



1407 W. North Temple, Suite 330  
Salt Lake City, UT 84116

April 25, 2023

RECEIVED  
2023 April 25, 4:32PM  
IDAHO PUBLIC  
UTILITIES COMMISSION

***VIA ELECTRONIC DELIVERY***

Jan Noriyuki  
Commission Secretary  
Idaho Public Utilities Commission  
1131 W. Chinden Blvd  
Building 8 Suite 201A  
Boise, ID 83714

**Re: CASE NO. PAC-E-22-15  
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER  
FOR AUTHORITY TO IMPLEMENT THE RESIDENTIAL RATE  
MODERNIZATION PLAN**

Dear Ms. Noriyuki:

Please find for filing Rocky Mountain Power's Reply Comments in the above-referenced matter.

Informal inquiries may be directed to Mark Alder, Idaho Regulatory Manager at (801) 220-2313.

Very truly yours,

Joelle R. Steward  
Senior Vice President of Regulation and Customer Solutions

Enclosures

Joe Dallas (ISB# 10330)  
PacifiCorp, Senior Attorney  
825 NE Multnomah Street, Suite 2000  
Portland, OR 97232  
Email: [joseph.dallas@pacificorp.com](mailto:joseph.dallas@pacificorp.com)

*Attorney for Rocky Mountain Power*

**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

<b>IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO IMPLEMENT THE RESIDENTIAL RATE MODERNIZATION PLAN</b>	<b>CASE NO. PAC-E-22-15</b>
--	-----------------------------

**ROCKY MOUNTAIN POWER’S REPLY COMMENTS**

In accordance with the Idaho Public Utilities Commission (“Commission”) Notice of Schedule, PacifiCorp d/b/a Rocky Mountain Power (the “Company”), by and through its counsel, provides these Reply Comments to the comments received from the Staff of the Commission (“Staff”), Northwest Energy Coalition (NVEC”) and Idaho Conservation League (“ICL” together “NVEC/ICL”), and Clean Energy Opportunities (“CEO”).

**INTRODUCTION**

The Company filed its application in this matter with the Commission on October 20, 2022 (“Application”), requesting the Commission issue an order authorizing this Application be processed under Modified Procedure and approving the modernization of its residential rates over a five-year period (“Residential Rate Modernization Plan”) effective December 1, 2022.

On November 30, 2022, the Commission issued a Notice of Application, Notice of Suspension of Proposed Effective Date, and Notice of Intervention Deadline. On December 8, 2022 CEO filed a petition to intervene and on December 21, 2022 ICL and NVEC both filed a

petition to intervene. CEO's petition to intervene was granted on December 20, 2022. ICL and NWEC's petitions were granted on January 5, 2023. On February 13, 2023, the Commission issued Order No. 35679 which included a Notice of Schedule, Notice of Public Workshop, Notice of Comment Deadlines, and Notice of Customer Hearing.

In accordance with Order No. 35679, Staff held a public workshop on March 18, 2023. On March 29 and March 30, 2023, the Company held two public information workshops where its Application was presented to customers and customer questions were answered by the Company. On April 11, 2023, Staff, CEO, and NWEC/ICL submitted comments on the Company's application.

The Company has reviewed the comments submitted by Staff, all intervenors and customers and continues to recommend the Commission issue an order approving the Company's Residential Rate Modernization Plan as it was presented in the Company's application.

### **REPLY TO STAFF'S COMMENTS**

The Company acknowledges and values Staff's thoughtful analysis of the Company's proposed Residential Rate Modernization Plan. Although the Company maintains that the flattening of the inclining block tiers is in the public interest and would resolve inequities for higher usage customers, on balance Staff's recommendation, if approved by the Commission, would make progress towards fairer residential pricing that appropriately reflects cost causation. The Company independently confirmed that Staff's proposed rates for each year of the transition are revenue neutral.

The Company continues to recommend that the Commission approve its proposal, which includes elimination of energy charge tiering for Schedule 1. Staff provides two key arguments in favor of retaining tiered rates, which the Company will address individually below.

First, Staff reasons that inclining block tiers send a conservation price signal that encourages customers to use less energy which can help the Company avoid expensive infrastructure investments. Taken in combination with the increased customer service charge, Staff argues that eliminating tiered rates may shift the pricing signal too far away from energy conservation.

The Company recognizes the importance of energy efficiency in its resource planning and acknowledges that providing accurate price signals to customers is crucial to achieving its energy efficiency objectives. The Company believes that the proposed transition plan's energy charge will continue to promote energy efficiency, even after the elimination of tiered rates. Under the proposed plan, every kWh a customer does not use would save them approximately 9 cents during summer months and approximately 7 cents would be saved during winter months, providing the same price signal to both small and large customers. Additionally, the Company's Wattsmart rebate programs are another essential component in achieving its energy efficiency goals. Considering the available incentives, customers will still have attractive paybacks for different energy efficiency measures, and have good reason to practice beneficial behaviors like turning off lights when not in use, under the Company's proposed pricing. Eliminating tiers will ensure fairness among customers and will send small and large customers alike a consistent and easily understandable price signal.

Second, Staff supports its alternative by explaining that its proposal would have less of an impact to smaller usage customers and would result in more customers achieving net savings from the changes. According to Staff's analysis, the break-even point would shift from 778 kWh in the summer and 1,002 kWh in the winter under the Company's proposal to 694 kWh in the summer and 833 kWh in the winter under Staff's proposal.

The Company recognizes the importance of mitigating the impact on customers and has therefore proposed a full five-year transition period for the changes it is seeking. As indicated in Exhibit No. 3 and Staff's comments, the average usage customer would experience a \$2.70 or 3.1 percent increase over this time, which Staff notes should result in year-to-year changes that would be nearly imperceptible to the average customer. Moderating this further is unnecessary and perpetuates inclining block rates that unfairly burden larger-usage customers. For many of these customers, their energy consumption levels may have nothing to do with their energy efficiency but could be attributed to other factors such as household size and having a home with electric heat in a location where natural gas service is unavailable.

