ORDER NO. 22-491

ENTERED Dec 16, 2022

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP, dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

ORDER

DISPOSITION: FIRST, SECOND, AND THIRD PARTIAL STIPULATIONS ADOPTED; REQUEST FOR CLARIFICATION GRANTED

This order addresses the first phase of a request for a general rate revision by PacifiCorp, dba Pacific Power. While the proceeding has been bifurcated, this phase of the proceeding addresses all rate issues, and thus we are able to approve a new revenue requirement that will be effective on January 1, 2023.[1] We adopt the first three stipulations filed by the parties.

We also rule in favor of Calpine Energy Solutions LLC's request for clarification regarding the operation of PacifiCorp's direct access schedules. Nothing in the language of the current tariff prevents a customer from switching to the five-year direct access schedule from the three-year direct access schedule after its first or second year, nor requires such a customer to pay the Returning Services Payment when not returning to cost-of-service rates. However, our decision merely interprets the current tariff language; going forward, PacifiCorp may seek to justify a change in the tariff language by presenting evidence and argument about its cost-shifting concerns.

Overall, we approve an increase to PacifiCorp's revenue requirement of $51.4 million, or $48.9 million including the impacts of the Oregon Corporate Activity Tax Credit and Rate Mitigation Adjustment. This is a 3.9 percent increase from PacifiCorp's currently effective revenue requirement. Residential customers will see an average increase of 5.35 percent.

I. BACKGROUND AND PROCEDURAL HISTORY

On March 1, 2022, PacifiCorp filed this general rate case for rates to be effective January 1, 2023. It asked for a revenue requirement increase of $84.4 million, as well as changes to its rate structure and spread and for structural changes to its Transition Adjustment Mechanism (TAM) and Power Cost Adjustment Mechanism (PCAM). Staff of the Public Utility Commission of Oregon; the Alliance of Western Energy Consumers (AWEC); Calpine Energy Solutions, LLC (Calpine); Fred Meyer Stores and Quality Food Centers, divisions of The Kroger Co. (Fred Meyer); the Klamath Water Users Association (KWUA); NewSun Energy LLC; the Northwestern & Intermountain Power Producers Association (NIPPC); the Oregon Citizens' Utility Board (CUB); the Oregon Farm Bureau Federation (OFBF); Small Business Utility Advocates (SBUA); Vitesse LLC; and Walmart, Inc., all participated as parties to the proceeding. Over the course of the proceeding, parties filed testimony and exhibits.

[1] ALJ Ruling (Oct. 6, 2022).

On March 22, 2022, PacifiCorp filed a motion to consolidate its general rate case docket (UE 399) with numerous deferral dockets. On March 30, 2022, AWEC filed a motion to consolidate docket UM 2201, which requests deferral of fly ash revenues. CUB filed a response to PacifiCorp's motion that requested consolidation of docket UM 2220, PacifiCorp's application for a deferral of operating costs and capital investments to implement its Distribution System Plan (DSP).

On April 11, 2022, an Administrative Law Judge (ALJ) issued a ruling consolidating docket UE 399 with the deferrals listed in the above caption. The ALJ denied CUB's request for consolidation of docket UM 2220 on the ground that the DSP is already subject to a multi-year process that will be addressed in docket UM 2198.

On May 24, 2022, a Public Comment Hearing was held at which the general public was given an opportunity to comment on PacifiCorp's filing.

On August 25, 2022, PacifiCorp, Staff, and CUB filed the First Partial Stipulation. On the same day, PacifiCorp, Staff, CUB, AWEC, Walmart, Calpine, KWUA, OFBF, and Vitesse filed the Second Partial Stipulation. No party objected to either stipulation.

On September 21, 2022, PacifiCorp, AWEC, Staff, CUB, Fred Meyer, Walmart, SBUA, KWUA, OFBF, Vitesse, and Calpine filed the Third Partial Stipulation, which settled all remaining issues in the docket except two. No party objected to this stipulation.

Several parties ultimately filed a Fourth Partial Stipulation, which was contested by NewSun. That stipulation was bifurcated into a second phase, which will be considered later.[2] The uncontested stipulations, along with a request for clarification from Calpine, remained in this first phase of the proceeding. All parties waved hearing and oral argument in this first phase.

The ALJ issued an order closing the record on December 12, 2022.

II. COMPANY FILING

In its initial filing, PacifiCorp proposed an $84.4 million rate increase or a total net increase of 6.8 percent. It filed for a return on equity of 9.8 percent and a capital structure of 47.74 percent debt and 52.25 percent equity, with 0.01 percent preferred stock. It also proposed changes to its rate design—most notably, it proposed to remove

[2] *Id.*

the inverted block structure under which the first "blocks" of energy used would cost less per kWh than subsequent "blocks," and instead to, switch to seasonal rates. With this, PacifiCorp filed a new rate spread under which, it stated, no customer class would see an increase greater than twice the average increase (*e.g.*, if the average increase across customer classes was 5 percent, no individual customer class would see an average rate increase greater than 10 percent for its customers).

PacifiCorp also filed a number of other structural changes to its rates. First, it filed to modify the Wildfire Mitigation and Vegetation Management (WMVM) mechanism which was put in place in its last general rate case (UE 374) to govern recovery of incremental WMVM spending. PacifiCorp's filing removed wildfire mitigation activities from the WMVM mechanism in favor of an automatic adjustment clause to be filed in a future docket and proposed to change the way violations of vegetation management standards counted against its ability to recover incremental costs.

Next, it filed structural changes to its TAM and PCAM mechanisms. For the TAM, it added a rate year update and revision to the current guidelines in order to add what PacifiCorp stated would be "more accurate" hydrologic data. For the PCAM, it filed to alter the deadbands and earnings test against which recovery of costs subject to the PCAM are tracked.

III. APPLICABLE LAW

In a rate case, we must first determine the overall revenues the company is entitled to receive. A utility's revenue requirement is determined based on a close examination of the utility's reasonable and prudent costs. Second, we must allocate the revenue requirement among the utility's customer classes.[3]

In establishing a revenue requirement, we must determine: (1) the utility's expected gross revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which a return should be earned; and (4) the rate of return to be applied to the rate base to establish the return to which the stockholders of the utility are reasonably entitled.[4] Establishing these values allows us to determine the utility's reasonable cost of providing service and thus its required revenues so that the company's rates will be set at just and reasonable levels.

As the petitioner in this rate case, PacifiCorp has the burden of proof, as it does with all but one of the consolidated deferrals. With respect to fly ash revenue deferral request

[3] *See, e.g., American Can Company v. Lobdell*, 55 Or App 451, 454-55, *rev den* 293 Or 190 (1982).
[4] *See Pacific Northwest Bell Telephone Company v. Sabin*, 21 Or App 200, 205 & n 4, *rev den* (1975).

originally filed in docket UM 2201, AWEC bears the burden of proof as the party that filed the initial deferral request.

ORS 757.210 establishes that burden of proof and provides that "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is fair, just, and reasonable." Thus, PacifiCorp must submit evidence showing that its proposed rates are just and reasonable. Once the company has presented its evidence, the burden of going forward (burden of production) then shifts to the party or parties who oppose including the costs in the utility's revenue requirement.[5] Staff or an intervenor, if it opposes the utility's claimed costs, may, in turn, show that the costs are not reasonable. For any change proposed by PacifiCorp that is disputed by another party, PacifiCorp still must show, by a preponderance of the evidence, that the change is just and reasonable.

IV. STIPULATIONS

The parties have filed four stipulations in this proceeding that collectively resolve all issues except the direct access issue discussed below. The Fourth Partial Stipulation—which concerns PacifiCorp's VRET program—is contested and has been separated into a second phase of this proceeding. The first three stipulations are not contested and resolve all revenue requirement issues, as well as deferrals, rate design and spread, and exit orders.

The Commission requires that stipulations be accompanied by sufficient information to allow us to understand the rate impact of the stipulation on customer bills.[6] In the Third Stipulation, the company has provided information showing that the revenue requirement resulting from the stipulations would raise customer bills an overall average of 3.92 percent. Residential customers would see an average increase of 5.35 percent. Due to a change in the rate structure that would eliminate the "inverted block" structure where customers were charged progressively more per kWh for each "block" of energy they used and due to an increase in the single-family residential basic charge, smaller residential customers will generally see a higher percentage increase than larger residential customers. The average single-family residential customer using 1,000 kWh per month will see an increase of 8.84 percent or $8.92 per month. The average multi-

[5] *See In the Matter of the Application of Northwest Natural Gas Company for a General Rate Revision*, Docket No. UG 132, Order No. 99-697 at 3 (Nov. 12, 1999).

[6] *In the Matter of Avista Corporation dba Avista Utilities, Application for a General Rate Revision,* Docket No. UG 366, Order No. 19-331 at 4 (Oct. 8, 2019). ("[F]or any stipulation that includes a change in rates, the accompanying testimony should include average monthly billing comparisons for each rate case. For any rate change including a significant change to rate design, more comprehensive bill impacts showing the impact at different usage levels may be appropriate.")

family residential customer using 600 kWh per month will see an increase of 6.98 percent or $4.42 per month.

