WUTC DOCKET: UE-230172 & UE-210852
EXHIBIT: RMM-1T
ADMIT ☑ W/D ☐ REJECT ☐

Exh. RMM-1T
Docket UE-230172
Witness: Robert M. Meredith

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-230172

PACIFICORP

DIRECT TESTIMONY OF ROBERT M. MEREDITH

March 2023 (REFILED April 19, 2023)

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ATTACHED EXHIBITS

Q. Please state your name, business address, and current position with PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company).

A. My name is Robert M. Meredith. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing and Tariff Policy.

I. QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science degree in Business Administration and a minor in Economics from Oregon State University. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 18 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over 12 years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In February 2022, I assumed my current position.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified for the Company in regulatory proceedings in Washington, California, Idaho, Oregon, Utah, and Wyoming.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present the Company’s functionalized class cost of service study, proposed revenue allocation of the requested revenue increase and proposed rates.

Q. What is the proposed change in rates requested by the Company in this case?

A. The Company is requesting a $26.8 million or 6.6 percent increase to rates for the first year of its rate plan with pricing becoming effective March 1, 2024. For the second year of the rate plan, the Company is requesting an additional $27.9 million or 6.5 percent increase to rates with pricing becoming effective March 1, 2025.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- First, I present the results of the cost of service study, including a description of the procedures used in the preparation of the study.
- Second, I present the Company's proposed rate spread, which is the allocation of the rate increase to the customer rate schedules.
- Third, I propose elimination of the Company's decoupling mechanism.
- Fourth, I propose an interim successor customer generator program for net metering.
- Fifth, I introduce proposed revisions to the tariffs.
- Lastly, I explain the Company's calculation of normalized present revenues, which are used for the calculation of the revenue requirement.

III. CLASS COST OF SERVICE STUDY

Q. What are the results from the class cost of service study?

A. Exhibit No. RMM-2 shows the results from the embedded class cost of service study. The study is based on the Company's annual results of operations for Washington presented in the direct testimony and exhibits of Company witness Sherona L. Cheung for the proposed first year of the rate plan. A cost of service study was not prepared for the second year of the rate plan. Exhibit No. RMM-2 summarizes, both by customer group and function, the results of the study for the 12 months ended June 30, 2022. Page17 shows the results at the Company's earned rate of return for that period. Page 18 shows the results using the target rate of return based on the requested $26.8 million revenue requirement increase for the first year of the rate plan.

Exhibit No. RMM-3 shows the cost of service results in more detail by class and function. Pages 1 and 2 summarize the total cost of service by class, pages 3 through 16 contain summaries by class for each major function, and pages 17 through 19 contain a summary by class and major function on a unit cost basis.

Exhibit No. RMM-4 shows the detailed results of the cost of service study using the methodology approved by the Washington Utilities and Transportation Commission (Commission) in the investigation into electric cost of service studies, docket UE-170002 (COS Rulemaking) and consistent with the rules resulting from that proceeding, Washington Administrative Code (WAC) Chapter 480-85. The cost of service model is also generally consistent with the cost of service study that the Company used in the Company's last general rate case, docket UE-191024 (2020 Rate Case).

A. Description of Procedures

Q. Please explain how the cost of service study was developed.

A. In accordance with WAC 480-85-060, the study employs a three-step process generally referred to as functionalization, classification, and allocation. These three steps recognize the way a utility provides electric service and assigns cost responsibility to the customer groups for whom those costs are incurred. A detailed description of the Company's functionalization, classification, and allocation procedures and the supporting calculations for allocation factors are contained in pages 1 through 9 of Exhibit No. RMM-4.

Q. Please describe functionalization and how it is used in the cost of service study.

A. Functionalization is the process of separating expenses and rate base items according to five utility functions—generation, transmission, distribution, customer, and common.

- The generation function consists of the costs associated with power generation, including wholesale purchases and sales.
- The transmission function includes the costs associated with the high voltage system used for the bulk transmission of power from the generation source and interconnected utilities to the load centers.
- The distribution function includes the costs associated with all the facilities that are necessary to connect individual customers to the transmission system. This includes distribution substations, poles and wires, line transformers, service drops, and meters.
- The customer function includes the costs of meter reading, billing, collections, and customer service.
- The common function includes administrative and general costs along with cash working capital.

Q. Describe how the classification process is used in the cost of service study.

A. Classification identifies the component of utility service being provided. The

Company provides service that includes at least three different cost components: demand-related, energy-related, and customer-related. Demand-related costs are incurred by the Company to meet the maximum demand imposed on generating units, transmission lines, and distribution facilities. Energy-related costs vary with the output of kilowatt hours (kWh). Customer-related costs are driven by the number of customers served.

Q. Please describe how the Company determines cost responsibility among customer classes.

A. After costs have been functionalized and classified, the next step is to allocate them among the customer classes. This is achieved by the use of allocation factors that specify each class's share of a particular cost driver, such as system peak demand, Washington distribution system peak demand, energy consumed, or number of customers. The appropriate allocation factor is then applied to the respective cost element to determine each class's share of the costs.

Q. How are generation costs classified between demand and energy?

A. The Company's generation-related resources must provide the capacity to meet peak load (demand) and the energy needs of its customers throughout the year. The Company uses the Renewable Future Peak Credit method to determine the proportion of fixed generation costs that are demand related. In this proceeding, the calculation results in 74 percent of generation costs classified as demand-related and the remaining 26 percent of costs classified as energy-related. The variable costs within the generation function, which include costs such as fuel, purchased power, and sales for resale, are classified as energy related.

Q. Please describe how the Renewable Future Peak Credit value was developed.

A. Exhibit No. RMM-5 shows the calculation of the Renewable Future Peak Credit value. The Renewable Future Peak Credit value was developed by calculating the costs of the lowest cost renewable energy generation source and storage resource considered in the Company's 2021 integrated resource plan (IRP). Accordingly, to determine the demand component of the Renewable Future Peak Credit method, the lowest cost storage resource of a 50 megawatt (MW), 200 megawatt hour (MWh) lithium-ion battery system was used. The cost to charge the system, including losses due to system efficiency, was used to determine the fixed cost per kW attributed to the demand cost of the credit.

The lowest cost renewable energy generation source is a 200 MW, 43.6 percent capacity factor wind resource located in Wyoming. To determine the energy component, the fixed cost per kW of the Wyoming wind resource was first multiplied by the quotient of the PacifiCorp system load factor and output capacity factor. This quotient is listed as the total kW capacity required, since this is the quantity of nameplate capacity that would be needed to produce the same energy as one kilowatt of PacifiCorp system load on an annual basis. The portion of cost attributed to capacity contribution, which is based on the cost of storage, was subtracted from the total fixed costs to yield the total energy related cost. Dividing the total energy cost and demand cost by the sum of both costs gives the demand and energy components of the Renewable Futures Peak Credit to be used in the classification of fixed Generation function costs. The calculation results in a classification of fixed generation costs of 74 percent to demand and 26 percent to energy.

Q. How are generation costs allocated?

A. The demand-related portion is allocated using class loads coincident with the Company's highest 12 monthly retail system peak loads net of renewable output. The energy-related portion is allocated using class annual MWh adjusted for losses.

Q. How are transmission costs classified and allocated?

A. Transmission costs are classified as demand-related and are allocated using class loads coincident with the Company's 12 monthly PacifiCorp system peaks.

