BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 399

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
Request for a General Rate Revision.	)
	)
	)

OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

August 11, 2022

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 399

In the Matter of PACIFICORP, dba, PACIFIC POWER, Request for General Revision.	REBUTTAL AND CROSS ANSWERING TESTIMONY OF THE OREGON CITIZENS' UTILITY BOARD

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

A. My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/101.

Q. What is the purpose of your testimony?

A. CUB continues to be concerned about the rate shock that residential customers will feel in January as higher rates from a combination of proceedings hit at the peak of the winter heating season.[1] CUB believes the Public Utility Commission of Oregon (Commission) must act in this proceeding to reduce rate shock impact for PacifiCorp's (PAC or the Company) customers. In this testimony, CUB makes a proposal to manage the rate increases included in this docket and related dockets.

[1] UE 399 – CUB/100/Jenks/1-5.

A. Customers are Facing Rate Shock in January

Q. Do you have an update to your Opening Testimony related to rate shock?

A. Yes. CUB continues to be concerned about the rate shock that residential customers face in January. In addition to this proceeding, additional PAC dockets propose substantial rate increases on January 1, 2023. The same day CUB raised the issue of rate shock in our Opening Testimony in this docket, PacifiCorp filed its update to its Transition Adjustment Mechanism (TAM), which increased the proposed rate hike associated with that proceeding from $78.7 million more than the 2022 TAM to $102.3 million more than the 2022 TAM. On July 19, 2022, PacifiCorp filed its Reply Testimony in this docket which reflected "an increase of $9.7 million from the Company's initial filing due to the current rising cost environment."[2] The Company's Power Cost Adjustment Mechanism (PCAM) proposes to add $50.5 million to customer rates.[3] In Opening Testimony, CUB expressed concern that the GRC, the TAM and the PCAM would combine to produce a 18% rate hike. On top of those cases, there are deferrals associated with wildfires and COVID 19 and there is the potential for an additional rate hike associated with coal plant decommissioning.[4] Now, a couple months later, the situation facing customers is not better – it is worse. Residential customers are facing their largest increase in decades and it is coming at the worst possible time.

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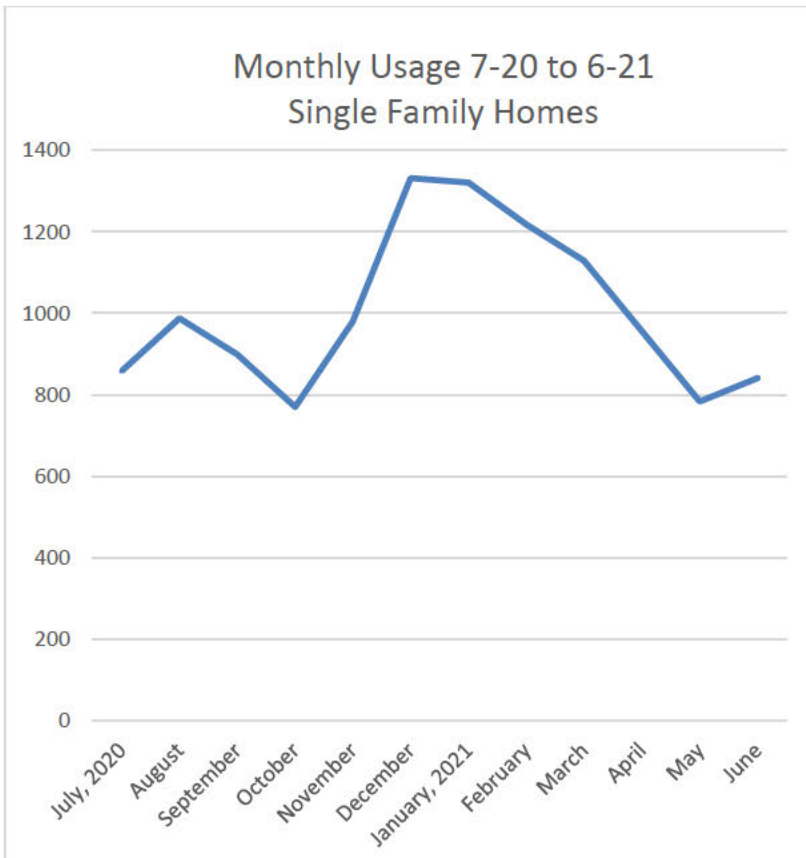
[2] UE 399 – PacifiCorp/1200/Steward/3.
[3] UE 404 – PacifiCorp's 2021 Power Cost Adjustment Mechanism, Initial Filing at 1 (May 16, 2022).
[4] *See* OPUC Docket Nos. UM 2114, UM 2115, UM 2183.

Q. Explain why this is the worst possible time?

A. CUB Exhibit 301 provides the monthly residential usage from July 2020 to June 2021 for both single family homes and multi-family homes. As we can see from this chart, usage is highest in the winter months:

Figure 1 (CUB Exhibit 301)



The average usage is 1,006 kWh per month, and only the 4 winter months, December through March are higher than the average. In January, when these rate hikes are expected to hit customers, the average 2021 bill was 131% of the average monthly bill. Raising rates in the winter, during the highest usage season, means taking customers' highest bills of the year and making them even higher. This is too much to ask of customers, especially all at once. The Commission must establish just and reasonable rates at a level that balances the interests of the utility shareholders and customers. Commission approved rates must be affordable to customers.[5]

Q. Why is January 1 the target date for PAC's rate changes?

A. It is caused by the combination of two policies: direct access regulation and attempting to minimize rate changes. Oregon's direct access program requires utilities to forecast rates for a calendar year and allow large customers the option to seek alternative supplies. Because this requires a January to December forecast of power costs, the Company proposed, and the Commission approved, updating residential rates at the same time. Limiting the number of rate changes has long been a general policy of this Commission, in fact, it is one of the statutory justifications for a deferral.[6] Once it was established that there was an annual rate change on January 1 for power costs, the general policy of attempting to minimize rate changes led to all other rate changes occurring at this time. But it is important to remember that the only thing that is actually required on January 1 relates to direct access.

B. Tools to Address Rate Shock

Q. Does the Commission have the power to address rate shock?

A. The Commission has several tools that it has identified that it can deploy to reduce the rate shock to customers. In a 2001 general rate case, the Commission expressed a hesitancy to adjust rates due to rate shock, but later reconsidered. In 2003, Commissioner Beyer testified to the legislature that it had tools to address rate shock.[7]

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[5] OPUC Order No. 08-487 at 5.
[6] ORS 757.259(2)(e).
[7] CUB Exhibit 302 Commissioner Lee Beyer Testimony to Oregon Legislature.

According to Commissioner Beyer's testimony, the Commission has three tools that can be used to address rate shock:

- Deferring or phasing in the rate increase—with or without carrying charges;
- Setting the rate at a level that is not lower than the lowest reasonable rate; and
- Requiring the utility to propose and implement other rate mitigation measures.

Q. How would the Commission go about deploying these tools?

A. Each of these would be applied in a different manner.

- The first tool, phasing in the rate increase with or without carrying charges, would allow the Commission to approve a rate increase, but limit how much of that rate increase could be allowed to go into effect immediately and provide a schedule to for phasing in the remainder of the increase.
- The second tool is a recognition that there is normally a range of reasonableness when rates are established.[8] This can be clearly seen from testimony on return on equity (ROE). Most of the witnesses first determine a reasonable range of ROEs and then make a recommendation as to where within this reasonable range to set the ROE. This ROE range can be viewed as the range of reasonableness for rates generally. As long as the Commission is setting rates that seek to allow the utility to receive earnings that are within this range, the rates are reasonable. Because of this range, the Commission can reduce rate shock by setting rates at the lowest level that is reasonable but still in the reasonable range.

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[8] *In re Portland General Electric Company,* OPUC Docket Nos. UE 180, UE 181, UE 184, Order No. 07-015 at 26 (Jan. 12, 2007) citing *Duquesne Light Co. v. Barasch*, 488 US 299, 312 (1989).

- The third tool is ordering the utility to take actions that mitigate rate shock. At the time that legislation that addressed rate shock was discussed, Portland General Electric had implemented a smart meter replacement program on top of a large rate hike. The idea behind this third tool is that while the Commission believed that the meter replacement programs was prudent, it still had the power to order the utility to delay cost recovery due the rate shock that existed at the time.

Q. Which of these tools should the Commission deploy?

A. CUB believes that each of these tools can help reduce the impact that customers will feel.

- ***Phasing In Rate Increases***. While CUB understands that there is a general policy to limit the number of rate changes, that policy should not take priority over ensuring that winter bills are affordable. Therefore, CUB believes that the Commission can apply this tool by delaying much of the rate increase beyond the winter months as practicable.
- ***Lowest Reasonable Increase***. While CUB believes that the Commission should consider utilizing this tool, CUB's testimony does not necessarily reflect adjustments based on this tool. CUB and AWEC's cost of capital witness recommends an ROE of 9.25% based on a reasonable range for ROE of 8.80% to 9.70% with 9.25% as the midpoint.[9] AWEC and CUB's witness is not recommending establishing rates with an ROE of 8.80%. However, AWEC and CUB's witness is not analyzing a case that will

[9] UE 399 – AWEC-CUB/100/Gorman/57.

inherently cause rate shock in combination with other PacifiCorp proceedings. One of the problems with the increasing number of alternative ratemaking mechanisms, is that it makes it difficult to apply this tool because the rate shock is not caused by a specific proceeding but by the combination of different proceedings. The Commission will rule on this case after TAM rates are established and in the context of all of the other proceedings, and can take into account the expected January rate hike as long as evidence regarding the rate hike is submitted to the record in this proceeding.

- ***Order the Company to Take Actions***. CUB urges the Commission to direct the Company to take certain actions that can reduce the effect of rate shock. The Commission should order the Company to conduct a January educational campaign encouraging customers to sign up for its equal pay program that will help customer manage their winter bills. The Commission should also consider ordering the Company to spread its recovery of its outstanding deferrals over longer periods of time where appropriate in order to reduce the 2023 impact.

Q. Does CUB has a specific proposal for how the Commission should address rate shock?

A. At this point, CUB does not know the final revenue requirement in this case, whether the final TAM update will increase the rate hike in that case, and whether there will be an additional increase associated with decommissioning coal plants. In addition, while we know that there is a risk of an arctic cold front in January which will increase the rate shock, we don't know if it will happen. Without full knowledge of what will happen without addressing rate shock, we are able to make the following proposal.

- The Commission should establish a rate increase cap for the residential increase that will be imposed on January 1, 2023. If the total amount that residential rates are increasing (combining all cases going into effect on January 1, 2023) is above 15% but below 20%, CUB recommends that this January 1 rate increase cap be set at a 10% average residential increase. If the increase is greater than 20%, then CUB recommends the Commission consider establishing a cap of no more than 15%.
- The Commission could allow an additional increase on April 1, 2023, at the end of the winter heating season. This increase should be limited to an additional 5%. At this point, bills are generally declining but many customers will still be paying off their winter heating bills.
- The Commission should allow the remainder of the 2023 rate increase go into effect on September 1, 2023, at the end of the summer cooling period.