A. First Partial Stipulation

The First Partial Stipulation resolves several issues related to WMVM capital and expenses; they also reached a partial agreement on how those issues will be handled in the future. This stipulation is attached to this order as Appendix A.

First, the parties agreed to increase WMVM expenses from their current level of $30 million to $69.7 million in these rates: $50 million of that will be allocated to vegetation management spending and the remaining $19.7 million will be allocated to wildfire mitigation expense. This is a reduction of $300,000 from the as-filed rates. The base rates will reflect the $34.9 million of capitalized WMVM investments included in PacifiCorp's filing; projects not in service as of January 1, 2023, will be removed from the base rates.

Second, the parties agreed to three modifications to the WMVM mechanism that was put in place during the last rate case in docket UE 374. That mechanism made a certain amount of incremental wildfire mitigation and vegetation management spend subject to an earnings test that uses the company's authorized ROE minus basis point deductions based on the number of vegetation management violations identified by Commission Safety Staff. The parties agreed to extend the WMVM mechanism through 2024 (assuming PacifiCorp does not file a new rate case before then) and to the following modifications of the mechanism:

- Elimination of the two-tiered approach under which the first tier is subject to a more rigorous earnings review than the second tier; and

- Modification of violations levels included in each level of the earnings test by significantly increasing the number of violations needed to lose ROE points in the earnings test (*i.e.*, the "no penalty" category would go from 0-75 violations in the current formulation to 0-150 violations under the stipulation; the starting points for the next levels would be increased to 151 to 225 for Level I; 226 to 325 for Level II; and 326 for above Level III).

The parties also noted that PacifiCorp has filed a request to recover wildfire mitigation costs through an automatic adjustment clause in docket UE 407. Given this, the parties have agreed that wildfire mitigation costs going forward will generally be handled according to our ultimate decision in that docket. Requests under the current WMVM will thus be:

- Filed in 2023 for 2022 vegetation management *and* wildfire mitigation costs incremental to $30 million in base rates;

- Filed in 2024 for 2023 vegetation management costs *only* incremental to $50 million in base rates; and

- Filed in 2025 for 2024 vegetation management costs *only* incremental to $50 million in base rates (unless a new general rate case has been filed).

B. Second Partial Stipulation

In the Second Partial Stipulation, the parties agreed that the long-term cost of debt embedded in the revenue requirement would be 4.717 percent; this would increase the long-term cost of debt by $6.96 million from the company's initial filing (and again, this was incorporated into the final numbers in the third stipulation). This stipulation is attached to this order as Appendix B.

Parties also agreed to extend the Jim Bridger Units 1 and 2 depreciable lives to December 31, 2029, due to their conversion to gas-fired resources.

In addition, the parties agreed to settle a number of the revenue requirement issues, particularly those raised by Staff in its testimony. Because those issues were ultimately folded into the overall revenue requirement agreed to in the Third Stipulation, we do not detail each here.

C. Third Partial Stipulation

In the Third Partial Stipulation, the parties settled the remaining issues in this case except as previously specified. In particular, they agreed on the following key points (as they differ from the initial filing):

Issue	Original Filing	Stipulation
Revenue Requirement Increase	+$84.4 million	+ $59.3 million
Return on Equity	9.8 percent	9.5 percent
Capital Structure	47.74 percent long-term debt/52.25 percent common equity;	49.99 percent long-term debt/50 percent common equity; 0.01

	0.01 percent preferred stock	percent preferred stock.
Residential Single Family Basic Charge	$12	$11

The return on equity, cost of preferred stock, and capital structure are the same as those we authorized in PacifiCorp's last rate case in docket UE 374.[7] PacifiCorp's overall resulting rate of return under this stipulation would be 7.109 percent, as shown in the table below. This stipulation is attached to this order as Appendix C.

Capital Component	% of Total	Cost %	Weighted Cost %
Long-Term Debt	49.99	4.717	2.358
Preferred Stock	0.01	6.75	0.001
Common Equity	50.00	9.5	4.750
Total	100.00	ROR	7.109

The parties also reached agreement on rate design issues and on rate spread. PacifiCorp's filing had eliminated the "inverted block" structure discussed above and added a seasonal component to rates. The stipulation also eliminates the inverted block structure but does not include a seasonal component. The stipulation contains the following rate spread; this table shows percentages of the initial increase allocated to particular customer classes based on the overall net increase:

Schedule	**% of Net Increase**
Schedule 4 (Residential)	136 percent
Schedules 23 (Non-Residential), 41 (Agricultural Pumping Load)	140 percent
Schedule 48 (> 1000 KW)	103 percent
Lighting	50 percent
Schedules 28 (Non-Residential – 31	0 percent

[7] *See* Order No. 20-473.

KW - 200 KW), 30 (Non-Residential – 201 KW - 99 KW).	

The remaining increase will be spread equally over Schedules 4, 23, 28, 30, and 41.

This stipulation also included agreements from the parties on the deferral dockets that were consolidated with this case—both the balances and the amortization periods:

Deferral Docket	**December 2022 Balance ($)**	**Amortization Period**
UM 1964 Transportation Electrification	2,839,892	3 years
UM 2134 Cedar Springs II	681,475	3 years
UM 2186 TB Flats	17,900,662	3 years
UM 2167 Renewable Energy Credits from Pryor Mountain	(364,127)	3 years
UM 2142 Cholla Unit 4-Related Property Tax Expense	639,589	3 years
UM 2063 Covid-19 Deferral	17,887,722	4 years
UM 2201 Fly-Ash	(1,700,000)	1 year
Total Balance and Annual Amortization	**37,885,213**	

And the parties reached agreement on certain exit orders requested from the Commission:

Plant	**Exit Date**	**Change from Status Quo?**
Craig Unit 2	September 30, 2028	Yes; previously December 31, 2026.
Hayden Unit 1	December 31, 2028	No previous date
Hayden Unit 2	December 31, 2027	No previous date
Jim Bridger Unit 1	December 31, 2023	Date remains same but specification added that only applies to coal.

Finally, the parties agreed on certain non-rate terms related to the issues raised by Staff and intervenors. In particular, the Stipulation provides that:

Stay-Out Provision. PacifiCorp will not file a new general rate case with rates effective earlier than January 1, 2025. The stipulation also includes some limitations on deferrals during 2023. PacifiCorp will not request a new deferral in 2023 unless: (a) it is authorized by the Commission order on the Commission's own initiative or by statute; (b) it is a reauthorization of a previously-filed deferral; (c) laws, regulations, or orders become effective requiring significant new expenses; (d) the expenses result from a federal or state declaration of emergency; or (e) it is necessary to respond to a material threat to the company's financial stability for "unique and unforeseen" reasons outside the company's reasonable control.

TAM and PCAM. In its initial filing, PacifiCorp had filed several revisions that would change the mechanics of the TAM and PCAM. Here, the parties agreed that PacifiCorp would withdraw all structural changes and instead hold "collaborative discussions" and provide recommendations by December 31, 2023.

Customer Surveys. The parties agreed that PacifiCorp would conduct residential customer surveys by September 30, 2023, and also agreed on certain specific items that need to go into the surveys.

Attestations for Capital Projects. PacifiCorp will file attestations on the in-service date of capital projects over $1 million that are not related to wildfire mitigation and vegetation management.

D. Resolution

We review the terms of a stipulation for reasonableness and accord with the public interest: that is, we attempt to determine whether, on a holistic basis, they serve the public interest and result in just and reasonable rates. In doing so, we consider the fact that there is not *one* just and reasonable rate, but rather a range of just and reasonable rate outcomes.

We further consider that stipulations are negotiated as integrated agreements, with give and take on numerous issues to reach a settled result that the parties agree is in the public interest. We are therefore mindful of the balance achieved between parties representing divergent interests under the stipulation. Thus, the fact the parties have reached an agreement on the issues presented in the stipulation is relevant to our determination, albeit not dispositive.

Here, we have reviewed the partial stipulations and supporting briefs, and testimony submitted by the parties. We find the terms of the stipulations are supported by sufficient evidence, appropriately resolve the issues in this case, and will result in fair, just, and reasonable rates.

We make special note of the second stipulation, which significantly alters the cost recovery model we had established for vegetation management and wildfire mitigation. We recognize that promoting rapid and cost-effective wildfire risk reduction is a new regulatory challenge, involving new technologies and accelerating risks. In docket UE 374, we adopted a performance-based approach that sought to align the company's incentives with the shifting risks on the Oregon landscape. This stipulation significantly increases the vegetation management budget, better balancing it with other hardening measures. It also opens a more fulsome discussion in docket UE 407 on aligning wildfire mitigation spending beyond vegetation management with cost-effective risk reduction. We find this stipulation is a reasonable evolution of our approach to investments in risk reduction.

We find that the three stipulations, taken together, represent a reasonable resolution of the identified issues and contribute to an overall settlement in the public interest. We adopt the First, Second, and Third Partial Stipulations in their entirety.