In the event that the Commission prefers to maintain tiered rates during the transition period, the Company proposes an alternative to Staff's proposal. Instead of keeping the differential between the first and second tier energy prices the same in absolute terms (about 1.9 cent difference in the summer and about 1.6 cent difference in the winter), the Company suggests keeping it the same in percentage terms (approximately 17 percent in both seasons). This would ensure that the scale of tiering appropriately reflects the change in magnitude for energy charges. Table 1 below shows how this alternative compares to Staff's proposal:

**Table 1. Comparison of Staff Proposal to Alternative Where Differential is Fixed in Percentage Terms**

Staff Proposal					Alternative to Staff Proposal				
	Summer Season		Winter Season			Summer Season		Winter Season	
Transition Year	First Tier Energy Charge (¢/kWh)	Second Tier Energy Charge (¢/kWh)	First Tier Energy Charge (¢/kWh)	Second Tier Energy Charge (¢/kWh)	Transition Year	First Tier Energy Charge (¢/kWh)	Second Tier Energy Charge (¢/kWh)	First Tier Energy Charge (¢/kWh)	Second Tier Energy Charge (¢/kWh)
Present	11.1966	13.0999	9.3305	10.9165	Present	11.1966	13.0999	9.3305	10.9165
1	10.5846	12.4879	8.8205	10.4066	1	10.6118	12.4157	8.8431	10.3464
2	9.9726	11.8759	8.3105	9.8966	2	10.027	11.7315	8.3558	9.7762
3	9.3606	11.2639	7.8005	9.3866	3	9.4422	11.0473	7.8685	9.2061
4	8.7486	10.6519	7.2905	8.8766	4	8.8574	10.3631	7.3812	8.6359
5	8.1366	10.0399	6.7805	8.3666	5	8.2726	9.6789	6.8939	8.0657

The Company maintains its recommendation in its initial proposal. However, if the Commission decides to keep tiered rates in place during the transition period, the Company believes that the alternative in Table 1 is preferable to Staff’s proposal.

**REPLY TO NORTHWEST ENERGY COALITION (“NVEC”) AND IDAHO CONSERVATION LEAGUE (“ICL”) COMMENTS**

NVEC/ICL has recommended that the Commission reject the Company’s proposal to raise the fixed customer service charge and eliminate inclining block tiers for several reasons. NVEC/ICL first argues that the changes proposed by the Company should have been requested in a general rate case where greater stakeholder engagement could take place and consideration could be given to other factors, such as the Company’s authorized return on equity (“ROE”). NVEC/ICL also discussed how the Company was able to raise the customer service charge and flatten tiered rates in its most recent rate case (“2021 Rate Case”),<sup>1</sup> as a result of a settlement and characterized

---

<sup>1</sup> *In the Matter of Rocky Mountain Power’s Application for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations*, Case No. PAC-E-21-07.

the Company's proposal as "disingenuous at best," since it was made ten months after rates took effect in the rate case.

The Company's proposed Residential Rate Modernization Plan is revenue neutral and does not need to take place within the context of a general rate case. In fact, isolating the residential rate change within this docket has the advantage of analyzing customer impacts without an additional rate increase, which could make measuring customer impacts more difficult. Instead of having the residential rate design changes currently proposed be overshadowed by rate increases or other rate changes, customers have been able to engage with this issue separately and thoroughly as evidenced by the 58 customer comments received on this docket. The Company believes waiting until the next rate case is not necessary. While the Company's filing in this proceeding was made about 10 months after rates took effect for the 2021 Rate Case, more than a year will have elapsed before the first transition takes place if the plan is approved by the Commission. Also in its proposal, the Company balanced the need for faster action with the important principal of gradualism and has proposed a five-year transition plan instead of a one-year or two-year transition plan.

ICL/NWEC criticizes the Company for proposing its plan outside of a general rate case, arguing that that this format does not allow for a sufficient level of stakeholder outreach. However, the Company has made a concerted effort to reach out to customers in this proceeding. To explain the Company's proposal to customers, the Company has hosted two virtual customer workshops, one on March 29, 2023, in the morning, and another on March 30, 2023, in the evening, to accommodate customers with different schedules. At these workshops Company personnel made a presentation of its proposal and responded to customer questions. Additionally, Staff conducted

an in-person workshop in Idaho Falls on March 14, 2023, in the evening, which PacifiCorp representatives attended to be available for informal discussions with customers.

ICL/NWEC claims that “higher fixed charges equate to increased likelihood of cost recovery, due to the elimination of sales variations attributable to weather and the economy” and speculates that “[i]nvestors are more likely to invest in a utility with less risk, meaning a downward adjustment in the utility’s ROE may be warranted.” The Company disagrees with this assertion that the proposal will negatively impact the Company’s risk level. First, the proposed changes are minor relative to the totality of the Company’s revenue requirement in the state of Idaho. The shift from energy charges to fixed charges for Schedule 1 only represents a little less than five percent of the Company’s Idaho revenue requirement.<sup>2</sup> In some respects, revenue from the Schedule 36 time of day customers is less certain under the Company’s proposal, since the on-peak hours would be shortened. Second, removing fixed costs from the volumetric charge removes the potential for higher revenues that could result from load growth or weather events that increase usage; as such the Company (and its shareholders) is foregoing potential upside from unrelated increases in usage. The Company will address volumetric charges and their relationship with regulatory risk and ROE in its response to CEO in the section below but the proposed changes do not represent a regulatory de-risking on par with revenue decoupling.

NWEC/ICL cited the Bonbright principles which they group into four general categories:

1. Sufficiency: Rates should be designed to yield revenues sufficient to cover utility costs.
2. Fairness: Rates should be designed so that costs are fairly apportioned among different customers, and “undue discrimination” in rate relationships is avoided.

---

<sup>2</sup> Multiplying the difference in fixed charge cost recovery for Schedule 1 between the present and proposed levels (32 percent minus 9 percent or 23 percent) by the \$60,147 thousand of base Schedule 1 revenue and dividing this amount by total Idaho base revenue of \$279,491 thousand as shown on Attachment 2 in the Settlement Stipulation filed on October 25, 2021 in the 2021 Rate Case produces about five percent.

3. Efficiency: Rates should provide efficient price signals and discourage wasteful usage.
4. Customer acceptability: Rates should be relatively stable, predictable, simple, and easily understandable.

