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BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant

v.

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

Respondent.

DOCKET UE-230172

RESPONSE TESTIMONY OF DAVID E. DISMUKES, PH.D.
ON BEHALF OF
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT DED-1T

September 14, 2023

RESPONSE TESTIMONY OF DAVID E. DISMUKES

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DOCKET UE-230172

TABLE OF CONTENTS

RESPONSE TESTIMONY OF DAVID E. DISMUKES

EXHIBIT DED-1T

DOCKET UE-230172

EXHIBITS LIST

Exhibit DED-2	Curriculum Vitae of David E. Dismukes
Exhibit DED-3	Comparison of Prior PacifiCorp Rate Increases
Exhibit DED-4	Results of Company Class Cost of Service Study
Exhibit DED-5	Results of Alternative Class Cost of Service Study
Exhibit DED-6	Company's Proposed Rate Spread
Exhibit DED-7	Comparison of Parity Ratios
Exhibit DED-8	Results of Alternative Rate Spread
Exhibit DED-9	Survey of Regional Residential Customer Charges
Exhibit DED-10	Residential Bill Comparison at Different Usage Level

I. INTRODUCTION

Q. Please state your name and business address?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. Please state your occupation and place of employment?

A. I am a Consulting Economist with the Acadian Consulting Group (ACG).

Q. Please describe ACG and its areas of expertise.

A. ACG is a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and located in Baton Rouge, Louisiana.

Q. Do you hold any academic positions?

A. Yes. I am a professor emeritus at Louisiana State University (LSU). Prior to my retirement this past January, I served as a full professor, executive director, and director of policy analysis at the LSU Center for Energy Studies and as a full tenured professor in the Department of Environmental Sciences and the director of the Coastal Marine Institute in the LSU College of the Coast and Environment. I also served as a senior fellow at the Institute of Public Utilities at Michigan State University, where I taught energy regulatory staff and other utility stakeholders about principles, trends, and issues in the electric and natural gas industries. Exhibit DED-2 provides my academic curriculum vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. Have you previously testified before the Washington Utilities and Transportation Commission?

A. Yes. Exhibit DED-2 includes a list of the Washington Utilities and Transportation Commission (Commission) proceedings in which I have testified, a list of all my publications, presentations, pre-filed expert witness testimony in other jurisdictions, expert reports, expert legislative testimony, and affidavits.

Q. Was this testimony prepared by you or under your supervision?

A. Yes. Although my colleagues at ACG assisted me with the research related to the formulation of my opinions, as well as the preparation of my testimony, the opinions are mine alone.

Q. What is the purpose of your testimony?

A. I have been retained by the Public Counsel Unit of the Washington State Attorney General's Office (Public Counsel) to provide expert testimony and opinions to the Commission on a number of regulatory issues implicated by the application of Pacific Power and Light Company (Company or PacifiCorp), including cost of service, rate spread, and rate design.

Q. How is the remainder of your testimony organized?

A. The balance of my testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Proposed Rate Increase
- Section IV: Cost of Service Study
- Section V: Revenue Distribution
- Section VI: Rate Design

- Section VII: Summary of Recommendations

Q. Please identify the exhibits supporting your response testimony.

A. The following Response Exhibits accompany my response testimony:

- Exhibit DED-2: Curriculum Vitae of David E. Dismukes
- Exhibit DED-3: Comparison of Prior PacifiCorp Rate Increases
- Exhibit DED-4: Results of Company Class Cost of Service Study
- Exhibit DED-5: Results of Alternative Class Cost of Service Study
- Exhibit DED-6: Company's Proposed Rate Spread
- Exhibit DED-7: Comparison of Parity Ratios
- Exhibit DED-8: Results of Alternative Rate Spread
- Exhibit DED-9: Survey of Regional Residential Customer Charges
- Exhibit DED-10: Residential Bill Comparison at Different Usage Levels

II. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your Class Cost of Service Study Recommendation.

A. I recommend the Commission adopt the alternative generation plant classification methodology as is illustrated within my alternative Class Cost of Service Study (CCOSS). This alternative methodology corrects the Company's demand and energy allocators, and provides for a more accurate representation of PacifiCorp's generation costs.

Q. What is your rate spread recommendation?

A. First, I recommend that the Commission adopt a revenue distribution that reflects the alternative CCOSS recommendations in my testimony. Second, I recommend that the

Commission adopt a more reasonable revenue distribution allocation method that limits the Rate Year 1 (RY1) rate increase to 1.15 times the system average increase using the following three-step approach:

i. For all classes with parity ratios below 0.95, I recommend a RY1 increase of 1.15 times the system average increase;

ii. Any remaining increase should bespread across all classes with parity ratios between 0.95 and 1.05. This increase should, again, be limited to 1.15 times the system average increase;

iii. To the extent there are still any additional amounts to be recovered, those should be applied to all classes with parity ratios in excess of 1.05.

Finally, for Rate Year 2 (RY2), the Company proposes to apply a uniform rate increase across all rate classes.

Q. What is your recommendation regarding the Company's basic residential customer charge proposal?

A. I recommend that the Commission reject the Company's proposed increase in residential customer charges for a number of reasons. First, the Company's proposal is based upon an inaccurate accounting of customer-related costs and is inconsistent with the Commission's own interpretation of these costs. Second, the Company's existing customer charge of $7.75 is already higher than the average monthly customer charge of peer IOUs in the region of $7.16 making those charges comparable to regional averages. Third, the Company's proposal would negatively impact the public policy goals of energy efficiency, and would burden low-use customers with a greater than average portion of any proposed increase in the case. The Commission should keep the PacifiCorp's residential basic charge at $7.75 per month for all residential customers.

Q. What is your recommendation regarding the Company's residential seasonal rate proposal?

A. I recommend that the Commission approve the Company's proposal The Company's proposed seasonal rate structure is fairer and more economically justified than the Company's existing inclining block rate structure. Further, the Company's proposed seasonal rates will do a far better job of facilitating progress towards Washington's decarbonization goals.

