I discuss several issues raised by the Company's initial March 1, 2022 General Rate Case ("GRC") filing in Docket UE 399 regarding: (1) the combined impact of PAC's proposed rate increases in this proceeding and in the 2023 Transitional Adjustment Mechanism case on Schedule 41 irrigation/drainage customers, (2) PAC's proposed modifications to its capital structure, (3) PAC's forecasted 2023 Test Period annual normalized energy

[2] Oregon Senate Bill 81 (2005).

load for the Schedule 41 customer class, (4) PAC's proposed allocation of Wildfire Mitigation and Vegetation Management Operations and Management costs to the Schedule 41 customer class, (5) PAC's proposed Schedule 41 distribution related demand cost allocations, and (6) PAC's proposed rate spread for the Schedule 41 customer class.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following KWUA-OFBF Exhibits:

- KWUA-OFBF/101: Resume of Lloyd C. Reed
- KWUA-OFBF/102: Ariel views of three major irrigated agricultural areas in Oregon
- KWUA-OFBF/103: Adjusted 12-month weighted average distribution peak loads

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Issue 1, PAC's Proposed Rate Increase to Schedule 41 Irrigation/Drainage Customers.
- Issue 2, PAC's Proposed Modifications to its Capital Structure.
- Issue 3, PAC's Proposed Schedule 41 Forecasted Test Period Annual Energy Load and Number of Customers.
- Issue 4, PAC's Allocation of Wildfire Mitigation and Vegetation Management Operations and Maintenance Costs.
- Issue 5, PAC's Distribution Related Demand Cost Allocations.
- Issue 6, PAC's Proposed Rate Spread for Schedule 41.

Q. Please summarize your recommendations and adjustments

A. My recommendations and adjustments are as follows:

1. PAC's Proposed Modifications to its Capital Structure:

a. The Commission should reject the Company's proposed modifications to its capital structure and retain the currently-in-place capital structure as approved in Order No. 20-473.

2. PAC's Proposed Schedule 41 Forecasted Test Period Annual Energy Load:

a. PacifiCorp should replace the overstated 2023 Test Period annual normalized energy load used for the Schedule 41 customer class in its initial UE 399 rate calculations with a value of 224,363 Mwh.

b. PacifiCorp should adjust its set of generation-based allocation factors utilized in the 2023 TAM to allocate Net Power Costs in order to incorporate an adjusted 2023 Test Period annual normalized energy load for the Schedule 41 customer class of 224,363 Mwh.

3. PAC's Proposed Allocation of Wildfire Mitigation and Vegetation Management Operations and Maintenance Costs:

a. PacifiCorp should derive a new and separate set of distribution related allocation factors to be used for the apportionment of distribution related Wildfire Mitigation and Vegetation Management Operations and Maintenance Costs among its individual customer classes.

b. PacifiCorp's new set of distribution-related allocation factors should incorporate the specific characteristics and locational topography of the Company's distribution infrastructure, including rights-of-way, on which the Company is targeting to implement Wildfire Mitigation and Vegetation Management actions.

4. PAC's Proposed Schedule 41 Distribution Related Demand Cost Allocation:

a. PacifiCorp should adjust the results of its initial 12-month weighted average distribution peak load calculations in order to incorporate a set of “reasonableness” sideboards so that the final results of the peak load allocation calculations are generally consistent with each customer class’s increase or decrease in its highest month’s peak load between the 12-month Base Period used in the Company’s initial 2021 Oregon Marginal Cost Study and the 12-month Base Period used in the Company’s initial 2023 Oregon Marginal Cost Study.

b. A recommended re-allocation of the 12-month weighted average distribution peak loads across all customer classes for the 2023 Test Period is shown in Table 2 under Issue 5.

5. PAC’s Proposed Rate Spread for Schedule 41:

a. PacifiCorp should modify its proposed rate spread such that the percentage rate increase to the Schedule 41 irrigation/drainage customer class is established at 1.0 times the average percentage rate increase across all of the Company’s Oregon customer classes, consistent with how the Company treats its irrigation/drainage customers located in Washington and California.

III. ISSUES

ISSUE 1, PAC'S PROPOSED RATE INCREASE TO SCHEDULE 41 IRRIGATION/DRAINAGE CUSTOMERS

Q. Can you summarize the impacts of PacifiCorp's proposals in its initial filing in this proceeding on irrigation and/or drainage customers located in Oregon that take service from PacifiCorp under rate Schedule 41?

A. Yes. As described in the Direct Testimony of Robert M. Meredith, PacifiCorp – also referred to in my testimony as "PAC" or "the Company" – is proposing to increase Schedule 41 Base Rates by 19.1%, to be effective January 1, 2023. On a Net Rates basis, the increase would be 13.2%.[3]

Q. How does the Company's proposed rate increase to Schedule 41 customers compare to its proposed rate increases to its other Oregon customers?

A. In its initial rate filing in the UE 399 proceeding, the Company proposed to increase Net Rates to irrigation and drainage customers who take service under the Schedule 41 – many of which are small farm owners – *by twice* the 6.6% average rate increase across all of its Oregon customer classes. Furthermore, the Company's proposed 13.2% increase in Net Rates to Schedule 41 irrigation customers is, by far, the highest proposed rate increase to any single customer class, with the next highest increase being 9.5% to the Schedule 23 (0-30 KW) class.[4]

---

[3] *In the Matter of PacifiCorp d/b/a Pacific Power Request for a General Rate Revision*, Docket No. UE 399 (Mar. 1, 2022). See Exhibit PAC/1100, Meredith/15. Also see Exhibit PAC/1110, Meredith/1.

[4] Exhibit PAC/1100, Meredith/15.

Q. What is the overall percentage rate increase to Schedule 41 customers including the Company's proposed changes to its Net Power Costs in its 2023 Transitional Adjustment Mechanism ("TAM") proceeding?[5]

A. In its response to OPUC Data Request 422, PacifiCorp indicated that the combined rate increase to Schedule 41 customers resulting from the Company's initial proposals in the UE 399 and UE 400 proceedings would be 18.3%. I note that the 18.3 percentage rate increase figure for the Schedule 41 customer class may actually be understated in that it does not appear to incorporate the potential rate impacts of deferred account balances associated with seven additional pending dockets that have been consolidated with the UE 399 Docket.[6]

ISSUE 2, PAC's PROPOSED MODIFICATIONS TO ITS CAPITAL STRUCTURE

Q. Can you summarize the Company's proposed capital structure in this case?

A. Yes. The Company's proposed capital structure/cost of capital was presented in the Direct Testimony of Nikki L. Kobliha. Table 1 from Ms. Kobliha's Testimony – which provides a summary of PacifiCorp's Overall Cost of Capital – is reproduced below in Table 1:[7]

[5] Advice No. 22-003/UE 400 – PacifiCorp's 2023 Transition Adjustment Mechanism (Mar. 1, 2022).

[6] The seven additional dockets are: UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, and UM 2201.

[7] Exhibit PAC/200, Kobliha/3.