V. DIRECT ACCESS ISSUE

The only contested issue in this phase of the proceeding was raised by Calpine and regards the terms of PacifiCorp's direct access schedules. Calpine seeks Commission clarification that customers in the three-year direct access program (*i.e.*, Schedule 295) can switch after their first or second year on that schedule to the five-year direct access program (*i.e.*, Schedule 296) without paying a Returning Service Payment under Schedule 201, the cost-of-service rate. Calpine argues that payment is explicitly meant for customers returning to cost-based rates, which a customer switching between direct access programs would not be. PacifiCorp opposes this request, saying it allows direct access customers to game the rates in particular years, leading to potential cross-subsidization issues, and that it is disruptive to its planning. PacifiCorp also argues that this is not the correct proceeding in which to decide this issue.

Calpine raised this issue in rebuttal testimony, stating that it had not done so earlier because PacifiCorp had not yet responded to discovery requests asking it to state its position on this issue. PacifiCorp responded in its surrebuttal testimony. On brief, AWEC and Staff supported Calpine's position. CUB opposed it.

A. Relevant Law and Tariff Framework

OAR 860-038-0275(5) requires that "[a]t least once each year, electric companies must offer customers a multi-year direct access program with an associated fixed transition adjustment." PacifiCorp offers Schedule 295, which has a three-year term, and Schedule-

296, which has a five-year term. The three-year program has a fixed transition adjustment for the whole term; at the end, customers can either return to regular service or elect a new direct access term.

Schedule 296's five-year term, on the other hand, was developed in response to the Commission's Order 12-500 in docket UM 1587. In that order (at 9), the Commission determined:

> We direct Pacific Power to file a tariff for a five-year opt-out program that allows a qualified customer to go to direct access and pay fixed transition charges for the next five years, and then to be no longer subject to transition adjustments—for so long as that customer remains a direct access customer (on the Pacific Power system).

In Order No. 15-060, Schedule 296 was ultimately approved as that five-year opt-out program. In doing so, the Commission required that Schedule 296 customers pay both the transmission charge and an opt-out charge to "protect other customers from cost-shifting."[8] A customer who remains on Schedule 296 for five years is effectively on "permanent" direct access at the end of that term and does not need to continue to pay transition charges or an opt-out charge.

The Commission's regulations also provide for a one-time charge for customers returning to bundled service from direct access. That charge is specifically meant to ensure that

> The electric company must design its cost-of-service rate for nonresidential consumers and one-time charges associated with returning to a cost-of-service rate so that residential consumers served under a cost-of-service rate are not assigned costs associated with other classes of consumers switching between direct access or standard offer and the cost-of-service rate. The electric company may limit switching through enrollment periods or by requiring minimum terms of service.[9]

B. Parties' Positions

1. Calpine

Calpine argues that customers should be able to switch from the three-year direct access program to the five-year direct access program at the end of the first or second year of the

[8] Order No. 15-060 at 6.
[9] OAR 860-038-0240(6).

three-year program *without paying the Returning Service Payment* discussed in the Commission's regulations and specified in PacifiCorp's Schedule 201.

Calpine first argues that the Returning Service Payment is not applicable as a matter of logic and tariff interpretation. It notes:

> PacifiCorp's tariff itself states that the Returning Service Payment "compensates for the *increased cost of serving such returning Consumer* due to an increase in market price as compared to the market price used in determining the Consumer's applicable transition credit as specified under Schedule 294."[10]

A customer in Calpine's scenario, it argues, would by definition not be returning to cost-of-service rates; it would instead be switching between two different types of direct-access programs.

Second, Calpine argues that switching customers will not incur additional costs for PacifiCorp: customers switching from a three-year direct access program to a five-year direct access program will actually pay more in transition-related fees than customers that opted directly into a five-year direct access program, as they will have paid the first year or two of payments under the three-year program followed by payments under the entire five-year program.

Calpine also opposes PacifiCorp's procedural objections, arguing that "[a] general rate case is an appropriate forum to seek resolution of how a public utility's direct access tariffs should work" and citing to earlier tariff interpretation disputes that the Commission resolved in the course of a general rate case.[11]

2. PacifiCorp

PacifiCorp makes three responses to Calpine's arguments. First, it argues that Calpine's reading of the tariff could lead to gaming that could ultimately result in other customers cross-subsidizing direct access customers that switch from one schedule to another mid-term. In particular, it points to Order No. 21-379, a Commission decision in docket UE 390 regarding PacifiCorp's TAM. It states that the Commission there concluded that "at least on an interim, non-precedential basis, the opt-out charge in the five-year program could go negative and become an opt-out credit." Thus, "[a]s long as this

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[10] Calpine Opening Brief at 7 (emphasis in Calpine Brief).
[11] *See, e.g.*, *In the Matter of Portland General Electric Company*, *Request for a General Rate Revision*, Docket No. UE 335, Order No. 19-129 at 18-20 & Appendix B (April 12, 2019); *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 262, Order No. 13-459, at 9-10 & Appendix B (Dec. 9, 2013).

interim decision remains in place, Calpine's proposal, in this case would allow a customer to freely switch from the three-year to the five-year program in the event market conditions produce an opt-out credit."[12]

Second, PacifiCorp raises concerns regarding its planning obligations. In particular, it notes that customers who have completed the five-year direct access opt-out may return to cost-of-service rates only with four years of advance notice. The company says it thus "is required to include the loads of one- and three-year direct access customers in its integrated resource planning, but not the loads of five-year opt-out customers."[13]

Finally, PacifiCorp argues that this is a poor forum for the Commission to consider this issue. First, it notes the fact that "Calpine waited until its rebuttal testimony at the very end of this case to raise this issue."[14] It also cites the meager record and the fact that this issue could be raised in the other direct access dockets pending before the Commission or in a separate complaint.[15]

3. Other Parties

AWEC, CUB, and Staff all addressed this issue on brief. AWEC and Staff support Calpine. Staff cites to the language of OAR 860-038-0240(6), which concerns customers returning to cost of service schedules, and notes that it does not address switching between direct access tariffs.[16] It also emphasizes, as did Calpine, that a customer switching to the five-year program will ultimately pay the transition adjustment for a longer period of time.[17] In its brief, AWEC argues that PacifiCorp has not identified any prohibition on switching from the three-year program to the five-year program or demonstrated that Calpine inaccurately laid out the cost framework in question.[18]

CUB supports PacifiCorp in its brief, writing that Calpine has "failed to meet its burden to produce sufficient evidence to demonstrate that its proposed change *** would not cause unwarranted cost shifting."[19] It also argues that the ongoing direct access dockets would be a more appropriate place to address the issue.[20]

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[12] PacifiCorp Opening Brief at 4. PacifiCorp also states that this issue is being revisited in dockets UM 2024 and AR 651, an investigation into direct access and companion rulemaking.
[13] PacifiCorp Opening Brief at 3.
[14] PacifiCorp Opening Brief at 4.
[15] PacifiCorp Opening Brief at 5.
[16] Staff Reply Brief at 3.
[17] *Id.* at 4.
[18] AWEC Brief at 10.
[19] CUB Brief at 2.
[20] *Id.* at 1-2.

C. Resolution

We find that Calpine has correctly interpreted the relevant PacifiCorp schedules and thus affirm its position that a customer may switch from the three-year direct access program to the five-year direct access program mid-term without paying the Returning Service Payment. As Calpine points out, a customer making that transition would not be returning to the retail service schedule; by its terms, the Returning Service Payment is accordingly not applicable to it.

The language of Schedule 201, the company's cost of service schedule, is clear: it states that a returning direct access customer becomes eligible to receive Schedule 201 service "by making a request to the [c]ompany for service under this schedule and agreeing to pay the [c]ompany a Returning service Payment [sic]." A customer seeking to switch to a different type of direct access service is not seeking service under Schedule 201.[21] Likewise, neither Schedule 295 (the three-year opt-out) or Schedule 296 (the five-year opt-out) prohibit customers from switching from one schedule to the other.

It is worth noting that Schedule 201 does state that the Returning Service Payment is intended to "compensate[] for the increased cost of serving each returning Customer due to an increase in market price as compared to the market price used in determining the Consumer's applicable transition credit." This, perhaps, hints at PacifiCorp's concern that the applicable transition credit could differ between schedules and allow direct access customers to game the timing of their switch. However, we apply the tariff as it is written and do not read into its restrictions or applications based on statements of the tariff's policy goals that are not part of the operative tariff language.

In doing so, we recognize that the potential cross-subsidization concerns raised by PacifiCorp may have merit in some scenarios, but we cannot determine that on the record before us. No party has submitted, for instance, quantitative analyses or illustrative examples showing how a three-year customer switching to the five-year schedule might benefit from such a change at the expense of other customers. Likewise, PacifiCorp has asserted that such a change might prove problematic in light of its planning obligations but did not submit any details as to what problems may in reality occur, particularly given that PacifiCorp has at least a one or two-year lead-time before the three-year customer would have returned to service under its original planning assumptions.

We also agree that the fact that this issue was raised for the first time in rebuttal testimony made it difficult to develop a complete record. We are comfortable making a

[21] Available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rates/201_Net_Power_Costs_Cost_Based_Supply_Service.pdf.

decision based on the language of the tariff itself. However, we also understand that PacifiCorp might propose to change the tariff, either in the ongoing direct access proceedings or in a stand-alone filing. In that case, we would expect to see a more developed record explicating the potential harms of allowing direct access customers to switch from one option to another.