In order to manage this, the Commission will have to determine how the revenue requirement of various proceedings are being layered in order to determine their holistic effect. CUB believes the something along the following lines will be necessary:

- The residential revenue requirement for the TAM would be the first layer. As long as it is under 10%, it will be fully implemented in January 2023.

Because the TAM represents one year of power costs, delaying it either causes the Company to lose its chance to recover its costs, or will lead to recovering it into 2024, when the next year's TAM is also added to rates.

- The GRC should be second. While the GRC is based on a calendar year test year, unlike the TAM, the test year does not define the rate effective period. PGE's recent rate case did not perfectly match the first year of increase with the test year.[10] In addition, GRCs establish a level of rates that extend until the next GRC which could be several years away. Delaying the rate effectiveness of part of the GRC for a few months will not have the same effect as delaying the TAM.
- The Commission would then have to specify what order to layer on the PCAM, each deferral, and any other adjustments that are coming in 2023, such as decommissioning. At the same time, the Commission has to set an amortization period for most of these proceedings, since the costs are unrelated to the test year. CUB proposes the following but recognizes that the Commission will have the full context of all the increases when it makes its decision in this case – something CUB does not have at this time.
- The PCAM should be layered on next. CUB believes the PCAM should be amortized over 4 years. The PCAM was established as a tool to deal with power cost variations that were significant and outside of normal

[10] *In re Portland General Electric Company, Request for a General Rate Revision*, OPUC Docket No. UE 394, Order No. 22-129 at 3, 8 (Apr. 25, 2022). PGE's recent general rate case utilized a 2022 test year with a May 9, 2022 rate effective date.

circumstances. It is not expected that there will be a PCAM surcharge in most years. In fact, this will be the first time that there has been a PCAM surcharge since PacifiCorp's PCAM was established in 2012.[11] Because a PCAM adjustment is not expected to be triggered in most years, spreading the collection over 4 years is reasonable.

- In its original filing in this case, the Company proposed to address six pending deferrals.[12] Two additional deferrals were added to this docket on April 11.[13] CUB recommends that the Commission consider these deferrals in this case, establish the level of cost recovery that is consistent with prudent operation of a utility, and set an amortization schedule. This will allow the interest rate to move to the amortization phase of deferred accounting. The layering of these deferrals should be established consistent with the rate increase caps proposed above. As to the amortization period, PacifiCorp generally proposes a three-year recovery period, while Staff generally supports a two-year recovery period.[14] However, given the potential rate shock, Staff indicated that it "may" support a three-year amortization period.[15] CUB believes that, rather than assigning an arbitrary number of years, the amortization period should consider the type of deferral and whether it is likely to be repeated before the current deferral is amortized, and should recognize that rate shock is a

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[11] OPUC Order No. 12-493.
[12] UE 399 – PAC/100/Steward/14.
[13] UE 399 – Administrative Law Judge Lackey's Ruling (Apr. 11, 2022).
[14] UE 399 – Staff/200/Fox/28.
[15] UE 399 – Staff/200/Fox/29.

2023 issue. Deferrals subject to potential reauthorization before amortization should be delayed. The COVID-19 deferral is associated with an unprecedented public health emergency, unlike anything that has happened in the last 100 years, and is fairly significant. Recovering it over 5 years, or even longer, would be reasonable.

Q. These rate increase caps are set for residential customers, do you have a proposal for other customer classes?

A. Rate shock is not something that is limited to residential customers. Other classes of customers also have trouble absorbing large increases. In addition, there would be a fairness question if the Commission used these rate increase caps to limit increases to residential customers but allowed the full increases to other classes of customers. Before amortizing the revenue requirement associated with any of the dockets contributing to rate shock, the Commission must rule on how to spread the costs. CUB proposes that the residential rate increase caps be used to limit the recovery to other classes of customers consistent with the rate spread of those elements. For instance, if CUB's proposed January rate increase cap allows 100% of the TAM increase, but only 75% of the GRC increase for residential customers (with the rest on April 1), then other classes of customers would also get 100% of the TAM increase and 75% of their GRC increase on January 1, 2023. This means that the rates of other classes would be limited by the residential rate increase caps, but the limit would not necessarily be 10% or 15%.

Q. What about the other tools for rate shock?

A. The Commission should consider the impact of rate shock when setting revenue requirement. If rates are going up by more than 15%, the Commission should consider setting rates in the lower half of the zone of reasonableness.

The Commission should order PacifiCorp to conduct a public education campaign with its customers to ensure that customers know how to sign up for an equal pay program that will help reduce their winter heating bills. The Commission should order the Company to establish amortization periods for the deferrals that help manage rate shock consistent with the rate increase caps.

Q. Does this conclude your testimony?

A. Yes.

UE 399 / PacifiCorp
May 11, 2022
CUB Data Request 18

CUB Data Request 18

Please provide the following information:

(a) Average monthly average single family electricity usage for residential (Oregon) in 2021.

(b) Average monthly average multi-family electricity usage for residential (Oregon) in 2021.

Response to CUB Data Request 18

PacifiCorp does not have the requested data readily available for calendar year 2021. Instead, please refer to the tables below which provides the monthly averages for the 12 months ended June 2021, which is the historic test period for this general rate case (GRC).

(a) Please refer to the table below which provides average monthly kilowatt-hour (kWh) usage for single-family residential customers for the 12 months ended June 2021:

Dwelling Type	Year / Month	Total Bills	Total kWh	Average kWh usage
Single	202007	413,931	355,304,193	858
	202008	414,038	408,970,033	988
	202009	414,300	372,568,260	899
	202010	411,851	317,016,375	770
	202011	412,658	404,359,334	980
	202012	414,302	551,902,420	1,332
	202101	414,359	547,568,260	1,321
	202102	413,974	504,418,293	1,218
	202103	414,491	467,914,068	1,129
	202104	414,829	396,512,988	956
	202105	415,352	325,388,242	783
	202106	416,224	349,998,099	841
	Annual	**4,970,309**	**5,001,920,565**	**1,006**

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May 11, 2022
CUB Data Request 18

(b) Please refer to the table below which provides average monthly kWh usage for multi-family residential customers for the 12 months ended June 2021:

Dwelling Type	Year / Month	Total Bills	Total kWh	Average kWh usage
Multi	202007	104,491	49,277,728	472
	202008	104,550	55,954,053	535
	202009	104,627	52,770,003	504
	202010	104,101	47,156,486	453
	202011	104,647	61,874,971	591
	202012	105,656	87,955,036	832
	202101	111,934	87,327,408	780
	202102	105,089	83,783,320	797
	202103	105,132	77,481,935	737
	202104	105,109	63,611,626	605
	202105	105,346	49,327,604	468
	202106	105,683	50,958,369	482
	Annual	**1,266,367**	**767,478,539**	**606**

MEASURE: HB 3575
EXHIBIT: R
H Business, Labor, and Consumer Affairs
DATE: 4-14-03 PAGES: 7
SUBMITTED BY: LEE BEYER

BEFORE THE HOUSE COMMITTEE
On
BUSINESS, LABOR & CONSUMER AFFAIRS

HB 3575

Testimony of Lee Beyer, Commissioner
Oregon Public Utility Commission

April 14, 2003

I am here today to discuss the effects of the HB 3575 on the Public Utility Commission and the parties we regulate.

This bill amends numerous laws that govern utility ratemaking and other proceedings before the Commission. Some of these changes merely codify existing regulatory standards used by the Commission. Others create new processes and restrictions.

Let me start by saying that the Commission is not wildly enthusiastic about this bill. We do not particularly see a need for it and realize that it will embark us on a considerable rule making adventure over the next 12 to 18 months. We also are concerned about the way it treats the four industries we regulate differently and believe that this may lead to confusion about fairness in Oregon's regulatory process.

However, we feel strongly that everyone involved in the regulatory process must feel that it is fair and provides equal access to all parties. If the parties and the Legislature feel that this is a journey that should be taken, we are ready to do so.

Before getting into the details of the bill, I would also like to commend the sponsoring parties for working with the Commission to address our concerns. Their proposed amendments have resolved many of our initial concerns.

Now to the details; in view of the numerous and varied changes proposed by this bill, I would like to walk through the bill's substantive changes section by section.

Section 1 makes two specific changes to the Commission's general powers to incorporate language from the Natural Gas Act. The United States Supreme Court construed this Act in its *Hope* decision, which established constitutional ratemaking standards used today. Section 1 inserts language to clarify that the Commission has discretion to set the lowest reasonable rates for a utility, and that reasonable rates must provide revenue only for prudent expenses and investment.

The Commission is already required to follow the Supreme Court's decision in *Hope.* Accordingly, Section 1 makes no change in the law or in Commission practice.

Section 3 modifies the Commission's process used in contested cases. It incorporates many ideas raised during the HB 3615 Task Force review relating to *ex parte* communications. It also restricts the involvement of the Governor's Staff, Executive employees, Legislators, and employees of the Legislature in Commission decision-making.

Current law restricts private communications between a party to a case and a decision-maker. The law defines decision-maker to include an administrative law judge (ALJ) and a Commissioner but exempts communications with Commission staff.

HB 3575 expands these restrictions by limiting decision makers from communicating with (1) staff witnesses, (2) Assistant Attorney Generals that represent staff, and (3) staff members that participate in settlement discussions. The proposal to expand ex parte restrictions to include communications with individuals in the first two categories should not significantly change Commission practice. Our internal operating guidelines currently prohibit agency decision makers from privately communicating with any staff member who appeared as a witness in a particular proceeding, or any Assistant Attorneys General that represented Staff in that proceeding.

The proposal to restrict communications with any staff member that participates in settlement discussions, however, is more problematic. Settlement discussions are an important part of our proceedings. The Commission prefers that parties resolve disputes informally rather than proceed with contested litigation. Because these events play an important role, parties prefer that experienced staff members participate in these discussions to help negotiate a settlement that will likely be approved by the Commission.

Due to limited agency resources, however, agency decision makers also must rely on these experienced staff members to provide technical advice. Thus, a conflict exists between the parties' need for key staff at settlement conferences and the Commissioner's need to obtain competent technical advice.

These expanded ex parte restrictions do not apply to all senior staff. HB 3575, however, requires the Commission to adopt rules addressing communications between agency decision makers and staff members not identified above. The Commission's internal operating guidelines noted previously currently address these communications. Consistent with the Commission's obligations to conduct fair and impartial proceedings, these guidelines restrict the conduct of any senior staff that provides technical advice. In providing this assistance, senior staff members are expected to provide independent, expert recommendations and refrain from advocacy.

Finally, it is important to note that the proposed ex parte restrictions are more stringent than those currently imposed on other agencies by the Administrative Procedures Act (APA). While the APA restricts ex parte communications on "a fact in issue," HB 3575 restricts "any communication concerning the issues, merits or facts of the case." The need for this more rigid standard is unclear.

Section 4 requires at least one Commissioner to attend hearings at which substantive testimony is presented related to a request by an electric or natural gas public utility to change rates. A Commissioner need not attend such a hearing if agreed to by all parties to the proceeding.

In response to recommendations by the HB 3516 Task Force, the Commissioners are attending most evidentiary hearings. Moreover, parties may now request an opportunity to appear before the Commission for oral argument. Of these two proceedings, the Commission has found that the oral arguments are of more benefit to the decision-making process than attending evidentiary hearings.