NWEC/ICL then criticized the Company for focusing on only the fairness aspect of the Company's proposal. However, the Company agrees with NWEC/ICL and Mr. Bonbright that ratemaking must balance all of these principles and has done so with this rate design proposal.

First, the plan will produce the sufficient level of revenue required. Second, it does more fairly apportion costs amongst different customers. Tiered rates that do not reflect cost causation would be eliminated, customer service charges would be set at a level that fairly assigns costs to all customers, and the time periods for Schedule 36 would be modernized to better reflect current conditions. Third, it continues to reward and encourage economic efficiency, because the majority of a residential customer's costs will continue to be recovered through volumetric energy charges. Smaller users and larger users will face the exact same incremental cost for energy usage, which will continue to drive behavior to curb energy use. Importantly though, economic efficiency will be promoted by sending customers more accurate price signals that will give them better information about important energy decisions like whether to get an electric vehicle, invest in rooftop solar, or replace a water heater with newer technology. NWEC/ICL's summary of the efficiency principle references discouraging wasteful energy. Not all energy usage is wasteful though. Electricity is an essential service that makes people's lives better. It heats and cools homes, draws water from wells, and enables a modern standard of living. Sending a clear and consistent price for energy use across a variety of different households upholds this principle and discourages wasteful or inefficient usage.

Finally, the plan meets the principle of customer acceptability because it promotes more stable and predictable bills since the recovery of distribution and customer service costs is achieved through a fixed charge. The elimination of tiered rates also makes residential rates less confusing for customers and will make it easier for customers to understand their bill.

NWEC/ICL claim that “high fixed charges send negative price signals regarding energy efficiency and conservation.” This is inaccurate. Higher fixed charges may send a slightly weaker price signal to conserve, but not a negative one. Customers would still pay approximately 9 cents for each additional kWh they use in the summer and about 7 cents per kWh for each additional kWh they use in the winter.

NWEC/ICL also insist that the customer charge was “never intended to cover any of the fixed costs not related to utility costs that vary by the number of customers.” They then cite a definition given by the Regulatory Assistance Project (“RAP”), and decisions made by the Hawaii Public Utilities Commission and the Washington Utilities and Transportation Commission. NWEC/ICL concludes that at most the Company’s customer service charge should include distribution-service, meter, and the retail function for a total charge of \$10.36. Their citation to other Commissions and to a RAP report does not mean that this is the opinion of all experts on the subject. For example, a report from Lawrence Berkeley National Laboratory written by Lisa Wood and Ross Hemphill examines different perspectives on recovery of utility fixed costs, including a discussion the merits of raising fix charges to a level where they cover the cost of grid services.<sup>3</sup> Also in the Utah Public Service Commission’s final order in the Company’s last general rate case

---

<sup>3</sup> Future Electric Utility Regulation Report No. 5. Lawrence Berkeley National Laboratory (June 2016).

in that jurisdiction, they found that distribution line transformers were a fixed cost that appropriately belonged in the customer service charge.<sup>4</sup>

At \$29.25, the proposed customer charge would be similar to the customer charges of consumer-owned utilities in Idaho. The Company's proposal to set the fixed charge at a level that recovers distribution costs is not an outlier and its basis in the principal of cost causation is sound. The distribution system connects customers to the larger diversified footprint of PacifiCorp's integrated generation and transmission system and to wholesale markets that provide customers with low-cost energy. This system is available to all customers whether they use one kWh or 2,000 kWh. The poles, wires, transformers, and the cost of field personnel who fix them during a storm to get power restored are fixed. Charging customers primarily based on their energy usage is not cost based and is inequitable, as it would result in some customers paying less for distribution services than others, even though they are using the same infrastructure. For example, a customer with a vacation home who uses power only during one season of the year or a customer who has installed rooftop solar should not pay less than others for distribution. Therefore, including fixed costs related to distribution in the customer service charge is a reasonable approach to ensure that all customers pay their fair share of the costs of maintaining and upgrading the distribution system.

NWEC/ICL examined the Company's transformer data and claim that its inclusion in the customer charge is problematic because 51 percent of transformers serve one customer and about three percent serve ten or more customers. They then argue that the inclusion of transformers in the customer charge could result in the urban customers subsidizing rural customers. However,

---

<sup>4</sup> Utah Public Service Commission Final Order in Docket No. 20-035-04 – Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, issued on December 30, 2020 at 77.

this information actually supports the inclusion of these charges in the customer charge, since it demonstrates that line transformers typically serve one or a very small number of customers.

NWEC/ICL present insufficient evidence to demonstrate that a move towards recovering a greater proportion of costs in a fixed charge, instead of volumetric charges, would cause urban customers to subsidize rural customers to a greater extent than presently exists. Per the Company's Rule 12 – Line Extensions, a new home receives a line extension allowance of \$1,550. If the cost to connect service to a new home in a rural location exceeds this amount, which is likely, that incremental costs is paid for by the new customer or developer. The incremental installation cost for remote or more rural home locations is therefore covered by the customer or applicant's advance during construction. While ongoing maintenance for rural locations may be more costly, it is not clear from NWEC/ICL's comments that the Company's proposal would cause greater cost shifting from urban to rural customers. A rural customer could be on net metering and pay no energy charges. Under that scenario, shifting recovery of distribution costs from the energy charge to the customer service charge as proposed by the Company would reduce cross-subsidization.

NWEC/ICL reasons that the Residential Rate Modernization proposal would unfairly burden low-income customers since it would raise bills for customers who use less electricity on average, asserting that is often the case for low-income households. However, the Company disagrees with this argument and believes that the Residential Rate Modernization Plan could actually help customers who experience high energy burdens (that is, customers who spend a high proportion of their income on energy costs). NWEC/ICL's argument relies upon national information to draw its conclusion. Information specific to Rocky Mountain Power's customers in Idaho is a better indicator of how the plan could impact low-income customers. In response to discovery from Staff, the Company prepared some of the same bill impact information found on

Exhibit No. 3, but for only low-income customers who had received energy assistance or weatherization services.<sup>5</sup> The impact of the proposed changes for these customers would be an average *savings* of \$8.30 per month for Schedule 1 and \$3.59 per month for Schedule 36. Exhibit No. 6 shows this information.