Q. How are distribution costs classified and allocated?

A. Distribution costs are classified as either demand-related or customer-related. In this study, meters, services, and transformers are considered customer-related, with all other costs considered demand-related. Distribution substations and primary lines are allocated on class loads coincident with the Company's highest Washington distribution system peak in the summer and winter seasons. Distribution line transformers are allocated based on the cost to install new transformers multiplied by the number of transformers serving each customer class. For the Street and Area Lighting class, line transformers are allocated on non-coincident peak since assignment of transformers to this class is challenging with the datasets available to the Company. The costs of secondary lines are allocated on 12 monthly non-coincident peaks, but are only allocated to residential, small general service, and street and area lighting customers where line transformers are jointly used by more than one customer. Services costs are allocated to secondary voltage delivery customers only. The allocation factor is developed using the installed cost of new services for different types of customers. Meter costs are allocated to all customers.

The meter allocation factor is developed using the installed costs of new metering equipment for different types of customers.

Q. Please explain how customer accounting and customer service expenses are allocated.

A. Customer accounting expenses are allocated to classes using weighted customer factors. The weightings reflect the resources required to perform activities such as meter reading, billing, and collections for different types of customers. Other customer service expenses are allocated based on the number of customers in each class.

Q. How does the Company allocate administrative and general expenses, general plant, and intangible plant?

A. Most general plant and intangible plant are functionalized and allocated to classes based on generation, transmission, and distribution plant. Administrative and general expenses are functionalized to the Common function. Costs identified as supporting customer systems are considered part of the customer function and have been allocated using customer factors. Coal mine plant is allocated consistent with generation resources.

Q. How are other revenues treated in the cost of service study?

A. Other electric revenues are treated as revenue credits. Revenue credits reduce the revenue requirement that is to be collected from retail customers.

Q. Does the cost of service study include results for partial requirements service on Schedule 47T (customers 1,000 kW and over)?

A. No. Customers on Schedule 47T are not included in the embedded cost of service study because large commercial or industrial partial requirements customers typically have very sporadic loads that vary from day to day and from year to year, producing volatile cost of service results depending on whether or not service has been required during actual peak hours. The Company's practice is to derive prices for this service from rates for full requirements service. Revenue from customers on Schedule 47T is allocated back to other classes as a revenue credit.

IV. RATE SPREAD

Q. How is the Company proposing to allocate the revenue increase to customer classes?

A. Based on the direct testimony and exhibits of Company witness Cheung, the Company's requested base revenue requirement increase in this case is $26.8 million, or 6.6 percent in the first year of the rate plan and $27.9 million, or 6.5 percent in the second year of the rate plan. For the first year of the rate plan, the Company proposes a rate spread that allocates the revenue requirement change to rate schedule classes guided by the results of the cost of service study. Specifically for the first year of the rate plan, the Company proposes to: (1) have no increase for Schedule 24 whose cost of service results indicate it needs a slight decrease; (2) increase rates by half of the average increase (3.3 percent) for Schedule 36 whose cost of service results support a below-average increase; and (3) spread the remaining increase equally to the rest of the rate schedules whose cost of service results support an above-average increase (9.1 percent). For the second year of the increase, the Company proposes applying the 6.5 percent increase on an equal percentage basis to all classes. Table 1 shows the

Company's proposed rate spread compared to the cost of service study results as adjusted upward for the second year increase of the rate plan.

Table 1. Proposed Rate Spread Relative to Adjusted Cost of Service Results

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

*Dedicated Facilities (DF)

Column C shows the percentage increase required from the adjusted cost of service study. Column D shows each rate schedule's current revenues as a percentage of adjusted cost of service. Column E shows the Company's proposed rate spread for the requested increase over both years of the rate plan. Column F shows each rate schedule's proposed revenues as a percentage of adjusted cost of service. Table 1 demonstrates that the proposed rate spread minimizes price impacts on customers while fairly reflecting cost of service and moving each class closer to its cost of service.

Q. Please explain Exhibit No. RMM-6.

A. Page 1 of Exhibit No. RMM-6 shows the effect of the proposed base rate increase, and displays rate schedule numbers and descriptions, customer counts during the test year, MWh of energy consumption during the test year, normalized present revenues for the test year, proposed revenues for both years of the rate plan, and the associated revenue changes expressed in both percentage and dollar terms. Page 2 of Exhibit No.

RMM-6 shows the same information, but broken out by revenue class (residential, commercial, industrial, irrigation, and lighting).

V. RATE DESIGN

Q. What is the Company's rate design goal in this proceeding?

A. The Company's goal for this proceeding is to design rates that are fair, just, reasonable, reflect cost causation principles and promote equitable outcomes for the Company's customers.

Q. How does the Company propose to design rates to implement the proposed revenue increase?

A. The Company's rate design proposals are guided by the cost of service study to reflect costs and to recover the proposed revenue requirement. Pages 1 through 72 of Exhibit No. RMM-6 contain typical bills calculated using both present and proposed prices, as well as the test year units used to calculate the proposed prices for both years of the rate plan.

A. Residential Rate Design

Q. Please describe the Company's proposed rate design for residential customers.

A. The Company proposes splitting the Basic Charge into two separate charges for customers living in single-family and multi-family dwellings. The Company proposes increasing the basic charge from its current level of $7.75 per month to $10.00 for customers who live in single-family dwellings and retaining the current $7.75 per month for customers who live in multi-family dwellings. The Company also proposes to eliminate the inclining tier block structure and replace it with seasonal energy charges. The Company proposes gradually making these structural changes over the two years of the rate plan. The Company also proposes replacing Schedule 18 with a phase-differentiated basic charge.

Q. Has the Company previewed these concepts with its Equity Advisory Group?

A. Yes. In January, the Company shared in-concept the structural changes it was considering for residential customers, including charging a separate basic charge for single-family and multi-family customers, and replacing tiered energy charges with seasonal energy charges. While the Company received feedback in support of the proposed changes, there was a concern raised that eliminating a tiered rate structure could benefit larger homes at the expense of others. I believe the Company's residential pricing proposals, taken as a whole, better align with cost causation and will be more equitable for customers. From an energy usage perspective, a larger home may be very similar to a multi-generational household with a large number of people living together using electric space heating. As discussed later in my testimony, the combination of residential pricing structural changes that the Company proposes will result in a lower increase for customers who receive low-income bill assistance.

Q. Why is the Company proposing an increase in its basic charge for most residential customers?

A. At $7.75 per month, the Company's present basic charge falls far short of recovering the fixed costs of local distribution infrastructure and customer service. Making movement towards a cost-based basic charge helps the Company keep energy charges more affordable for its customers. Given a fixed level of revenue to be collected from all residential customers, an increase in the basic charge will correspondingly lower energy charges.

Q. What costs should be reflected in the residential basic charge?

A. The residential basic charge should include the fixed costs associated with customer service, billing, and the local infrastructure that is located geographically close to the customer and is dedicated to serving one or a small number of customers. Specifically, it is appropriate for the residential basic charge to recover the full costs as shown in the cost of service study for the Customer function and the portions of the Distribution function that are related to meters, services or service drops and line transformers.