Table 1: PacifiCorp's Proposed Cost of Capital

Component	$m	% of Total	Cost %	Wtd Ave Cost %
Long-Term Debt	$9,989	47.74%	4.38%	2.09%
Preferred Stock	2	0.01%	6.75%	-
Common Stock Equity	10,933	52.25%	9.90%	5.12%
	$20,924	100.00%		7.21%

Q. How does the Company's proposed capital structure differ from the currently-in-place capital structure that was approved by the Commission in its final order in PacifiCorp's previous 2021 GRC?[8]

A. In this proceeding, PAC is proposing to make several changes to its capital structure. First the Company proposes to increase its authorized Return on Equity ("ROE") from 9.5% to 9.8%. Second, the Company proposes to modify its cost of its long-term debt to 4.38% and its cost of preferred stock to 6.75%. And lastly, the Company proposes to increase its common equity level from 50% to 52.25%. The overall impact of these proposed changes would be to increase PAC's Overall Cost of Capital from 7.137% to 7.212.[9]

Q. In its initial filing in this proceeding, did the Company indicate how much of its requested $82.2M increase[10] in its annual revenue requirement on a Net Rates basis is associated with its proposed changes to its capital structure?

A. I could not identify where or if the Company provided this information in a clear fashion in its initial testimony in this case. However, utilizing figures contained in the Direct

[8] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE-374, Order No. 20-473 (Dec. 18, 2010).

[9] Exhibit PAC/200, Kobliha/1-3. Also see Exhibit PAC/1001, Cheung/1.

[10] Exhibit PAC/100, Steward/3.

Testimony of Sherona L. Cheung,[11] I was able to estimate that PacifiCorp's proposed changes to its capital structure would act to increase its annual revenue requirement by approximately $3.2M, which represents approximately 4% of its overall requested revenue requirement increase on a Net Rates basis.

Q. Do you support the Company's proposed changes to its capital structure?

A. No. Given the Company's proposed rate spread in this case, modifying its capital structure as it proposes to do would increase the percentage rate increase to Schedule 41 irrigation customers from approximately 12.7% to 13.2% on a Net Rates basis. So, in effect the Company's proposal to increase its profit margin via modifications to its capital structure acts to make an already bad situation – i.e., a 12.7% rate increase under the current capital structure – even worse for Schedule 41 customers. I therefore recommend that the Commission retain the Company's currently-in-place capital structure.

ISSUE 3, PAC'S PROPOSED SCHEDULE 41 FORECASTED TEST PERIOD ANNUAL ENERGY LOAD AND NUMBER OF CUSTOMERS

Q. Have you reviewed the actual annual historical energy loads, annual temperature normalized energy loads, and the annual normalized forecasted energy loads that the Company has incorporated into its initial UE 399 filing?

A. Yes. The general process by which the Company derived its forecasted annual temperature normalized energy loads for the January 2023-December 2023 Test Period is discussed in the Direct Testimony of Mr. Kenneth Lee Elder, Jr.[12] Actual annual historical energy loads and annual temperature normalized energy loads for each of the

[11] See Exhibit PAC/1001, Cheung/1.
[12] Exhibit PAC/900, Elder, Jr.

Company's individual customer classes during the July 2020-June 2021 Base Period are detailed in an exhibit to Mr. Meredith's testimony, as are the forecasted temperature normalized energy loads for the Test Period.[13]

Q. Are there any other sources of information that you reviewed in this case regarding the Company's actual annual historical energy loads, annual temperature normalized energy loads, and its annual normalized forecasted energy loads?

A. Yes. In response to OPUC Data Request 322, the Company provided monthly actual energy usage figures for each customer class across the period 2017-2021. In addition, in response to OPUC Data Requests 254 and 255, the Company provided additional supporting details regarding its derivation of temperature normalized annual energy forecasted loads for each customer class for the Calendar Year ("CY") 2023 Test Period, as well as the forecasted number of customers in each class.

Q. Do you have any concerns with regard to the Company's forecasted annual temperature normalized energy loads for the Calendar Year 2023 Rate Period?

A. Yes. The Company has apparently significantly overstated the CY 2023 Test Period normalized energy load for the Schedule 41 irrigation/drainage customer class. For example, the normalized actual load for the Schedule 41 class during the Base Period was 224,363 Mwh.[14] However, the Company's forecasted 2023 Test Period normalized load for the Schedule 41 class is shown as 265,565 Mwh, which equates to an approximately 17.5% increase. In addition, the Company is also apparently forecasting that the average number of customers in the Schedule 41 class will increase significantly between the

[13] Exhibit PAC/1109, Meredith/7.
[14] *Ibid.*

historical Base Period and the CY 2023 Test Period. For example, Mr. Meredith's Oregon Marginal Cost of Service Study for CY 2023 ("2023 MCS") forecasts that the average number of Schedule 41 customers in CY 2023 will be 21.7% higher than the actual average number of Schedule 41 customers that the Company served during the July 2020-June 2021 Base Period.[15] Finally, in its confidential response to OPUC Data Request 322, PacifiCorp's figures indicate that the average annual historical energy load for the Schedule 41 customer class across the period 2017-2021 was significantly lower than its forecast for the CY 2023 Test Period.

Q. Are there any inconsistences in the Company's initial testimony with regard to the CY 2023 Test Period normalized energy sales forecast for the Schedule 41 customer class?

A. Yes. For example, Table 3 contained on page 4 of Mr. Elder's testimony indicates that the forecasted sales volume for CY 2023 to its Oregon irrigation customer class will only be 0.1% higher than the CY 2021 figure than what was forecasted in the Company's previous 2021 GRC. However, by comparison, the tables contained on page 7 to Exhibit PAC/1109 to Mr. Meredith's testimony indicates that sales to Schedule 41 customers during CY 2023 are forecasted to increase by 17.5% as compared to the temperature normalized annual energy load that occurred during the historical Base Period.

Q. Do you believe that the Company's forecasted annual normalized energy load for the Schedule 41 rate class during the CY 2023 Test Period is accurate?

[15] Exhibit PAC/1108, Meredith/pages labeled Cust Data 1 and Cust Data 2.

A. No, and for several reasons. First, after discussing this point with multiple representatives of KWUA and the OFBF, these representatives were not aware of any general trends in the Oregon agricultural industry that would drive such a large increase in annual energy consumption and the number of agricultural customers relative to the July 2020-July 2021 historical Base Period. Second, PacifiCorp's forecasted 17.5% increase in the normalized annual energy load for the Schedule 41 customer class is significantly out of sync with its CY 2023 normalized energy load forecasts for its other customer classes and for its overall energy load. For example, the Company is forecasting a 2.1% *decrease* in the Residential class's normalized energy load between the historical Base Period and the CY 2023 Test Period.[16]

Q. In general, how does the Company utilize the CY 2023 normalized annual energy load forecasts in its rate calculation processes?

A. The CY 2023 Test Period normalized annual energy load and number of customer forecasts are incorporated into multiple computational processes in the Company's initial UE 399 rate filing including: (1) the calculation of PacifiCorp's Oregon annual revenue requirement, which is discussed in Ms. Cheung's testimony, (2) the allocation of multiple functional costs to the Company's separate customer classes and individual rate schedules, which are discussed in Mr. Meredith's testimony, and (3) the derivations of the proposed rate spread and rate design, which are also discussed by Mr. Meredith.

[16] Exhibit PAC/1109, Meredith/3.

Q. Can you describe some of the specific rate impacts of the Company's apparently overstated CY 2023 Test Period normalized annual energy load for the Schedule 41 customer class?

A. Yes. First, if the forecasted normalized annual energy load for the Schedule 41 customer class is overstated, the amount of the Company's annual revenue requirement to be recovered from the Schedule 41 class will also be overstated. Second, forecasted normalized annual energy loads for the CY 2023 Test Period are utilized by PacifiCorp to derive generation-based allocation factors for each customer class that, in turn, are used in the Company's 2023 Transitional Adjustment Mechanism ("TAM") case in Docket No. UE 400 to allocate PacifiCorp's forecasted CY 2023 Net Power Costs ("NPC") among the different customer classes.[17]

Q. How does the overstated CY 2023 normalized annual energy load forecast for the Schedule 41 customer class in this proceeding impact its allocation of NPC in the 2023 TAM?