NWEC/ICL claim that “properly designed block rates are indeed cost-based.” They attempt to back up this claim by referencing how the first tier rate could be based upon “a rate for in-service, older units” and the second tier rate could be based upon “a higher rate for newer resources or short-term market purchases to meet peak load.” However, this is a misguided approach. Simply because a residential customer uses more energy in a monthly billing period than average does not mean that this particular customer caused incremental new generation resources to be built or that this customer’s load above a threshold should be priced at some incremental market-based level.

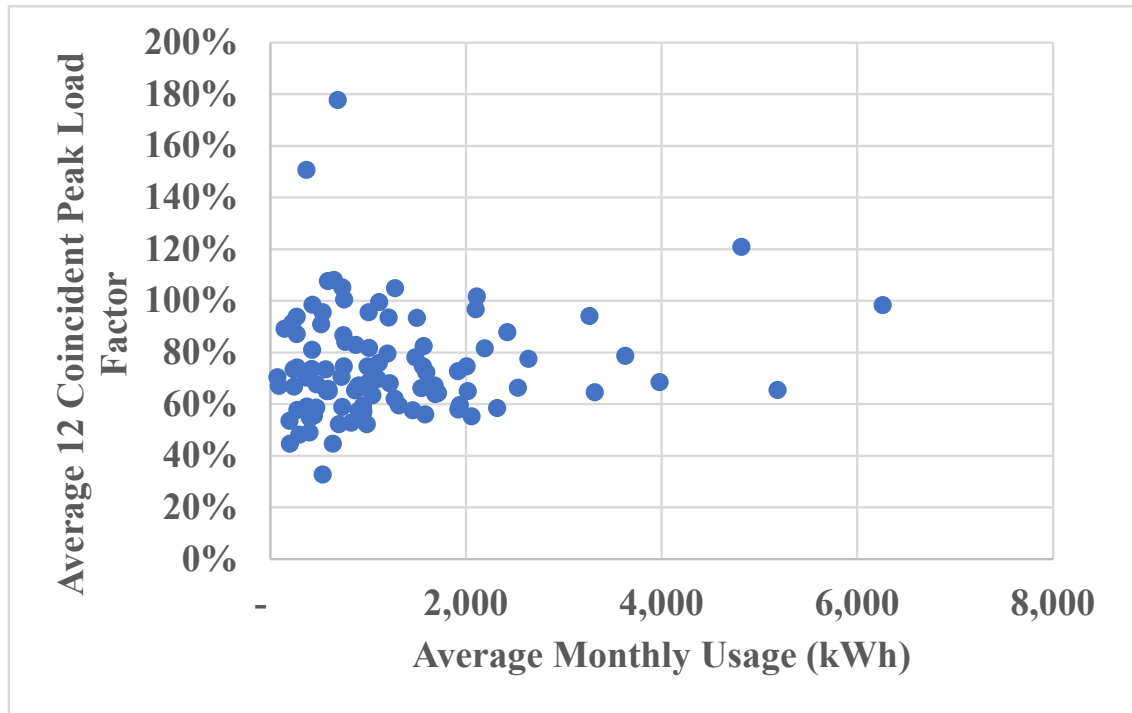
NWEC/ICL also speculate that a cost basis for tiered rates could be set based upon the load factor of residential customers with different usage sizes, assuming that that higher usage customers who use space heating and cooling would have worse load factors that coincide with peak times. However, NWEC/ICL did not provide any analysis of the Company’s customers to support this theory.

To better understand this dynamic, the Company examined information from the load research study that was prepared for the 2021 Rate Case. Figure 1 below shows how average monthly usage compares to load factor for the average of the 12 monthly PacifiCorp system coincident peaks with each point representing a different customer participating in the load research study:

---

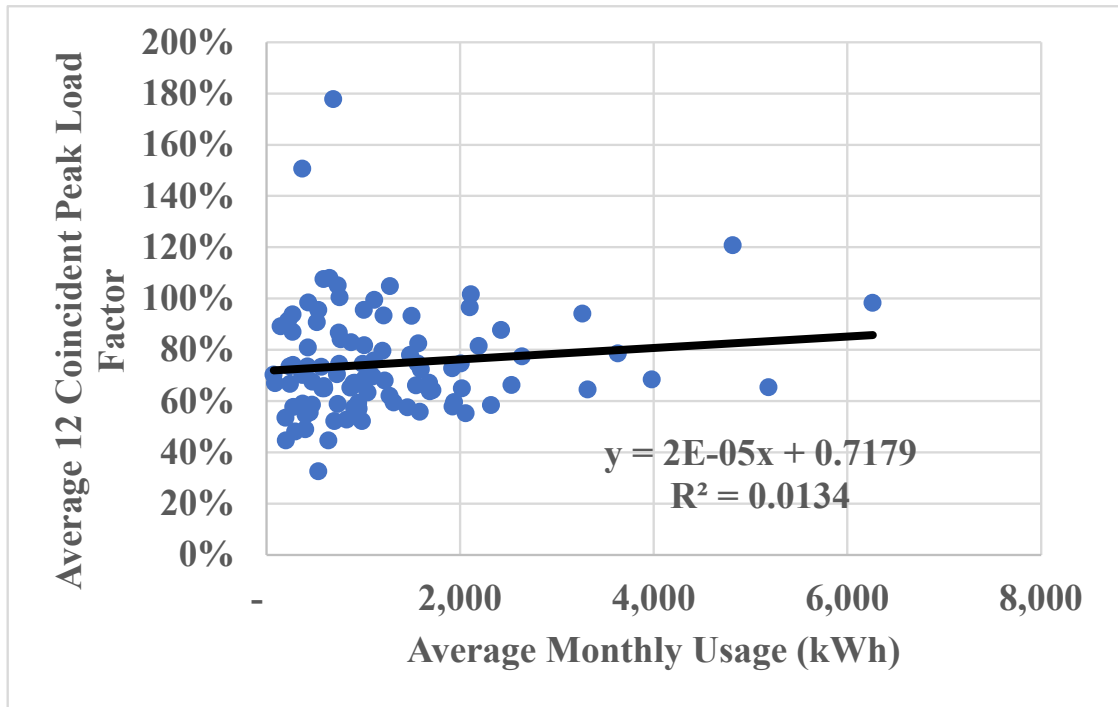
<sup>5</sup> Company response to Staff Production Request No. 4.