Q. What is the basis for a multi-family basic charge that is lower than the basic charge for single-family customers?

A. The Company used the difference in the cost of line transformers between single- and multi-family customers to inform the difference in its proposed residential basic charge. Transformer costs are largely driven by the number of customers on average who utilize a shared transformer. On average for the entire residential class, 3.3 customers are served from a transformer. This value is significantly different for multi-family and single-family customers. On average, 2.9 single-family residential customers are served by a transformer compared to 9.1 multi-family customers per transformer. In general, customers who dwell in multi-family buildings live in more dense habitations and there are economies of scale related to the cost of stepping down voltages to a level they can use relative to single-family where more equipment must be installed to serve a less dense population.

Q. What basic charge does the Company propose for single- and multi-family customers?

A. The Company proposes increasing the single-family basic charge to $10.00 per month and leaving the multi-family basic charge at its current level of $7.75 per month. The support for these basic charges can be found on Exhibit No. RMM-7. Exhibit No. RMM-7 shows a breakout per customer for each of the cost categories I identified as belonging in the basic charge. It shows these values in total and also separate breakouts for single-family and multi-family customers with different line transformer costs that reflect the difference in the customers per transformer for these two groups. While a basic charge of $13.40 could be justified for single-family customers, the Company is only proposing $10.00 for this proceeding. With keeping the multi-family basic charge at $7.75, the $2.25 differential is very close to the $2.26 difference in cost.

Q. Is recovering line transformers in the basic charge appropriate?

A. Yes. There are several reasons why the cost of line transformers should be recovered in the basic charge. First, the cost of line transformers is unaffected by changes in customer energy usage. Transformers are usually set at the time of construction and are designed to provide a sufficient level of capacity for the needs of a small group of customers that are located close-by. Transformers come in standard sizes and are not available in a continuous and granular range of capacities. For example, the smallest sized transformer is 10 KVA. The next largest size is 25 KVA or two and a half times larger. The next largest single-phase transformer is 50 KVA, or twice as large. When designing the electric infrastructure for a community of residential homes, appropriately sized transformers are selected to ensure that ample capacity is available to serve the different customers connected to them including some level of potential load growth. While a customer's conservation efforts may lessen the strain on upstream utility facilities and consequently could defer the need to re-conductor a line, upgrade a substation, or build new generating plants, these conservation efforts would not lower the Company's cost of line transformers.

Second, the cost of a transformer does not increase proportionately to overall customer size. A pole mounted 25 KVA transformer costs about $3,713 to install. A pole mounted 50 KVA transformer that has twice the capacity costs about $4,494 to install, an increase of only approximately 21 percent. Because of these economies of scale, a large factor in the overall cost of the Company's line transformers is the total number of transformers deployed. The cost to provide this equipment is consequently not driven entirely by size, but by the number of customers and their geographic dispersion.

For the residential class, customer size may be particularly unimportant in driving the Company's cost of line transformers. This is due to the way line extension allowances work. When service is provided to residential customers, the portion, if any, of the cost to connect to the Company's system for which they are responsible, otherwise known as the line extension allowance, is a fixed dollar amount. If the cost to connect a residential customer exceeds their line extension allowance,[1] they will pay for that additional cost. For a very large residential customer who requires a much larger than average transformer, that customer would likely not have had a

[5] *See* Rule 14 of the Company's tariffs. The line extension allowance for residential customers is currently set at $3,150.

sufficiently large line extension allowance and would have paid for the incremental cost of the larger transformer serving it upfront.

Finally, line transformers typically serve a small number of customers and are located geographically close to the customers they serve. On average, 3.3 residential customers are served by a transformer. Line transformers should not be lumped together with generation, transmission and upstream distribution costs that are often included in the energy charge for residential customers. Generation, transmission, and upstream distribution facilities are used by many customers, are often located far away from a customer's location and are consequently a more fungible resource that can more flexibly serve customers as they come and go and as loads rise and fall. Line transformers are more similar to meters and service drops, because they serve only one or a very small number of customers and are located close to customers. They are inflexible and cannot be easily redeployed to other customers as loads fluctuate.

Q. What is the effect of increasing the basic charge?

A. Given a fixed level of revenue to be collected from all residential customers, an increase in the basic charge will correspondingly lower energy charges.

Q. How does the Company's basic charge compare to other utilities in the state?

A. Table 2 below shows how the Company's current basic charge compares with the other electric investor-owned utilities (IOUs) in the state as well as nearby local publicly owned utilities.

Table 2. Residential Basic Charges from Other Utilities

Utility Name	Residential Basic Charge
Avista (Washington)	$9.00
Benton PUD	$19.16
Chelan County PUD	$12.95
Columbia REA	$47.00
Franklin PUD	$34.00
Grant County PUD	$16.73
Klickitat County PUD	$22.33
Puget Sound Energy	$7.49
Average Single-Family Rate	**$21.08**

The Company's current basic charge is well below the $21.08 average of the other eight utilities examined in Table 2. Even with the Company's proposed $10.00 basic charge for single-family customers, only two other utilities would have lower basic charges.

Q. Distinguishing between residential customers who dwell in single and multi-family homes is a new feature for the Company's tariffs. How will this difference be defined?

A. The Company's proposed definition of a multi-family home will be the same as defined in its Electric Service Requirements Manual (ESR), which is a resource that clarifies electric service requirements for the Company's customers prior to and during construction. The ESR defines a multi-family dwelling as "a building that contains three or more dwelling units."[2] On tariff Rule 1 - Definitions, multi-family home will be defined as "a residential building that contains three or more dwelling units", and single-family home will be defined as "a residential building that contains less than three dwelling units."

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[2] *See* PacifiCorp's 2022 Electric Service Requirements Manual at xii, available at https://www.pacificpower.net/working-with-us/builders-contractors/electric-service-requirements.html.

Q. How are residential energy charges currently structured?

A. Residential energy charges use what is called an inclining block or tiered rate structure where energy usage up to a specific threshold per month receives a lower price and successive energy consumption is priced at a higher rate. Presently, the first 600 kWh in a month are 8.276 cents per kilowatt hour and all additional kWh are 11.198 cents per kilowatt hour.

Q. What are the potential benefits of an inclining block structure?

A. The inclining block rate structure is often referred to as a tool for encouraging customers to save energy. The theory is that the first block covers some basic level of usage at a lower rate to help keep the overall bill affordable for customers and a second and possibly third block with a higher rate makes incremental energy usage more expensive. For a customer with usage in the higher tiers, making energy efficient choices like installing a heat pump water heater will yield greater savings than would have been achieved under a flat energy charge rate design. Inclining blocks are also sometimes considered more progressive for low-income users, who theoretically have lower usage and would consequently pay a lower average price.

Q. Is the inclining block structure still an appropriate rate design for residential customers?

A. No, not in light of changes in the electric industry and the likelihood of further evolution in the energy landscape of the future. While well intentioned, tiered rates produce more problems than they solve. Tiered rates are unfair, are not economically justified, and create perverse incentives. In addition, tiered rate structures can be a source of confusion for residential customers.