A. Using information contained in Mr. Meredith's testimony in this proceeding,[18] I have determined that the NPC allocation factor utilized for the Schedule 41 class in the 2023 TAM is 1.82%. By comparison, the Schedule 41 class's NPC allocation factor in the 2022 TAM was only 1.54%.[19] Therefore, the overstated CY 2023 energy load forecast for the Schedule 41 customer class derived in this proceeding acts to overstate the allocation of NPC to Schedule 41 irrigation customers in the 2023 TAM.

[17] Docket No. UE 400, Exhibit PAC/401, Ridenour/1.

[18] See Exhibit PAC/1108, Meredith/Table 3, line 58.

[19] Advice No. 21-008/UE 390 – PacifiCorp's 2022 Transitional Adjustment Mechanism. See Exhibit PAC/301, Ridenour/1.

Q. Do you have a recommendation with regard to adjusting the Company's initial annual CY 2023 normalized annual energy load forecast for the Schedule 41 customer class?

A. Yes. I recommend that the Company use the annual normalized energy load for the Schedule 41 customer class during the July 2020-June 2021 Base Period (224,363 Mwh) as its forecasted annual normalized energy load for this class during the CY 2023 Test Period. Furthermore, I recommend that the Company re-compute the set of generation-based allocation factors that are used in the 2023 TAM to allocate NPC among its various customer classes using: (1) the adjusted CY 2023 load forecast for the Schedule 41 class and, (2) if appropriate, adjusted energy load forecasts for other customer classes as well.

ISSUE 4, PAC'S PROPOSED ALLOCATION OF WILDFIRE MITIGATION AND VEGETATION MANAGEMENT OPERATIONS AND MAINTENANCE COSTS

Q. Two of the major capital cost and Operations and Maintenance ("O&M") cost items that the Company is seeking to recover in this case are related to Wildfire Mitigation and Vegetation Management, collectively referred to in the Company's filing as WFVM costs. With regard to WFVM O&M-related costs, how is the Company proposing to recover these costs from its individual customer classes?

A. The Company appears to be allocating WFVM O&M costs among its various customer classes in the same fashion as it does for its general system transmission and distribution related O&M costs.

Q. How does the Company derive the various allocation factors that it utilizes to apportion its general system transmission and distribution related O&M costs among its multiple customer classes?

A. The various allocation factors used by the Company to apportion its general system transmission and distribution related O&M costs among its multiple customer classes were derived in the Company's 2023 MCS, which is sponsored in testimony by Mr. Meredith.[20]

Q. With regard to distribution related O&M costs, what are some of the key cost components incorporated into the 2023 MCS and how does PacifiCorp generally allocate these costs among its different customer classes?

A. There are several cost components involved and, in general, distribution-related O&M costs are allocated based upon the amount of infrastructure that the Company needs to maintain in order to serve each customer class. Some of the key distribution-related infrastructure cost components include lines, poles, substations, line transformers, and labor costs. In addition, the rights-of-way that distribution lines traverse also need to be maintained.

Q. How is PacifiCorp allocating distribution related WFVM O&M costs to the Schedule 41 customer class in its 2023 MCS?

A. It appears that the Company is utilizing the same set of allocation factors that it uses to allocate general system distribution O&M costs to the Schedule 41 customer class to also allocate distribution related WFVM O&M costs to the class.

Q. Do you believe that the Company's approach to allocating distribution related WFVM O&M costs to the Schedule 41 customer class is reasonable?

[20] See Exhibit PAC/1108, Meredith.

A. No. First of all, according to my discussions with representatives from KWUA and the OFBF, the majority of PacifiCorp's irrigation pumping and drainage loads in Oregon – along with the distribution lines that serve these loads – are located in flat, open areas as opposed to densely forested areas. For example, a large percentage of the Company's Oregon agricultural irrigation and drainage loads are concentrated in three areas: (1) the Upper Klamath River basin north and south of Klamath Falls, (2) the area around the cities of LaGrande and Baker City in northeastern Oregon, and (3) the area around the city of Bend in central Oregon. All three of these productive agricultural areas share the common characteristics of being located in open, relatively flat areas with a minimum of tree cover. In fact, it is counterintuitive to believe that irrigated farmland located in the Company's Oregon service territory would be located in heavy forested areas; quite the opposite, virtually all crops need ample sunlight in order to grow. The generally wide-open terrain of the three large agricultural areas that I mentioned above can be seen from the series of ariel screenshots taken from Google Earth that are contained in Exhibit KWUA-OFBF/102.

Q. In its 2023 MCS, does the Company take into account the topography and degree of tree cover of large farming areas in its allocation of distribution related O&M WFVM costs to the Schedule 41 customer class?

A. I could not identify in the Company's 2023 MCS where it accounted for any of the physical characteristics I noted above when allocating distribution related O&M WFVM costs to the Schedule 41 irrigation customer class. I do note, however, that Mr. Berreth describes a number of specific wildfire mitigation measures that PacifiCorp has implemented or intends to implement in Oregon in the near future.[21] Many of these measures relate to either re-building transmission and/or distribution lines to be more fire-resistant, or more aggressively clearing vegetation from around the lines, especially tall trees that could come in contact with the line conductors. However, very little of these types of WFVM activities would be expected to take place on the distribution infrastructure that serves irrigation loads, for the reasons I state above. Therefore, in my opinion, the Company is over-allocating distribution related WFVM O&M costs to Schedule 41 irrigation customers in this proceeding.

Q. In general, are any of the three major irrigated agricultural areas in Oregon that you identified above located in the Fire High Consequence Areas ("FHCAs") that the Company has identified in this proceeding?

A. I do not believe so. While the map of the FHCAs located within the Company's Washington, Oregon, and California service territories, does not allow for precise, small-scale observations,[22] it appears that there is little, if any, overlap between the FHCAs located in Oregon and the three large, open areas that contain concentrated numbers of PacifiCorp's agricultural customers that take service under the Schedule 41 irrigation rate.

Q. How do you recommend that the Company modify its 2023 MCS in order to address the over-allocation of WFVM distribution related O&M costs to the Schedule 41 customer class?

[21] Exhibit PAC/700, Berreth/8-16.
[22] See Exhibit PAC/701, Berreth/1.

A. I recommend that the Company derive a new and separate set of distribution-related allocation factors to be used for the apportionment of distribution related WFVM O&M costs among its individual customer classes. This new set of allocation factors would incorporate the specific characteristics and locational topography of the Company's distribution infrastructure (including rights-of-way) on which the Company is targeting to implement WFVM actions.

ISSUE 5, PAC'S PROPOSED SCHEDULE 41

DISTRIBUTION RELATED DEMAND COST ALLOCATIONS

Q. Have you reviewed the Company's derivation of the 12-month weighted average distribution peak loads for each of its customer classes for the CY 2023 Test Period?

A. Yes. PacifiCorp's derivation of 12-month weighted average distribution peak loads for each of its customer classes for the CY 2023 Test Period is contained in the Company's 2023 MCS.[23]

Q. What are the 12-month weighted average distribution peak loads you referred to above primarily used for in the Company's initial rate filing?