Because the Commissioners are attending more hearings, the proposed requirement that one Commissioner attend major energy cases should not significantly impact current Commission practice.

We have reservations, however, about making Commissioner participation mandatory even if attendance does not benefit the decision-making process. Moreover, we question the basis to require Commissioner attendance at hearings involving rates for energy utilities but not telecommunications utilities.

Section 5 states that the Commission shall enter findings of fact and conclusions of law "*based upon a preponderance of the evidence in the record of the case.*" The Commission is already required to use this standard. Thus, like Section 1, this section makes no change in the law or in Commission practice.

Section 6 requires the Commission to audit accounts of each electric and natural gas utility on a schedule set by Commission rule. The Commission recently renewed its audit program after it had been disbanded for several years. The current policy is to conduct audits in advance of general rate filings and investigate special issues as they merit. Consequently, the proposal to require the Commission to perform these audits should not significantly change current Commission policy. Again, however, we question the requirement for energy utilities while excluding telecommunications utilities.

Section 7 clarifies that, in setting rates for energy utilities, the Commission may take action to mitigate rate increases that would adversely affect customers or the state's economy. These actions include:

1. deferring or phasing-in the rate increase—with or without carrying charges,
2. setting the rate at a level that is not lower than the lowest reasonable rate, and
3. requiring the utility to propose and implement other rate mitigation measures.

The Commission currently has the authority to take any of these actions to mitigate the impact of a rate increase. Consequently, like Sections 1 and 5, this new language makes no change to the law or Commission practice.

Section 8 amends the suspension process used by the Commission to investigate energy utility rate filings. This section requires the Commission to rule on a rate request within nine months of when the rate is to go into effect. No longer would Commission inaction allow a tariff to go into effect by operation of law.

This section substantially modifies the traditional suspension concept used to review and approve utility rate filings. Rather than allowing a filing to go into effect by operation of law, the Commission would be under a legal obligation to rule one way or the other within the nine months suspension period. If it failed to act within that time period, the Commission would be subject to a writ of mandamus.

Section 9 amends laws that govern tariff filings by requiring energy utilities to provide additional justification and notice of rate changes scheduled to take effect upon less than 30 days notice. Utilities must establish the need for the filing and provide copies of work papers and supporting documents on a notice list maintained by the Commission. This section also requires that a majority of the Commission approve any change to rate schedules, and that the Commission establish by rule various procedures to implement the amendments.

The change requiring a majority of Commissioners to approve rate changes is a substantive change to existing regulations. If there is no suspension of a tariff, it will no longer go into effect by operation of law.

The remaining amendments in this section are primarily procedural and should not significantly impact Commission practice. The purpose for these procedural changes, however, is unclear, as the Commission is not aware of any abuse of filings requesting rate changes on less than 30 days notice. Moreover, we again question the adoption of new standards and procedures for energy utilities while excluding telecommunications utilities.

Section 10 amends the deferred accounting provisions by limiting any deferral requested by an electric utility to five (5) percent of the utility's gross revenues. The Commission may exceed this cap if it determines, after a hearing, that a greater deferral is necessary to protect the financial integrity of the electric utility and the public interest.

Limiting the amount of a deferral to five (5) percent of the revenues of an electric utility may have unintended consequences. The power cost deferrals filed by Portland General Electric and PacifiCorp in 2000-01 greatly exceeded this cap. Had the Commission limited those deferrals to the five (5) percent cap, these utilities would have been forced to try to recover these expenses in a general rate filing. Under ratemaking standards, however, those higher power costs probably would have been considered transitory and not appropriate to include in base rates going forward. While HB 3575 allows the Commission to exceed the cap under certain circumstances, the restriction may prevent electric utilities from recovering prudently incurred expenses.

Again, we question the adoption of such a restriction for electric utilities, while excluding natural gas and telecommunications utilities.

Section 11 requires the Commission to conduct a proceeding to investigate and review the use of deferred accounting and report to the 2005 Legislative Assembly. This provision is consistent with the Commission current concerns with deferred accounting and desire to review current statutes, rules and procedures. We question, however, the need to include a request for such an investigation—including topics for consideration—in statute.

No effect on ORS 757.262 mechanisms; change is housekeeping prompted by other changes in deferred accounting in Section 10.

Section 12

Section 12 moves the current deferred accounting provisions for certain purchases from Bonneville Power Administration (BPA) out of ORS 757.259 into ORS 757.663, which authorizes these purchases.

No effect on ORS 757.663 purchases; change is housekeeping prompted by other changes in deferred accounting in Section 10.

Section 13

This section states that amendments in HB 3575 apply only to proceedings before the Commission that were commenced on or after the effective date of the Act.

This section merely indicates when these proposed changes would take effect, if HB 3575 is enacted.

How Utilities Attract Mission-Critical Facilities

by & Timothy R. ComerfordOctober 4, 2015

UNDERSTANDING POWER REQUIREMENTS, ENERGY COSTS AND INCENTIVES

More than any other industry, electric supply is the most important attribute necessary for siting and operating a data center or mission-critical facility. Here we take a look at how utilities can affect the location and operation of data centers by understanding specific power requirements and costs, and review incentives offered by utilities in each state for data centers.

DATA CENTER POWER REQUIREMENTS

Simply stated, data centers require a lot of power. That said, there is no "typical load." Rather, a small data center, especially one housed within a standard office operation, could require less than 1MW while some of the larger data centers easily exceed 100MW. The greatest amount of market activity is generally in the 5-20MW range.

From a utility perspective, data centers have desirable load factors. Many data center operators will plan for a 90 percent load factor, although utility professionals frequently report the actual number is more typically around 80-85 percent.

The voltage characteristics will be dependent on the utility's policy and, in most cases, are determined by the requested capacity and available service in the area. Most large facilities (over 10MW) will be fed via the utility's transmission or sub-transmission systems. Service at this level will then require the data center operator to design, construct and maintain a substation to provide distribution voltage (13.2kV) to the facility. Due to the cost of a substation ($3-$7 million), users will seek opportunities to convert this cost from a capital cost to an operation cost, with the utility or a third party providing the substation.

RELIABILITY AND UPTIME

Power is the lifeline of the data center. Without power, the data center ceases to function. Employees and customers can't access information. Transactions stop. Financial trades aren't possible. Planes stop flying. Health records can't be accessed.

System interruptions are measured by the cost per second of downtime. In financial service operations, these costs can be millions of dollars per second, with downtime having a tremendous impact on customer satisfaction as well as creating embarrassing media coverage, as has been seen recently with the New York Stock Exchange and United Airlines. This is why many data centers are considered "mission critical." Keeping the data center(s) up and running is job No. 1 for the CIO and site manager. Careers end when data centers go down.

For data center operations, the key measure is "uptime," with success measured in "9s" (the percentage of time the data center is available is indicated by the number of nines; for example, 99.998 percent of the time would be considered "four 9s"). New data centers being built today are generally targeting three 9s or better, which works out to be less than nine hours of total downtime per year.

Adequate and reliable power is necessary to avoid such downtime. For an electric utility, data centers can be challenging customers. Data center operators are very demanding, requiring information on power quality factors, outage frequencies, causes and what has been or will be done to avoid future events.

Electric utilities measure uptime or reliability using three indices:

- Customer Average Interruption Duration Index (CAIDI), measured in hours and minutes, tracks the average time a customer on the system is out of service.
- System Average Interruption Duration Index (SAIDI), measured in hours and minutes, tracks the sum of all customer outage duration divided by the total customers on the system, typically over a year.
- System Average Interruption Frequency Index (SAIFI) measures number of interruptions per customer.

COST OF POWER

Power represents 60-70 percent of the total operational cost (TOC) of a data center. If able, a user will chase lower-cost power to reduce the overall operating cost of the facility. This, coupled with optimizing the data center design for energy conservation, reduces the TOC, as well as the facility's carbon footprint. As a result, data center operators are beginning to consider alternative sources of energy to reduce cost. These include renewables, fuel cells and cogeneration.

Enterprise users, which typically have fewer business limitations on where they can locate, will make the cost one of the most heavily weighted selection factors. Many non-financial services enterprise users will decline to consider a location where the average cost will be above $0.07/kWh. Often, a rate less than $0.05/kWh is the target, and multiple data center operations have been able to secure prices below $0.04, particularly in areas utilizing hydro generation.

Colocation providers, on the other hand, tend to locate in close proximity to their customers and along robust fiber routes. Thus, we see a lot of data center activity in large metropolitan markets such as New York/New Jersey, Chicago and Dallas. In the last few years, secondary markets (non-NFL cities) have seen strong growth in data center development, including Columbus, Ohio, and Indianapolis, Indiana, in the Midwest. The colocation providers are less sensitive to national price differentials, but they work hard to ensure the lowest cost possible within their target geography.

However, the price per kWh is not the only material cost to be considered. Due to the large infrastructure requirements of a data center, another critical factor is the total cost required to provide electric service, and whether any of those costs are offset by credits or refunds via the utilities tariffs/service policies. It is necessary to analyze tariffs and rates for any hidden costs that may make a region less competitive, such as duplicate service cost, demand ratchets, revenue credit, security deposits and startup costs that negatively impact data center operations.

These costs can have a significant impact on the financial analysis. The greater the cost borne by the customer, the greater the chance the customer will choose an alternate location.

REDUNDANT SERVICE/ALTERNATE FEEDS

In addition to considering the general reliability of the utility's system, and particularly its record at the site and within the surrounding area, the data center site selection teams look for utilities that understand and accommodate their need for *redundancy*.

Redundancy to a data center can be defined as an equally reliable power source to serve as a backup to the primary or main, source. The backup power source, in almost all cases, will be provided by the utility.

The alternate can be supplied via the same substation as long as a failure of the primary would not have a significant impact on the secondary supply feed. Smaller data center users can be accommodated on lower distribution voltages, without redundancy, but it is critical that the site have adequate capacity and proximity to the source to reduce the potential for outages.

TIMING AND CONSTRUCTION

Timing is also important in selecting a data center location. Capacity that "can be added" is not as favorable as existing available capacity due to the time it will take to make the needed upgrades. For this reason, it is imperative for the utility to communicate with the data center operator to assure adequate capacity can be available within the time frame requested.

The issue of timing also relates to the provision of information. The longer it takes to perform rate estimates, provide cost of service estimates or explore other policy questions, the more likely the customer will be to find another site that works, allowing the operation to be up and running faster.

Once a site for a data center has been defined, development will typically be fast-tracked with an 18-month construction completion schedule as the goal. When construction is complete, facilities and all equipment are commissioned for a period of time during which all critical systems are tested to their design limits. This commissioning process will require cooperation from the local utility to assure adequate capacity for testing is available and that the user's demand, capacity, transmission and ratchet charges in the tariff are waived during the commissioning period. Once commissioning is complete, the site will go into commercial operation. Depending on the end use, loads will gradually grow over time, with an enterprise user growing more quickly and colocation growth dependent on lease activity and tenant equipment deployment. Enterprise users will typically achieve design limits over a several-year period. Meanwhile, co-location may possibly never achieve full design capacity.