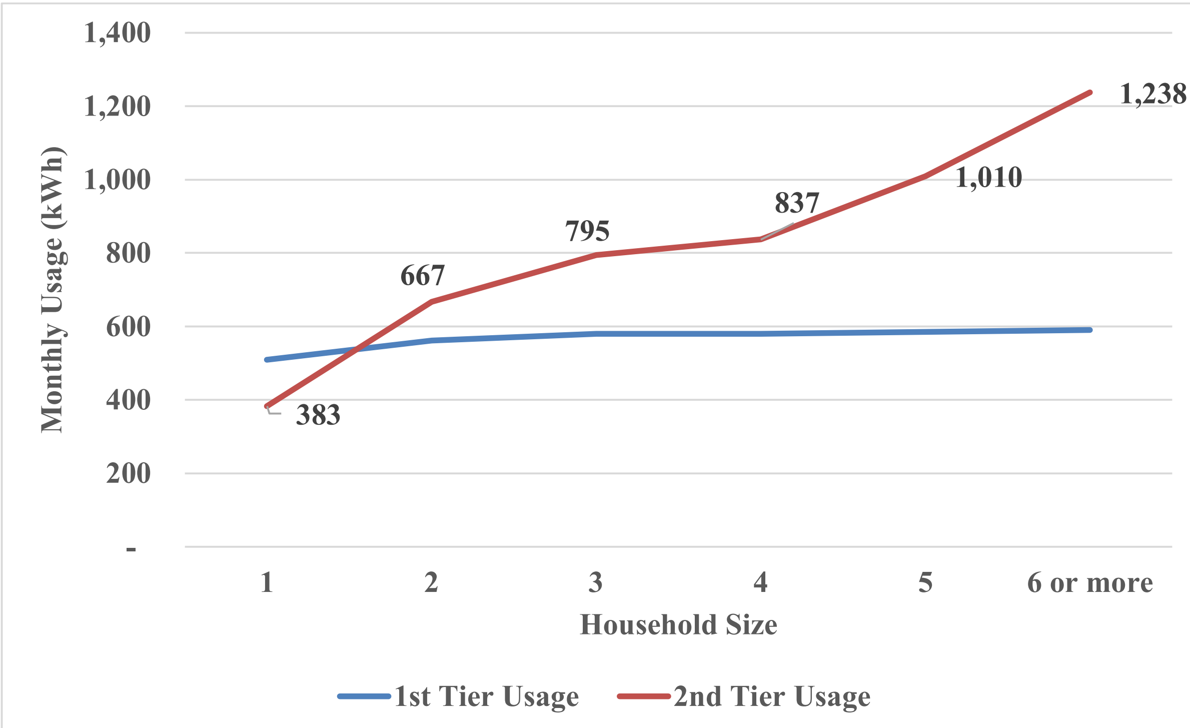
Q. How are tiered rates unfair?

A. Charging higher prices for greater usage in a given month arbitrarily benefits some customers at the expense of others. Customers who heat their home with natural gas or a woodstove benefit and those who choose to heat their home with electricity or otherwise do not have access to natural gas pay more. A bustling, multi-generational household with a large number of people living under one roof will have a higher power bill and the person living alone in an apartment will pay less. A customer who chooses to buy an electric vehicle and charge it from home is likely to fall into the second block and pay more to fuel that vehicle and another customer who keeps their internal combustion engine vehicle will pay a lower average price. Effectively, inclining block rates unfairly reward some customers and punish others, often for reasons outside the customer's control or in ways that incentivize behaviors that are at odds with changes in energy policy.

Q. Do you have any evidence that larger households and customers who heat their homes with electricity end up with more usage priced at the higher cost second block?

A. Yes. In 2021, the Company conducted an email survey of its customers and collected end use and demographic information from participants. From examining the data from the Company's 2021 residential customer survey, the average usage that occurred in the second block was higher for larger households. Figure 1 below shows these differences:

Figure 1: Average Monthly Tier Usage by Household Size from PacifiCorp's 2021 Residential Customer Survey



The Company's survey results also showed that customers who used electricity as their primary fuel for heating their home had almost double the usage in the second block on average. Table 3 below shows how usage compares for survey respondents who answered that they use electricity as the fuel for their main source of heating equipment and those who use other fuels:

Table 3: Average Monthly Usage by Primary Heating Fuel from PacifiCorp's 2021 Residential Customer Survey

Primary Heating Fuel	Average First Tier Usage (kWh)	Average Second Tier Usage (kWh)
Electricity	567	836
Other (natural gas, propane, oil, wood/pellets)	542	464

Q. Please describe why tiered rates are not economically justified.

A. There is no reason why after using 600 kWh in a given month that the next kilowatt hour consumed by a customer should cost more. The timing of energy consumption, both seasonally and during different hours, can affect the utility's cost of providing kilowatt hours to the customer. The load factor or the effective utilization of kilowatt hour consumption relative to peak kilowatt demand can also change the average cost of providing energy. However, there is nothing special about additional overall usage in a monthly billing period that makes it more expensive for the utility to produce that next kilowatt hour of electricity.

Q. How do tiered rates create perverse incentives?

A. Relative to a flat energy charge rate structure, inclining block prices encourage customers to switch fuels to natural gas. Cascade Natural Gas Corporation (Cascade), the natural gas provider who is located in and around the Company's service area and is the most likely to serve the Company's customers, does not use an inclining block rate structure for its residential customers for volumetric gas consumption. In other words, the price for each therm that a Cascade customer purchases is flat and does not become more expensive with greater usage within a monthly billing period. As the result of its rate structure, PacifiCorp customers are sent an inaccurate price signal with respect to the actual incremental cost difference of heating their home with natural gas versus electricity. Such outcome is inconsistent with the Washington's decarbonization policies, including the Climate Commitment Act that requires steep reduction in greenhouse gas emission for natural gas companies.[3]

Another unfavorable result of tiered rates is that they make residential transportation electrification less attractive. While a customer can at this time still experience "fuel" savings with charging their electric vehicle at the higher second tier price relative to purchasing gasoline, as more costs get pushed into the customer's incremental cost of energy on the second tier, the economic rationale to choose an electric car is weakened.

Q. Do tiered rates help low-income customers by making a modest level of usage tied to a customer's basic needs more affordable?

A. Not necessarily. It is true that overall average monthly usage tends to increase with income, but it is also true that the overwhelming majority of PacifiCorp's lower income customers use more than 600 kWh a month on average. Table 4 below highlights some of the Company's findings regarding energy usage and income from its 2021 residential survey:

[3] RCW 70A.45.020; *see also In the Matter of Chair Danner's Motion to Consider Whether Natural Gas Utilities Should Continue to Use the Perpetual Net Present Value Methodology*, Docket No. UG-210729, Order 01 ¶ 25 (October 29, 2021) ("In 2021, the legislature amended RCW 80.28.074 to clarify that advancing the availability of natural gas services to Washington residents is no longer state policy. Additionally, as several commenters noted, the legislature directed that Washington's energy code be revised to make new construction more efficient, which will result in new homes and buildings using less natural gas than existing structures currently use.").