III. PROPOSED RATE INCREASE

Q. Please summarize the Company's request.

A. The Company's proposal represents its first request for a general rate increase since 2020. Importantly, this is also the Company's first rate case since the enactment of RCW 80.28.425, which overhauled Washington's regulatory model and required the filing of multi-year rate plans (MYRPs). The Company notes that its MYRP proposal in the current proceeding is designed to comply with all requirements of RCW 80.28.425 and allow the Company to increase revenues by a total of $54.7 million, which would be spread over two separate rate years ($26.8 million in Rate Year 1 and $27.9 million in Rate Year 2).[1]

Q. What is driving the Company's proposed rate increase?

[1] Direct Testimony of Robert M. Meredith, Exh. RMM-1T at 2:2–5.

A. According to the Company, there are two major factors driving its proposed rate increase: (1) an increase in net power costs, and (2) new capital additions.[2]

Q. Please discuss the Company's increase in net power costs (NPC).

A. In the Company's last rate case, the settling parties agreed that PacifiCorp would file a Power Cost Only Rate Case (PCORC) by June 2021. The Company argues that the forecasted base NPC of $1.470 billion approved in the 2022 PCORC was significantly under-forecast and that forecasted NPC is $199.0 million, which is $53.8 million higher, or a 37 percent increase, from the level approved in the 2022 PCORC and reflected in rates.[3]

Q. Please discuss the Company's proposed capital additions.

A. The Company is anticipating the addition of $10.5 billion in new capital additions on a total-Company basis between the end of the base period and the end of 2025.[4] These projects include, but are not limited to, the Gateway South and Gateway West Segment D.1 transmission projects, the Rock Creek I and II wind projects, and the Foote Creek II-IV and Rock River repowering projects.[5]

Q. How do the amounts requested in PacifiCorp's last general rate case compare to the amounts requested in this case?

A. In its last rate case from 2019–2020 (Docket UE-191024), the Company requested a $3.1 million increase in total additional revenues, which was offset by $7.1 million in the

[2] Direct Testimony of Matthew D. McVee, Exh. MDM-1T at 8:18–19.
[3] McVee, Exh. MDM-1T at 8:21–9:7.
[4] McVee, Exh. MDM-1T at 14:20–15:3.
[5] McVee, Exh. MDM-1T at 14:20–15:3.

proposed amortization of certain tax reform benefits, for a total rate decrease of approximately $4.0 million, or 1.1 percent.[6] Ultimately, the Commission approved a settlement authorizing a rate decrease in the amount of $4.15 million in 2021 and no rate changes in 2022 and 2023.[7]

Q. How does the Company's current rate request compare to requests dating back to 2010?

A. Exhibit DED-3 presents the incremental revenues approved by the Commission since 2010 on a dollar and percentage basis. This analysis shows that since 2010 the Commission has granted the Company average base rate increases of $12.6 million, or 4.35 percent. As noted above, in the instant case, the Company is requesting approximately $54.7 million. This represents a 13.5 percent increase over current rates. In other words, the Company's current rate request exceeds recently authorized rate increases by approximately $42.1 million, or 9.1 percent.

IV. CLASS COST OF SERVICE STUDY

A. Introduction

Q. What is the purpose of a CCOSS?

A. A CCOSS reconciles utility costs and revenues across different customer classes. The goal of a CCOSS is to estimate the cost of providing service to an individual customer class and the revenue contribution each class makes to cover those estimated cost

[6] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co*., Docket UE-191024, Final Order, ¶ 3 (Dec. 14, 2020).
[7] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co*., Docket UE-191024, Revised and Amended Settlement Stipulation (Appendix B), ¶ 9 (Dec. 14, 2020).

responsibilities. The results of a CCOSS produce results that can be used to develop class specific rate changes and overall rates.

Q. How is a CCOSS prepared?

A. A CCOSS utilizes a set of historic or project cost information, which is (1) "functionalized," (2) "classified," and (3) "allocated." The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The classification process characterizes costs by "type" including those that are (1) demand-related, (2) commodity-related, or (3) customer-related. The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class as appropriate.

Q. Please explain the cost classification process.

A. After all costs have been identified by functional type ("functionalization"), a CCOSS then classifies costs based on the appropriate measure associated with each particular cost type. For example, most costs are classified based on their relationship to system demand measured as either coincident peaks ("CP") or non-coincident peaks ("NCP"). CP demand measures evaluate each class' contribution to overall system peak demand, while NCP demand measures evaluate each class' peak demand irrespective of the wider system requirements. CP demand measures are typically used in the allocation of costs associated with transmission and distribution facilities with significant diversity of loads present, while NCP measures of demand are used in the allocation of costs associated with transmission and distribution facilities that serve less diversified loads. Likewise, customer related costs may be allocated based on the number of customer accounts, or weighted customer metrics such as weighted cost of installed meters to allocate costs associated with meter reading.

Q. Can you explain what you mean by demand-related costs?

A. Yes. Demand-related costs are associated with meeting maximum energy demands. At the distribution level, electric substations and line transformers are designed, in part, to meet the maximum customer demand requirements. At the production level, most power plants or electric generation units (EGUs) are typically viewed as being designed to serve both energy and demand/capacity needs of the utility. The exact degree of this split between energy and demand functionality depends on the individual EGU in question and its place in a utility's dispatch curve, with more baseload units serving more of the utility's energy needs and more peak units serving more of the utility's capacity or demand needs. Therefore, it is not uncommon to develop composite energy and demand allocators to allocate plant in service costs associated with a utility's generation fleet.

Q. How are energy-related costs defined?

A. Energy-related costs are defined as those that tend to change with the amount or volume of electricity (i.e., kWh) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales.