A. The Company utilizes the 12-month weighted average distribution peak loads in order to allocate its forecasted annual demand-related distribution costs among its different customer classes in both its 20-year 2023 MCS and in the 10-year 2023 MCS.[24]

Q. Do you have any concerns regarding the Company's allocation of demand-related distribution costs among its different customer classes?

[23] See Exhibit PAC/1108, Meredith/Cust Data 5 tables.

[24] See Exhibit PAC/1408. The 20-year demand-related distribution cost allocations are shown on the page labeled "Table 3" while the 10-year demand-related distribution cost allocations are shown on the page labeled "10-year MC."

A. Yes. The 12-month weighted average peak load computational methodology employed by the Company in its 2023 MCS has resulted in an unreasonably high allocation of demand-related distribution costs to the Schedule 41 customer class as compared to the similar cost allocation that the Company presented in its initial filing in its 2021 GRC.[25]

Q. Can you explain why the Company's allocation of demand-related distribution costs in its 2023 MCS has produced an unreasonable result for the Schedule 41 customer class?

A. Yes. While I do not take a position on the overall computational methodology employed by Mr. Meredith in deriving the 12-month weighted distribution peak loads, in this particular circumstance there is an anomaly in the results whereby the 12-month weighted distribution peak load derived for the Schedule 41 class increased much more on a percentage basis than for any other customer class, relative to the results from the previous 2021 MCS.

Q. Can you provide some specific examples as to why the Company's 12-month weighted average distribution peak load computations in its 2023 MCS have produced unreasonable results for the Schedule 41 class as compared to the previous 2021 MCS results?

A. Yes. In the previous 2021 MCS, the highest monthly distribution peak load during the 12-month Base Period for the Schedule 41 class was 80.1 MW, which occurred in August 2018. By comparison, the highest monthly distribution peak load during this case's 12-month Base Period for the Schedule 41 class was 86.3 MW, which occurred in July

[25] Docket UE 374, Exhibit PAC/1408, Meredith/81.

2020. I note that the percentage increase in the Schedule 41 distribution peak load between the 2021 MCS and the 2023 MCS is only 7.7%. However, the Schedule 41 12-month weighted average distribution peak figure – the value that is subsequently utilized by the Company to allocate demand-related distribution costs across all customer classes – increased from 32.8 MW up to 61.7 MW, *which equates to a whopping 88.1% increase.*

Q. Did other rate classes see such a radical discrepancy in how much their 12-month weighted average distribution peak figures increased between the 2021 MCS and the 2023 MCS relative to the increase in their highest monthly peak loads during the two Base Periods?

A. No. For example, the Schedule 4 residential class's highest monthly distribution peak load increased from 1,280.3 MW in the 2021 MCS to 1,440.6 MW in the 2023 MCS, which is an increase of 12.5%. By comparison, the residential class's 12-month weighted average distribution peak load figure increased from 1,122.2 MW to 1,265.5 MW, which is an increase of 12.8%. As another example, the Schedule 48 transmission class's highest monthly distribution peak load increased from 128.0 MW in the 2021 MCS to 198.5 MW in the 2023 MCS, which is an increase of 55.1%. In comparison, the Schedule 48 transmission class's 12-month weighted average distribution peak figure increased from 115.0 MW to 178.9 MW, which is an increase of 55.6%. In both of these examples, the percentage increases in the classes' 12-month weighted distribution peak loads *were virtually identical* to the percentage increase between their highest monthly distribution peak load. These results are in stark contrast to the results for the Schedule 41 class where the percentage increase in the 12-month weighted distribution peak load was over *eleven times higher* than the percentage increase between its highest monthly distribution peak load.

Q. Do you have a proposal to address the computational anomaly you identify above for the Schedule 41 customer class in the Company's derivation of the 12-month weighted average distribution peak loads to be utilized in allocating demand-related distribution costs among all customer classes?

A. Yes. However, in order to avoid making wholesale changes to the Company's 12-month weighted average distribution peak load computational methodology, I propose that a simple set of adjustments can be applied to the Company's initial results from its 2023 MCS that would more reasonably align the percentage increases or decreases between each class's highest 12-month monthly distribution peak load during the two Base Periods with the resultant 12-month weighted average distribution peak figures that will be utilized to allocate demand-related distribution costs for the CY 2023 Test Period. These adjustments would act to limit the change in a rate schedule's 12-month weighted distribution peak load between the 2021 MCS and the 2023 MCS to within a +/- 5.0% range of the change in the class's highest monthly peak load during the two Base Periods. Table 2 shows the Company's initially proposed computation of the 12-month weighted average distribution peak loads for each customer class, the adjustments that I propose, and the final resultant modified figures to be utilized by the Company in allocating demand-related distribution costs among all customer classes.

Table 2 – Adjusted 12-Month Weighted Average Distribution Peak Loads

	Initial		Final
Rate Schedule	Sum of 12-month Weighted Average Distribution Peak Loads (MW)	Adjustments	Sum of 12-month Weighted Average Distribution Peak Loads (MW)
Res - Schedule 4	1,265.5	0.0	1,265.5
GS - Schedule 23			
0-15 KW	83.7	0.0	83.7
15+ KW	93.3	5.3	98.6
Primary	0.3	(0.0)	0.3
GS - Schedule 28			
0-50 KW	66.7	(0.0)	66.7
51-100 MW	98.1	(0.0)	98.1
100+ KW	125.2	(0.0)	125.2
Primary	3.0	(0.0)	3.0
GS - Schedule 30			
0-300 KW	27.7	1.1	28.8
301+ KW	136.6	12.8	149.4
Primary	13.4	1.2	14.6
LPS - Schedule 48			
1-4 MW (Sec)	70.4	0.0	70.4
1-4 MW (Pri)	66.2	2.7	68.9
>4 MW (Sec)	4.8	0.0	4.8
>4 MW (Pri)	120.0	0.0	120.0
Transmission	178.9	0.0	178.9
Irrigation - Schedule 41	61.7	(23.2)	38.5
Total	**2,415.5**	**0.0**	**2,415.5**

Exhibit KWUA-OFBF/103 contains a spreadsheet (with all formulas intact) that provides the supporting calculations for the figures shown in Table 2.

ISSUE 6, PAC'S PROPOSED RATE SPREAD FOR SCHEDULE 41

Q. Can you summarize the Company's proposed rate spread in this proceeding?

A. Yes. As I previously mentioned, the Company's proposed rate spread is shown in Table 1 of Mr. Meredith's testimony.[26] PacifiCorp is proposing a rate spread that ranges from a 0.0% rate increase in Net Rates for two customer classes, up to a 13.2% increase in Net Rates for Schedule 41 irrigation/drainage customers. The Company's proposed average increase in Net Rates across all customer classes is 6.6%.

Q. Does the Company make any general statements regarding its proposed Rate Spread in this proceeding as compared to the rate spread agreed to by the parties in its previous 2021 GRC in Docket No. UE 374?

A. Yes. On page 14 of her testimony, Ms. Steward states that the Company is not proposing any major updates to rate spread and rate design because the Commission approved a Stipulation Agreement among certain parties regarding rate spread and rate design in Order 20-473 in the UE 374 case.[27] Ms. Steward further states that "*the Company is only proposing discrete changes to how rates are currently designed*." (Emphasis added.)[28]

Q. Do you agree with Ms. Steward's statement that "the Company is only proposing discrete changes to how rates are currently designed"?