UTILITY INCENTIVES

States offer incentives to attract new businesses or expand existing facilities within their borders. Utility companies offer incentives for the same reasons states do: they have millions of dollars of investments in their service territories and many have capacity available along existing infrastructure. Most utility incentives are offered by electric companies, though some are offered by gas utilities. However, determining the available incentives is often difficult since utility service territories don't typically fall along established state, city or county lines. Also, many states have more than one utility company and each will have different incentive options available for companies expanding or relocating into a particular service territory.

Utilities are particularly fond of data center projects, since a data center's high electric load factor allows them to maximize their assets. Recently, a few utilities have incorporated load factor into their incentive rates.

The incentives offered by utility companies typically range from two to five years, with a few lasting longer. All rate discounts depreciate over time during their term and most have minimum kW demand or kWh threshold requirements, either determined as a new load or incremental load increase. The kW demand requirements ranges as low as 10- 25 kW, and while most utilities require a total demand of 200 kW or more to qualify, some require as much as 1,000 kW.

In the case of facility expansions, an increase over prior use, known as incremental load, must meet a threshold over the prior year. The incremental load forms the basis of the credit. In some special cases, some utilities are permitted to negotiate 'off tariff' rates.

Many utility economic development tariff riders are linked with the creation of new full-time

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399

OPENING TESTIMONY OF THE

OREGON CITIZENS' UTILITY BOARD

EXHIBIT 400

I. INTRODUCTION

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

A. My name is William Gehrke. I am a Senior Economist employed by Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/101.

Q. What is the purpose of your testimony?

A. This Rebuttal and Cross-Answering Testimony responds to issues raised by PacifiCorp (PAC or the Company) in its Reply Testimony, filed July 19, 2022 as well as issues raised by other parties to this proceeding in their respective Opening Testimony, filed June 22, 2022.

Q. How is your testimony organized?

A. My testimony is organized as follows:

II. VRET PROCUREMENT CAP

Q. What is the purpose of this section of your reply testimony?

A. In this section of my testimony, I address proposals and positions by Vitesse and PacifiCorp regarding the cap of the Company's proposed Voluntary Renewable Energy Tariff (VRET) program.

Q. Please summarize other parties' proposals regarding the procurement cap.

A. Vitesse proposed that a new procurement cap be set at 175 aMW for new incremental load from existing or new customers.[1] PacifiCorp supports maintaining the current 175 aMW cap but supports a case-by-case approach for new loads should the program be fully subscribed.[2]

Q. Before you respond to other parties' position on the procurement cap, what is CUB's primary concern around the VRET?

A. CUB primary interest is that PacifiCorp's VRET program does not result in undue cost increases to cost of service customers and that unwarranted costs shifting does not occur between program participants and non-participants.

Q. Why is Vitesse seeking to create a new cap under the VRET?

A. Vitesse is a limited liability company owned by Meta and operates data processing and hosting centers for Meta. For the public, Meta is known as the company that runs Facebook and its associated businesses. Meta has expressed a corporate goal to be 100% renewable. Meta is concerned that the program is not sufficiently flexible to accommodate new load it may seek in Oregon.

Q. What is CUB's position on expanding the cap for green tariff customers?

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[1] UE 399 - Vitesse/100/Cebulko/19-21.
[2] UE 399 – PAC/1700/McVee/2.

A. It does not make sense to expand the cap prior to starting the program. CUB is concerned about the risk of expanding the cap prior to having any real-world experience with the program.

Q. What is CUB's response to creating a new cap for new load?

A. Vitesse provides no analysis justifying its proposed 175 aMW cap for new load. From CUB's review of Vitesse's testimony, it appears that Vitesse proposed a cap that would enable acquisition of renewable energy for its Oregon facilities.

Q. How much demand did the Company estimate is queued for the green tariff program?

A. PacifiCorp has only seen 10 customers express an interest in the VRET program, with a total estimated load of 32.2 aMW.[3] This does not indicate a need to expand the cap at this time.

Q. What resources have been acquired for Meta in Oregon for PacifiCorp?

A. PacifiCorp's cost of service ratepayers are paying for the 100 MW Millican and Prineville solar projects. All of PacifiCorp's cost of service ratepayers are paying for the Pryor Mountain (240 MW) project, which was acquired to provide renewable energy credits Meta.

Q. Have other resources in other utilities been acquired for Meta in Oregon?

A. It is CUB's understanding that Meta is a client of QTS' new data center. 250 MW of renewable resources will be needed to meet QTS energy needs in Washington County, Oregon on Portland General Electric's system. Meta has also announced that it is going to create a new data center in Idaho Power's service territory in Kuna,

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[3] UE 399 - Staff/502/Bolton/5.

Idaho. Facebook is the largest corporate buyer of renewable energy in United States. For all three of Oregon's investor-owned utilities, Meta has been able to receive renewable energy facilities to meet its renewable requirements. The Oregon regulatory system and Oregon utility customers have already been more than accommodating to help Meta meet its corporate goals.

Q. Why is CUB detailing these resources?

A. Meta has been able to meet its needs for renewable resources at all three investor-owned utilities that operate in Oregon.

Q. What tension is there between expanding the cap for Meta and maintaining the size of the green tariff cap?

A. Meta is one of the largest corporations in the world. Meta also has corporate goals for its electricity generation to be powered with renewable electricity. Meta would like to continue operating in accordance with its corporate goals and is willing to pay a premium above the cost-of-service rates to acquire renewable electricity for its data centers in Oregon.

However, non-subscribing customers may be in tension with Meta's procurement goals. In the Integrated Resource Plan (IRP) setting, traditionally, electricity resources are acquired in response to either a system capacity or energy need and subject to further rigor in a request for proposals (RFP). RFP-vetted electricity generation resources are acquired either though a power purchase agreement (PPA) or as a utility asset. The subsequently acquired generation resources are the best available prudent resources to meet that need. The value of new generating resources is not guaranteed, because the system is experiencing a specific system need. Green tariff procurements are not subject to these circumstances. Under PacifiCorp's proposed design, green tariff projects are selected from the RFP list after system and state policy resources are selected. Instead of resource need driving green tariff procurement like in an IRP, it is merely customer preferences driving these resource acquisitions. While subscribing green tariff customers pay a premium, all customers bear the risk that the forecasted benefits of the project vary over the life of the project.

Q. Does CUB oppose the VRET program?

A. No. CUB recognizes that customers may want to acquire renewable resources to meet their values, climate action plans or corporate promises. CUB is also aware of the demand for community green tariffs. The controlling VRET guidelines were carefully developed after collaborative and contested processes to protect cost of service customers while enabling a subset to have more control over the energy that serves them. CUB believes that it is premature to expand the VRET program cap at this time.

Q. Are there risks with early action associated with renewable resource procurement?

A. Broadly, yes. Due to federal energy policy support and engineering advances, wind and solar renewable resources have become more effective over time. In the last twenty years, advances in wind technology such as larger nacelles, larger wind facilities, and improved wind generation gearboxes have increased turbine output and reduced costs associated with wind electricity generation. In 1999, PacifiCorp constructed its first utility scale wind project at Foote Creek in Wyoming. When initially constructed, the 41.4 MW facility consisted of 68 600-kilowatt turbines. The Company recently repowered the facility and replaced the existing 20-year-old turbines with 13 new turbines. Solar facilities have improved in performance overtime. Due to advances in technology, solar panels have become more efficient and cheaper to install. Utility scale solar projects are being designed around energy storage facilities to take advantage of federal tax credits, and to enable solar facilities to provide energy during high value periods.

Under PacifiCorp's proposed VRET program, the above market cost premium paid by the subscribing customer is fixed over the life of the resource. The premium paid by subscribing customers is subject to the value of the forecast. A variety of factors can the change the forecasted value of the VRET resource, include changes in natural gas prices, lower all-in costs for future renewable resources, and a mismatch between the timing of renewable generation and system needs.

Q. Please describe Vitesse's argument around new load and HB 2021.

A. Vitesse states that allowing qualifying participants to bring on new load though the VRET would enable customers to willingly take on the incremental cost that would normally be shared with other cost-of-service customers.[4]

Q. Does CUB agree that Meta is taking on all the incremental cost associated with new load, if a new customer cap was created and subscribing customers paid for the premium associated with a new VRET resource?

[4] UE 399 – Vitesse/100/Cebulko/20.

A. No. CUB acknowledges that there is a benefit to customers subscribing to a VRET resource and paying for portions of the incremental costs associated with the resource and being on cost-of-service rates. However, CUB disagrees that a large new industrial customer subscribing to a VRET program would be taking on all the incremental cost associated with new load.

Q. What kind of load profile do enterprise data centers have?

A. Data centers are known to have a very high load factor. Enterprise data centers have high and consistent energy usage all day.[5]

Q. What kind of resources are being acquired to meet Meta and other data center companies' resource needs?

A. Renewable resources that are variable, such as solar (which only produces during daylight hours), and wind (which only generates electricity during appropriate cut-in speed at turbines and stops producing once wind reaches the turbines cut-out speeds).

Q. What type of system benefits do renewable resources such as wind and solar provide?

A. Renewable resources cannot meet the energy and capacity needs of a large data center customer. While renewable resources such as a wind and solar provide a capacity value to PacifiCorp's system, these resources primarily provide energy benefits to the system.

Q. What kind of resources are needed to handle the difference between data center loads and a new renewable resource's production?

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[5] CUB Exhibit 401.

A. PacifiCorp has an obligation to meet the electricity load on its systems. PacifiCorp manages a portfolio of electricity resources to meet load. The Company owns, operates, or contracts for coal, natural gas, wind, hydro, solar and geothermal electricity generation. The Company may also rely on economic market purchases of wholesale electricity. Generally, PacifiCorp operates its energy portfolio to meet system needs on a long-term, mid-term, and short-term basis. In short, renewable resources alone cannot meet the load factor and demand of a data center.

Q. What are the differences between new load entering PacifiCorp system as a system need versus as a new customer entering the system as a VRET customer?

A. In the IRP, PacifiCorp develops a portfolio that meets system need. All six of PacifiCorp's states pay for resources that meet system needs. A new large industrial customer in Oregon may bring a system need and would require six states to bear the risk and costs of new resources. In contrast, Oregon is situs-assigned all the VRET costs under the 2020 Multi-State Process Protocol, and bears the risk of the new resource. VRET resources are not planned for the in the IRP, and therefore Oregon customers would be on the hook for their costs.

Q. Please summarize Vitesse's alternative recommendation to creating a new cap for new load.

A. Vitesse recommend that the Commission provide a case-by-case waiver to the cap for a perspective new load customer.

Q. Why is CUB concerned about the waiver proposal from Vitesse?

A. CUB is concerned about external political interference that would be placed on the Commission prior to a waiver request to expand the cap to meet new load customers. This has already occurred in past waiver requests on Meta-associated projects before the Commission. In UM 2022, QTS and Portland General Electric filed for a petition to increase green tariff customers supply option capacity levels. The mayor of Hillsboro wrote:

> [t]he approval of this filing is critical for Meta (formerly Facebook) to support its operations with 100% renewable energy, and it would also support the State's and City of Hillsboro's decarbonization goals and generate positive economic impact and jobs… Approval of this filling is critical to QTS to have a pathway for its potential long-term tenant, Meta, to support its operation in Hillsboro with 100% renewable energy.[6]

CUB would like to note that it is not criticizing the mayor of Hillsboro for writing this letter. CUB believes that Hillsboro was seeking to reasonably represent its interests before the Commission. CUB is bringing this forward to highlight how political influence can impact green tariff waiver applications. While economic development is not the mission of the Commission, political pressure may make it difficult for the Commission to avoid approving a waiver approach. Further, requests for waivers are viewed in expedited proceedings that contain a limited ability for stakeholders to review the costs and benefits of the resource in question.