VI. ORDER

IT IS ORDERED that:

1. The First, Second, and Third Partial Stipulations, attached as Appendix A, B, and C to this order, are adopted in their entirety.

2. Advice No. 22-002, filed on March 1, 2022, is permanently suspended.

3. PacifiCorp, dba Pacific Power, must file new tariffs consistent with this order no later than 3:00 p.m. on December 23, 2022, to be effective January 1, 2023.

4. Calpine Energy Solutions, LLC's request for clarification is granted.

Made, entered, and effective Dec 16, 2022.

Megan W. Decker
Chair

Letha Tawney
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

Mark R. Thompson
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 399

In the Matter of PACIFICORP, d/b/a PACIFIC POWER, Request for a General Rate Revision	**FIRST PARTIAL STIPULATION ON WILDFIRE MITIGATION AND VEGETATION MANAGEMENT ISSUES**

This Partial Stipulation resolves all issues related to wildfire mitigation and vegetation management in PacifiCorp d/b/a Pacific Power's (PacifiCorp or Company) 2022 general rate case, docket UE 399, now pending before the Public Utility Commission of Oregon (Commission).

PARTIES

1. The parties to this Partial Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon (Staff), and the Citizens' Utility Board (CUB), together referred to as the Stipulating Parties. Other parties have participated in the settlement discussions between Staff and PacifiCorp, and none have objected to this Partial Stipulation.

BACKGROUND

2. On March 1, 2022, PacifiCorp filed its 2022 general rate case, which included direct testimony on wildfire mitigation and vegetation management issues. PacifiCorp also filed a revised Wildfire Mitigation and Vegetation Management Mechanism (WMVM) and a revised tariff sheet for Schedule 94 to implement its proposed WMVM adjustments.

3. The Commission approved the WMVM in PacifiCorp's 2021 general rate case, docket UE 374, to allow the Company to recover incremental wildfire mitigation and vegetation

management costs (i.e., those costs PacifiCorp reasonably incurs above the amounts included in base rates) outside a general rate case.

4. In its direct testimony, the Company supported an increase in base rates to cover its expanded wildfire mitigation and vegetation management programs. The Company also proposed to remove incremental wildfire mitigation costs covered by the Company's Wildfire Protection Plan (WPP) from the WMVM. Instead, the Company plans to collect these costs through a WPP automatic adjustment clause, in accordance with ORS 757.963. Finally, the Company proposed modifications to certain components of the WMVM to better align recovery of incremental vegetation management costs with the Company's vegetation management program.

5. On June 22, 2022, Staff and intervenors filed opening testimony. Staff was the only party to submit testimony addressing wildfire mitigation and vegetation management issues. Staff proposed certain adjustments to PacifiCorp's base rate increase for wildfire mitigation and vegetation management costs and opposed PacifiCorp's proposed revisions to the WMVM.

6. On July 1, 2022, the parties to docket UE 399 convened a settlement conference.

7. Thereafter, PacifiCorp filed reply testimony from Joelle R. Steward and Allen Berreth on July 19, 2022, addressing wildfire mitigation and vegetation management issues.

8. The parties to docket UE 399 then held another settlement conference on July 28, 2022.

9. On August 10, 2022, the parties to docket UE 399 held a settlement conference focused only on wildfire mitigation and vegetation management issues. At that settlement conference, the Stipulating Parties reached an agreement that resolves all issues related to wildfire mitigation and vegetation management in this case. The terms of the settlement are

captured in this Partial Stipulation.

AGREEMENT

10. Overall Agreement: The Stipulating Parties agree to submit this Partial Stipulation to the Commission and request that the Commission approve the Partial Stipulation as presented. The Stipulating Parties agree that the rate changes resulting from the Partial Stipulation are fair, just, and reasonable, as required by ORS 756.040.

11. Base Rates Expense: The Stipulating Parties agree to increase wildfire mitigation and vegetation management expense included in PacifiCorp's base rates from $30 million to $69.7 million, which includes $50 million in vegetation management expense and $19.7 million in wildfire mitigation expense. These changes result in a net reduction of expense of approximately $300 thousand.

12. Base Rates Capital: The Stipulating Parties agree that PacifiCorp's base rates should reflect the revenue requirement impact of PacifiCorp's wildfire capital investments in this case. These investments total $34.9 million, and all will be in service by January 1, 2023. Prior to the rate effective date, the Company will provide a single officer attestation verifying the final dollar amount for wildfire capital projects that have been placed in service by January 1, 2023. In the event that the wildfire capital projects are not complete and in service by January 1, 2023, the revenue requirement associated with those projects will be removed from the test year rate base and the January 1, 2023 base rate change so that customer rates do not reflect charges for plant not presently used and useful.

13. Incremental Costs: The Stipulating Parties agree that PacifiCorp's incremental vegetation management costs will be recovered through the WMVM. Parties agree that they will address the request for recovery of incremental wildfire mitigation costs, as set forth in

PacifiCorp's WPP, in PacifiCorp's application for a WPP automatic adjustment clause, now pending in docket UE 407.

14. Resolution of Proposed Adjustments: The Stipulating Parties agree that the settlement resolves Staff's proposed adjustments for a $6.5 million reduction in vegetation management and wildfire mitigation costs in base rates and a ten percent "holdback" of forecast costs for vegetation management and wildfire mitigation in base rates.

15. Modification of WMVM: The Stipulating Parties agree to modify the current WMVM in three ways. First, the Stipulating Parties agree to eliminate the two-tiered approach, under which the first tier is subject to a more rigorous earnings review than the second tier. Second, the Stipulating Parties agree to extend the WMVM, which now covers incremental costs incurred through the end of 2023, by one year to include incremental costs incurred through 2024, unless PacifiCorp files a general rate case with a new forecast for 2024. Third, the Stipulating Parties agree to modify the WMVM violation levels per the table below for recovery of incremental costs:

Performance Metric	Number of Violations	Earnings Test
Below Violation Level 1	0-150	None
Above Violation Level I, but below Violation Level II	151-225	Authorized ROE minus 100 basis points
Above Violation Level II, but below Violation Level III	226-325	Authorized ROE minus 150 basis points
Above Violation Level III	326+	Authorized ROE minus 200 basis points

16. Application of Modified WMVM: The Stipulating Parties agree that the modified WMVM will apply to requests for recovery under the WMVM filed in 2023 (for 2022 vegetation management and wildfire mitigation costs incremental to $30 million in base rates), 2024 (for 2023 vegetation management costs incremental to $50 million in base rates), and, unless

PacifiCorp has filed another general rate case with new forecast costs for 2024, 2025 (for 2024 vegetation management costs incremental to $50 million in base rates).

17. Tracking of Vegetation Management Costs: On an annual basis, PacifiCorp will track its actual vegetation management costs in relation to the $50.0 million of costs included in base rates to determine the amount of incremental costs or costs below base rate levels. PacifiCorp will defer any annual difference between what has been included in base rates and actual costs when actuals are less than $50.0 million to allow the Commission to consider how to address this differential. The Stipulating Parties agree to support PacifiCorp's requests for ongoing deferral of these costs.

18. Tracking of Wildfire Mitigation Costs: On an annual basis, PacifiCorp will track its actual wildfire mitigation costs in relation to the $19.7 million of wildfire mitigation costs in base rates to determine the amount of incremental costs or costs below base rate levels. The Stipulating Parties agree to ask the Commission to address treatment of these differences in the Company's WPP automatic adjustment clause filing, docket UE 407.

19. WPP Automatic Adjustment Clause: Nothing in this Partial Stipulation prevents the Stipulating Parties from taking any position on the legal requirements of ORS 757.963 in docket UE 407 or other proceeding.

20. Entire Agreement: The Stipulating Parties agree that this agreement represents a compromise among competing interests and a resolution of all contested issues in this docket.

21. This Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Partial Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Partial Stipulation at the hearing, and recommend that the Commission issue an order adopting the

settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting joint testimony or a brief in support of the Partial Stipulation in accordance with OAR 860-001-0350(7).

22. If this Partial Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Partial Stipulation. The Stipulating Parties agree to cooperate in any hearing and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Partial Stipulation.

23. The Stipulating Parties have negotiated this Partial Stipulation as an integrated document. If the Commission rejects all or any material part of this Partial Stipulation or adds any material condition to any final order that is not consistent with this Partial Stipulation, each Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Partial Stipulation or to withdraw from the Partial Stipulation. The Stipulating Parties agree that in the event the Commission rejects all or any material part of this Partial Stipulation or adds any material condition to any final order that is not consistent with this Partial Stipulation, the Stipulating Parties will meet in good faith within 15 days and discuss next steps. A Stipulating Party may withdraw from the Partial Stipulation after this meeting by providing written notice to the Commission and other Stipulating Parties. The Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Partial Stipulation.

24. By entering into this Partial Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Partial Stipulation, other than those

specifically identified in the body of this Partial Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Partial Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Partial Stipulation.

25. The Stipulating Parties agree to make best efforts to provide each other any and all news releases that any Stipulating Party intends to make about the Partial Stipulation two business days in advance of publication. This provision is not binding on the Commission itself.