Table 4. Usage Characteristics and Household Income from PacifiCorp's 2021 Residential Customer Survey

	Income Level		
Average Monthly Usage Level	**Below $60,000**	**$60,000 to $74,999[1]**	**$75,000 and greater**
0 - 600 kWh	18%	12%	11%
601 - 1,200 kWh	43%	42%	37%
1,201 kWh and over	39%	46%	52%

Average Monthly Usage (kWh)	1,129	1,233	1,347

	Income Level		
	Below $60,000	**$60,000 to $74,999[1]**	**$75,000 and greater**
Natural Gas Used as Main Fuel for Heating	27%	37%	43%
Sample Size	1,242	296	882

Note - The median household income in Yakima, WA in 2021 was $61,012.
https://www.deptofnumbers.com/income/washington/yakima/

According to the Company's survey results, about 82 percent of customers with household incomes less than $60,000 per year have average monthly usage greater than 600 kWh a month. The survey results also show that lower income households are much less likely to use natural gas as their main fuel for heating. Customers who heat their homes with electricity will have a much harder time staying warm and keeping kilowatt hour consumption in the winter below the 600 kWh monthly threshold than customers who use gas. Table 4 shows that only 27 percent of PacifiCorp households making less than $60,000 per year use natural gas as their main fuel for heating. In contrast, customers making $75,000 and greater are far more likely to use gas with 43 percent reporting that they use natural gas as their main fuel to heat their homes. The tiered rate structure makes energy bills less affordable for many lower income customers, particularly when they use electricity to heat their home. The average monthly usage for survey respondents making less than $60,000 per year who do not use natural gas as their primary heating fuel during the peak heating season in the billing months of December, January, and February, was 1,821 kWh—nearly three times the 600 kWh first tier threshold.

Q. What does the Company propose for residential customers instead of the inclining tiered rate structure?

A. In light of the inequities that the tiered rate structure presents, and the need for residential price signals to support the state's decarbonization goals, the Company proposes replacing the inclining block tiered rate structure with seasonal pricing. As opposed to tiered rates that make energy prices vary based upon monthly household usage, seasonal rates would make energy rates lower in winter months and higher in summer months. This structure for residential charges would better reflect the economics of energy consumption and would treat customers more fairly, regardless of household size or heating fuel used. The Company proposes that the differential between the energy pricing in the summer season months of June through September be 1.921 cents per kWh higher than energy pricing during the winter season months of October through May. Specifically, the Company proposes that the tiered rate differential be gradually reduced and transitioned to seasonal rates over the two-year rate plan with a 50 percent flattening occurring and half the proposed 1.921 cents per kWh seasonal differential being applied in the first year price change, and the remaining transition occurring in the second year of the rate plan.

Q. What is the cost justification for differentiating residential rates based upon season?

A. Seasonal pricing reflects the fact that wholesale market prices are often higher during the summer season. Examining the most recent official market price curve that was used in this rate case (PacifiCorp's December 30, 2022, Official Forward Price Curve), the average price at the Mid-Columbia hub between the months of June through September is forecast to be about 3.842 cents per kWh higher during the two-year price effective period of the rate plan from March 2024 to February 2026 than during the months of October through May in this same period. The Company proposes using half this value, or a 1.921 cents per kWh differential, between its summer and winter residential energy charges.

Q. How will seasonal rates send better price signals that encourage wise use of the system?

A. By charging cost-based prices that vary by season of the year, the Company's proposed rate structure will encourage customers to prioritize energy efficiency in the higher cost of service summer period. This could include installing a heat pump water heater or choosing a high-efficiency air conditioner. At the same time, the Company's rates will no longer disincentivize heating homes with electricity as the current tiered rate structure does.

Q. How do customers' share of usage by season vary by income level?

A. From examining the results from the Company's 2021 Residential Email Survey, it found that lower income respondents tended to have a greater share of their overall usage occurring during the winter season months of October through May. Table 5 shows the winter season share of overall usage for different income levels:

Table 5. Winter Season Share of Usage and Household Income from PacifiCorp's 2021 Residential Customer Survey

	Income Level		
	Below $60,000	**$60,000 to $74,999[1]**	**$75,000 and greater**
Proportion of Usage in Winter (October-May) Months	70.3%	68.0%	66.3%

Note - The median household income in Yakima, WA in 2021 was $61,012.
https://www.deptofnumbers.com/income/washington/yakima/

Q. How will the Company's proposed prices impact residential customers?

A. Exhibit No. RMM-6 shows how the Company's proposed residential price change would affect the monthly bill for different customer usage levels.

Q. On average, how does the Company estimate that its proposed changes to the rate structure for residential customers will impact customers who are on its Schedule 17 Low Income Bill Assistance program?

A. The Company estimates that on average the base revenue from Schedule 17 before any discounts will increase by 15.7 percent under the Company's proposed residential pricing (by the second year of the rate plan). This compares to the 16.2 percent average increase the Company proposes for all residential customers.

Q. What rate design change does the Company propose for residential customers who receive three-phase service?

A. The Company proposes to replace Schedule 18 with a phase-differentiated basic charge on Schedules 16, 17, and 19. Under this new structure, three-phase customers would pay a basic charge that is $8 higher than what single-phase customers pay each month.

Q. Please describe Schedule 18.

A. Schedule 18 is a rider schedule applicable to all three-phase residential customers. It includes a $1.78 per kW demand charge and $3.50 demand charge minimum, each billed monthly.

Q. Why is the Company proposing to cancel Schedule 18 and charge three-phase residential customers a higher basic charge?

A. A higher basic charge instead of a demand charge and associated minimum charge is easier for customers to understand, simplifies metering, and better aligns with cost causation.

Q. What is the basis for a basic charge for three-phase residential customers that is $8 higher than the basic charge for single-phase customers?

A. Three-phase residential customers typically require the Company to install a three-phase instead of a single-phase transformer. Per Section II.D of the Company's Rule 14 – Line Extensions, customers requesting three-phase service pay for the initial additional capital cost for three-phase facilities. However, the Company must continue to maintain this equipment. $8 per month represents the Company's estimate of the incremental cost to maintain a three-phase transformer. Exhibit No. RMM-8 provides the details behind the Company's calculation.

Q. What is the estimated impact of this change on the Company's revenue from three-phase customers?

A. The Company determined there were 1,049 three-phase customer bills with monthly demands totaling 6,381 kW and monthly minimum bills totaling 596 during the test year. If the Company were to retain the $1.78 demand charge and $3.50 minimum demand charge on Schedule 18, this would produce $13,446 of revenue annually. Replacing this with a $8 higher basic charge produces $8,390, or a decrease in revenue of $5,056.

B. <u>Low Income Customers</u>

Q. What does the Section (2) of the multi-year rate plan legislation, codified in RCW 80.28.425, require for utilities requesting a multi-year rate plan?

A. Section (2) requires the Commission to approve "an increase in the amount of low-income bill assistance to take effect in each year of the rate plan where there is a rate increase" that must at a minimum be double the increase, if any, in each year of the rate plan.

Q. To comply with this requirement of the multi-year rate plan legislation, what change does the Company propose for its Schedule 17 discounts?

A. The Company proposes to increase each of the three discount levels on Schedule 17 so that they will be exactly double the increase in each year. Since the Schedule 17 discounts are already structured as percentages to be applied to the customer's bill, the discount afforded will already naturally increase by 100 percent of the price change that takes effect. Exhibit No. RMM-9 shows how the Company proposes calculating the discount for both years, and Exhibit No. RMM-11 includes Schedule 17 tariff sheets that reflect the Company's proposal.

Q. Do you have any comments regarding the requirement of the multi-year rate plan legislation that low-income bill assistance be increased by double the approved increase?

A. Right now, PacifiCorp has a low-income program that provides for up to 70 percent off a customer's bill. While the level of the discount provided can be increased by double the increase uniformly in this particular rate plan, this requirement could potentially become unsustainable, since there could be a point at which the Company runs out of room to expand its discounts. I do not have a solution for this longer term issue but wish to flag it and simply note that more creativity may be needed to meet this requirement at some point in the future.