Q. Does CUB agree that the Commission should determine a criterion for waiver approaches at this time?

A. No. In Opening testimony, Vitesse advocated as an alternative to expanding the cap to establish a process for providing waivers that provides certainty for the applicant.[7]

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[6] UM 2202 – City of Hillsboro Mayor Steve Callaway's letter of support.
[7] UE 399 – Vitesse/100/Cebulko/22.

Vitesse put forward two conditions: the first is that the petitioner must demonstrate that the resources will help the state meet the goals of HB 2021, and the expansion of the VRET program will not harm the competitive market. If adopted, these seem to be weak conditions, and would functionally lead to no cap being present. All VRET resources will help with the goals of HB 2021 by introducing new renewable energy resources, and the VRET program is a different program than direct access energy procurement. CUB asks the Commission to address expanding the cap, based on the facts at the time, rather than based on Vitesse's waiver conditions.

Q. What are PacifiCorp's incentives around large new customer growth?

A. While CUB appreciates the PacifiCorp's support of not expanding the cap, the Company appears to be open to allowing waivers. Since PacifiCorp is a vertically integrated fully regulated utility, a new data center is attractive to PacifiCorp's bottom line. Unlike residential customers, large energy users such as data centers have options on where to place their facilities, and competitive options for procuring new energy. Large energy users such as Vitesse provide PacifiCorp the opportunity to finance new capital investments for large new usage energy customers.

III. VRET ADMINISTRATIVE FEES

Q. What is the purpose of your testimony?

A. In this testimony, CUB responds to PAC's testimony on the VRET Administrative fee revenue. As a compromise position, CUB accepts PacifiCorp's proposal to pass back administrative fee revenue back to all cost-of-service customers.

Q. What is CUB's position on the Company's offer to defer administrative fee revenue to customers?

A. CUB is willing to accept this proposal as a compromise position, and to provide certainty on this topic. CUB disagrees that forecasting these revenues in the Transition Adjustment Mechanism (TAM) would be administratively burdensome and should not occur. PacifiCorp routinely introduces difficult to forecast net variable cost items in their forecast. However, CUB's primarily goal in addressing this issue is ensuring that cost of service customers timely receive administrative fee revenues to symmetrically match the Company timely recovering costs associated with VRET PPAs in the TAM.

Q. Does CUB agree that the credit should apply to all cost-of-service customer rates?

A. Yes. CUB agrees that the Company's proposal is reasonable. CUB understands the double counting issue.

IV. VRET AND PACIFICORP-OWNED PROJECTS

Q. What is the purpose of your testimony?

A. In this section of the testimony, I respond to the testimony of PAC, the Northwest & Intermountain Power Producers Coalition (NIPPC) and Staff of the Public Utility Commission of Oregon (Staff) on the Company's proposed VRET and Company-owned Projects.

Q. Please summarize your position.

A. CUB recommends that the Commission not allow the Company to acquire Company owned resources under the VRET program, until the Company proposes a sharing methodology of rate of return on Company projects or adequate safeguards on VRET Company owned projects.

Q. What is Staff's position?

A. Staff proposes that the Company should not be allowed to own VRET resources, until it complies with the Commission's owned resource condition. Staff believes this position to protect the competitive market for electric generating resources.

Q. What is PacifiCorp's position?

A. The Company's position is that it will bring forward specific safeguards before the Commission for consideration before investing in any owned resource for the program. Therefore, CUB's arguments around the VRET resource type should not preclude approval of the VRET.

Q. Is CUB recommending rejection of the VRET?

A. No. CUB recommends approval of VRET. CUB is proposing to modify what resources the Company can procure for the VRET.

Q. What is CUB's position?

A. PacifiCorp has had several years to review the Commission's guidelines for a VRET program. While the requirements were recently updated in UM 1953, the overall guidelines have not been updated. The Company had the opportunity to propose specific requirements to protect cost-of-service customers from owned resources when filing this case. The Company did not provide these protections. In Opening Testimony, CUB gave the Company the opportunity to provide protections to customers. In Reply Testimony, the Company did not provide any protections.

Protections for customers should be in place prior to entering into the program. The Company has a huge financial incentive to own a new resource. CUB is concerned that the Company will move forward with a Company owned resource in the VRET.

The burden will be on Staff and intervenors to ensure that conditions are favorable. If Staff or CUB oppose company-owned VRET resources due to appropriate safeguards, VRET procurement may be delayed, and customers may be upset with the regulatory process.

Q. How are Company built resource costs recovered from customers?

A. In general, PacifiCorp does not develop new renewable resources. The Company acquires the resource through a build transfer agreement. Under these agreements, the Company agrees to pay a developer a negotiated set price for a fully constructed renewable facility. Once the project is completed and operational, the project developer transfers ownership of the project to the utility. The capital costs of the utility are financed. Through cost-of-service pricing, customers bear the risk of changes in operating costs, financing costs, and capital costs over the life of the resource. PacifiCorp annually forecasts the energy benefits of a new project, when calculating TAM rates. Customers also bear the production risk of a new resource over the life of the project. In general, customers bear the bulk of risk associated with changes in the fixed operation and maintenance costs and capital costs of PacifiCorp owned facility.

Q. How are contracted projects costs recovered from customers?

A. The Company signs a purchased power agreement with a developer. Through this contract arrangement, the utility agrees to pay a price for the output of the project for a set period. The utility passes these costs to cost of service customers. In a PPA, customers are protected from risks. In a purchased power agreement, developers bear the risk of energy production. Wind resources generate based on wind conditions at the facility. Solar resources generate based on the amount of solar energy collected. Under a PPA, if a resource underperforms forecasted generation, the developer bears that risk through less electricity sales to the utility.

V. TAM GUIDELINE CHANGES

Q. What is the purpose of your testimony?

A. CUB responds to the testimony of Staff and PacifiCorp on changes to the TAM guidelines.

Q. What changes has PacifiCorp proposed on the TAM guidelines in Reply testimony?

A. PacifiCorp has proposed to change the TAM guidelines to have a TAM rate year update on April 1st during rate case years, and on March 1st during non-rate case years. PacifiCorp is asking permission to have multiple rate changes occur within the rate case year for the TAM.

Q. What are implications of the rate year update, if adopted by PAC and in a future proceeding by Portland General Electric?

A. CUB would be in the position of constantly reviewing power cost updates on a regular basis throughout the year. This is extremely burdensome and would be exacerbated if Portland General Electric were to adopt a similar rate year update. While PacifiCorp has a dedicated net variable power cost (NVPC) team, intervenors do not have the luxury of a full-time, ratepayer-funded team to review these costs on a regular basis.

Q. What is Staff's position on the mid-year TAM rate update?

A. Staff supports the Company's proposal to have a mid-year TAM update, because it will result in a more accurate forecast.

Q. What is CUB's response to Staff's position on the TAM update?

A. The primary goal of the TAM is to establish an accurate annual forecast of NVPC. However, that goal was articulated in regards to the current structure of the TAM. It would be more accurate to monthly update net power costs rates within the year, based on updated power and natural gas curves and load forecast. However, such a proposal would have the downside of increasing the variability of customer rates. Rates are based on annualized costs. CUB is surprised that Staff is supporting the Company's modeling change, because PacifiCorp's proposal to update costs within the year on a regular basis is contrary to how rates are created.

Q. Has PacifiCorp rebutted CUB's position on hydroelectricity being a lower portion of PacifiCorp's system overtime?

A. No. PacifiCorp's response is that comparing capacity to energy is misleading.[8] CUB agrees that capacity and energy are not equivalent. CUB use of capacity to compare the quantity of hydroelectric systems on PacifiCorp's portfolio does not take away from CUB's point that hydroelectricity is expected to be a lower part of PacifiCorp's resource mix looking ahead. The Klamath River facilities are expected to close in the next few years. As the Company adds new resources, hydroelectric facilities are going to be a smaller portion of the Company's generation mix.

Q. Do other utilities use a non-normalized forecast for hydro?

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[8] UE 399 – PAC/700/Wilding/21.

A. Yes. Idaho Power uses a non-normalized forecast for hydro. In contrast to PacifiCorp's proposal, Idaho Power does not rely on a mid-year rate year update to address APCU costs. Instead, Idaho Power updates power costs in June of each year. In contrast to PacifiCorp, Idaho Power relies on a large portion of hydroelectricity from the Snake river basin to meet its electricity needs. PacifiCorp has a significantly lower portion of hydropower on its system compared to Idaho Power.

Q. Does CUB support WRAP contracts being included in a rate year update?

A. No. The program is currently in the non-binding phase. The Company has presented no evidence as to the frequency of costs or revenues due to the WRAP program—parties are unaware whether the WRAP will be a net benefit or cost to PAC and its customers. Since the program has not yet begun full operation, it is premature to include these costs in rates. CUB is concerned about reviewing these contracts costs for the first time on an accelerated basis in a mid-year update.

Q. PacifiCorp states that CUB misunderstands the Company's proposal around the mid-year update. Is that correct?

A. No. In the last round of testimony, CUB clearly detailed a scenario where CUB responded to an update to a power cost proceeding without testimony and briefing. In the current TAM framework, the November update is the final TAM proceeding that is used to calculated NVPC in the next calendar year. Other updates are advisory, and do not result in a rate change. CUB objects to seeing new power contracts, hydroelectric streamflow modeling, and load forecasts with less than 1 month to review and potentially contest an issue to protect customers.

Q. Does CUB have any other concerns with the mid-year update?

A. Yes. CUB is concerned about the ability to adequately conduct discovery in a mid-year update. CUB is wary to accept an accelerated proceeding, which may depend on discovery from PacifiCorp. CUB may not be able to timely receive the information it needs to fully audit the Company's proposal.

VI. PCAM

Q. What is the purpose of your testimony?

A. In this testimony, CUB responds to the testimony of Staff, PacifiCorp, and the Alliance of Western Energy Consumers (AWEC) on proposed changes to the Power Cost Adjustment Mechanism (PCAM).

Q. What principles have been associated by the PCAM by the Commission?

A. In UE 246, Order No. 12-493, the Commission detailed five general principles "that form the basis of a well-designed PCAM:"

> (1) any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those normal business risk for the utility;
>
> (2) there should be no adjustments if the utility's overall earnings are reasonable;
>
> (3) the PCAM's application should result in revenue neutrality;
>
> (4) the PCAM should operate in the long-term to balance the interests of the utility shareholder; and, implicitly,
>
> (5) the PCAM should provide an incentive to the utility to manage its costs effectively.

Q. What is CUB's position on the PCAM?

A. CUB recommends that the Commission make no changes to the PCAM in this case. PacifiCorp recently requested PCAM changes which were fully contested in a recent general rate case, and the Commission should decline to address changes to the PCAM mechanism until other power cost issues are resolved.