**Figure 1. Average Monthly Usage Compared to Average 12 Coincident Peak Load Factor for Load Research Participants**



The 12 monthly coincident peaks are a significant driver of cost allocations in the Company's cost of service studies. A lower coincident peak load factor indicates a customer whose demand is high during peak times relative to average energy usage. A higher coincident peak load factor indicates a customer whose demand is low during peak times relative to average energy usage. Some of the customers have a greater than 100 percent coincident peak load factor, which means that their average usage is higher than their peak usage. Figure 1 shows that there is basically no relationship between usage and coincident peak load factor. Figure 2 shows the same information, but with a linear trendline of the data, which is nearly flat and inclines very slightly:

**Figure 2. Average Monthly Usage Compared to Average 12 Coincident Peak Load Factor for Load Research Participants with Linear Trendline**

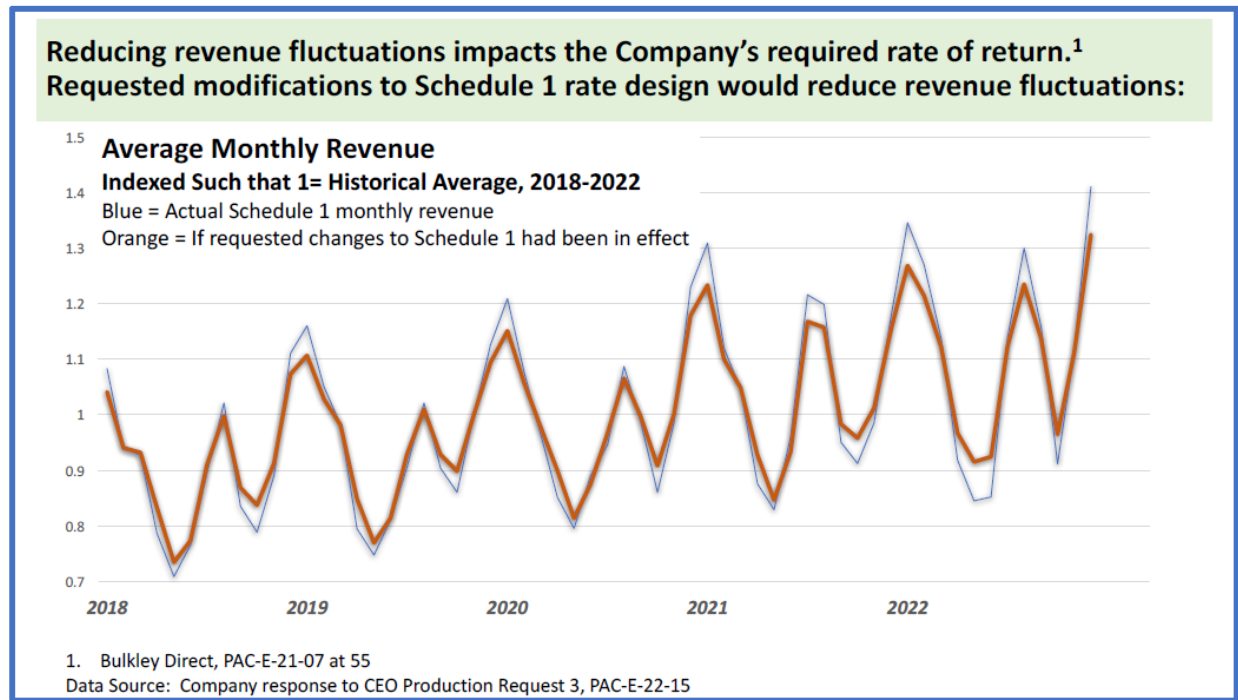


Contrary to NWECC/ICL’s hypothesis there is no correlation between peak load factor and monthly energy usage.

#### **REPLY TO CLEAN ENERGY OPPORTUNITIES (“CEO”) COMMENTS**

CEO raises similar arguments to NWECC/ICL. The Company will not reiterate the same points it already made in its response to NWECC/ICL here for CEO. Like NWECC/ICL, CEO claims that the Company’s Residential Rate Modernization Plan cannot take place outside of a general rate case. CEO makes a similar argument to NWECC/ICL claiming that the Company’s proposal would reduce volumetric risk. CEO produced a chart that shows how the Company’s revenue from Schedule 1 would have changed had the Company’s proposed rates been in place compared to current rates for the past five years. The chart showing CEO’s risk analysis is reproduced below:

**Figure 3. CEO's Volumetric Risk Analysis<sup>6</sup>**



Along with the relatively minor size of the shift from fixed pricing to volumetric pricing for Schedule 1 to total revenue requirement that the Company referenced in its response to NWECC/ICL, CEO's Figure 1 actually illustrates how insignificant the change in revenue volatility would be from the Plan. Schedule 1 revenue would still have the same seasonal pattern but would be slightly higher during shoulder months and slightly lower during the winter and summer peak months. This does not represent a material de-risking for the Company that should result in a lower ROE.

CEO discusses how some customers value more control over their bills and others value greater stability. They suggest an average billing option could be provided for customers who value stability while retaining the existing rate structure and not raising fixed monthly charges on all customers. The Company does offer equal payment plans that balance out the monthly highs

<sup>6</sup> See p. 4 of CEO Comments, figure 1.

and lows throughout the year for participating customers to provide bill stability, but fundamentally the pricing of usage is the same as other non-participating customers. Offering a new rate option that is additional to the current Schedule 36 time of day program that has a different rate structure would create customer confusion, increase the likelihood that the Company under-recovers its costs, and would shift costs between customers.

CEO mischaracterizes the testimony of the Company's expert witness on ROE from 2021 Rate Case claiming it identified rate design as a key factor in determining ROE.<sup>7</sup> Ms. Ann E. Bulkley's testimony is cited by CEO:

*S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.*

CEO has taken Ms. Bulkley's analysis out of the context of her testimony. The "tariff-setting procedures and design" referenced above does not refer to actual rate design issues, like how much is a customer charge or if residential rates are tiered, but the specific circumstances under which the Company can request recovery of its costs. Ms. Bulkley's testimony goes onto explain the risk factors evaluated such as test year convention, treatment of rate base, power cost adjustment mechanisms, and revenue decoupling.<sup>8</sup>

CEO cites another section of the testimony that discusses volumetric risk, but this section is about revenue decoupling and not rate design.<sup>9</sup> As CEO Figure 1 demonstrates, any incremental

---

<sup>7</sup> See p. 4 CEO Comments.