Q. What about customer-related costs?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. Is this a relatively simple process?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize and, thus, difficult to allocate. Therefore, unique allocation factors are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations.

Q. How does a CCOSS relate to economic principles?

A. A CCOSS is also referred to as a "fully allocated cost study" since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the CCOSS is to estimate the cost responsibility for various jurisdictions and/or customer classes, which in turn are used to develop rates. At the core of a CCOSS is a set of historic book costs for a utility that have accumulated over decades. Rates are, therefore, based upon historic average costs; whereas economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with a number of joint and common costs, difficult. This problem is exacerbated by the fact that the cost information utilized in a CCOSS are usually historic and static, not dynamic and forward-looking. These analytic deficiencies undermine many experts' cost causation/pricing claims. As a result, in regular practice there is no single correct answer that is revealed in a CCOSS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the CCOSS, and the implications both have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use CCOSS results as a "guide" in setting rates and are not bound by their results.

Q. What controversies arise in the analysis and comparison of various CCOSS methodologies?

A. The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining how much revenue will be recovered through rates, the CCOSS process determines how those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various CCOSS results often rests with determining the methods that will be used to assign costs (revenue requirements). These methods can include the relative customer share of each class, the peak load contributions of each customer class, or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily skewed toward customer and peak considerations, for instance, can tend to shift costs disproportionally to relatively lower load-factor customers, such as residential and small commercial customers. These approaches can also fail to capture the service being provided by the utility (*i.e.*, electric service in this case), and how the value of that service varies by the amount purchased by different customer classes.

Q. Please explain why methodologies that are skewed toward peak considerations shift costs towards lower load-factor customers such as residential and small business customers.

A. A large portion of residential and small commercial customer electricity loads in the U.S. are associated with weather sensitive air conditioning loads. Larger industrial customers, on the other hand, use electricity within industrial processes that are not weather sensitive. Because of this, daily and annual usage patterns for these two customer classes are significantly different. The peak loads for residential and small commercial customers tend to be more peaked than those for industrial customers, which are more steady and evenly distributed across peak and non-peak hours. For example, an average residential customer has relatively little electricity use during overnight hours and during weekday day-time working hours. Residential customers do exhibit relatively significant use during early summer evening hours corresponding to returning home from work, and potentially during chilly early winter morning hours if the customer uses electric resistance heating. Similarly, small commercial customers see limited electricity use outside of workday hours.

Q. How do these usage behaviors differ from large industrial customers?

A. Large industrial customers utilize electricity within industrial processes with little weather sensitive loads. Thus, industrial loads tend to be more evenly distributed across the hours of the day, depending upon plant or facility operations. Since these loads are not weather sensitive, there is usually limited differences between industrial summer and winter usage patterns. These customer classes are typically viewed as having high load factors, with peak energy demands relatively consistent to average daily and annual energy demands. This differs from residential customers, which tend to have lower load factors given the wide differences between their average and peak loads.

Q. Please define what is meant by a "load factor."

A. A load factor is defined as the ratio of the average load in kilowatt hours supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by taking the energy used during a period and dividing by the product of the maximum demand and the number of hours in the period.

$$Annual\ Load\ Factor =$$

$$Annual\ kWh\ Energy\ Use \Big/ (Peak\ kW\ Use * 8760\ Hours)$$

A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently since usage is consistent and does not swing largely between average and peak periods. Conversely, systems with low load factors must maintain idle capacity in order to meet the relatively large swings in load between average and peak periods.

B. Company's CCOSS

Q. Have you prepared a summary of the results of the Company's CCOSS?

A. Yes, and this summary is presented as Exhibit DED-4. The Company finds that it earned a system average rate of return during the test year of 5.77 percent. The Company also finds that class-based rate of return ranges from 2.41 percent for the large general dedicated facilities customer class, to 8.27 percent for the small general service class. The Company's test year residential class returns are estimated to be 5.38 percent.

Q. Do you disagree with any of the assumptions or allocation factors incorporated in the Company's proposed CCOSS?

A. Yes. The Company's CCOSS has one inconsistency regarding the classification of generation plant. I believe this incorrect classification leads to the Company overstating the class peak contribution relative to annual energy use.

C. Generation Plant Classification

Q. What functions do generation facilities serve?

A. Generation units are designed to serve both energy and demand/capacity needs of a utility. The exact degree of this split between energy and demand functionality depends on the individual generator in question and its place in the utility's dispatch curve. Generators defined as baseload units are designed with low operating costs in mind and are thus designed to operate during most hours of the year. Generators defined as peaking units, on the other hand, are designed with additional operational flexibility relative to baseload units in mind, specifically in the ability of the units to quickly and cost effectively "start-up." Peaking units are typically held in reserve and only utilized by a utility during periods of peak demand when the utility requires additional generation resources not required during lower demand periods. These functional differences impact the function the generator provides to a utility's energy system, with generators defined as baseload serving more of a utility system's energy needs, while generators defined as peaking units serve more of the utility's demand/capacity needs. It is therefore not uncommon to develop composite energy and demand allocators that represent this mixed use and classification. It is therefore not uncommon to use hybrid demand and energy cost allocation methods to account for this dual function.