C. Schedule 24 – Small General Service

Q. Please provide an overview of the current pricing structure for Small General Service Schedule 24.

A. Schedule 24 has a basic charge, three energy charges, and a demand charge that only applies to monthly usage in excess of 15 kilowatts. Schedule 24 has three declining block energy charges where the first 1,000 kWh is 11.906 cents, the next 8,000 kWh hours are 8.381 cents and all additional kilowatt hours are 7.860 cents. The much higher first tier is helpful at this time, because there is no demand charge for Schedule 24 customers who use less than 15 kilowatts of demand. This higher volumetric rate ensures an appropriate level of cost recovery from smaller Schedule 24 customers who do not have meters capable of recording a demand register.

Q. What changes do the Company propose for Small General Service Schedule 24?

A. The Company proposes changing the rate design in three ways. First, the Company proposes moving the different price components 10 percent closer to the proportions of cost that the cost of service study suggests should be in those categories in each year of the rate plan. Second, the Company proposes fully merging the second and third tier energy charges. In the 2020 Rate Case, the Company proposed and the

Commission approved a partial merging of these two charges. Third, the Company proposes implementing a seasonal energy price differential like the one it proposes for residential customers gradually over the two periods of the rate plan.

When determining the cost categories that should be included in different rate components for Schedules 24, 36, 40, and 48T, each cost component was increased to include an allocation of the Common function. For Schedule 24, the categories related to the basic charge were considered to be the full costs as shown in the cost of service study of the Customer function and the portions of the Distribution function that are related to meters and services. Transformers were not included in the determination of what should be included in the basic charge, because the Schedule 24 rate design has a demand charge that kicks-in after the first 15 kilowatts and a declining block energy charge where the first 1,000 kWh are significantly more expensive. These pricing components are intended to recover fixed costs like transformers. The basic charge was increased each year by a level sufficient to bring the revenue it recovers 10 percent closer to the adjusted cost of service for the Customer function and the portions of the Distribution function that are related to meters and services. All other costs are considered energy and demand charge related and were increased proportionately to make up the remaining revenue increase required.

Schedule 24 has three declining block energy charges. Like inclining block tiered rates used in the current residential rate structure, declining block tiered rates create additional complexity and send confusing price signals. As discussed previously, the much higher first tier is useful, because many smaller Schedule 24 customers do not have meters capable of recording a demand register. However, the

Company proposes eliminating the difference between the second and third tier prices.

The Company proposes applying the same 1.921 cent per kWh seasonal differential to energy charges that it recommends for residential customers over the two steps of the rate plan with half of the differential taking effect in the first year and the full differential taking effect in the second year. The Company proposes making this change for Schedule 24 for the same reasons it is proposing seasonal energy pricing for residential customers. Like the residential class, Schedule 24 is a relatively more temperature sensitive class. The Company is not at this time recommending seasonal pricing for other non-residential classes, because their loads are less driven by heating and cooling and because the Company is concerned about how such a change could impact industries in the Company's service area that are tied to agriculture.

Q. What other change does the Company propose for Small General Service Schedule 24?

A. The Company proposes adding a time of use option for Schedule 24 that would have the same on-peak period as residential time of use option Schedule 19 of 6am to 8am and 4pm to 10pm from October through May and 2pm to 10pm from June through September. This new time of use option would employ the same 3.060 cents per kWh surcharge for on-peak usage and credit of -2.245 cents per kWh for off-peak usage as Schedule 19, and would have a $2 per month fixed metering fee to recover the cost of a meter that can measure time-varying energy.

Q. What are the estimated bill impacts from the proposed rates?

A. Exhibit No. RMM-6 shows monthly billing comparisons for Schedule 24 customers with different consumption levels.

D. <u>Schedule 36 – Large General Service Less than 1,000 kW</u>

Q. What changes are proposed for General Service Schedule 36?

A. The Company proposes that the different rate components for Schedule 36 make a ten percent movement towards alignment with what the cost of service study indicates should be recovered in the different cost categories in each year of the rate plan. The categories related to the basic charge were considered to be the full costs as shown in the cost of service study of the Customer function and the portions of the Distribution function that are related to meters and services. The categories related to the load size charge were considered to be the full costs as shown in the cost of service study of the portions of the Distribution function that are related to poles and conductor, transformers, and substations, the demand-related component of the Transmission function, and approximately 11.5 percent of the Generation function. The rationale behind including about 11.5 percent of Generation function costs in the load size charge is discussed later in my testimony when I discuss the Schedule 48T rate design. The categories related to the demand charge were considered to be the full costs as shown in the cost of service study of demand-related Transmission function costs and the approximate remaining 88.5 percent of demand-related Generation function costs. All other costs are considered energy charge related. The Company also recommends that the first and second tier energy prices be eliminated.

Q. What are the estimated bill impacts from the proposed rates?

A. Exhibit No. RMM-6 shows monthly billing comparisons for Schedule 36 customers with different consumption levels.

E. <u>Schedule 40 – Agricultural Pumping Service</u>

Q. What changes are proposed for General Service Schedule 40?

A. The Company proposes that the different rate components for Schedule 40 make a ten percent movement towards alignment with what the cost of service study indicates should be recovered in different cost categories in each year of the rate plan. The categories related to the annual load size charge were considered to be the full costs as shown in the cost of service study of the Customer function, the portions of the Distribution function that are related to meters, services, transformers, poles and conductor and substations and the Generation and Transmission function that are related to demand. All other costs are considered energy charge related.

Q. What are the estimated bill impacts from the proposed rates?

A. Exhibit No. RMM-6 shows annual billing comparisons for Schedule 40 customers with different consumption levels.

F. <u>Schedule 48T – Large General Service – 1,000 kW and Over</u>

Q. What changes does the Company propose for General Service Schedule 48T?

A. The Company proposes that the different rate components for Schedule 48T make a ten percent movement towards alignment with what the cost of service study indicates should be recovered in different cost categories in each year of the rate plan. The Company also proposes that a new category of prices be added to the tariff that would be applicable to any large customers that would take service from the Company at the transmission voltage level.

Q. How were the proposed prices for Schedule 48T set?

A. The Company proposes that the different rate components for Schedule 48T make a ten percent movement towards alignment with what the cost of service study indicates should be recovered in different cost categories in each year of the rate plan. The categories related to the fixed component of the load size charge are considered to be the costs as shown in the cost of service study of the Customer function and the portions of the Distribution function that are related to meters and services. The categories related to the per kilowatt load size charge are considered to be the full costs as shown in the cost of service study of demand-related Transmission function costs, approximately 11.5 percent of demand-related Generation function costs, and the portions of the Distribution function that are related to poles and conductor, transformers, and substations. The approximate 11.5 percent of demand-related Generation function costs that were assigned to the load size charge represent the proportion of fixed costs that are related to the Company's planning reserve margin. In the Company's long-term planning that takes place through its integrated resource plan process, the Company plans for its peak load plus a 13 percent planning reserve margin to account for uncertain events and operating reserve requirements.[4] Recovering a portion of fixed Generation function costs based on the portion of capacity planning that is related to the planning reserve margin[5] through the load size

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[4] *See* PacifiCorp's 2021 Integrated Resource Plan, Volume 1 at page 135 and 152. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

[5] Dividing 13 percent by 113 percent is approximately 11.5 percent.

charge is reasonable since unknown events can potentially cause times that would otherwise be considered off-peak to become operationally critical for the Company, and the load size charge is a more stable demand-based charge that is not bound by on-peak times.