A. No. In fact, the opposite is true for the Schedule 41 customer class. Furthermore, Ms. Steward's statement is in direct conflict with the rate spread proposed by Mr. Meredith in his testimony. The UE 374 Stipulation Agreement specified that the percentage rate increase to the Schedule 41 customer class would be established at 1.5 times the average rate increase across all customer classes. In addition, the

[26] Exhibit PAC/1100, Meredith/15.
[27] Order No. 20-473 at p. 140 and Appendix A.
[28] Exhibit PAC/100, Steward/14.

Company's initial rate spread proposal in the UE 374 case indicated that the maximum percentage rate increase to any customer class would be limited to 10%.

Q. With regard to the Schedule 41 rate, how does the Company's proposed rate spread in this proceeding differ from what was ultimately agreed to in the UE 374 Proceeding?

A. In this proceeding, the Company is proposing that the percentage rate increase in Net Rates for the Schedule 41 customer class be established at 2.0 times the average rate increase across all customer classes as compared to the 1.5 figure that was specified in the UE 374 Stipulation Agreement. Furthermore, in this proceeding the Company is also proposing that the percentage rate increase to the Schedule 41 customer class would be limited to 13.2%, which is significantly higher than the 10.0% maximum percentage rate limit that it originally proposed in the UE 374 Case. I note that Mr. Meredith – who sponsored the Company's proposed rate spread in testimony – presents no specific rationale as to why the Company is proposing to make these material modifications to rate spread and the maximum rate increase limit (which is implemented via the Rate Mitigation Adjustment) as they apply to the Schedule 41 customer class.

Q. How does the Company's proposed rate spread with regard to the Schedule 41 irrigation/drainage customer class in this proceeding compare to the rate spread for similarly situated irrigation/drainage customers who are located in PacifiCorp's Washington service territory?

A. In Washington, PacifiCorp currently serves irrigation/drainage customers who generally take service under Schedule 40 under a set of rates that were established in its 2020 GRC in Docket No. UE-191024. The *Joint Testimony in Support of Settlement Stipulation* dated July 17, 2020, in this docket specified that the percentage rate increase to the Schedule 40 irrigation customer class would be established at the average percentage rate increase across all of the Company's Washington customer classes.[29] The Washington Utilities and Transportation Commission approved the stipulation agreement in the UE-191024 proceeding in an order issued on December 14, 2020.[30]

Q. How does the Company's proposed rate spread with regard to the Schedule 41 customer class in this proceeding compare to its proposed rate spread for similarly situated irrigation/drainage customers that are located in PacifiCorp's California service territory?

A. In California, PacifiCorp serves irrigation/drainage customers that generally take service under Schedule PA-20. On May 5, 2022, the Company filed a GRC with the California Public Utilities Commission in Docket No. U-901-E.[31] In that rate filing, PacifiCorp proposed that the percentage rate increase to the Schedule PA-20 irrigation customer class would be established at the same equal percentage base rate spread that the Company proposed to utilize across all of its California customer classes.[32]

Q. What rate spread do you propose in this proceeding with regard to PacifiCorp's Oregon irrigation/drainage customers that take service under Schedule 41?

A. Consistent with the Company's current rates to its irrigation/drainage customers located in Washington and its proposed rate spread for its irrigation/drainage customers located

---

[29] Docket UE-191024, *Joint Testimony in Support of Settlement Stipulation*, pp. 19-20.

[30] Final Order 09/07/12.

[31] In the Matter of the Application of PACIFICORP (U-901-E) for an Order Authorizing a General Rate Increase Effective January 1, 2023 (May 5, 2022).

[32] Docket No. U-901-E, Exhibit PAC/1100, Meredith pp. 3-4.

in California, I propose that the percentage rate increase for PacifiCorp's Oregon Schedule 41 customer class be established at 1.0 times the average percentage rate increase across all of its Oregon customer classes.

Q. Do you have a proposal in this proceeding with regard to the rate spread as it applies to customer classes other than the Schedule 41 irrigation/drainage class?

A. No. I take no position on the rate spread in this proceeding as it applies to any customer class other than the Schedule 41 class.

Q. Does this conclude your testimony?

A. Yes.

LLOYD C. REED
10025 Heatherwood Lane
Highlands Ranch, CO 80126

EXPERIENCE:

REED CONSULTING, Highlands Ranch, CO. August 2009 - Present

President. Provided advice to multiple utility companies and/or their outside legal counsel regarding power system operational and regulatory issues. Assisted an electric utility in incorporating potential regional power shortage events into their long-term integrated resource plan. Performed a cost-of-service study for a Tribally-owned hydroelectric facility. Advised a group of Northwest publicly-owned utilities on proposals received under an RFP issued for new renewable and conventional generating resources. Prepared and submitted expert testimony to the Federal Energy Regulatory Commission in the California Refund Case and Pacific Northwest Refund Case proceedings. Performed a detailed analysis regarding the design and implementation of an intermittent resources regulation tariff on behalf of a large investor-owned utility and submitted expert testimony in a related rate case proceeding at the FERC. Derived wind generation integration costs to be included in an investor-owned utility's retail rate case. Assisted a publicly-owned utility with the marketing of surplus renewable energy and renewable energy credits into the Western markets. Performed multiple triennial Market Power Studies on behalf of two Northwest electric utilities and also prepared numerous Market Concentration Studies in support of generating plant acquisitions by these utilities. Performed preliminary feasibility studies for the development of a solar generating plant to be located in the Northwest region and hydroelectric pumped storage plants to be located in the Rocky Mountain and Northwest regions. Made multiple presentations to FERC Staff regarding the impacts of utility-scale wind generation plants on power systems operations.

GOLDEN ENERGY SERVICES, INC., Highlands Ranch/Littleton, CO. April 2001 - August 2009

Partner/Vice President. Acted as an arbitrator in a contract dispute regarding the operation of a group of hydroelectric generating facilities and an associated set of long-term multi-party wholesale power purchase agreements. Advised the trading staff of a major Western utility in the short term and intermediate term optimization of the utility's wholesale power and natural gas portfolios. Advised a group of Northwest publically-owned utilities regarding potential power pooling arrangements and performed a preliminary pooling feasibility study. Performed multiple Market Power Studies on behalf of two electric utilities in support of FERC Section 203 and 205 rate tariff filings. Submitted testimony to the FERC in the California Refund Case on behalf of a large Northwest utility. Analyzed and recommended actions concerning open access electricity purchase options for several large industrial end use customers. Provided ongoing operational and contractual support to utility and end user customers concerning the operation of the Pacific Northwest hydroelectric generation system. Researched and presented to a national scope merchant power plant developer an assessment of Northwest area transmission availability and potential future impacts of RTO formation. Assisted the staff of an electric utility in the redesign of its retail tariff structure to incorporate alternate pricing and hedging mechanisms. Actively participated in the ongoing risk management process for a major electric/natural gas utility. Assisted in the analysis of a proposed new interstate natural gas pipeline and a proposed new major lateral for a natural gas LDC system. Advised a large Western utility in power marketing strategies for the Northwest and California markets. Assisted several end use industrial customers in the drafting and implementation of integrated energy management policies.