Q. Please describe the Company's allocation of generation plant.

A. The Company allocates generation plant using the Renewable Future Peak Credit (RFPC) methodology,[8] as promulgated in Commission rule by WAC 480-85-060.[9] The Company's RFPC model results in 74 percent of generation plant costs being classified as demand related and 26 percent of generation plant costs being allocated as energy-related.[10]

Q. Please describe the RFPC methodology.

A. The RFPC methodology consists of an energy component and a demand component. The Company derives the demand component from the lowest cost storage resource in its 2021 Integrated Resource Plan (IRP), and it calculates the energy component based upon the lowest cost renewable energy generation resource listed in its 2021 IRP.[11] This methodology is, itself, an updated version of the Thermal Peak Credit allocation method, which dates back to Washington rate proceedings as far back as the 1970s.[12]

Q. Please provide an overview of the thermal peak credit allocation methodology.

A. The Thermal Peak Credit allocation method is the predecessor to Washington's current RFPC methodology, and it also based upon an energy component and a demand component. Under this allocation approach, the demand component is calculated by dividing the cost of a demand resource (represented by the cost of a combustion turbine plant or "CT") by the cost of an energy resource (represented by a combined cycle

[8] Meredith, Exh. RMM-1T at 5:17–19.
[9] WAC 480-85-060.
[10] Meredith, Exh. RMM-1T at 5:19–21.
[11] Meredith, Exh. RMM-1T at 6:3–5.
[12] Peak Credit Methodology of Staff, *In re Amending WAC 480-07-510 and Adopting Chapter 480-85 WAC Relating to Cost of Serv. Studies for Elec. and Nat. Gas Investor-Owned Utils*., Docket UE-170002 (filed Mar. 5, 2018).

turbine plant or "CCT"). The energy component, meanwhile, is equal to one minus the demand component. Collectively, these two components are represented via the following formulas:

$$Demand =$$

$$\left(\frac{1}{2}\right) CT\ Fixed + O\&M/kW\ CT \Big/ (CCT\ Fixed + O\&M) * C.F./\ kW\ CT$$

$$Energy = 1 - Demand$$[13]

Q. Is the Company's calculation of the energy and demand components consistent with the above approach?

A. No. The Company's renewable peak credit methodology represents an evolution of the historic thermal peak credit methodology to account for the differences in renewable generation resources compared to fossil-fuel driven thermal generation. Unlike when examining thermal generation units where the levelized cost of new generation capacity is less expensive than the levelized costs for new baseload units designed to provide inexpensive energy, renewable generation capacity resources such as battery energy storage are generally more expensive than inexpensive renewable energy resources such as wind farms and solar generation systems. However, the Company also calculates the demand component by dividing the cost of the demand resource (i.e. the storage resource) by the sum of the demand and energy resource costs. This is inconsistent with the above framework, which utilizes only energy within the denominator when determining the relative demand allocation.

[13] *Id*.

Q. Does the Company's addition of energy and demand components within its calculation make logical sense?

A. No. The Company calculates the levelized cost of a 50 MW Lithium-Ion battery as representing the costs of a new capacity asset, while the Company calculates the levelized costs of the Company's 200 MW wind farm in Medicine Bow, Wyoming represent the costs of a new energy asset.[14] Rather than estimating the relative levelized costs of a new energy storage battery asset to an inexpensive wind farm asset solely serving customer's energy needs, the Company estimates the cost of a new energy storage battery asset to the cost of **both** this energy storage battery asset and the before mentioned wind farm assets. The addition serves no logical purpose other than to incorrectly inflate the capacity component of the Company's calculation relative to the energy component.

Q. What impact does this inconsistency have upon the allocation of generation plant?

A. As previously explained, the Company's generation plant classification results in a demand component of 74 percent and an energy component of 26 percent. When this inconsistency is resolved, however, the demand component declines to 65 percent, and the energy component increases to 35 percent.

D. CCOSS Recommendations

Q. Please summarize your CCOSS recommendation.

A. I recommend the Commission adopt the alternative generation plant classification methodology as is illustrated within my alternative CCOSS. This alternative methodology is consistent with the Commission's newly approved cost of service

[14] Meredith, Exh. RMM-5.

guidelines and simply corrects the Company's demand and energy allocators, while also providing for a more accurate representation of PacifiCorp's generation costs.

Q. Would your CCOSS recommendations change the class rates of return?

A. Yes. Using my recommended allocation factors, I have prepared an explanatory alternative CCOSS, which is attached to this testimony as Exhibit DED-5. It should be noted, however, that the alternative CCOSS presented in Exhibit DED-5 is independent of revenue requirement adjustments supported by other witnesses and is thus presented for explanatory purposes only.

V. REVENUE DISTRIBUTION

A. Revenue Distribution Policy Objectives

Q. Please explain the purpose of the revenue distribution process in setting rates.

A. The revenue distribution process (which can also be called the "revenue spread" or "rate spread" process) allocates (or "spreads") a utility's overall revenue deficiency across customer classes, which in turn is used to establish a new set of retail rates to be applied prospectively. The revenue distribution process often uses the results from the CCOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The class revenue responsibilities that are finally established are then used, in conjunction with each class's billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. Does the revenue distribution process include any policy considerations?

A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis could result in outcomes inconsistent with Commission policies, including situations leading to adverse rate impacts for certain under-earning classes. To avoid such a result, regulators often temper the revenue responsibilities assigned to various customer classes in order to meet a broad set of ratemaking policy goals.

Q. What are those broader ratemaking policy goals?

A. There are several generally accepted ratemaking principles used in utility regulation that include:

- Rates should be fair, just, and reasonable, and not unduly discriminatory.
- To the extent possible, gradualism should be used to protect customers from rate shock.
- Rate continuity should be maintained.
- Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
- Rates should be understandable to customers.

Q. How are the above principles applied in developing an appropriate rate spread for a regulated utility?

A. Regulators often consider all, or many of the principles I mentioned above. However, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and result in rates that are fair, just, and reasonable. There is no pre-set or universally accepted formula for developing rates and, as a result, judgment is necessary to formulate a rate design that meets these objectives.