26. This Partial Stipulation is not enforceable by any Stipulating Party unless and until adopted by the Commission in a final order. Each signatory to this Partial Stipulation acknowledges that they are signing this Partial Stipulation in good faith and that they intend to abide by the terms of this Partial Stipulation unless and until the Partial Stipulation is rejected or adopted only in part by the Commission. The Stipulating Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Partial Stipulation.

27. This Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document. The Stipulating Parties further agree that any electronically-generated signature of a Stipulating Party is valid and binding to the same extent as an original signature.

28. This Partial Stipulation may not be modified or amended except by written agreement among all Stipulating Parties who have executed it.

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PUBLIC UTILITY COMMISSION OF OREGON STAFF	**PACIFICORP**
By: /s/ Johanna Riemenschneider	By: ______________________________
Date: August 24, 2022	Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: ______________________________

Date:______________________________

PACIFICORP

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: /s/ Michael Goetz

Date: August 25, 2022

PUBLIC UTILITY COMMISSION OF OREGON STAFF	**PACIFICORP**
By: ____________________	By: ____________________
Date: ____________________	Date: Aug 25, 2022

OREGON CITIZENS' UTILITY BOARD

By: ____________________

Date: ____________________

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 399

In the Matter of PACIFICORP, d/b/a PACIFIC POWER, Request for a General Rate Revision	**SECOND PARTIAL STIPULATION**

This Second Partial Stipulation resolves certain issues in PacifiCorp d/b/a Pacific Power's (PacifiCorp or Company) 2022 general rate case, docket UE 399, now pending before the Public Utility Commission of Oregon (Commission).

PARTIES

1. The parties to this Second Partial Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon (Staff), the Oregon Citizens' Utility Board (CUB), the Alliance of Western Energy Consumers (AWEC), Calpine Energy Solutions, LLC (Calpine Solutions), Walmart Inc. (Walmart), Vitesse, LLC (Vitesse), and the Klamath Water Users Association and Oregon Farm Bureau Federation (KWUA/OFBF), together referred to as the Stipulating Parties. A copy of this Second Partial Stipulation has been shared with all parties to this case, and no party has objected to it.

BACKGROUND

2. On March 1, 2022, PacifiCorp filed its 2022 general rate case, which included direct testimony and exhibits on the issues contained in this Second Partial Stipulation.

3. On June 22, 2022, Staff and intervenors filed opening testimony. Staff and AWEC filed testimony addressing the issues resolved by this Second Partial Stipulation.

4. On July 1, 2022, the parties to docket UE 399 convened a settlement conference.

5. Thereafter, PacifiCorp filed reply testimony on July 19, 2022, addressing the issues contained in this Second Partial Stipulation.

6. The parties to docket UE 399 then held additional settlement conferences on July 28, 2022 and August 19, 2022. As a result of these settlement conferences, the Stipulating Parties have reached an agreement that resolves the issues contained herein. The terms of the settlement are captured in this Second Partial Stipulation.

AGREEMENT

7. Overall Agreement: The Stipulating Parties agree to submit this Second Partial Stipulation to the Commission and request that the Commission approve the Second Partial Stipulation as presented. The Stipulating Parties agree that the rates resulting from the Second Partial Stipulation are fair, just, and reasonable, as required by ORS 756.040.

8. Wyoming Wind Tax Update: The Stipulating Parties agree that PacifiCorp will include a phased calculation for the Wyoming Wind Generation Tax for Ekola Flats and TB Flats based on the staggered in-service dates for the various turbines. This adjustment resolves Issue 5 in Staff/200 and will result in a $45,000 reduction in PacifiCorp's Oregon-allocated revenue requirement from the Company's initial filing.

9. Merwin Downstream In-Lieu Project Removal: The Stipulating Parties agree to the removal of the Merwin Downstream In-Lieu capital project from PacifiCorp's test year rate base, which will result in a $438,000 reduction to the Oregon-allocated revenue requirement from the Company's initial filing. This resolves Issue 1 in Staff/800.

10. Meter Replacement Amortization Adjustment Removal: The Stipulating Parties agree that PacifiCorp will remove the annual amortization expenses related to the Advanced Metering Infrastructure (AMI) Replaced Meters that were recorded as a regulatory asset in Order

No. 20-473, issued in the Company's last general rate case. The expenses will be amortized over five years in a separate tariff schedule. Removing this adjustment from base rates will result in $1.0 million reduction to the Oregon-allocated revenue requirement from the Company's initial filing. This resolves Issue A11 in AWEC/100.

11. Clean Fuels Revised Amortization Removal: The Stipulating Parties agree that PacifiCorp will remove $1.24 million in expenses associated with the Oregon Clean Fuels Program Amortization from the Base Period. This includes the amortization amounts recorded in the 12-month period ending in June 2021. The estimated Oregon-allocated revenue requirement impact for this change is a $1.28 million reduction from the Company's initial filing. This resolves Issue 1 in Staff/1600.

12. Long-Term Debt: The Stipulating Parties agree that PacifiCorp will update its calculation of the cost of debt embedded in the revenue requirement to 4.717 percent. As a result, the cost of long-term debt included in the Oregon-allocated revenue requirement will increase by $6.96 million from the Company's initial filing.

13. Fuel Stock Inventory Update: The Stipulating Parties agree that PacifiCorp will update its fuel stock inventory forecast and decrease the forecast by $22.9 million to $151.6 million. The estimated Oregon-allocated revenue requirement impact of this update is a $525,000 reduction to the Company's initial filing. This resolves Issues A9 and A10 in AWEC/100.

14. 30-Day Work Papers on Transition Adjustment Mechanism (TAM): The Stipulating Parties agree that, as addressed in PacifiCorp's TAM docket UE 400, the Company will provide all Schedule 296 calculations used to calculate the Consumer Opt-Out Charge, including all supporting work papers, within 30 days of filing the TAM. This change will not result in any adjustment to PacifiCorp's Oregon-allocated revenue requirement. The provision

of the TAM Guidelines addressing the 30-day work papers will be amended as follows: "Within 30 days of the Initial Filing, PacifiCorp will deliver to the Parties a sample calculation, including all supporting work papers, of Schedule 296 as applicable to customers currently served under rate schedules 30 and 48 (Primary). PacifiCorp may file a motion to waive this requirement of the TAM Guidelines and would ensure that motion is served on Calpine Solutions, LLC on or before PacifiCorp makes the initial filing in the TAM."

15. Correction to Interest Calculation: The Stipulating Parties agree that PacifiCorp will correct the calculation of the amount of interest synchronization to a reduction in overall Oregon-allocated revenue requirement of $1.3 million from the Company's initial filing. This resolves Issue 1 in Staff/200.

16. Update of Jurisdictional Load Factors: The Stipulating Parties agree that PacifiCorp will remove the anticipated generation offset previously included as a reduction to Utah's jurisdictional load factors. The estimated Oregon revenue requirement impact for this change is a $2.05 million reduction from the Company's initial filing. This resolves Issue A17 in AWEC/100.

17. Update to Commission Fees: The Stipulating Parties agree that the Company's Commission fee will be updated to reflect the latest approved fee of 0.43 percent as approved by Order No. 22-062. The estimated Oregon revenue requirement impact for this change is a $93,000 increase to the Company's initial filing. This resolves Issue 4 in Staff/200.

18. Oregon Corporate Activity Tax (OCAT): The Stipulating Parties agree that the OCAT will be moved from FERC Account 409.11 (State Income Tax) to FERC Account 408 (Taxes Other than Income). The estimated Oregon revenue requirement impact for this change is a $276,000 reduction from the Company's initial filing.

19. Jim Bridger Units 1 and 2 Depreciable Lives: The Stipulating Parties agree that Oregon's depreciable lives for Jim Bridger Unit 1, Unit 2 and Common Lives will be extended to December 31, 2029, reflecting the conversion of Units 1 and 2 to natural gas-fired resources in 2024 consistent with PacifiCorp's acknowledged 2021 Integrated Resource Plan. The Company's calculation of updated depreciation rates reflects a revenue requirement reduction of approximately $12 million, and the Stipulating Parties agree this is a reasonable approximation of new rates for purposes of extending the lives. PacifiCorp will confirm the final revenue requirement impact in its compliance filing. The Stipulating Parties further agree that: (a) all components of the depreciation rates will be updated in the Company's next depreciation study; (b) coal specific assets retired as part of the gas conversion project will be fully depreciated at the time of retirement, and remaining assets at Units 1 and 2 are used and useful for purposes of natural gas fired generation providing energy to Oregon customers; and (c) the agreement to extend the depreciable lives of Jim Bridger Units 1 and 2 is not designed to address the Oregon exit dates or operational lives for these units.

20. Entire Agreement: The Stipulating Parties agree that this agreement represents a compromise among competing interests and a resolution of all contested issues in this docket which are contained in this agreement.

21. This Second Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Second Partial Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting joint testimony or a brief in support of the Second Partial Stipulation in accordance

with OAR 860-001-0350(7).

22. If this Second Partial Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Second Partial Stipulation. The Stipulating Parties agree to cooperate in any hearing and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Second Partial Stipulation.