Q. What is the PacifiCorp's goal around the PCAM?

A. PacifiCorp very transparently stated in reply testimony that the Company's long-term goal is to enable the 100% pass through of NVPC to customers. The Commission should view the Company's constant PCAM proposals as a tactic to gradually eliminate the PCAM. Regardless of the outcome of this proceeding, CUB expects that the Company would continue to advocate for positions that would result in a movement towards 100% percent pass though of NVPC. The Company wants to earn a profit on financing new generation, while eliminating normal business risks around generation costs to serve the interests of shareholders. The Company does not want to bear normal business risk for NVPC.

Q. Does CUB agree with any other party on the PCAM?

A. CUB agrees with AWEC's position articulated in AWEC's Opening Testimony. CUB agrees with many of the points raised by AWEC regarding the PCAM. CUB recommends that the Commission decline to address any PCAM changes in this case.

Q. Does CUB have issues with any of the evidence that PacifiCorp provided on NVPC recovery?

A. Yes. In PAC Exhibit 1500, Figure 1 the Company produced a chart that detailed Oregon NVPC collected in Rates versus Actual NVPC in rates. PacifiCorp asserts that it will under-recover NVPC by 81 million in 2021. In the 2021 PCAM, PacifiCorp has requested recovery of 47 million of 2021 NVPC in the PCAM. [9] PacifiCorp's testimony exaggerates the quantity of NVPC recovery in 2021. While the final 2021 PCAM amount is still subject to Commission approval, CUB expects that customers will pay millions of dollars to support the Company's 2021 profits in the future under the 2021 PCAM.

Q. What are the Company's arguments around that the PCAM ensures that the distribution of risk results in a systematic bias against the company and does not achieve revenue neutrality?

A. The Company argues that the Company is incentivized to accurately forecast NVPC, while intervening parties are incentivized to under-forecast NVPC.[10] CUB disagrees with the Company's assertion. In the ratemaking process, customers and the Company have different incentives. The Company would like to earn as high of a profit as possible from customers and reduce risks for shareholders. Customers would like to receive electricity service that meets their needs, at lowest possible cost. This is how the regulatory system works.

Q. The Company states that non-company parties advocate for low NVPC so that customers rates are kept low, without triggering the PCAM. The Company asserts that this behavior is driven by two reasons. The first is that there is no customer outrage if the costs of under-recovery are borne solely by the Company. The second is that PacifiCorp, as a subsidiary of Berkshire

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[9] UE 404 – ERRATA PAC/100/Painter/5.
[10] UE 404 – PAC/1500/Wilding/10.

Hathaway, is immune from economic harm. What is your response to these statements from PacifiCorp?

A. The TAM began as a mechanism to accommodate direct access for certain customers. As a side effect of needing to calculate transition costs for direct access customers, the Company had to annually calculate NVPC for cost of service. Under the TAM paradigm, customers bear 100% of forecasted NVPC, and these costs are updated annually. Shareholders do not complain when customers' rates increase by millions in response to increases in NVPC for shareholders to have a greater opportunity to earn its regulated profits. If natural gas prices increase by 300%, PacifiCorp is allowed to pass the impact of these costs increases to customers. The current framework reduces risk for the Company and reduces economic harm for the Company. The Company is allowed to recover 100% of forecasted NVPC and is allowed to recover differences between forecasted and actual power costs subject the PCAM.

Q. The Company states that it faces "competition for customers, public relations, and the Company's own corporate principals … PacifiCorp is therefore incentivized to advocate for changes in the TAM's NPC forecast that result in an accurate forecast of NPC, with neither under nor over-recovery."[11] What is CUB's response to this statement?

A. CUB fails to see what competition the Company faces for its captive customers in its monopoly service territory. PacifiCorp is a vertically integrated investor-owned electric utility. Residential customers do not have ability to choose other electricity utility service providers. For larger customers, the Company has experienced little

[11] UE 404 – PAC/1500/Wilding/10, lines 5-10.

competition from direct access providers. CUB is also skeptical of the Company's public relations and corporate principals argument. In CUB's experience, the Company's primary goal in a regulatory proceeding is ensuring that PacifiCorp's business plan is executed by either raising rates or reducing risk for equity holders, regardless of public relations.

Q. The Company requests to exclude specific months from the PCAM. Do you agree with the Company's proposal?

A. No.

Q. Staff requests to exclude qualifying facilities (QFs) from the PCAM. Do you agree with Staff proposal?

A. No.

Q. Why does CUB disagree with both Staff and the Company's proposal to exclude specific items from the PCAM?

A. There is already a mechanism to handle variations between actual net variable power costs and forecasted net variable power costs: PacifiCorp's PCAM. Both Staff and the Company's proposals run contrary to established PCAM principles.

Both Staff and the Company's PCAM proposals allow for rate changes to occur without considering the Company's earnings, which violates the second PCAM principle.

Q. What is the Company's position on Staff's QF proposal?

A. The Company supports Staffs proposal to make QFs not subject to the PCAM, because it shifts 100% of PURPA performance to ratepayers. This aligns with the

Company's long-term goal to have power costs be 100% passed through to customers.

Q. Does CUB have an alternative to Staff's proposal?

A. Yes. Parties could work to improve PacifiCorp's qualifying facilities forecast in the 2024 TAM.

Q. PacifiCorp wants flexibility to exclude high-cost specific months from the PCAM. Would CUB be able to propose to exclude extremely low-cost months from the PCAM to refund to customers?

A. No. CUB will first address the barriers that exist to such a proposal. First, the Company would insist on a holistic look at historic earnings, annual historic net variable power. Second, there is a preparation gap between the Company and Intervenors. PacifiCorp has a dedicated net power cost team, who evaluate net power costs on a regular basis. The Company knows what is actual monthly power costs are, and has easy access to PacifiCorp's trading team, and subject matter experts. Intervenors and Staff, on the other hand, are reactive to the Company's filings. CUB does not know monthly power cost results until PacifiCorp files for its PCAM mechanism. It also takes extensive discovery and time to analyze historic power costs after the PCAM is filed. Unlike other utilities, PacifiCorp does not conduct quarterly net power cost workshops with Staff and frequent power costs intervenors. There is limited insight into PAC's actual operations and the power costs as it incurs.

Q. Does CUB support Staff's proposal to use deferred accounting to accommodate extreme unforeseen events?

A. No. As a matter of policy, CUB recommends that the Commission avoid using single issue deferrals to handle changes in NVPC. The PCAM already provides a framework for the Company to handle historic variations in NVPC. If Staff's recommendation was adopted, CUB is concerned that Staff and PacifiCorp do have a consensus on the appropriate time to use deferred accounting for extreme unforeseen events, in particular the magnitude, type and contours of events that qualify for deferred accounting.

Q. Can you provide a relevant example where clear expectations around the use of deferrals lead to disagreements between intervenors and an investor-owned utility?

A. Yes. There was a recent conflict over storm restoration costs. In UE 319, Portland General Electric had a storm restoration mechanism, where Portland General Electric annually collected storm restoration costs as a self-insurance mechanism with Level III storms. In UE 319 and UE 335, Staff and CUB stated that Portland General Electric could use deferred accounting if a large storm event depleted the self-insurance mechanism. In UM 1817, Portland General Electric filed for a deferral for storm restoration costs in 2017. Intervenors argued that Portland General Electric's storm restoration costs were not substantial enough for deferred accounting. There was not a common understanding on what costs are appropriate for deferred accounting between parties and the level of magnitude. CUB would like to avoid a repeat of that type of situation with the PacifiCorp's PCAM and deferred accounting. Therefore, CUB recommends that the Commission reject Staff's recommendation to allow deferred accounting for net variable power costs. PacifiCorp's PCAM has been functioning as intended and provides protection for both the Company and its customers. It also avoids unnecessary litigation.

VII. COAL PLANT DEPRECIABLE LIVES

Q. What is the purpose of your testimony?

A. In its initial testimony, PacifiCorp requested that several coal plant depreciable lives be adjusted and that deprecation rates be revised to match these new depreciable lives. In this testimony, CUB responds to the testimony of PacifiCorp and AWEC on Colstrip and Jim Bridger 1 and 2 depreciable lives.

A. Colstrip

Q. What is Colstrip?

A. Colstrip is a coal-fired power plant located in Montana. The power plant consists of two 740 MW generating units. PacifiCorp owns 10% of units 3 and 4 of the Colstrip Power Plant. Northwestern Energy, Talen Energy, Puget Sound Energy, Avista, Portland General Electric and PacifiCorp own a portion of Colstrip Units 3 and 4. The current depreciable life of Colstrip in rates is 2027.

Q. Please summarize PacifiCorp's position on Colstrip.

A. In its direct filing, the Company proposed to set Colstrip Units 3-4 depreciable life to 2025. The Company relies on the IRP analysis from the 2021 IRP to support its proposal to set Colstrip Units 3-4 life to 2025.

Q. Please summarize AWEC's position on Colstrip.

A. AWEC's proposes that Colstrip's depreciable life be maintained at 2027. AWEC has concerns about the potential economic life of Colstrip. AWEC argues that since PacifiCorp is a minority owner in Colstrip, the Company has a limited ability to influence the actual retirement of the plant. AWEC states that it believes the 2027 life is a better balance between cost and risk for customers due to uncertainty over the plant's operating life.

Q. Please summarize PacifiCorp's response to AWEC's position on Colstrip.

A. The Company does not agree with AWEC's recommendation. The Company argues that setting the depreciable life of Colstrip in 2025 reduces future rate pressure risk or stranded investment cost risk for PacifiCorp. The Company also reasons that the 2025 date aligns with the Company's acknowledged 2021 IRP.

Q. What is CUB's response to AWEC and PacifiCorp's testimony on Colstrip?

A. CUB is sensitive to AWEC's concerns about rates increasing and does agree that there is considerable cost pressure on customers in this proceeding. However, CUB position is that cost recovery of coal units should follow state policy established by law or be informed by the economic portfolio analysis in the Company's acknowledged IRP. PacifiCorp's proposal to set Colstrip's depreciable life at 2025 is reasonable and informed by planning in the 2021 IRP. This indicates that the proposal aligns with a least cost, least risk portfolio.

Q. What is CUB's response to AWEC's position that PacifiCorp does not have the ability to effectuate the retirement of Colstrip Units 3 and 4?

A. This is a complex issue. CUB acknowledges that the closure of Colstrip is subject to owner disputes and lawsuits around closing Colstrip, and that there are competing interests for continuing to operate Colstrip. However, most of the Colstrip owners support closing Colstrip units 3 and 4 by 2025. Avista, Puget Sound Energy, PacifiCorp and Portland General Electric are all planning on closing the power plant by 2025.

Ultimately, CUB agrees with the Company that Colstrip should be depreciated in alignment with the 2021 IRP analysis, to reduce stranded cost risk for customers, and the Company.

B. Jim Bridger Units 1 and 2

Q. What are Jim Bridger Units 1 and 2?

A. Jim Bridger Units 1 and 2 are two coal thermal units. There are four thermal coal units located at Jim Bridger. PacifiCorp is the majority owner of the Jim Bridger Coal units, and Idaho Power is a minority owner.