Q. What factors has the commission historically relied upon in the determination of an appropriate rate spread?

A. The Commission has historically considered a multitude of factors, including the cost of service, fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.[15] Out of all of these factors, rate parity, i.e. the relationship between revenues and costs, seems to be most heavily relied upon within the Commission's review and determination of rate spread proposals.[16]

Q. Please explain the concept of a parity ratio.

A. The parity ratio refers to the relationship between a rate class's revenues and its costs. A parity ratio of 1.00 occurs in which a utility collects 100 percent of the revenue needed to cover the costs of serving the class. A parity ratio of 0.90, likewise, indicates that the utility collects 90 percent of the revenue needed to cover the costs of the customer class, and a parity ratio of 1.10 occurs when a utility collects 110 percent of the revenues required to serve the customer class.[17]

Q. What are acceptable parity ratios within the context of utility rate cases in Washington?

[15] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-200900, Final Order, ¶ 328 (Sep. 27, 2021).
[16] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-190529 and UG-190530, Final Order, ¶ 516 (Jul. 8, 2020).
[17] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Docket UE-152253, Final Order, at 74-75, (Sep. 1, 2016).

A. The Commission provided the following guidance in the Company's 2015 rate case: "A COSS uses precise math to follow elaborate cost assignments. Commission practice considers the error or range of accuracy to be +/-0.05. In other words, COSS results within the range 0.95 to 1.05 are considered within the precision of the COSS."[18]

B. Company's Proposed Revenue Distribution/Rate Spread

Q. Please explain how the Company proposes to distribute its class revenue requirements.

A. The Company is requesting a revenue increase of $26.8 million in RY1 and a revenue increase of $27.9 million in RY2, and it proposes to use two distinct revenue distribution methodologies for such rate increases. In RY1, the Company proposes to distribute its revenue increase of 6.6 percent based largely on the results of its CCOSS, and in doing so, it relies upon a three-step approach: (1) it implements no rate increase for Schedule 24, small general service customers; (2) it implements a rate increase equal to 50 percent of the system average increase for Schedule 36 general service customers; and (3) it allocates the remaining revenue increase equally across the remaining classes (i.e. the residential and large general service classes). Meanwhile, in RY2, the Company proposes an equal rate increase for all rate classes.[19]

Q. What are the results of the Company's proposed revenue distribution?

A. Exhibit DED-6 presents the Company's proposed rate increase and relative rate of return (Relative ROR or RROR) for each major rate class across each rate year, as well as on a

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[18] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Docket UE-152253, Final Order, at 74 (Sep. 1, 2016).
[19] Meredith, Exh. RMM-6.

cumulative basis. In RY1, the Company proposes that residential and large general service customers receive a 9.1 percent increase, which represents a Relative ROR of 1.38 for RY1. Meanwhile, in RY1, the Company proposes that small general service customers receive no rate increase and that standard general service customers receive a rate increase of 3.3 percent. In RY2, the Company is proposing an equal rate increase of 6.5 percent across the residential, small general service, general service, and large general service classes.[20]

Q. What do you mean by a Relative ROR?

A. A Relative ROR effectively standardizes class-specific rates of return to the overall system average. In other words, it divides the estimated class ROR by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight percent ROR and further assume that the system-wide average ROR estimated by the same CCOSS is also eight percent. The residential class, in this example, can be said to be earning a 1.0 Relative ROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 Relative ROR can be said to be making its full contribution to the system's overall ROR (*i.e.*, there is no cross-subsidy). A Relative ROR that is greater than one indicates that a particular class is contributing more than the system average contribution to the Company's overall return. Likewise, a class that earns a Relative ROR less than 1.0 can be said to be making a less-than-average contribution to the overall system and is effectively being partially subsidized by other classes.

[20] Meredith, Exh. RMM-6.

C. Revenue Distribution Recommendations

Q. Do you agree with the Company's rate spread proposal?

A. No. The Company's proposal to increase rates for multiple rate classes in RY1 in excess of 1.38 times the system average increase conflicts with the Commission's explicit goals of gradualism and rate stability. Further, such a large rate increase is not necessary from a rate parity perspective.

Q. Have you performed any analysis of the Company's parity ratios?

A. Yes, Exhibit DED-7 presents a comparison of present revenues and costs, as well as proposed revenues and costs, across various rate classes. This analysis demonstrates that the residential class, for which the Company is proposing to increase rates at 1.38 times the system average increase in RY1, already recovers 99 percent of total costs. Furthermore, this analysis demonstrates that if the Company's proposed rate spread is approved, the parity ratio for the residential class will exceed 1.00, indicating that its revenues will exceed its costs. Based upon this analysis, it is clear that the Company's proposed rate spread is arbitrary (i.e. not guided by established precedent in the State) and inappropriate (i.e. inconsistent with the principles of gradualism and rate stability).

Q. What is your rate spread recommendation?

A. First, I recommend that the Commission adopt a revenue distribution that reflects the alternative CCOSS recommendations discussed earlier. Second, I recommend that the Commission adopt a more reasonable revenue distribution allocation method that limits the RY1 rate increase to 1.15 times the system average increase using the following three-step approach:

i. For all classes with parity ratios below 0.95, I recommend a RY1 increase of 1.15 times the system average increase;

ii. Any remaining increase should bespread across all classes with parity ratios between 0.95 and 1.05. This increase should, again, be limited to 1.15 times the system average increase;

iii. To the extent there are still any additional amounts to be recovered, those should be applied to all classes with parity ratios in excess of 1.05.

Finally, for RY2, I recommend that the Company apply a uniform rate increase across all rate classes.

Q. Have you prepared an exhibit that illustrates the results of your proposed revenue distribution?

A. Yes. Exhibit DED-8 provides this illustration using the Company's proposed revenue requirement and my proposed alternative CCOSS recommendations. However, based on the Company's proposed revenue requirement and my alternative rate spread proposal, the maximum, cumulative increase for any single rate class would be 14.5 percent; this rate increase equates to a relative rate of return of 1.08, and is far more reasonable than the Company's proposed revenue increases of 16.2 percent for several of its customer classes.

Q. Have you examined the impact that your alternative rate spread recommendation will have upon rate class parity ratios?