<sup>8</sup> *In the Matter of Rocky Mountain Power's Application for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations*, Case No. PAC-E-21-07. Bulkley Direct. p.54

<sup>9</sup> Ms. Bulkley's complete regulatory risk assessment is shown on Exhibit No. 18. Revenue decoupling, not volumetric risk or rate design, is listed as one of the six regulatory risk factors.

revenue stability from the Company's proposal is small. Nowhere does the testimony reference the actual composition of pricing elements.

CEO argues that the Company's proposal is unfair because had it been raised in the 2021 Rate Case, a different set of stakeholders could have been involved in the case. It then claims that absent the presence of all the same parties who participate in a general rate case, a proper review cannot be completed. The Company's application has been publicly noticed and the Company has communicated the contents of its application through a press release, bill inserts, and public information meetings. Had the 2021 Rate Case parties been interested in intervening, they had every opportunity to do so and engage in the present proceeding.

CEO puts forth a number of philosophical arguments about why it believes that the Company's proposal is flawed. It states that "costs follow benefits" and argues that customers who use more benefit more from shared infrastructure and should consequently pay more. It claims that the "costs follows benefits" principle is commonly practiced in competitive markets. It then puts forward what it believes to be a truly modern best practice of treating only those costs that actually vary with the number of customers as customer-related and apportioning all shared generation, transmission and distribution assets and the associated operating expenses on measures of usage.

The Company disagrees with CEO that this approach is superior to the approach to residential rate design proposed by the Company. CEO's arguments in favor of a very limited view of fixed charges primarily reflects its philosophical convictions. In the Company's view costs should follow cost-causation. Assignment of some costs is straightforward. Assigning the cost of metering to the customer charge or fuel and purchased power to the energy charge is largely non-controversial. For other costs, application of a cost to a specific pricing component is more nuanced and should take into consideration its primary driver. The cost of the distribution system is both

customer-related and demand-related. For non-residential customers, these costs can be recovered through customer and demand charges. Demand charges for residential customers have challenges, so the fundamental question becomes what is the greater driver of the cost of the distribution system for residential customers – energy usage or customer count? The number of customers and their geographic presence on the system is a significant driver for the cost of the distribution system. Using volumetric energy usage as a proxy for demand has a far weaker basis in cost causation. As discussed in the Company’s direct testimony, “[i]f a residential customer uses more energy, that incremental usage will not cause the Company to deploy more poles and wires or set more transformers.” The fixed costs of upstream transmission and generation facilities would continue to be recovered from residential customers through the energy charge under the proposed plan, since those facilities serve more customers and their capacity can more easily be redeployed to serve load in different locations.

CEO contends that the fixed charges for consumer-owned utilities should not be considered, because it believes that investor-owned utilities have greater access to capital markets and can better handle revenue volatility. It is unclear to the Company whether this is true or not, because CEO provides no real evidence to support its claim. The Company does not think that the comparative financing characteristics of investor-owned versus public-owned utilities is relevant to the usefulness of benchmarking customer charges from a variety of different electric utilities across the state. Consumer-owned utilities charge these prices to their customers and those prices have been approved by their governing bodies who are commissioned with acting in the interest of their customers. The fixed charges for both investor-owned and public-owned utilities provide

useful comparison for consideration by the Commission. Also, the Company notes that Avista Corporation has proposed a similar change to its basic charge in its current rate case.<sup>10</sup>

CEO references the Idaho Energy Plan and critiques the Company's proposal since it reduces "the customer's economic incentive to conserve energy or to invest in any technology which would reduce or change the timing of their electricity purchases from the Company." The proposed plan will alter the rate structure so that more costs are recovered from fixed charges, but the overwhelming majority of costs will still be recovered from energy charges, which customers can save when they conserve energy or utilize more efficient technology. As discussed earlier, more closely aligning rate design with cost causation sends customers important information about the economics of different energy decisions. It is important to note that the energy prices paid by customers are adjusted from time to time, including through the annual Energy Cost Adjustment Mechanism. These changes enable the information sent to customers about the cost of using a kWh to evolve over time.

For Schedule 36, CEO recommends that instead of reducing the on-peak window from 15 hours to eight hours, a much shorter window of three to four hours in the summer should be used. The Company appreciates CEO's thoughtfulness on this subject. The Company does have a time of use pilot in Oregon that has a four hour on-peak window. This option in Oregon is a new offering though which stands in contrast to the time-of-day option in Idaho which has been in place for several decades and has the highest adoption rate for residential customers of any of the Company's programs in the six jurisdictions it serves. The Company hopes that the success in Idaho with time varying pricing can continue and is concerned about making changes that could

---

<sup>10</sup> See *In the Matter of the Application of Avista Corporation for the Authority to Increase its Rates and Charges for Electric and Natural Gas Customer in the State of Idaho*, Case No. AVU-E-23-01 and AVU-G-23-01. Miller Direct at p. 27. Proposing schedule 1 basic charge increasing from \$7 to \$35 over 5 years.

be too drastic for current participants. Under the Company's plan for Schedule 36, energy prices for both seasons are relatively stable even with the reduction to on-peak hours. If the on-peak hours were halved from eight to four, a significantly greater price would be needed for on-peak energy charges. The Company is concerned that such a move could cause customers to unenroll from the program.

CEO indicates that it is supportive of an opt-out time of use rate design and believes that in any effort to eliminate inclining block rates, the Company should simultaneously propose a more effective instrument for encouraging the efficient and effective use of energy. The Company thinks that CEO is referencing default opt-out time of use, where all customers are put onto time of use rates and can opt-out onto a tiered rate instead. While the Company is supportive of time of use rates, defaulting customers onto a program and allowing them to opt-out creates confusion and raises a host of consumer protection issues which would need to be dealt with beforehand. Accordingly, CEO's alternative for an opt-out time-of-use is not fully developed nor does it reasonably address the Company's proposal in this case.