Q. What is AWEC's proposal around Jim Bridger Units 1 and 2?

A. AWEC proposes to extend the depreciable life of Jim Bridger Unit 1 and 2 to 2038. AWEC makes this proposal to align with the company's plan to convert Jim Bridger Units 1 and 2 to natural gas units.

Q. What is PacifiCorp intending to do to Jim Bridger Units 1 and 2?

A. Informed by IRP analysis, PacifiCorp sought acknowledgement of Jim Bridger Units 1 and 2 being converted to natural gas in 2024.

Q. Does CUB find extending the life of Jim Bridger Units 1 and 2 to be reasonable? If so, why?

A. Yes. AWEC's proposal aligns with the Company's resource planning efforts to acquire a least cost and least risk portfolio for customers. In particular, the conversion of Jim Bridger Units 1 and 2 to natural gas is an economic resource option. In the 2021 IRP, Staff indicated it "supports conversion of Jim Bridger Units 1 and 2 to gas in order to provide flexible peaking capacity to the system. Staff also found that the greenhouse gas savings from retiring those units instead would be relatively expensive compared to other reduction options."[12]

Q. In agreeing with AWEC's proposal to extend the life of Jim Bridger Units 1 and 2 in Oregon rates, does CUB find the Jim Bridger Units 1 and 2 to be prudent?

A. It would be premature to opine on the prudence of the natural gas conversion of Jim Bridger Units 1 and 2. CUB takes no position on the prudence of Jim Bridger Units 1 and 2 at this time.

VIII. RESIDENTIAL RATE DESIGN

Q. What is the purpose of your testimony in this section?

A. In this testimony, CUB responds to the testimony of PacifiCorp and OPUC Staff on residential rate design. This section covers the seasonal rates, customer charge, and BPA rate design.

A. Seasonal Rates

Q. What is the purpose of your testimony in this section?

A. In portion of testimony, CUB responds to the testimony of PacifiCorp and Staff on seasonal rates.

Q. Please summarize CUB's position on seasonal rates.

A. CUB does not recommend that the Commission adopt seasonal rates for residential customers.

[12] OPUC Order No. 22-178 at 6.

Q. The Company disagreed with CUB's concern that seasonal rates arbitrarily benefit some customers, but disadvantage others. What was the Company's response?

A. The Company argued that seasonal rates are based on the higher costs to serve during the summer months.

Q. What is CUB's response to the Company reply to CUB's statement on the arbitrary nature of seasonal rates?

A. Seasonal rates impact residential customers based on the customers electricity usage patterns. The Company's seasonal rate proposal makes residential summertime electricity usage more expensive. If a residential customer uses air conditioning, that customer will pay a higher cost to cool their home. The Company's seasonal rate proposal makes winter time electricity usage cheaper. If a residential customer uses electricity to heat their home, the Company's proposal would decrease residential customers annual electricity bills. If a residential customer does not use electricity to heat their home and is an air conditioning user, the Company's proposal would increase the customers cooling costs, and have no effect on the customers heating costs. This is the arbitrary nature of PAC's proposal that CUB was alluding to in prior testimony.

Q. What controls do customers have to select their heating or cooling appliance?

A. The answer to this question varies upon whether the customer is buying a new home, buying a used home, or is a renter.

For new homes, homebuilders deploy a standard appliance build system for new construction. The HVAC system installed by new customers is dependent on the economics of homebuilding, customer preferences, and building codes. In general, communities in densely populated areas and or near interstate natural gas pipelines have access to natural gas as a heating fuel. Some portions of PacifiCorp's Oregon service territory are not economic to serve with natural gas. Customer preferences also impact the HVAC system installed in new home. Residential customers prefer to have air conditioning installed in new construction homes. Unless a residential customer customizes their home during the building process, new construction residential customers have limited options to customize their appliances. Building codes also influence what appliances are installed in the new construction home. For example, building codes determine minimum annualized fuel utilization efficacy ratings (AFUE) for natural gas furnaces, and minimum heating seasonal performance factors (HSPF) standards for air source electric heat pumps. For used homes that are owned by residential customers, the used homes appliances are inherited from the previous owners.

For owned residences, there are transition costs and barriers to switching to more efficient appliances or to a new fuel source. New replacement appliances have significant costs, even without installation and replacement costs. As of 2022, a new 50 gallon residential heat electric water heater has a unit cost of $529, while a heat pump water heater has a unit cost of $1,200. While CUB acknowledges that the heat pump water heater will have lower cost of ownership over the life of the appliance, Oregonians may be unable to afford the incremental cost of a heat pump water heater. It may be rational for these customers to not upgrade their appliances due to the customers' economic circumstances. The same issue occurs when a household needs to replace an electric HVAC system. While it may be cheaper over the life of the appliance to install an efficient heating and cooling system, due to lack of funds or high conversion costs, the customer may continue to use a functioning resistance heat system in the winter and use an inefficient cooling system in the summer. Access to capital is a barrier to customers using energy more efficiently.

Renters have limited options to convert their appliances and respond to PacifiCorp's proposed seasonal price signal. These upgrades are largely subject to how the landlord manages the rental unit.

Q. PacifiCorp provided a chart detailing the effect of its rate design proposal across regions. Does CUB have a response to that chart?

A. Yes. The Company noted in testimony that CUB only examined the differences in cooling bills across the state and did not analyze differences in heating bills across Oregon. CUB's opening testimony did address the benefit of reduced winter electricity costs in colder portions of the state. However, CUB would like to note that this chart was completed using historic residential usage data on usage from one year between November 2018 and October 2019. Weather refers to short term changes in atmospheric conditions. Climate is the weather of a region over a period. CUB does not agree that the Company should rely on an analysis of one-year of customer usage data to implement seasonal rates.

Q. What has happened in Oregon since the 2019 cooling season?

A. Oregon has experienced extremely hot summers. In 2021, Oregon experienced a "heat dome" event. From June 26 to June 30, Pendleton experienced five consecutive days with highs above 100 degrees, with an absolute high temperature of 115 degrees on June 29. From June 25 to June 28, Medford experienced four days above 100 degrees, with an absolute high temperature of 113 degrees on June 27. From June 26 to June 30, Portland experienced three days with highs above 100 degrees, with an absolute high temperature of 117 degrees on June 28. During the warmest days of the 2021 heat dome event, low temperatures were in the 70s and 80s, which made it difficult for non-air-conditioned residential customers to cool down at night.

At least 96 people died in Oregon due to the 2021 heat wave. CUB is concerned about the public policy implications of making summer electricity usage more expensive, as it could discourage them to use their air conditioners, which are potentially life-saving.

Q. What does CUB expect that Oregonians will do in response to longer heat waves?

A. CUB expects that residential customers will install air conditioning units in response to warm summers. In 2022, Oregon passed the Emergency Heat Relief Act, which required new rented building constructed after 2024 to have air conditioning. According to Google trends data for Oregon, Oregonians have an increased interest in air conditioning.[13] Oregon state and local government are subsidizing or providing air conditioners to residential customers.

Q. What is the relationship between air conditioning usage and income in PacifiCorp's service territory?

A. Broadly, household income is correlated with air conditioning usage. The Company's 2019 survey data signals that **[Begin Confidential** [redacted] **[End Confidential]** [14]

Q. What barriers exist to renters and low-income households that own homes to purchasing efficient air conditioners?

A. CUB appreciates that the Company is seeking to provide a price signal on energy efficient equipment. However, it is expensive to purchase a new air conditioning system. Ducted heat pump or air conditioning systems require the home to have air ducts. Ductless systems require multiple heads installed in the unit. The cheapest cost option for air conditioning, when only looking at the capital cost of acquiring new equipment, is a window air conditioner or a portable air conditioner. To cool an entire residence, multiple portable or window air conditioning units may be needed.

Unfortunately, cheaper cost portable air conditioners or window air conditioners have lower energy efficiency ratio (EER) than centralized heat pump systems. EER is the ratio of the cooling capacity (British thermal units) to power input (watts). EER is used to compare the energy efficiency of one air conditioning appliance to other

[13] CUB Exhibit 402.
[14] CUB Confidential Exhibit 403.

appliances. Cheaper capital cost portable air conditioning and window units will have a higher operating cost under the Company's proposal.

Q. Why does CUB recommend that the Commission not adopt seasonal rates for residential customers?

A. CUB is concerned about the differences in monthly residential electricity bills across Oregon. Due to cost pressure that PacifiCorp is proposing to impose on residential customers in this case, CUB recommends holding off on proposing major rate design changes to customers in this case.

Q. Staff recommended approval of a form of seasonal rates because the rate design is cost-based. PacifiCorp argues that seasonal rates are cost based because of seasonal differences in wholesale electricity costs at the Mid-Columbia Hub. What is CUB's response to that argument?

A. Cost-based rates are not the only criteria for designing rates. For example, the Company could argue that charging super peak energy rates are cost-based, because there is a difference between super peak costs, and all other periods electricity costs. Such a proposal is based in cost, but that does not mean that all customers can respond to that price signal. While CUB understands that seasonal rates will decrease winter heating bills for electricity customers, CUB prefers to not change rates to account for seasonal power cost differences.

Q. What are the advantages of seasonal rates for PacifiCorp?

A. PacifiCorp will benefit if seasonal rates are collected from residential customers. Before I explain the benefits for the Company, I will briefly explain how rates are calculated. Ratemaking starts by setting an annual revenue requirement. The annual revenue requirement is then allocated to each customer class. Next, rates are established by dividing each customers classes allocated revenue requirement by expected load. Expected statewide customer load is calculated based on a weather normalized load forecast. In the rate design section of ratemaking, prices are created through various charges such as the basic charge and unbundled volumetric charges.

Monthly customers' bills are calculated by multiplying customers monthly usage by the Commission's regulated residential rate plus the monthly customer charge. Since the load forecast is weather normalized, it is expected that overtime rates will enable the Company to have the opportunity to recover their costs plus a regulated profit. The Company's shareholders are compensated for the risk of forecasted rates versus actual rates in its ROE.

PacifiCorp is proposing this change to reduce their business risk by changing residential prices to better match wholesale electricity prices. In general, high summertime temperatures across the region are correlated with higher wholesale market electricity prices. In a warmer than expected cooling season, seasonal rates will allow the Company to recover more revenue than expected to offset higher summertime prices. Higher seasonal summer rates will also increase summer bills for residential customers.

Higher seasonal summer energy rates will decrease winter energy rates, which makes electric space heat more attractive to residential customers. Therefore, the Company's seasonal rate proposal would give the Company an advantage on the price of heating with electricity versus other fuels.

Q. Did PacifiCorp propose to move towards seasonal rates for all other customers classes?

A. No. The Company did not request seasonal rates for other customers. PacifiCorp argues that seasonal rates for seasonal energy charges and NVPC charges applies to other classes. While CUB does not agree with applying seasonal rates due to forecasted differences in wholesale power costs, the Company's argument that wholesale system power costs are higher in the summertime also applies to other customers. While CUB understands that seasonal rates are a within the tariff rate design proposal, CUB opposes the Company's proposal to charge seasonal rates on residential customers, while not charging seasonal rates on other customers classes.