A. Yes, and this analysis is also presented in Exhibit DED-8. Currently, there are three (out of seven) rate classes with parity ratios outside of the 0.95 to 1.05 parity ratio threshold. My alternative rate spread proposal would bring all classes, with the exception of one, within the boundaries of this parity ratio threshold. The only class that would fall outside of this boundary is the Large General Service - Dedicated Facilities class, and the parity ratio for this class would be 0.94. This analysis is significant because it demonstrates that it is possible to successfully balance competing revenue allocation factors, including gradualism, rate stability, and cost recovery—factors which the Company's proposal does not appropriately balance.

VI. RATE DESIGN

A. Rate Design Objectives

Q. How are utility rates typically structured?

A. Electric utility rates are typically comprised of three basic elements. The first element is the fixed monthly customer charge sometimes referred to as a basic service charge or a basic facility charge. The second is the energy-based component that is a volumetric rate applied toward a customer's monthly energy usage during a billing period, often measured in terms of kWh. Finally, demand rates are surcharges that are assessed based upon a customer's maximum usage during a billing period, commonly measured in terms of kW for those customers that are demand metered. Historically, some smaller use customer classes, such as residential and small commercial classes, are not demand-metered and thus, only pay customer and energy charges. Customers with just customer and energy charges have bills that are based upon what is commonly called a "two-part tariff" (e.g., energy and customer charge) whereas large demand metered customers face a "three-part tariff" (e.g., energy, customer, and demand charges).

Q. How should policy balance cost assignments between customer charges and volumetric rates?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by the two-part and three-part tariff form that is sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. What is the appropriate role of costs in setting rates based upon a two-part tariff?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates for them to be set optimally (i.e., fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs). There are other equally important considerations in setting rates in imperfect markets.

B. Basic Residential Customer Charge

Q. Please provide an overview of the Company's basic residential customer charge proposal.

A. The Company is proposing to split its basic residential customer charge into two separate charges; one that will apply to single-family dwellings, and another applicable to only multi-family dwellings.[21] The Company proposes to maintain the existing residential

[21] Meredith, Exh. RMM-1T at 11:17–12:2.

customer charge of $7.75 for residential customers who live in multi-family dwellings, but increase the basic customer charge to $10.00 for residential customers who live in single family dwellings. These changes would be applied over the two years of the Company's proposed rate plan.[22]

Q. What is the basis of the Company's proposed residential customer charge increase?

A. The Company's analysis (Exhibit RMM-7) purports to estimate customer related costs for each type of customer, finding costs of $13.40 per month for single-family residential customers and costs of $11.14 per month for multi-family customers.[23]

Q. Do you agree with the manner in which the Company made these calculations?

A. No. The Company's analysis significantly overstates the costs directly attributable to residential customers. Specifically, the Company assigns costs related to line transformers to the residential basic customer charge. In doing so, it overstates the estimated monthly residential customer costs by at least $4.47, or 44 percent.[24]

Q. Has the Company proposed a customer cost methodology like this in the past?

A. Yes. The Company proposed a similar methodology in its 2014 rate case when it proposed a residential customer charge increase of 81 percent, from $7.75 to $14.00.[25] The Company based this customer charge proposal, in large part, on a cost estimation

[22] Meredith, Exh. RMM-1T at 11:17–12:2.
[23] Meredith, Exh. RMM-7.
[24] According to the Company's Exhibit RMM-7, the costs attributable to service drops, meters, and customer service total $10.09, which increases to $14.57 when line transformer costs are included.
[25] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Docket UE-140762, Order 08: Final Order, ¶ 203 (Mar. 25, 2015).

methodology that included line transformers as well as additional non-customer costs as well.[26]

Q. Did the Commission accept the use of this methodology and its companion customer charge proposal?

A. No. The Commission rejected the Company's proposal on the grounds that basic charges should only reflect "direct customer costs" such as meter reading and billing.[27] The Commission stated, "Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals."[28]

Q. Does the Company provide any additional analysis in support of its proposed residential customer charge increase?

A. Yes. The Company has provided a comparison of its proposed residential customer charge to that of other electric utilities in the state. This analysis illustrates that the Company's proposed residential customer charge for single-family dwellings of $10.00 is less than half of that of other electric utilities in the state, which collectively apply residential customer charges of $21.08, on average.[29]

Q. Are there any issues with the Company's survey of other utilities' rates?

[26] Joelle R. Steward, Exh. JRS-8, *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Docket UE-140762, (filed Dec. 16, 2014).
[27] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co*., Docket UE-140762, Order 08: Final Order, ¶ 216 (Mar. 25, 2015).
[28] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co*., Docket UE-140762, Order 08: Final Order, ¶ 216 (Mar. 25, 2015).
[29] Meredith, Exh. RMM-1T at 17, Table 2.

A. Yes. This analysis examines the residential customer charges of eight other Washington utilities; however, 75 percent of this peer group is comprised of publicly-owned utilities. That is, only two of the utilities in the peer group are investor-owned utilities (IOUs), and the Company's proposed customer charge of $10.00 is higher than both of these utilities (Puget Sound Energy and Avista).[30]

Q. Did the Commission approve any residential customer charge increases for Puget Sound Energy and Avista in their most recent rate cases?

A. No. Puget Sound Energy recently proposed a residential customer charge increase of 10 percent, from $7.49 to $8.24,[31] and Avista, in its 2022 base rate case, proposed a residential customer charge increase of 22 percent, from $9.00 to $11.00.[32] However, neither proposal was ultimately approved.