PUGET SOUND ENERGY, INC., Bellevue, WA. September 1999 - March 2001

Director Power Supply Operations. Directed all aspects of PSE's forward power trading, real-time trading, scheduling, and power operations activities. Managed the operations of a diverse, 4500 MW power supply portfolio consisting of hydroelectric, coal, gas, and contract resources. Established and implemented short-term and seasonal operating plans for PSE's hydroelectric resources. Actively managed PSE's rights and obligations pursuant to the Pacific Northwest Coordination Agreement and the Mid-Columbia Hourly Coordination Agreement. Coordinated daily with the PSE Gas Operations group to optimize the operation of 1200 MW of gas-fired generation. Pursued long term power supply agreements and generation development projects as well as negotiating numerous intermediate-term power/heat rate purchases and sales. Actively assisted in the development and implementation of PSE's energy risk management procedures. Recommended various forward hedging strategies to senior management. Prompted PSE's expansion into new markets such as the CAISO and PX. Actively participated in regional energy initiatives such as RTO formation, BPA power and transmission rate cases, and WECC power supply coordination issues. Worked with large end use retail customers on market based pricing programs.

***e prime, inc.*/NEW CENTURY ENERGIES,** Denver, CO. February 1996 - August 1999
Vice President Power Marketing. Responsible for managing all aspects of *e prime's* power business including marketing, trading, scheduling, contract administration, generating plant acquisitions, and regulatory affairs. Developed and presented to senior management long-term business strategies for both *e prime* and its parent company, New Century Energies. Analyzed numerous merchant generating project opportunities and successfully completed negotiations for the purchase of long-term tolling rights from a new gas-fired generating facility. Co-authored *e prime's* risk management policies and procedures including the development and implementation of the company's power trading parameters and limits. Actively participated with other NCE personnel in the preparation of bid packages for utility sponsored asset auctions.

Director of Power Marketing. Developed all business systems necessary to start up a new power marketing/trading affiliate. Responsible for hiring and supervising all of *e prime's* power marketing and trading staff, as well as directing all of the company's wholesale and retail electric trading and marketing activities. Developed and implemented various marketing/trading strategies and policies designed to establish and rapidly grow *e prime's* business. Negotiated numerous power sale, purchase, and transmission agreements ranging in duration from one month to two years. Designed and implemented *e prime's* original power scheduling/accounting software systems as well as establishing the company's power related credit procedures. Oversaw the company's involvement in several electric retail open access programs.

PANENERGY POWER SERVICES, INC., Spokane, WA. October 1994 - January 1996
Manager Power Operations. Developed all necessary business and energy accounting systems required to start up a new power marketing company. Supervised and coordinated PanEnergy's short/intermediate term power marketing and trading activities throughout the Western United States. Negotiated and implemented enabling/tariff agreements allowing PanEnergy to transact business with over 100 different electric utilities and power marketers. Negotiated numerous power sale, purchase, and energy management agreements.

WASHINGTON WATER POWER, Spokane, WA. August 1993 - September 1994
Systems Operations Engineer. Acted as WWP's lead negotiator for the twenty-year extension of the eighteen party Pacific Northwest Coordination Agreement. Provided operational expertise and training to WWP's energy traders and support staff. Actively managed and optimized WWP's contractual rights under multiple power sale and hydroelectric resource coordination agreements. Coordinated WWP's short-term and seasonal hydroelectric operating plans with WWP's marketing and trading strategies. Responsible for all aspects of WWP's data submittals to the PNCA annual planning process.

PUGET SOUND POWER & LIGHT, Bellevue, WA. July 1982 - July 1993
Senior Power Scheduler/Intercompany Pool Representative. Managed the sale and purchase of up to 1000 aMW of short-term firm and non-firm energy. Developed and executed medium range operating and marketing strategies. Aggressively exercised and defended Puget's rights and obligations under more than thirty long-term power and transmission contracts. Provided real-time operational direction to Puget's power dispatchers. Represented Puget at regional Northwest Power Pool and Western Systems Power Pool meetings.

Power Scheduler/Intercompany Pool Representative. Devised hourly preschedules of Puget's hydroelectric, thermal, and contract resources while arranging all of Puget's prescheduled power purchase and sales transactions. Provided technical expertise during the negotiation of long-term power supply contracts. Developed and implemental short-term operating strategies for Puget's hydroelectric resources. Improved energy accounting methods and cut billing preparation time in half. Personally established new trading relationships with twelve utilities throughout the WECC region.

Assistant Power Resource Engineer. Provided technical support for PSE's annual hydroelectric and thermal resource planning processes. Performed hydroelectric plant optimization and redevelopment studies. Assisted in the development of PSE's short-term and medium-term resource operations strategies. Developed streamflow and generation forecasts for several of PSE's hydroelectric generating plants.

EDUCATION:
UNIVERSITY OF WASHINGTON – Seattle, WA. June 1982
B.S., Electrical Engineering

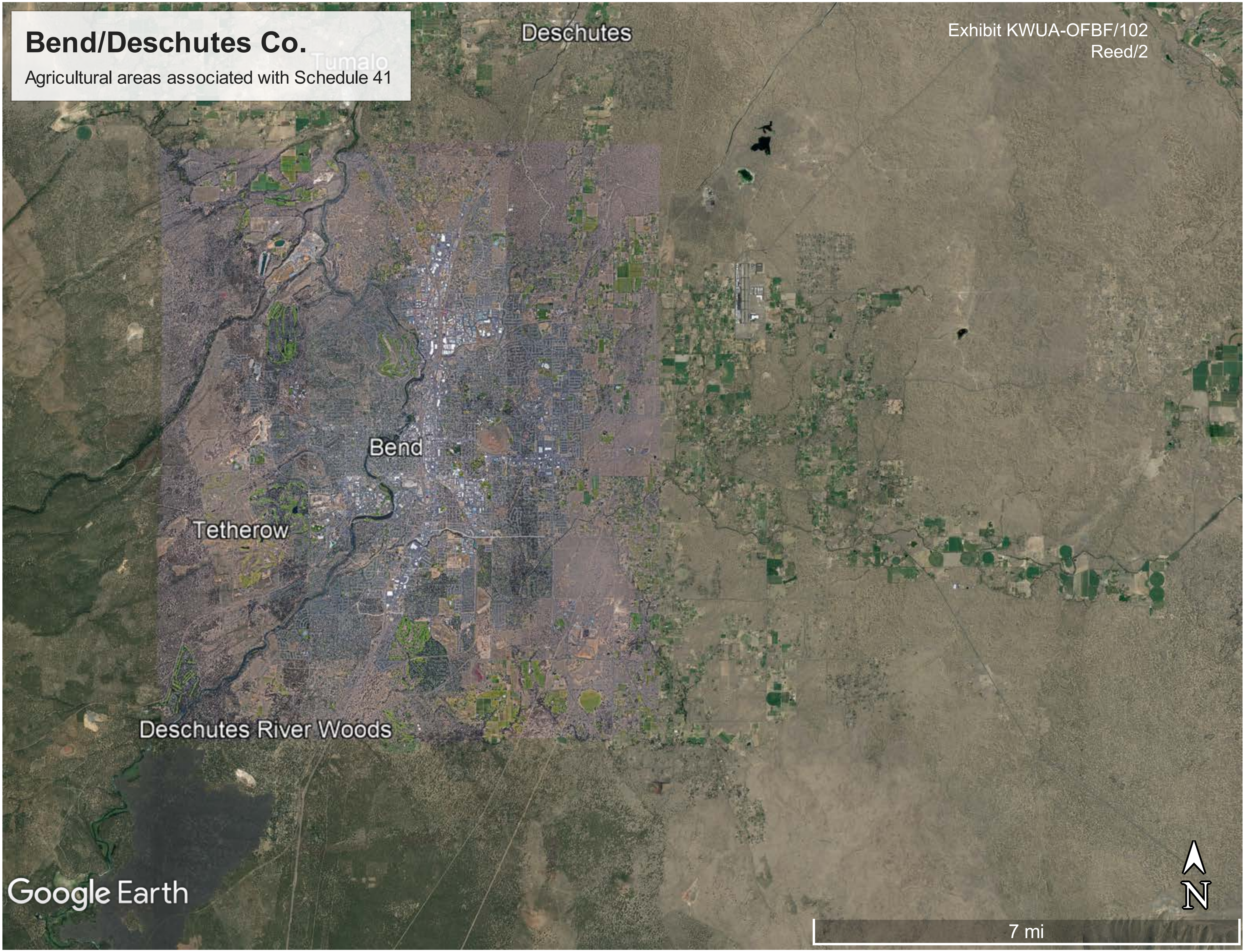
Upper Klamath Basin

Agricultural areas associated with Schedule 41

Bend/Deschutes Co.