The categories related to the demand charge were considered to be the full costs as shown in the cost of service study of approximately the remaining 88.5 percent of the Generation function that are related to demand. All other costs are considered energy charge related. The existing 0.933 cents per kilowatt hour differential between the prices for the on- and off-peak were used to set the time-of-use energy charges.

Q. Why is the Company proposing to include pricing for transmission voltage delivery within its Schedule 48T tariff?

A. Presently, Schedule 48T only includes pricing for secondary voltage delivery, primary voltage delivery, and primary voltage delivery for customers with dedicated facilities whose load size is greater than 30 megawatts. While the Company does not presently have any transmission voltage delivery customers in its Washington service area, it is a potential option for prospective customers and the Company gets inquiries about service at this level. Including pricing for transmission voltage delivery will enhance transparency for prospective customers and help them make an informed decision about their service.

Q. How did the Company calculate pricing for Schedule 48T transmission delivery service?

A. To develop pricing for a transmission delivery voltage category, the Company took the dollars that the Company proposes to allocate to the different cost categories for Schedule 48T secondary and primary, removed the cost of service for distribution substations, poles and conductor, transformer and service drop and adjusted the remaining costs down by the difference in line losses estimated for Schedule 48T and for transmission delivery voltage. The Company then set the basic charge at the same level as it proposes for Schedule 48T dedicated facilities. This adjustment sets a higher basic charge to better reflect the significant fixed costs associated with serving a large transmission delivery voltage customer. The other costs were then divided by Schedule 48T billing units to produce proposed transmission voltage pricing that is consistent with other Schedule 48T customers, but reflects the difference in cost from not requiring service from distribution facilities and experiencing lower line losses.

Q. Does the Company propose any changes to the language in the Schedule 48T tariff?

A. Yes. On the second page of Schedule 48T, there is a note that explains how the load size is calculated and reads "kW Load Size, for the determination of the Basic Charge, shall be the average of the two greatest non-zero monthly demands established any time." Previously, there had been a conclusion to this sentence that read "during the 12-month period which includes and ends with the current billing month." This ending was inadvertently omitted by the Company in a past tariff filing. The Company requests that a housekeeping change be made so that the clarifying language for the load size is added back into the tariff.

Q. What are the estimated bill impacts from the proposed rates?

A. Exhibit No. RMM-6 shows monthly billing comparisons for Schedule 48T customers with different consumption levels.

G. <u>Schedule 47T – Large Partial Requirements Service</u>

Q. What does the Company propose for Schedule 47T?

A. As in previous rate cases, the Company proposes that the prices for Schedule 47T continue to be based on Schedule 48T's prices.

H. <u>Lighting Schedules</u>

Q. What does the Company propose for the lighting class composed of Schedules 15, 51, 53, and 54?

A. The Company proposes an equal percentage increase to each of the prices in these schedules by the same price change requested for the class in each year of the rate plan. For Schedule 51, the Company proposes eliminating the Decorative Series lighting price and merging it with Functional Lighting, since only two lamps are presently on it. The Company also proposes removing listed per-lamp pricing for customer-owned street lighting service on Schedule 53 and moving these lamps to per-kWh charges for consistency.

I. <u>Decoupling</u>

Q. Please provide some background on the Company's decoupling mechanism.

A. The Company currently operates a decoupling mechanism for its Washington service area. The mechanism is a program that decouples a significant level of the Company's Washington revenue from its energy sales. The goal of the mechanism is to increase the stability of revenue by ensuring it stays at levels consistent with what the

Commission allowed in the most recent general rate case, even if energy sales fluctuate. The mechanism is currently the only one the Company has in its six-state service area. The Company proposed its decoupling mechanism in its limited-issue rate case filed on November 25, 2015 (docket UE-152253). In the Company's general rate case filed in 2014, docket UE-140762, the Commission invited a proposal from PacifiCorp to implement a decoupling mechanism similar to those implemented by Puget Sound Energy and Avista Corporation.[6] The rationale for the proposed decoupling mechanism was to provide the Company better fixed cost recovery in light of changes in usage due to weather or energy efficiency.

The Commission ultimately approved a pilot mechanism with a duration of five years. The Commission ordered the Company to, at the end of the third year, evaluate the effectiveness of the mechanism. In its 2020 Rate Case, the Company proposed and the Commission approved some refinements to the mechanism that took effect on January 1, 2021. In August 2021, the Company filed its decoupling mechanism evaluation, which is included in this proceeding as Exhibit No. RMM-10. The evaluation made some recommendations to improve the mechanism that the Commission ultimately approved. When the Commission was considering these recommendations during the public meeting held on December 9, 2021, Public Counsel recommended eliminating the mechanism, and the Company indicated that it did not oppose this. The Commission declined to eliminate the mechanism, but indicated that this could occur in a general rate case.[7]

[6] *WUTC v. PacifiCorp*, Docket No. UE-140762 et al., Order 08 at 94, ¶ 222 (March 25, 2015).
[7] Recording of open meeting available at: https://www.utc.wa.gov/documents-and-proceedings/open-meeting.

Q. Does the Company propose eliminating its decoupling mechanism?

A. Yes. The Company proposes eliminating the decoupling mechanism effective March 1, 2024. The Company proposes that the decoupling mechanism deferral period that began on January 1, 2023, would be extended to February 29, 2024, with no further deferrals booked after that time. The earnings test for this elongated period would be the Commission Basis Report for the 12-month period ending December 2023, and a final Schedule 93 rate adjustment that takes into account all triggers and caps would take effect from June 1, 2024, until May 31, 2025. Any residual balances at the end of this time would be erased and Schedule 93 would be cancelled.

Q. Why is the Company proposing to eliminate the decoupling mechanism?

A. One of the primary reasons for enacting decoupling mechanisms has been to remove a perceived revenue throughput disincentive for conservation from the utility, with the idea being that a coupling of earnings and sales creates a disincentive for the utility to pursue reductions in sales that come from energy efficiency efforts. However, in Washington, the Company is already required to pursue all cost-effective conservation measures per I-937, and must meet biennial goals or face penalties. A decoupling mechanism is therefore unnecessary for the Company given this dynamic. Also, given the state's decarbonization goals, a reduction in energy sales is now not always a desired outcome. While cost effective energy efficiency will reduce sales, electrification of transportation and heating will raise sales. Therefore, a decoupling mechanism could in theory be a disincentive for utilities to support electrification efforts. Finally, the passage of the multi-year rate plan legislation ushered in a new era for Washington of performance-based ratemaking for investor-owned utilities.

While specific policies for performance-based ratemaking are still under review in docket U-210590, the Company expects that these policies will better advance Washington state's policy objectives than decoupling. For all of these reasons, the Company believes that the decoupling mechanism has outlived its usefulness and should be eliminated.