### **REPLY TO INDIVIDUAL CUSTOMER COMMENTS**

Through April 17, 2023, the Commission has posted 58 customer comments on the proposed Residential Rate Modernization Plan on its website. Some of the comments appear to use standard forms that were submitted as part of a call-to-action from Sierra Club. Many of those comments are from people who are not the Company's customers and live in Boise, Coeur D'Alene, and Post Falls. The general themes of written customer comments are as follows:

- Concern that the plan will reduce incentives for conservation and onsite customer generation
- Concern that the plan will send a message that will encourage more energy usage
- Concern about how these changes could impact customers who are on a fixed income

The Company appreciates and acknowledges the feedback from its customers regarding the proposed changes to the structure of their electric bills. While all received comments expressed opposition to the plan, it is important to note that the plan is revenue neutral for the Company. The changes would lead to a gradual increase in bills for some customers, while others would experience a reduction in their bills. Customers who would see reduced power bills from the plan did not spend the time to comment. However, the lack of comments submitted by these customers does not imply that they are unaffected by the current pricing regime and tiered pricing, that penalizes their usage by a customer charge that should be set higher and makes energy incrementally more expensive after monthly usage goes over the threshold.

The Company empathizes with customers who may face challenges due to these changes, such as those with a fixed income. At one of the Company's online workshops, a customer who indicated that he was on a fixed income attended to get more information about the plan. He indicated that his winter usage is about 2,000 kWh per month, since he heats his home that was built in the 1970's with electricity. The Company is also sympathetic to customers like this gentleman. At the end of the transition plan, the monthly bill for a lower-than-average usage customer on Schedule 1 for 300 kWh would go up from \$47.74 to \$60.09 – a \$12.35 increase. The bill for a larger-than-average customer using 2,000 kWh per month would go down from \$225.97 to \$180.82 – a \$45.15 decrease.

The Company's plan would not send a message to customers to use more energy. Most costs would still be recovered from energy charges. Customers would save money for every kWh they reduce. At the same time, all customers would pay an equal share of the cost for the distribution system. They would not overpay for this cost if they were a large household with all

electric heating, nor would they underpay if they were a net metering customer with no net usage who still depends on the grid.

At the in-person Commission led customer hearing, eight customers attended and offered verbal testimony regarding the Company's proposal. The Company attended the hearing. The Company appreciates their concern and involvement on this matter. Many of the points made by the attendees were similar to those to which the Company has already responded. The Company will respond to new or unique arguments that were presented at the hearing.

One customer expressed his belief that the Company provides a product and not a service. He believed that a separate charge should not be made for the conduit that delivers the end product and felt that there should be no customer service charge. The Company respectfully disagrees. Electric utility service is unique compared to many other products people consume. It has a permanent connection into customers' homes, delivering it is capital-intensive, and it is not easily stored. At the same time, the level that a customer uses can be measured and there is a cost associated with that usage. The Company therefore believes that the electricity it provides is partially a service and partially a product. It is therefore appropriate to charge for electric service with both fixed monthly and volumetric pricing.

Other customers at the workshop spoke about how they had invested in onsite solar systems and how the increased cost of a higher customer service charge would impact them. They explained that they would not benefit from lower energy charges, since their net usage is either very low or zero. They discussed how their systems were costly and how the proposed plan alters the economics of their decision. The Company echoes Staff comments on this subject "that Idaho Code § 48-1805, Contents of Disclosure Statement for any Solar Agreement, clearly outlines that on-site generation participants should understand that net metering program, cost savings, or

incentives, are subject to change.” Purchasing an onsite solar system is not a risk-free investment. Electric prices are subject to change and gradually increasing the fixed monthly charge fairly assigns solar customers for the cost of the grid upon which they depend. One customer stated how it is difficult for someone who is not wealthy to afford a system that completely takes a customer off-grid and can cost about half a million dollars. The high cost of going off-grid demonstrates the technical challenges that are associated with providing customers with reliable power on-demand whenever they need it and why it is important for solar customers and all customers to pay the same fair share for the distribution system.

### **CONCLUSION**

The Company recommends that the Commission issue an order approving the Company’s Residential Rate Modernization Plan as it was presented in the Company’s application.

Respectfully submitted this 25th day of April, 2023.

A handwritten signature in blue ink, appearing to read "Joe Dallas", written over a horizontal line.

Joe Dallas

*Attorney for Rocky Mountain Power*

Case No. PAC-E-22-15  
Exhibit No. 6

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

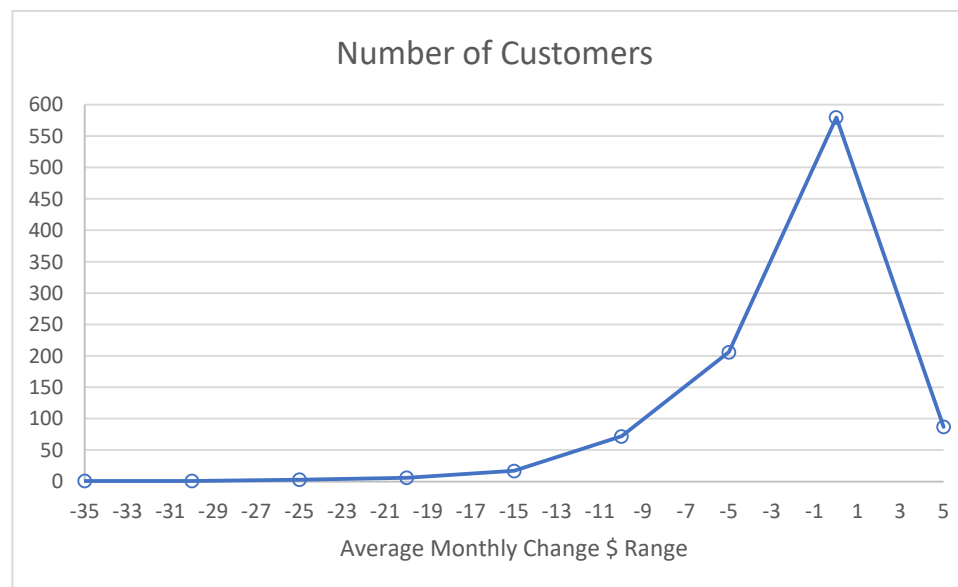
---

Exhibit Accompanying Reply Comments

April 2023

**Rocky Mountain Power**  
**State of Idaho**  
**Schedule 1 - Dollar Distribution of Monthly Bill Impacts across Customers for First Year Change**  
**Annual**