Agricultural areas associated with Schedule 41

Exhibit KWUA-OFBF/102
Reed/2



La Grande/Baker City

Agricultural areas associated with Schedule 41

Klamath Water Users Association/Oregon Farm Bureau Federation

PacifiCorp 2023 General Rate Case, Docket No. UE 399

Summary of 2023 Oregon Marginal Cost Study Adjusted 12-month Weighted Average Distribution Peak Loads

Rate Schedule	Initial Sum of 12-month Weighted Average Distribution Peak Loads (MW)	Adjustments	Final Sum of 12-month Weighted Average Distribution Peak Loads (MW)
Res - Schedule 4	1,265.5	0.0	1,265.5
GS - Schedule 23			
0-15 KW	83.7	0.0	83.7
15+ KW	93.3	5.3	98.6
Primary	0.3	(0.0)	0.3
GS - Schedule 28			
0-50 KW	66.7	(0.0)	66.7
51-100 MW	98.1	(0.0)	98.1
100+ KW	125.2	(0.0)	125.2
Primary	3.0	(0.0)	3.0
GS - Schedule 30			
0-300 KW	27.7	1.1	28.8
301+ KW	136.6	12.8	149.4
Primary	13.4	1.2	14.6
LPS - Schedule 48			
1-4 MW (Sec)	70.4	0.0	70.4
1-4 MW (Pri)	66.2	2.7	68.9
>4 MW (Sec)	4.8	0.0	4.8
>4 MW (Pri)	120.0	0.0	120.0
Transmission	178.9	0.0	178.9
Irrigation - Schedule 41	61.7	(23.2)	38.5
Total	**2,415.5**	**0.0**	**2,415.5**

Notes:
1) No adjustments are proposed for Lighting Schedules 53 & 54.

Klamath Water Users Association/Oregon Farm Bureau Federation

PacifiCorp 2023 General Rate Case, Docket No. UE 399

Re-Allocation of 2023 Oregon Marginal Cost Study 12-month Weighted Average Distribution Peak Loads by Customer Class/Schedule

Rate Schedule	2021 MCS 12-month Peak Load (MW)	2023 MCS 12-month Peak Load (MW)	**Factor 1** Ratio of 2021 Peak Load vs. 2023 Peak Load	2021 Sum of Weighted Ave Peaks (MW)	2023 Sum of Weighted Ave Peaks (MW)	**Factor 2** Ratio of 2021 Sum of W. Ave vs. 2023 Sum of W. Ave	Ratio of Factor 2 to Factor 1	Adjusted Ratio of Factor 2 to Factor 1	Adjusted Ratio Flag (0=No, 1=Yes)	Prelim Adjust 2023 Sum of Weighted Average Peaks (MW)	Sum of Weighted Ave Peaks True Up Step 1	Final Adjust 2023 Sum of Weighted Average Peaks (MW)	Final Adjustments (MW)
Res - Schedule 4	1,280.3	1,440.6	1.1252	1,122.2	1,265.5	1.1277	1.0022	1.0022	0	1,265.5	0.0	1265.5	0.0
GS - Schedule 23													
0-15 KW	105.3	101.6	0.9649	90.7	83.7	0.9228	0.9564	0.9564	0	83.7	0.0	83.7	0.0
15+ KW	103.6	110.0	1.0618	94.2	93.3	0.9904	0.9328	0.9500	1	95.0	95.0	98.6	5.3
Primary	0.2	0.5	2.5000	0.1	0.3	3.0000	1.2000	1.0500	1	0.3	0.3	0.3	(0.0)
GS - Schedule 28													
0-50 KW	83.6	78.7	0.9414	70.2	66.7	0.9501	1.0092	1.0092	0	66.7	0.0	66.7	(0.0)
51-100 MW	133.6	112.3	0.8406	114.0	98.1	0.8605	1.0237	1.0237	0	98.1	0.0	98.1	(0.0)
100+ KW	178.7	143.8	0.8047	161.5	125.2	0.7752	0.9633	0.9633	0	125.2	0.0	125.2	(0.0)
Primary	5.5	3.8	0.6909	4.4	3.0	0.6818	0.9868	0.9868	0	3.0	0.0	3.0	(0.0)
GS - Schedule 30													
0-300 KW	36.4	31.4	0.8626	33.9	27.7	0.8171	0.9473	0.9500	1	27.8	27.8	28.8	1.1
301+ KW	176.0	161.7	0.9188	164.9	136.6	0.8284	0.9016	0.9500	1	143.9	143.9	149.4	12.8
Primary	18.0	16.3	0.9056	16.4	13.4	0.8171	0.9023	0.9500	1	14.1	14.1	14.6	1.2
LPS - Schedule 48													
1-4 MW (Sec)	85.0	81.2	0.9553	76.8	70.4	0.9167	0.9596	0.9596	0	70.4	0.0	70.4	0.0
1-4 MW (Pri)	86.4	76.9	0.8900	78.5	66.2	0.8433	0.9475	0.9500	1	66.4	66.4	68.9	2.7
>4 MW (Sec)	8.0	5.5	0.6875	7.2	4.8	0.6667	0.9697	0.9697	0	4.8	0.0	4.8	0.0
>4 MW (Pri)	148.0	137.5	0.9291	132.5	120.0	0.9057	0.9748	0.9748	0	120.0	0.0	120.0	0.0
Transmission	128.0	198.5	1.5508	115.0	178.9	1.5557	1.0032	1.0032	0	178.9	0.0	178.9	0.0
Irrigation - Schedule 41	80.1	86.3	1.0774	32.8	61.7	1.8811	1.7460	1.0500	1	37.1	37.1	38.5	(23.2)
Total					**2,415.5**					**2,400.9**	**384.6**	**2,415.5**	**0.0**

Notes:

1) No adjustments are proposed for Lighting Schedules 53 & 54.