Q. Have you developed an alternative analysis of residential customer charges across regional electric peer utilities?

A. Yes. This analysis, presented in Exhibit DED-9, compares the Company's residential customer charge to other regional electric utilities. This analysis demonstrates that the Company's current residential customer charge of $7.75 per month is in excess of the average residential customer charge of $7.16 for other regional IOUs. Furthermore, when this survey includes minimum residential electric bills in place for utilities like Southern California Edison and Pacific Gas and Electric, the regional average increases from $7.16

[30] Meredith, Exh. RMM-1T at 17, Table 2.
[31] Direct Testimony of Birud D. Jhaveri, Exh. BDJ-1T at 29:11-21, *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-220066 and UG-220067 (*consol.*) (filed Jan. 31, 2022).
[32] Direct Testimony of Joseph D. Miller, Exh. JDM-1T at 11:10-12,*Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-220053, UG 220054, and UE-210854 (*consol.*) (filed Jan. 25, 2022).

to $9.48, and yet the Company's current residential customer charge is still reasonably consistent with this regional average as well.

Q. Is the Company's proposal to increase the customer charge consistent with the promotion of energy efficiency and conservation?

A. No. The Company's proposal is inconsistent with the promotion of energy efficiency and conservation in Washington because it places more costs into the fixed component of rates than in the variable component. This reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills can be altered through behavior changes or use of more efficient appliances and measures.

Q. Have other Commissions recognized the detrimental effect increased fixed charges have on energy efficiency?

A. Yes. In rejecting a request by Northern States Power Company to increase customer charges[33] as part of a larger rate design proposal, the Minnesota Public Utilities Commission (MPUC) recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Monthly customer charges are an important component of the Company's Residential and Small General Service rates by facilitating recovery of the costs caused by each customer that do not vary with the amount of energy used. However, higher fixed customer charges discourage customers from conserving energy and investing in renewable energy by reducing the impact of these efforts on the customers' bills. Customer charges also tend to confuse and alienate customers by impairing customer understanding of their energy bills. The Commission notes that Minn. Stat. §216B.03 requires the Commission to design rates to encourage energy conservation and renewable-energy use to "the maximum reasonable extent." Considering

[33] I*n re the Appl. of Northern States Power Co., for Authority to Increase Rates for Elec. Serv. in the State of Minn*., Docket E-002/GR-21-630, Findings of Fact, Conclusions, and Order, at 114 (MPUC July 17, 2023).

> this statutory mandate and the evidence submitted by the parties, the Commission agrees with the ALJ that it is reasonable and appropriate to lower the monthly customer charge for the Residential and Small General Service classes to $ 6.00.[34]

Q. Is the Minnesota Commission alone in its belief that high fixed charges discourage efficient use of energy?

A. No. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners (NARUC) lists Straight-Fixed Variable (SFV) rate design as an alternative to delink utility revenue from sales. SFV places all fixed-related costs to fixed charges while relegating only variable charges to volumetric rates. The NARUC research noted this type of rate design was problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. <u>This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume</u>.[35]

Q. Has any national public policy analysis noted the efficiency disincentives associated with SFV-type rate designs?

A. Yes. The National Action Plan for Energy Efficiency (NAPEE), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The

[34] *Id*. at 116-117.
[35] *Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)*, at 5, Grants & Rsch Dep't, Nat'l Ass'n of Regul. Util. Comm'rs (Sept. 2007) (emphasis added), https://www.maine.gov/mpuc/legislative/archive/2006legislation/DecouplingRpt-AttachC.pdf.

NAPEE postulated that SFV had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such disincentives persist even when applied to individual components of a customer's utility bill, such as SFV for strictly distribution services:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[36]

Q. Are there other concerns with increases to the proposed customer charge?

A. Yes. In addition to disincentivizing energy conservation measures, increased customer charges also shift the rate burden within a customer class to lower-use customers. This results in fairness concerns as lower-use customers have been shown to be consistently associated with lower-income households in empirical research.[37]

Q. Have you prepared a typical residential bill analyses associated with the Company's rate design proposals?

A. Yes. Exhibit DED-10 illustrates distribution bill changes for residential customers of varying monthly kWh usage levels. Three types of illustrative customers are identified in this analysis. Customer 1 represents a customer taking service under the standard residential service class who uses an average of 1,045 kWh per summer month and 1,278

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[36] William Prindle, *Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design*, at 13–14, Nat'l Action Plan for Energy Efficiency, ICF Int'l, Inc. (Sept. 2009) (emphasis added), https://www.epa.gov/sites/production/files/2015-08/documents/rate_design.pdf.

[37] Energy Info. Admin., *2020 Residential Energy Consumption Survey (RECS), Table CE2.1 Annual household site fuel consumption in the United States—totals and averages, 2020* (Mar. 2023), https://www.eia.gov/consumption/residential/data/2020/c&e/pdf/ce2.1.pdf.

per winter month. Customer 2 represents a smaller customer using an average of only 696 kWh per summer month and 852 kWh per winter month, a third less than the hypothetical system average. Customer 3 represents a larger customer using an average of 1,393 kWh per summer month and 1,704 kWh per winter month, a third more than the hypothetical system average. In summer months, the schedule shows that customers using close to the system average would see an increase of 18.7 percent in their bill. Those customers with greater than average use would incur a slightly smaller increase of 15.9 percent. Low-use residential customers would see their bill increase by 24.7 percent. In winter months, meanwhile, the schedule shows that customers using close to the system average would see an increase of 7.5 percent in their bill. Those customers with greater than average use would incur a slightly smaller increase of 5.4 percent, while low-use residential customers would see their bill increase by 11.9 percent.

Q. What is your recommendation regarding the Company's basic residential customer charge proposal?

A. I recommend that the Commission reject the Company's proposed increase in residential customer charges for a number of reasons. First, the Company's proposal is based upon an inaccurate accounting of customer-related costs and is inconsistent with the Commission's own interpretation of customer-related costs. Second, the Company's existing customer charge of $7.75 is already higher than the average monthly customer charge of peer IOUs in the region of $7.16 making those charges comparable to regional averages. Third, the Company's proposal would negatively impact the public policy goals of energy efficiency, and would burden low-use customers with a greater than average portion of any proposed increase in the case. The Commission should keep the PacifiCorp's residential basic charge at $7.75 per month for all residential customers.