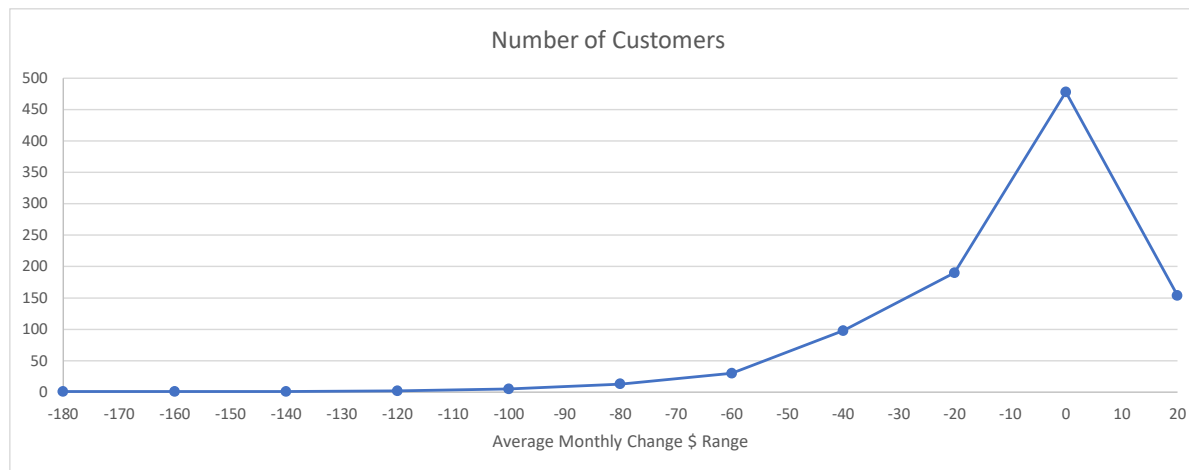
Change \$ Range	Number of Customer	AVG \$ Change	AVG KWH
-35	1	-37	5,685
-30	1	-32	5,159
-25	3	-25	4,105
-20	6	-19	3,436
-15	17	-15	2,843
-10	72	-9	2,134
-5	206	-5	1,515
0	580	0	761
5	87	3	287
<b>Grand Total</b>	<b>973</b>	<b>-2</b>	<b>1,051</b>



Rocky Mountain Power  
State of Idaho

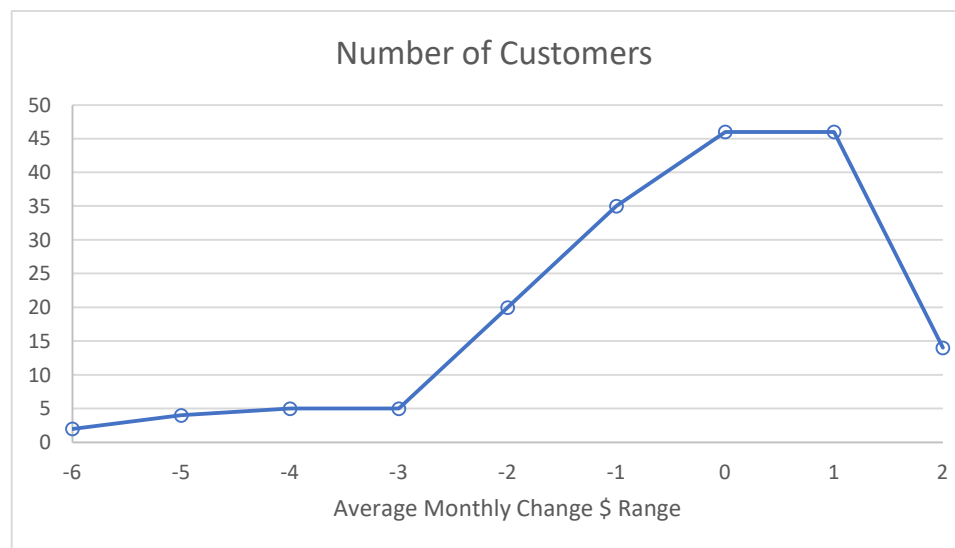
Schedule 1 - Dollar Distribution of Monthly Bill Impacts across Customers Over Full Transition Period  
Annual

Change \$ Range	Number of Customer	AVG \$ Change	AVG KWH
-180	1	-184	5,685
-160	1	-161	5,159
-140	1	-132	4,346
-120	2	-120	3,985
-100	5	-99	3,474
-80	13	-79	2,950
-60	30	-57	2,399
-40	98	-38	1,903
-20	190	-19	1,378
0	478	2	776
20	154	13	353
<b>Grand Total</b>	<b>973</b>	<b>-8</b>	<b>1,051</b>



**Rocky Mountain Power  
State of Idaho  
Schedule 36 - Dollar Distribution of Monthly Bill Impacts across Customers for First Year Change  
Annual**

Change \$ Range	Number of Customer	AVG \$ Change	AVG KWH
-6	2	-6	4,185
-5	4	-5	3,559
-4	5	-4	3,264
-3	5	-3	2,776
-2	20	-2	2,283
-1	35	-1	1,853
0	46	0	1,283
1	46	1	824
2	14	2	435
<b>Grand Total</b>	<b>177</b>	<b>0</b>	<b>1,505</b>



**Rocky Mountain Power**  
**State of Idaho**  
**Schedule 36 - Dollar Distribution of Monthly Bill Impacts across Customers Over Full Transition Period**  
**Annual**

Change \$ Range	Number of Customer	AVG \$ Change	AVG KWH
-40	2	-39	3,313
-30	5	-28	3,506
-20	17	-20	2,552
-10	42	-9	1,847
0	75	0	1,239
10	35	8	771
20	1	16	1,365
<b>Grand Total</b>	<b>177</b>	<b>-4</b>	<b>1,505</b>