Klamath Water Users Association/Oregon Farm Bureau Federation

PacifiCorp 2023 General Rate Case, Docket No. UE 399

2021 GRC Oregon Marginal Cost Study, Base Period Monthly Distribution Peak Loads by Customer Class

Rate Schedule	Jul-18 Peak Load (MW)	Aug-18 Peak Load (MW)	Sep-18 Peak Load (MW)	Oct-18 Peak Load (MW)	Nov-18 Peak Load (MW)	Dec-18 Peak Load (MW)	Jan-19 Peak Load (MW)	Feb-19 Peak Load (MW)	Mar-19 Peak Load (MW)	Apr-19 Peak Load (MW)	May-19 Peak Load (MW)	Jun-19 Peak Load (MW)	12-month Peak Load (MW)	Sum of Weighted Ave Peaks (MW)
Residential - Schedule 4	990.6	993.4	924.6	806.3	1,179.8	1,280.3	1,270.4	1,224.1	1,217.2	890.9	899.9	1,029.4	1,280.3	1,122.2
GS - Schedule 23														
0-15 KW	105.3	105.0	89.6	68.0	67.3	88.2	79.8	77.0	88.9	72.0	76.3	95.6	105.3	90.7
15+ KW	103.6	102.8	88.6	74.2	78.2	93.3	99.5	85.1	87.1	78.7	78.0	97.9	103.6	94.2
Primary	0.1	0.0	0.0	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.1
GS - Schedule 28														
0-50 KW	77.9	83.6	69.5	57.0	54.4	72.8	69.9	60.2	64.1	57.7	63.1	75.6	83.6	70.2
51-100 MW	133.6	129.5	100.9	100.1	91.4	113.5	103.6	95.5	108.7	111.7	91.4	122.4	133.6	114.0
100+ KW	172.9	178.7	139.5	135.8	134.4	155.3	147.0	151.7	162.7	138.3	126.6	154.2	178.7	161.5
Primary	3.9	4.5	4.0	5.2	3.4	5.0	4.7	4.5	5.5	4.5	2.8	3.5	5.5	4.4
GS - Schedule 30														
0-300 KW	36.4	34.7	27.4	30.2	31.0	33.7	27.9	33.0	32.7	28.0	27.6	34.7	36.4	33.9
301+ KW	169.9	176.0	147.2	152.1	162.3	174.5	148.4	162.0	157.0	152.0	139.9	150.9	176.0	164.9
Primary	17.5	17.3	14.5	17.1	18.0	16.6	15.9	15.4	15.7	15.9	13.1	16.0	18.0	16.4
LPS - Schedule 48														
1-4 MW (Sec)	79.4	80.7	72.4	74.8	78.6	85.0	66.9	74.6	72.9	77.7	66.6	73.8	85.0	76.8
1-4 MW (Pri)	86.4	84.2	78.5	80.6	82.6	81.2	69.1	71.8	73.8	78.0	67.4	82.8	86.4	78.5
>4 MW (Sec)	7.9	8.0	7.9	7.2	7.4	7.5	5.1	6.7	6.7	7.3	7.5	7.3	8.0	7.2
>4 MW (Pri)	146.0	148.0	144.9	31.8	136.0	137.9	93.9	122.4	123.8	134.6	137.4	133.8	148.0	132.5
Transmission	124.2	128.0	121.7	117.9	92.8	101.5	103.9	107.9	108.1	114.6	108.7	119.9	128.0	115.0
Irrigation - Schedule 41	71.0	80.1	63.3	14.0	3.0	1.0	1.0	1.1	5.3	11.6	40.2	47.2	80.1	32.8
Total	**2,326.6**	**2,354.5**	**2,094.5**	**1,772.4**	**2,220.8**	**2,447.5**	**2,307.2**	**2,293.1**	**2,330.3**	**1,973.6**	**1,946.6**	**2,245.1**		**2,315.3**

Notes:

1) Source: Docket No. UE 374, PacifiCorp Exhibit PAC/1108, Meredith/81.

2) The "Sum of Weighted Ave Peak" figures were derived separately by PacifiCorp.

3) The above figures exclude lighting Schedules 53 & 54.

Klamath Water Users Association/Oregon Farm Bureau Federation

PacifiCorp 2023 General Rate Case, Docket No. UE 399

2023 GRC Oregon Marginal Cost Study, Base Period Monthly Distribution Peak Loads by Customer Class

Rate Schedule	Jul-20 Peak Load (MW)	Aug-20 Peak Load (MW)	Sep-20 Peak Load (MW)	Oct-20 Peak Load (MW)	Nov-20 Peak Load (MW)	Dec-20 Peak Load (MW)	Jan-21 Peak Load (MW)	Feb-21 Peak Load (MW)	Mar-21 Peak Load (MW)	Apr-21 Peak Load (MW)	May-21 Peak Load (MW)	Jun-21 Peak Load (MW)	12-month Peak Load (MW)	Sum of Weighted Ave Peaks (MW)
Residential - Schedule 4	1,266.6	1,042.3	1,121.1	1,163.8	1,236.7	1,440.6	1,409.3	1,258.7	1,066.3	995.0	1,009.7	1,273.5	1,440.6	1,265.5
GS - Schedule 23														
0-15 KW	95.3	100.6	101.6	77.0	77.4	87.6	92.0	85.6	84.1	67.4	67.2	81.2	101.6	83.7
15+ KW	107.2	107.8	110.0	83.7	88.6	100.5	107.4	97.0	95.7	73.4	78.1	89.8	110.0	93.3
Primary	0.4	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.5	0.3
GS - Schedule 28														
0-50 KW	72.3	76.2	78.7	62.8	62.2	64.1	71.9	66.5	67.6	58.4	59.6	65.4	78.7	66.7
51-100 MW	110.5	112.3	111.2	94.2	96.7	98.6	105.0	101.6	100.0	87.2	83.7	95.7	112.3	98.1
100+ KW	139.3	143.4	141.9	118.5	128.5	132.0	143.8	135.3	133.1	112.2	104.5	120.2	143.8	125.2
Primary	3.5	3.7	3.8	3.8	3.6	3.7	3.8	3.7	3.6	3.2	2.7	2.7	3.8	3.0
GS - Schedule 30														
0-300 KW	29.7	31.4	29.7	28.8	31.0	28.2	30.5	29.2	29.6	27.2	21.4	26.9	31.4	27.7
301+ KW	145.5	161.7	149.0	143.4	156.4	145.1	149.5	146.6	148.8	139.7	104.9	131.4	161.7	136.6
Primary	14.9	16.3	15.0	15.3	16.2	14.5	15.1	14.7	15.3	14.4	11.2	12.7	16.3	13.4
LPS - Schedule 48														
1-4 MW (Sec)	72.7	79.2	81.2	78.5	79.4	73.2	70.8	72.8	72.4	75.7	50.4	69.2	81.2	70.4
1-4 MW (Pri)	70.2	76.9	75.5	73.9	72.5	67.2	64.0	63.7	63.4	63.1	46.3	65.8	76.9	66.2
>4 MW (Sec)	5.0	5.5	5.2	4.9	4.6	4.8	4.6	4.8	4.0	4.8	3.6	4.9	5.5	4.8
>4 MW (Pri)	125.6	137.5	130.2	121.0	113.9	118.4	114.3	118.8	99.1	118.4	89.3	121.4	137.5	120.0
Transmission	190.9	196.2	183.2	198.5	181.6	173.6	161.9	172.5	166.9	176.6	178.0	180.8	198.5	178.9
Irrigation - Schedule 41	86.3	72.0	78.3	13.2	2.5	2.3	2.6	2.6	6.1	16.1	51.6	77.8	86.3	61.7
Total	**2,535.9**	**2,363.5**	**2,416.1**	**2,281.8**	**2,352.2**	**2,554.9**	**2,547.0**	**2,374.6**	**2,156.4**	**2,033.2**	**1,962.6**	**2,419.7**		**2,415.5**

Notes:

1) Source: Docket No. UE 399, PacifiCorp Exhibit PAC/1108, Meredith/Cust Data 1 Tables.

2) The "Sum of Weighted Ave Peak" figures were derived separately by PacifiCorp.

3) The above figures exclude lighting Schedules 53 & 54.