23. The Stipulating Parties have negotiated this Second Partial Stipulation as an integrated document. If the Commission rejects all or any material part of this Second Partial Stipulation or adds any material condition to any final order that is not consistent with this Second Partial Stipulation, each Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Second Partial Stipulation or to withdraw from the Second Partial Stipulation. The Stipulating Parties agree that in the event the Commission rejects all or any material part of this Second Partial Stipulation or adds any material condition to any final order that is not consistent with this Second Partial Stipulation, the Stipulating Parties will meet in good faith within 15 days and discuss next steps. A Stipulating Party may withdraw from the Second Partial Stipulation after this meeting by providing written notice to the Commission and other Stipulating Parties. The Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Second Partial Stipulation.

24. By entering into this Second Partial Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Second Partial Stipulation, other than those specifically identified in the body of this Second Partial Stipulation.

No Stipulating Party shall be deemed to have agreed that any provision of this Second Partial Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Second Partial Stipulation.

25. The Stipulating Parties agree to make best efforts to provide each other any and all news releases that any Stipulating Party intends to make about the Second Partial Stipulation two business days in advance of publication. This provision is not binding on the Commission itself.

26. This Second Partial Stipulation is not enforceable by any Stipulating Party unless and until adopted by the Commission in a final order. Each signatory to this Second Partial Stipulation acknowledges that they are signing this Second Partial Stipulation in good faith and that they intend to abide by the terms of this Second Partial Stipulation unless and until the Second Partial Stipulation is rejected or adopted only in part by the Commission. The Stipulating Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Second Partial Stipulation.

27. This Second Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document. The Stipulating Parties further agree that any electronically-generated signature of a Stipulating Party is valid and binding to the same extent as an original signature.

28. This Second Partial Stipulation may not be modified or amended except by written agreement among all Stipulating Parties who have executed it.

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PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: /s/ Johanna Riemenschneider

Date: August 24, 2022

PACIFICORP

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date: ______________________________

WALMART INC.

By: ______________________________

Date: ______________________________

CALPINE ENERGY SOLUTIONS, LLC

By: ______________________________

Date: ______________________________

OREGON FARM BUREAU FEDERATION

By: ______________________________

Date: ______________________________

VITESSE, LLC

By: ______________________________

Date: ______________________________

KLAMATH WATER USERS ASSOCIATION

By: ______________________________

Date: ______________________________

PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

OREGON CITIZENS' UTILITY BOARD

By: /s/ Michael Goetz

Date: August 25, 2022

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________

Date: ______________________

WALMART INC.

By: ______________________

Date: ______________________

CALPINE ENERGY SOLUTIONS, LLC

By: ______________________

Date: ______________________

OREGON FARM BUREAU FEDERATION

By: ______________________

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VITESSE, LLC

By: ______________________

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KLAMATH WATER USERS ASSOCIATION

By: ______________________

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PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: ______________________________

Date:______________________________

PACIFICORP

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date:______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date:______________________________

WALMART INC.

By: ______________________________

Date: August 24, 2022

CALPINE ENERGY SOLUTIONS, LLC

By: ______________________________

Date:______________________________

OREGON FARM BUREAU FEDERATION

By: ______________________________

Date:______________________________

VITESSE, LLC

By: ______________________________

Date:______________________________

KLAMATH WATER USERS ASSOCIATION

By: ______________________________

Date:______________________________

PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: Aug 25, 2022

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date: ______________________________

WALMART INC.

By: ______________________________

Date: ______________________________

CALPINE ENERGY SOLUTIONS, LLC

By: ______________________________

Date: ______________________________

OREGON FARM BUREAU FEDERATION

By: ______________________________

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VITESSE, LLC

By: ______________________________

Date: ______________________________

KLAMATH WATER USERS ASSOCIATION

By: ______________________________

Date: ______________________________

PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date: 8/25/2022

WALMART INC.

By: ______________________________

Date: ______________________________

CALPINE ENERGY SOLUTIONS, LLC

By: ______________________________

Date: ______________________________

OREGON FARM BUREAU FEDERATION

By: ______________________________

Date: ______________________________

VITESSE, LLC

By: ______________________________

Date: ______________________________

KLAMATH WATER USERS ASSOCIATION

By: ______________________________

Date: ______________________________

PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date:______________________________

WALMART INC.

By: ______________________________

Date:______________________________

OREGON FARM BUREAU FEDERATION

By: ______________________________

Date:______________________________

PACIFICORP

By: ______________________________

Date:______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date:______________________________

CALPINE ENERGY SOLUTIONS, LLC

By: ______________________________

Date: 8/24/22

VITESSE, LLC

By: ______________________________

Date:______________________________

KLAMATH WATER USERS ASSOCIATION

By: ______________________________

Date:______________________________

PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: ______________________________

Date:______________________________

PACIFICORP

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date:______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date:______________________________

WALMART INC.

By: ______________________________

Date:______________________________

CALPINE ENERGY SOLUTIONS, LLC

By: ______________________________

Date:______________________________

OREGON FARM BUREAU FEDERATION

By: ______________________________

Date:______________________________

VITESSE, LLC

By: ______________________________

Date: 8/24/2022

KLAMATH WATER USERS ASSOCIATION

By: ______________________________

Date:______________________________

PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date: ______________________________

WALMART INC.

By: ______________________________

Date: ______________________________

CALPINE ENERGY SOLUTIONS, LLC

By: ______________________________

Date: ______________________________

OREGON FARM BUREAU FEDERATION

By: Paul S. Simmons

Date: 8-25-2022

VITESSE, LLC

By: ______________________________

Date: ______________________________

KLAMATH WATER USERS ASSOCIATION

By: Paul S. Simmons

Date: 8-26-2022

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 399

In the Matter of

PACIFICORP, d/b/a PACIFIC POWER,

Request for a General Rate Revision

THIRD PARTIAL STIPULATION

This Third Partial Stipulation resolves all remaining issues except for two discrete issues in PacifiCorp d/b/a Pacific Power's (PacifiCorp or Company) 2022 general rate case, docket UE 399, now pending before the Public Utility Commission of Oregon (Commission). The first discrete issue is PacifiCorp's proposed voluntary renewable energy tariff (VRET) for nonresidential customers, which is proposed in Schedule 273, Accelerated Commitment Tariff (ACT), which is the subject of a Fourth Partial Stipulation. The second discrete issue that will be litigated is the Calpine Energy Solutions, LLC's (Calpine Solutions) recommendation that the Commission should determine that a direct access customer participating in a three-year opt-out program may commence service in the five-year opt-out program prior to the end of the customer's three-year opt-out program without paying penalties.

PARTIES

1. The parties to this Third Partial Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon (Staff), the Oregon Citizens' Utility Board (CUB), the Alliance of Western Energy Consumers (AWEC), Fred Meyer and Quality Food Centers (Fred Meyer), Walmart Inc. (Walmart), Small Business Utility Advocates (SBUA), the Klamath Water Users Association and the Oregon Farm Bureau Federation (KWUA/OFBF), Vitesse, LLC (Vitesse),

and Calpine Solutions, together referred to as the Stipulating Parties. A copy of this Third Partial Stipulation has been shared with all parties to this case, and no party has objected to it.

BACKGROUND

2. On March 1, 2022, PacifiCorp filed its 2022 general rate case, which included direct testimony and exhibits on the issues contained in this Third Partial Stipulation.

3. On June 22, 2022, Staff and intervenors filed opening testimony. Staff, CUB, AWEC, KWUA/OFBF, SBUA, and Walmart filed testimony addressing the issues resolved by this Third Partial Stipulation.

4. On July 1, 2022, the parties to docket UE 399 convened a settlement conference.

5. PacifiCorp filed reply testimony on July 19, 2022, addressing the issues contained in this Third Partial Stipulation.

6. The parties to docket UE 399 then held additional settlement conferences on July 28, 2022, and August 10, 2022.

7. On August 11, 2022, Staff and intervenors filed rebuttal testimony. Staff, CUB, AWEC, Fred Meyer, KWUA/OFBF, SBUA, and Calpine Solutions filed testimony addressing the issues resolved by this Third Partial Stipulation

8. The parties to docket UE 399 then held additional settlement conferences on August 19, 2022, August 24, 2022, and August 26, 2022.

9. PacifiCorp filed surrebuttal testimony on August 26, 2022, addressing the issues contained in this Third Partial Stipulation.

10. The parties to docket UE 399 then held an additional settlement conference on August 30, 2022.

11. As a result of these settlement conferences, the Stipulating Parties have reached

an agreement that resolves the issues contained herein. The terms of the settlement are captured in this Third Partial Stipulation.

AGREEMENT

12. Overall Agreement: The Stipulating Parties agree to submit this Third Partial Stipulation to the Commission and request that the Commission approve the Third Partial Stipulation as presented. The Stipulating Parties agree that the rates resulting from the Third Partial Stipulation are fair, just, and reasonable, as required by ORS 756.040.