B. Customer Charge

Q. Please summarize your testimony on this topic.

A. In response to PacifiCorp and Staff testimony on the customer charge, CUB proposes that the single family customer charge be increased by $1 to $10.50. CUB makes this proposal in response to the testimony of Staff and PacifiCorp, and as a compromise between CUB, Staff, and PacifiCorp's position.

Q. What did PacifiCorp and Staff detail on this topic?

A. PacifiCorp continues to seek a customer charge of $12. Staff supports the Company's proposal to increase the customer charge by $2.50 to $12 for residential customers.[15]

Q. What do CUB and the Company disagree on?

[15] UE 399 – Staff/700/Dlouhy/21.

A. The Company position is that costs need to be recovered through a combination of fixed and customer charges. The Company wants to increase the residential customer charge to avoid having low usage residential customer being subsidized by other residential customers. CUB position is that it is not necessary to collect fixed costs through a fixed customer charge, and that volumetric pricing is appropriate to charge residential customers electricity use. CUB would like to avoid low to moderate usage customers receiving an above average bill increase to due to a large customer charge increase. There is a difference of opinion between CUB and PacifiCorp on the best way to design the customer charge for residential customers.

Q. Why is CUB proposing a customer charge increase of $1, which would raise the single family customer charger to $10.50?

A. In general, customers have expressed to CUB a preference to have low customer charges. Low customer charges enable customers to have increased control over their bill. In this case, PacifiCorp is proposing to increase the customer charge by $2.50. This is a significant increase to the customer charge. While CUB would prefer to maintain the customer charge to reduce the price impact on low usage customers, CUB recommends the Commission adopt a $10.50 customer charge as a compromise between the parties' positions.

C. BPA Residential Exchange Rate Design

Q. What did PacifiCorp and Staff detail on this topic?

A. PacifiCorp proposed to eliminate inverted block rates for the BPA residential exchange. Staff proposed to make the BPA residential exchange credit either subject to a flat 1000 kWh cap or allocated on a per customer basis. Staff is concerned that a flat BPA credit would benefit large residential customers disproportionately, and believes that their proposal would provide the value of this credit more to low income customers, and the majority of Oregonians.

Q. Why was CUB willing to adopt a flat rate design for the BPA residential exchange?

A. The Pacific Northwest Electric Power Planning and Conservation Act enacted the Residential Exchange Program to provide residential and farm customers of Pacific Northwest utilities access to low-cost federal power. It is my understanding that the residential exchange program is meant to provide the value of low-cost hydropower to residential and farm customers. The power is not physically provided to these customers, instead, these customers are given residential exchange credits to compensate them for this value. While federal power uses a variety of resources, low-cost hydro power is the primary reason why federal hydropower is cheaper than investor owned utilities hydropower. PacifiCorp's customers have access to low-cost hydroelectric facilities, such as the Lewis River, North Umpqua River, and Rouge River projects. These older hydroelectric facilities provide cheap zero fuel power to all cost-of-service customers. The benefits and costs of PacifiCorp's hydroelectric projects are allocated on a volumetric basis, when calculating energy charges. Therefore, CUB found it reasonable in opening testimony to allocate the energy charge on a flat basis.

Q. Has CUB changed its position after reviewing Staff's testimony on this topic?

A. Yes. CUB understands Staff's concern about the impact of flattening the BPA residential exchange credit on subsidizing high usage residential customer bills.

Q. Has the Company offered a compromise position between the Company's position and Staff's position?

A. Yes. The Company proposed that a monthly per residential kWh cap would be a reasonable compromise. The Company did not propose a specific cap in the last round of testimony, but recommended that it be above 1,000.

Q. What is CUB's response to the Company's compromise position?

A. CUB finds it reasonable to have a 2000 kWh cap on the residential customer charge. 92.8 percent of residential customers use less than 2000 kWh of electricity per month.[16] The average single-family customer uses 900 units of electricity per month.[17] Many residential customers would benefit under a cap of 2,000 kWh. Additionally, CUB analysis indicates that a 2,000-kWh cap could conservatively be able to accommodate additional load due to transportation electrification for the average household.[18]

Q. Has CUB reviewed Staff testimony in response to PacifiCorp?

A. No. CUB reserves the right to change its position in briefing after reviewing Staff's testimony.

IX. MARGINAL COST STUDY - GENERATION

Q. What is CUB's position on this topic in testimony?

A. In this testimony, CUB responds to the testimony of PacifiCorp, Staff and AWEC on the generation portion of the marginal cost of service study.

Q. Why are parties recommending changes to the marginal cost of service study?

[16] UE 399 – Staff /700/Dlouhy/41, Table 6.
[17] UE 399 – PAC/1100/Meredith.
[18] CUB Exhibit 104.

A. Broadly, parties are recommending changes to the marginal cost of service study due to state policy and recent legislation. HB 2021 makes it unlikely that natural gas generation are the marginal electricity.

Q. What is CUB's recommendation on this topic?

A. CUB understands AWEC and Staff's concerns around the calculation of generation marginal costs. However, CUB recommends that the Commission not adopt a specific generation methodology for PacifiCorp in this proceeding. CUB agrees with the Company that is reasonable to not change to a new marginal cost methodology currently. This change is occurring due to HB 2021. PacifiCorp has not engaged in a comprehensive planning docket to detail how it would meet capacity needs under the requirements of HB 2021, which would inform an appropriate capacity and energy resource methodology. There is also a lack of consensus around the best way to calculate marginal capacity and energy costs post HB 2021 in this proceeding. Staff, AWEC and PacifiCorp has have presented three different methodologies. The incumbent generation marginal cost methodology around has been in place for several decades.

X. COAL DECOMMISSIONING COSTS

Q. What is CUB's position on this topic in testimony?

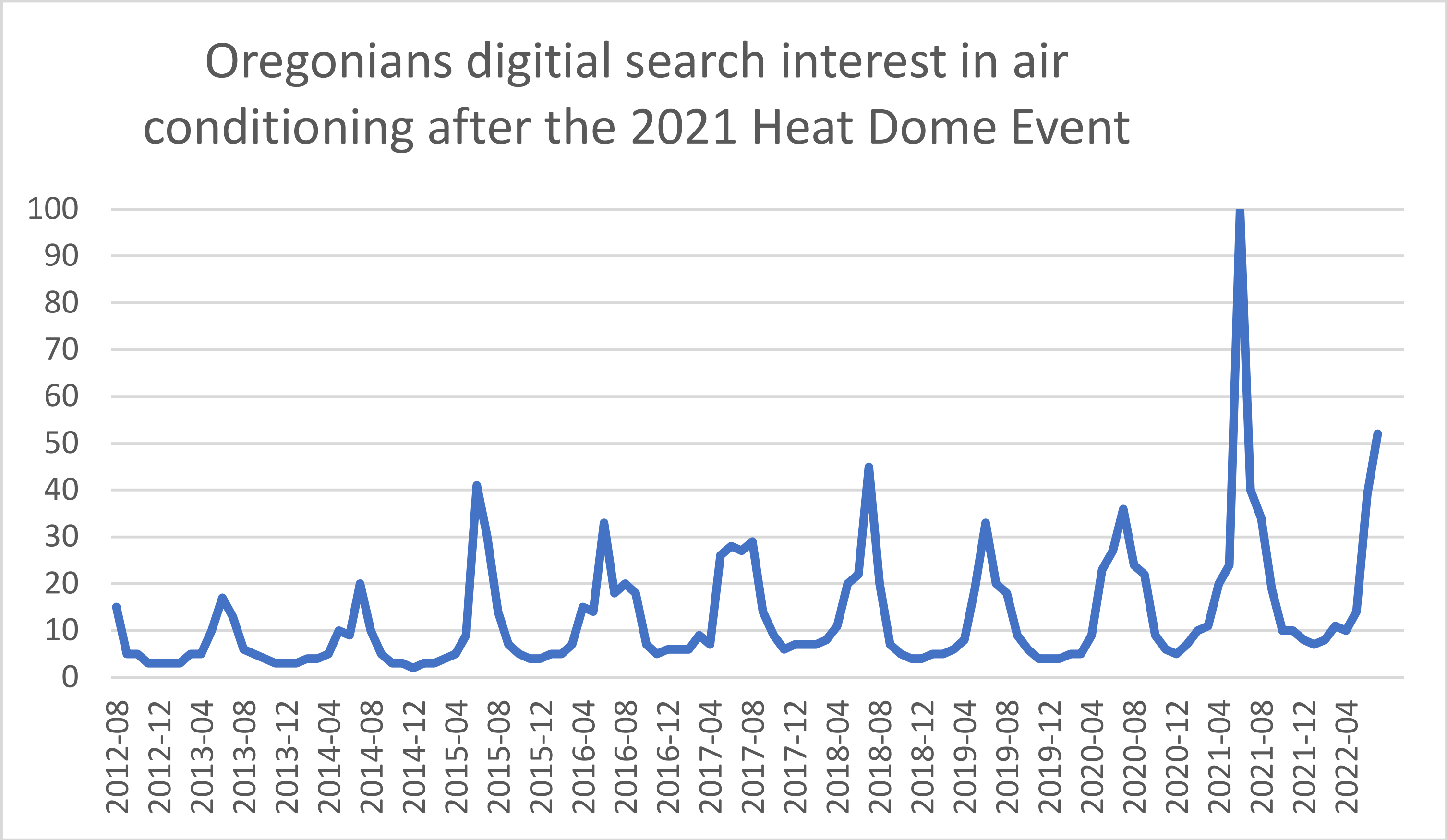
A. After reviewing other parties' testimony on coal decommissioning costs, CUB withdraws their testimony on coal decommissioning. CUB will address these issues in UM 2183 or future rate proceeding around coal decommissioning.

Q. Does this conclude your testimony?

A. Yes.

employees or the approval of state or local economic development incentives in order to receive the discounted rate.

Each utility’s threshold to qualify for an economic development tariff, how the discount is applied, the term of the discount and the value of the discount varies widely. The characteristics of each utility’s incentive program must be considered along with state and local economic development incentive programs.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CUB Exhibit 403 is Confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 22-044.

A 2000 kWh BPA RES CAP can accomidate electricification of residential transportion

[1]	Average Miles Driven by American Driver - from Federal Highway Administration	13476
[2]	Average Efficency of Electric Vehicle - # of kWh per 100 miles	30
[3]	kWh per mile of average electric vehicle	0.3
[4] = [1] * [3]	Average kWh per year of average electric vehicle driving	4043
[5] = [4] / 12	Monthly kWh of EV residential charging	337
[6]	National average cars per household - from Bureau of Transportion Statisics	1.9
[7] = [5] * [6]	kWh increase due to electrification of transportion for residenital customer	640
[8]	Average Single Family monthly usage of electricity	900
[9] = [7] + [8]	Average Residential Customer usage plus electricity usage from 1.9 cars	1540

Note: This number is conservative, because the number assumes 100% residenital charging.

UE 399 – CERTIFICATE OF SERVICE

I hereby certify that, on this 11th day of August 2022, I served the **Confidential Rebuttal and Cross Answering Testimony of the Oregon Citizens' Utility Board** in docket UE 399 upon the Commission and each party designated to receive confidential information pursuant to Order 22-044 through a secure, encrypted attachment to an e-mail.

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Respectfully submitted,

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