J. Interim Net Metering Successor Program

Q. Please provide a summary of the Company's proposal for an interim net metering successor program.

A. The Company proposes Schedule 138, Net Billing Service as a successor program to Schedule 135, Net Metering Service. Schedule 138 will allow customer generators to continue to receive credit for all energy exported to the grid from their generation systems. The Company's current net metering Rate Schedule 135 allows participation until June 30, 2029, or the first date upon which the cumulative generating capacity of net metering systems equals four percent of the utility's peak demand during 1996, or 37.2 Megawatts of capacity. As of January 10, 2023, the capacity of net metering systems in Washington is approximately 29.9 Megawatts and it is anticipated that the generating capacity of net metering systems will exceed the 37.2 Megawatts of capacity within the proposed two-year rate plan. The Company seeks an interim tariff solution to allow for continued customer-generator participation once the cap is reached.

Q. What does the Company want to accomplish with its proposal?

A. The Company's main objective is to put in place an interim Net Billing program structure that will allow customer-generators to continue to participate in generating power and being credited for exporting it back to the grid until a more permanent solution can be implemented.

The Net Billing program would require residential and small commercial customers to take time-of-use service to ensure participants are subject to more accurate price signals. This will help customers make a more informed decision whether to invest in onsite generation facilities and will encourage customers to build and operate their systems in ways that are the most beneficial to the power grid.

The Net Billing program structure will have exported energy credited at 100 percent of the customer's standard retail rate.

Q. Please present the Company's proposed Net Billing tariff.

A. The Company's proposed Net Billing program is set forth in the proposed tariff Schedule 138, Net Billing Service, which is provided in Exhibit No. RMM-11. Energy charges for exported energy to the grid from the customer's generating facility would be credited at 100 percent of retail energy charges and usage taken from the grid would be billed at the rates in the customer's applicable tariff.

Q. How is the Company's proposed Schedule 138, Net Billing Service, different than Schedule 135, Net Metering Service?

A. The Company's proposed Schedule 138 requires residential and small general service customer-generators participating in Net Billing take service on a rate schedule that has time-of-use prices. Differentiated pricing encourages customers to shift their export of energy from the low usage, middle of the day, to the higher value, early evening period. This shift encourages energy production during costly periods when the demand for energy increases rapidly from diminishing solar production and increasing net residential usage. The higher compensation for exported energy during the on-peak periods will encourage customers to find innovative solutions to their energy needs such as building west facing systems which generate more energy later in the day. Along with building generation systems that produce more during on-peak periods, customer generators can achieve more value from their system by shifting consumption to use more of their energy production during high output off-peak periods.

Schedule 138 also provides more definition around the annualized billing period for exported customer-generated energy credits, provides for termination of customer participation on the Schedule under specific conditions, provides more detail on customer aggregation for additional customer meters, and requires a disconnect switch for renewable generating facilities of ten kilowatts or greater and are not inverter-based.

Q. Please describe how the proposed Schedule 138, Net Billing Service, is similar to Schedule 135, Net Metering Service.

A. Schedule 138 contains similar provisions related to safely interconnecting to customer systems. It also grants the customer-generator to aggregate meters and allows for multi-family facilities to distribute benefits to tenants of the facility.

Q. Under the Company's proposed Net Billing program, will export credits ever expire?

A. Yes. The Company's proposed Net Billing program is for customers to offset some or all of their energy bill with onsite generation, not for a customer to become a power producer. To encourage customers to appropriately size their generation systems to match actual usage at the site of the system, the Company proposes that export energy continues to roll over until March of each year. This proposal allows customers a reasonable opportunity to accumulate and use energy to offset actual energy use at the location of the generation system.

Q. Will the exported customer-generated energy offset a customer's entire monthly bill?

A. No. All customers, including those with onsite generation, should be responsible for paying basic charges which are designed to reflect some of the fixed aspects of service like having a meter and getting a bill that are not avoided regardless of how much a customer generates.

Q. Will the Company credit or charge customers for kilowatt-hours that are generated by the customer and consumed on-site?

A. No. Kilowatt-hours generated and consumed on-site will lower the customer generator's imported energy needs from the Company, thereby lowering their electric bill from the standard tariff. There will be no other charges or credits for these kilo-watt-hours under the proposed Net Billing program.

Q. What changes does the Company propose for existing Schedule 135, Net Metering Service?

A. To efficiently transition to the new Net Billing Service successor tariff, the Company proposes to revise Schedule 135 to close it to new applications for service 30 days after the level of accepted applications exceeds the cap and to provide customers with a 12-month period to interconnect with a 6-month extension available upon request for Large Non-Residential Customers. Exhibit No. RMM-11 shows proposed tariff revisions for Schedule 135 with language describing when it will be closed to new applications and this timing. After the cap is reached the Company would provide notice on its customer-generation website and would make a compliance filing reflecting the actual date Schedule 135 would no longer accept new applications. After providing this notice, the Company would accept applications for Schedule 135 up to 30 days following the date that approved applications and installed facilities exceed the cap, with all new applications after the 30-day deadline falling under the interim Schedule 138 program.

The Company also proposes to add a Special Condition to Schedule 135 clarifying that "A Residential Customer submitting an application for service under this Schedule has 12 months from the Customer's receipt of confirmation that the interconnection request is approved to interconnect. Large Non-Residential Customers will be allowed a 6-month extension from the interconnection request to interconnect." This provision will give customers a reasonable amount of time to interconnect their customer generation system after they submit their application and still qualify for Schedule 135.

Q. Should the Schedule 138 program structure remain in place indefinitely?

A. No. The structure of providing credits for exported energy at 100 percent of full retail energy charges is not sustainable long-term and that in the future a more detailed study of the value of exported energy should be conducted that would inform a future export credit rate. The Company therefore proposes that customers only be allowed to submit applications to interconnect under Schedule 138 for a two-year period beginning when Schedule 135 is closed to new applications.

Q. Please summarize your testimony on the proposed interim Net Billing Service.

A. The Company's proposed Net Billing Service will provide customers with the continued opportunity to interconnect renewable generating facilities to the Company's system and be compensated for the energy they provide to the grid. The Net Billing program is fair, just, in the public interest, and provides compensation to customer generators for their output.

K. Proposed Tariffs

Q. Have you included the Company's proposed revised Washington electric tariff schedules in this filing?

A. Yes. Exhibit No. RMM-11 contains revised tariff sheets incorporating the changes proposed for approval in this proceeding. It also includes a housekeeping update to Schedule 80 to add Rider Schedule 99[8] and remove Rider Schedule 94[9].

VI. NORMALIZED REVENUES

Q. Please explain how the Company prepared normalized revenues for the test period in this case.

A. Normalized revenues are the 12-month revenues for the test period with certain adjustments applied to establish a 12-month base period on which to determine revenue requirement. Normalized revenues are developed using the actual billing units for the 12 months in the test period. Billing units include the number of customers, demand measurements (kW), both maximum and by time period such as on-peak, where applicable, energy measurements by block (kWh), and excess kilovolt-amperes reactive (kVar). The Company removes any out of period billing

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[8] See Docket No. UE-220441.
[9] See Docket No. UE-210532.

adjustments from historical billing units and revenues then applies temperature adjustments. Current rates are then applied to all billing units to calculate annualized revenues. Using a full 12-month period for billing units is necessary to capture seasonal variations in customers and usage and to be consistent with the cost of service study that allocates costs using the same 12-month period. This calculation is consistent with the Commission's long-established practice.

Q. Does this conclude your direct testimony?

A. Yes.