13. Rate Increase and Rate Effective Date: Together with the First and Second Partial Stipulations and this Third Partial Stipulation, the Stipulating Parties agree that PacifiCorp shall be authorized to implement rate changes based on a revenue requirement increase of $51.4 million or $48.9 million, including the impacts of the Oregon Corporate Activity Tax Credit and Rate Mitigation Adjustment. This results in an overall increase of 3.9 percent. The Stipulating Parties also agree to the approval and amortization of certain deferrals through separate schedules as explained in Section 16 below, which is an increase of approximately $10.4 million in the first year of amortizations, or 0.8 percent. Appendix A to this Third Partial Stipulation reflects the agreed-upon calculation of the base rate change and the change related to the deferral amortizations. The Stipulating Parties agree that the rate change attributable to the revenue requirement identified herein will be effective with service on and after January 1, 2023. The rate change attributable to the deferral amortizations will be effective with service on or after April 1, 2023. The suspension period in this case ends on December 31, 2022.

As shown in Appendix A and detailed below and in the First and Second Partial Stipulations, the Stipulating Parties agree that the proposed total overall $59.3 million increase reflects specific updates and adjustments to the Company's filed case, as well as an additional non-specific adjustment related to a compromise of issues on which resolution could not be reached.

14. Rate of Return: The Stipulating Parties agree to maintain the current authorized capital structure and cost of equity that were previously approved for PacifiCorp in Docket UE 374.[1] In the Second Partial Stipulation, the parties agreed to update the cost of long-term debt to 4.717 percent. Together, these components result in a rate of return of 7.109 percent.

15. Non-Specific Adjustment: The Stipulating Parties agree to a $6.0 million reduction to the Company's revenue requirement as resolution of all other revenue requirement items for which specific settlement was not reached.

16. Deferral Amortizations: The Stipulating Parties agree to the approval, as applicable, and amortization of the following deferrals:

- Docket UM 1964, Deferred Accounting for costs associated with PacifiCorp's Transportation Electrification Program;[2]
- Docket UM 2134, Deferred Accounting for costs associated with Cedar Springs 2;[3]
- Docket UM 2142, Deferred Accounting for costs associated with Cholla Unit 4 property taxes (previously approved);[4]

[1] PacifiCorp's previously authorized return on equity was 9.5 percent, with an authorized capital structure of Long-Term Debt at 49.99 percent, Common Stock Equity at 50.00 percent, and Preferred Stock at 0.01 percent.
[2] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for a Balancing Account Related to PacifiCorp's Transportation Electrification Program,* Docket No. UM 1964, Application filed July 27, 2018.
[3] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120,* Docket No. UM 2134, Application filed Dec. 10, 2020.
[4] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for a Balancing Account Related to Cholla Unit 4-Related Property Tax Expense,* Docket No. UM 2142, Application filed December 24, 2020, Order No. 21-044 (Feb. 12, 2021).

- Docket UM 2167, Deferred Accounting for revenues associated with Renewable Energy Credits (RECs) from Pryor Mountain;[5]
- Docket UM 2185, Deferred Accounting for costs associated with Non-Contributory Defined Benefit Pensions Plans;[6]
- Docket UM 2186, Deferred Accounting for the costs associated with the TB Flats Wind Project;[7]
- Docket UM 2063, Deferred Accounting for the costs associated with the COVID-19 Public Health Emergency (previously approved);[8] and
- Docket No. UM 2201, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues.[9]

The Stipulating Parties agree to the balance to be amortized and the amortization periods of the above deferrals as follows:

[5] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Revenues Associated with RECs from Pryor Mountain,* Docket No. UM 2167, Application filed May 13, 2021.
[6] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pensions Plans,* Docket No. UM 2185, Application filed July 27, 2021.
[7] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Costs Related to a Renewable Resource Pursuant to ORS 469A.120,* Docket No. UM 2186, Application filed July 27, 2021.
[8] *In the Matter of PacifiCorp dba Pacific Power Application for Order Approving the Deferred of Costs Associated with the Response to COVID-19 Public Health Emergency,* Docket No. UM 2063, Order No. 20-375 (Oct. 27, 2020); Reauthorization Order No. 22-090 (Mar. 24, 2022) and Reauthorization Order No. 22-139 (May 9, 2022).
[9] *In the Matter of Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues,* Docket No. UM 2201.

Table 1: Amortization of the Deferral Balances

Deferral Docket	December 2022 Balance	Amortization Period	Year 1 Annual Amortization
UM 1964 Transportation Electrification Program	2,839,892	3 Years	978,604
UM 2134 Cedar Springs II	681,475	3 Years	234,831
UM 2186 TB Flats	17,900,662	3 Years	6,168,426
UM 2167 Renewable Energy Credits from Pryor Mountain	(364,127)	3 Years	(125,475)
UM 2142 Cholla Unit 4-Related Property Tax Expense	639,589	3 Years	220,063
UM 2063 COVID-19 Deferral	17,887,722	4 Years	4,664,754
UM 2201 Fly-Ash Deferral – One Half	(1,700,000)	1 Year	(1,723,322)
Total Balance and Annual Amortization	**37,885,213**		**10,417,881**

The pension plan deferral, docket UM 2185, is being amortized as part of the pension costs reflected in the stipulated revenue requirement in this case.

The Stipulating Parties agree that the amortizations will commence on April 1, 2023. Interest will accrue at the Commission's applicable modified blended treasury rate (MBTR) published in January 2023, starting January 1, 2023. The Stipulating Parties also agree that 50 percent of the fly-ash revenues that are the subject of docket UM 2201, will be returned to customers through the deferral rider over 1 year (current forecast is a total of $3.4 million).

17. Capital Additions:

a. For capital projects unrelated to wildfire mitigation and vegetation management (which are the subject of the First Partial Stipulation), PacifiCorp agrees to file attestations affirming the in-service date for discrete capital projects in excess of $1 million on an Oregon-allocated basis scheduled for completion in the fourth quarter of 2022, before that project may be included in rates.

b. The Company affirms that none of the plant repairs that resulted from the transformer outage at the Aeolus Substation on September 30, 2021 have been included in the docket UE 399 rate case. The Stipulating Parties agree that any funds recovered from third parties related to such repairs, not related to reimbursement of power costs, will be used to credit rate base to offset, in part or in full, the plant repair costs in the event the Company includes such costs in any future rate filing. PacifiCorp agrees to provide an informal status update on PacifiCorp's efforts to recover funds prior to PacifiCorp filing its next general rate proceeding.

18. Exit Orders:

a. The Stipulating Parties agree to support updating the Exit Order for Craig Unit 2 as approved by the Commission in PacifiCorp's last general rate case, docket UE 374,[10] to reflect an Exit Date of September 30, 2028. The Stipulating Parties also agree to support the issuance of Exit Orders for Hayden Units 1 and 2 with Exit Dates of December 31, 2028, and December 31, 2027, respectively. Finally, the Stipulating Parties support a modification to the Jim Bridger Unit 1 Exit Order approved in Order No. 20-473[11] to specify that the Exit Order only applies to this unit as a coal-fired unit.

b. PacifiCorp agrees that if Jim Bridger Unit 1 is not converted to gas by December 31, 2023, PacifiCorp commits to file a notification with the Commission and request a change to the Exit Order for Jim Bridger Unit 1[12] as soon as the Company becomes aware that coal-fueled operations at Jim Bridger Unit 1 are expected to continue past December 31, 2023 – but at any rate no later than September 30, 2023.

19. Pricing and Cost of Service: The Stipulating Parties agree on the pricing and cost of service parameters described in this section. Appendix B to this Third Partial Stipulation

[10] *In Re PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 12 (Dec. 18, 2020).
[11] The Commission approved an Exit Order for Jim Bridger Unit 1 in Order No. 20-473 at 12.
[12] *Id.*

contains estimated rate spread and rates as calculated based on these parameters. To resolve all issues related to pricing and cost of service, the Stipulating Parties agree to the terms listed below.

a. Workshop: The Stipulating Parties agree to support a workshop to discuss different marginal generation methodologies for use in the cost-of-service study that reflect a non-emitting resource portfolio.

b. Residential Customers: By September 30, 2023, the Company will prepare a report using its 2021 Residential Email Survey that will be distributed to the Stipulating Parties. The analysis will demonstrate that the data used is consistent with a random, representative sample of the Company's service territory, or provide the steps used to correct for bias introduced by non-random sampling. The analysis will answer the following questions:

- Question 1: How many residential customers (customers) are classified at the various discount levels associated with "low income" or "energy burdened" in the Company's service territory, and how are they distributed geographically? Please assume that a customer is energy burdened if more than 6 percent of their monthly income goes to energy bills, and is low income if they would qualify for any of the Schedule 7 discounts.
- Question 2: How do customer bills vary with income, geography, and time of year?
- Question 3: How does ownership of air conditioning equipment vary with income levels and location in the Company's service territory? Further, please discuss any correlations between income, location, and the type of air conditioning equipment (i.e. heat pump, central A/C, window units, etc.).

- Question 4: How does the residential choice of winter heating equipment (i.e. electric resistance, natural gas, heat pump, etc.) vary with income and location in the Company's service territory?
- Question 5: What does the Company believe that residential customers' price elasticity to be in its service territory, and how does price elasticity vary with income and location in the Company's service territory?