C. Residential Energy Charges

Q. How are the Company's residential variable rates currently structured?

A. The Company's basic residential tariff relies upon a tiered energy rate structure in which prices for a customer's first 600 kWh are charged at a rate of $0.08276 per kWh, while all usage above that is charged at a rate of $0.11198.[38] This is referred to as an inclining block.

Q. Please discuss the Company's proposed changes to this rate structure.

A. The Company is proposing to eliminate its current inclining block rate structure in favor of seasonal energy rates. Under this proposal, variable energy rates would be higher in summer months (June through September) and lower in winter months (October through May).[39]

Q. Why is the Company proposing to eliminate its tiered rate structure?

A. The Company identifies numerous flaws inherent within its current variable rate structure. First, it explains that tiered rates unfairly punish customers for reasons outside of the customer's own control.[40] Second, the Company states that tiered rates are not economically justified due to an inherent mismatch between prices and costs.[41] Third, the Company forecasts that tiered rates in Washington will lead its customers to switch from heating their homes with natural gas as opposed to electricity, which is an outcome that is

[38] Meredith, Exh. RMM-6.
[39] Meredith, Exh. RMM-6.
[40] Meredith, Exh. RMM-1T at 19:10–13.
[41] Meredith, Exh. RMM-1T at 21:2–9.

inconsistent with Washington's decarbonization goals. Cascade Natural Gas Corporation, the natural gas provider in the Company's service territory, does not utilize inclining residential energy rates, and as a result, the Company's customers will be sent an inaccurate price signal regarding the incremental cost of electricity versus natural gas.[42]

Q. Why is the Company proposing to replace its tiered rate structure with seasonal-differentiated rates?

A. The Company states that under a seasonal rate structure, its prices will be more aligned with its costs. This, in turn, will provide residential customers with more accurate pricing signals and encourage greater levels of energy efficiency.[43]

Q. How did the Company develop its seasonal rate differential?

A. The Company compared the average forecasted price at the Mid-Columbia hub between the months of June through September for the period of March 2024 to February 2026 against the average forecasted price between the months of October through May for the same period, and this analysis revealed a rate differential of $0.03842 per kWh. The Company is proposing to use half of this value ($0.01921 per kWh) as the differential between its summer and winter residential energy charges.[44]

Q. Do you agree with the Company's arguments regarding its proposal to move away from inclining rates?

A. Yes. I agree that the Company's inclining block rates are unfair and contrary to the Washington's decarbonization goals. Under inclining block rates, a low use customer is

[42] Meredith, Exh. RMM-1T at 21:11–22:2.
[43] Meredith, Exh. RMM-1T at 24:22–25:15.
[44] Meredith, Exh. RMM-1T at 25:2–7.

not able to improve his energy efficiency and will continue to be subsidized by a larger customer, who has installed as many cost-effective energy efficiency measures as he can. It is simply not fair to the larger users, and as a result, the Company's experiment with inclining block distribution rates should end. Further, I agree that flat energy rates, as proposed by the Company, are easier to understand and more customer friendly.

Q. Please provide an example of how inclining block rates are contrary to Washington's decarbonization goals.

A. In 2022, Washington passed a law that requires all new vehicles sold in the state to be 100 percent electric by 2035.[45] This decarbonization legislation is intended to transition Washington residents towards the ownership of electric vehicles; however, the Company's present inclining block rate structure amplifies the incremental costs of EV charging and thus serves as a significant headwind towards the State's 2035 EV objectives.

Q. What is your recommendation regarding the Company's residential seasonal rate proposal?

A. I recommend that the Commission approve the Company's proposal. The Company's proposed seasonal rate structure is fairer and more economically justified than the Company's existing inclining block rate structure. Further, the Company's proposed seasonal rates will do a far better job of facilitating progress towards Washington's decarbonization goals.

[45] WAC 173-423-400.

VII. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your CCOSS recommendation.

A. I recommend the Commission adopt the alternative generation plant classification methodology as is illustrated within my alternative CCOSS. This alternative methodology corrects the Company's demand and energy allocators, and provides for a more accurate representation of PacifiCorp's generation costs.

Q. What is your rate spread recommendation?

A. First, I recommend that the Commission adopt a revenue distribution that reflects the alternative CCOSS recommendations in my testimony. Second, I recommend that the Commission adopt a more reasonable revenue distribution allocation method that limits the RY1 rate increase to 1.15 times the system average increase using the following three-step approach:

i. For all classes with parity ratios below 0.95, I recommend a RY1 increase of 1.15 times the system average increase;

ii. Any remaining increase should be spread across all classes with parity ratios between 0.95 and 1.05. This increase should, again, be limited to 1.15 times the system average increase;

iii. To the extent there are still any additional amounts to be recovered, those should be applied to all classes with parity ratios in excess of 1.05.

Finally, for RY2, I recommend that the Company apply a uniform rate increase across all rate classes.

Q. What is your recommendation regarding the Company's basic residential customer charge proposal?

A. I recommend that the Commission reject the Company's proposed increase in residential customer charges for a number of reasons. First, the Company's proposal is based upon an inaccurate accounting of customer-related costs and is inconsistent with the Commission's own interpretation of these costs. Second, the Company's existing customer charge of $7.75 is already higher than the average monthly customer charge of peer IOUs in the region of $7.16 making those charges comparable to regional averages. Third, the Company's proposal would negatively impact the public policy goals of energy efficiency, and would burden low-use customers with a greater than average portion of any proposed increase in the case. The Commission should keep the PacifiCorp's residential basic charge at $7.75 per month for all residential customers.

Q. Does this conclude your response testimony?

A. Yes. However, I reserve the right to supplement my testimony if material new information becomes available.