Responses to Questions 2 through 5 will provide specific statistics and percentages rather than general statements that could potentially be carried over to a complete residential billing distribution.

c. Schedule 23 customers: The Company will complete an analysis of the usage characteristics of Schedule 23 customers and will report to Parties on the results at the same time it reports on the residential assessment referenced above. The analysis will include:

- Providing by SIC code the current number of Schedule 23 customers in Oregon, and the electricity consumption of those customers. If a particular SIC code contains a very small number of customers or seems that the data will easily be identifiable to a particular customer, the Company may aggregate to a broader SIC code grouping.
- Providing time of usage patterns (on- and off-peak kWh usage using the time periods specified in Schedule 210 and Residential Schedule 6) by SIC code for Schedule 23 where available. If a particular SIC code contains a very small number of customers or seems that the data will easily be identifiable to a particular customer, the Company may aggregate to a broader SIC code grouping.

Furthermore, the Company will create a Webpage regarding specifically small commercial rate options including Schedule 210, equal payment plans, electric vehicle charging incentives, Blue

Sky options, and available in no more than two clicks on the Pacific Power homepage https://www.pacificpower.net/.

d. Rate Spread: The Stipulating Parties agree to the following method to establish the rate spread of the overall net rate increase (prior to deferrals) amongst classes:

- The adjustments to net rate spread described herein will be achieved through the use of the Schedule 299 Rate Mitigation Adjustment through the setting of surcharge or credit rates applicable to each delivery service rate schedule.
- No class shall receive a net price change less than zero.
- The initial increase allocation to residential Schedule 4 will be approximately 136 percent of the overall net rate increase. The initial increase allocation to Schedule 23 and Schedule 41 will be approximately 140 percent of the overall net rate increase. The initial allocation to Schedule 48 will be approximately 103 percent of the overall net rate increase. The initial allocation to lighting schedules will be approximately 50 percent of the overall net rate increase. The initial allocation to Schedule 28 and Schedule 30 will be approximately zero percent.
- The remaining increase will be spread as an equal percentage of the overall net rate increase to Schedules 4, 23, 28, 30 and 41. This additional allocation will increase the allocation to each of those rate schedules on top of the initial allocation described above.
- The total dollar amount designed to be collected and distributed amongst the classes under the Rate Mitigation Adjustment for the test period will sum to approximately zero.

e. Deferral Amortizations: The Stipulating Parties agree that the deferral amortizations in Table 1 above will generally be collected from customers as described in the reply testimony of Mr. Robert Meredith, Exhibit PAC/2100, with costs spread to the classes as follows:

- Recovery of deferrals related to docket UM 2134 Cedar Springs II and docket UM 2186 TB Flats will be spread to the classes based on a generation rate spread.
- Recovery of deferral related to docket 2063 COVID-19 costs will be spread to customer classes in the following manner:
  - 73.9 percent to residential
  - 11.5 percent to Schedule 23
  - 5.5 percent to Schedule 28
  - 2.3 percent to Schedule 30
  - 5.8 percent to Schedule 48
  - 1.1 percent to Irrigation
  - 0.03 percent to Lighting
- Recovery for all other deferrals listed in Table 1 above will be spread to classes based on an equal percentage of base revenues rate spread.

f. Residential Rate Design: The Stipulating Parties have an agreement resolving all issues on residential rate design, comprised of the following:

- The residential single-family basic charge will be set at $11.
- Residential energy rates will be un-tiered (single rate per kWh for all kWh)
- Residential energy rates will not be seasonal.
- The BPA residential exchange credit will be a single per kWh credit with a cap on monthly usage of 2,000 kWh.

g. Non-Residential Rate Design: The Stipulating Parties agree to the following changes from PacifiCorp's filed case for rate design for non-residential rate schedules:

- Schedule 48 basic charges do not decrease from current level.
- Schedule 48 Facilities Charge for primary voltage customers greater than 4,000 kW will decrease by 41 percent.

20. Transition Adjustment Mechanism (TAM) and Power Cost Adjustment Mechanism (PCAM):

a. The Stipulating Parties agree to withdraw all recommendations on changes to PacifiCorp's TAM (and TAM Guidelines) and PCAM (with the exception of the provision of workpapers on the Schedule 296 calculation as described in the Second Partial Stipulation). The Stipulating Parties additionally agree to hold collaborative discussions and provide recommendations or report back to the Commission on the following issues associated with PacifiCorp's power costs by December 31, 2023:

- Changes to the TAM Guidelines to include updates and increase the administrative efficiency of the TAM proceeding; and
- Changes to the structure of the PCAM that may be necessary in light of the changing resource mix, the move to structured markets, and other shifts in the energy landscape.

b. The Stipulating Parties who are also parties to docket UE 404 agree to file a settlement to resolve the PCAM in Docket UE 404,[13] based on the terms reflected in the Term Sheet of September 1, 2022 sent by PacifiCorp.

21. Stay-Out Provisions: PacifiCorp agrees to a one-year general rate case stay-out for calendar year 2023 and will not file a general rate case with rates effective earlier than January 1, 2025. With respect to deferral applications, for the calendar year 2023, the Stipulating Parties agree not to request the deferral of costs or revenues, unless (a) the deferral is authorized

[13] *In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Power Cost Adjustment Mechanism,* Docket No. UE 404, Application (May 16, 2022), amended (July 13, 2022).

by statute or Commission order, resulting from a Commission-initiated deferral mechanism, a reauthorization of an existing deferral, or approval of an agreed-upon deferral mechanism in a proceeding, (b) the Stipulating Parties seek reauthorization of a previously filed deferral, (c) laws, regulations or orders become effective that require significant cost reductions or expenditures, (d) the Company incurs major expenses or savings as a result of a state or federal declaration of emergency, or (e) a deferral is necessary to respond to material threat to the financial stability of the Company resulting from unique and unforeseen circumstances outside the Company's reasonable control. The Stipulating Parties agree that their goal is to minimize rate changes during calendar years 2023 and 2024 with regards to amortizations resulting from any deferral of costs approved during the 2023 Stay-out Period. Any Stipulating Party may take any position before the Commission on whether these deferred costs are appropriate to be recovered or credited in retail customers rates.

22. Entire Agreement: The Stipulating Parties agree that this agreement represents a compromise among competing interests and a resolution of all the remaining contested revenue requirement issues in this docket which are contained in this agreement.

23. This Third Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Third Partial Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting joint testimony or a brief in support of the Third Partial Stipulation in accordance with OAR 860-001-0350(7).

24. If this Third Partial Stipulation is challenged, the Stipulating Parties agree that

they will continue to support the Commission's adoption of the terms of this Third Partial Stipulation. The Stipulating Parties agree to cooperate in any hearing and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Third Partial Stipulation.

25. The Stipulating Parties have negotiated this Third Partial Stipulation as an integrated document. If the Commission rejects all or any material part of this Third Partial Stipulation or adds any material condition to any final order that is not consistent with this Third Partial Stipulation, each Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Third Partial Stipulation or to withdraw from the Third Partial Stipulation. The Stipulating Parties agree that in the event the Commission rejects all or any material part of this Third Partial Stipulation or adds any material condition to any final order that is not consistent with this Third Partial Stipulation, the Stipulating Parties will meet in good faith within 15 days and discuss next steps. A Stipulating Party may withdraw from the Third Partial Stipulation after this meeting by providing written notice to the Commission and other Stipulating Parties. The Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Third Partial Stipulation.

26. By entering into this Third Partial Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Third Partial Stipulation, other than those specifically identified in the body of this Third Partial Stipulation. The Third Partial Stipulation addresses the reasonableness of the costs in rates for the 2023 test period and the Stipulating Parties agree that no provision of this Third Partial Stipulation is appropriate for

resolving issues for future periods or proceedings, except as specifically identified in this Third Partial Stipulation.

27. The Stipulating Parties agree to make best efforts to provide each other any and all news releases that any Stipulating Party intends to make about the Third Partial Stipulation two business days in advance of publication. This provision is not binding on the Commission itself.

28. This Third Partial Stipulation is not enforceable by any Stipulating Party unless and until adopted by the Commission in a final order. Each signatory to this Third Partial Stipulation acknowledges that they are signing this Third Partial Stipulation in good faith and that they intend to abide by the terms of this Third Partial Stipulation unless and until the Third Partial Stipulation is rejected or adopted only in part by the Commission. The Stipulating Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Third Partial Stipulation.

29. This Third Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document. The Stipulating Parties further agree that any electronically-generated signature of a Stipulating Party is valid and binding to the same extent as an original signature.

30. This Third Partial Stipulation may not be modified or amended except by written agreement among all Stipulating Parties who have executed it.

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PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: */s/ Johanna Riemenschneider*

Date: 9/21/2022

PACIFICORP

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date:______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

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WALMART INC.

By: ______________________________

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FRED MEYER AND QUALITY FOOD CENTERS

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By: ____________________

Date: ____________________

PACIFICORP

By: [signature]

Date: September 21, 2022

ALLIANCE OF WESTERN ENERGY CONSUMERS

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FRED MEYER AND QUALITY FOOD CENTERS

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ALLIANCE OF WESTERN ENERGY CONSUMERS

By: [signature]

Date: Sept 26, 2022

WALMART INC.

By: ______________________

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FRED MEYER AND QUALITY FOOD CENTERS

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By: KBah

Date: 9.21.22

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FRED MEYER AND QUALITY FOOD CENTERS

By: ______________________________

Date:______________________________

OREGON FARM BUREAU FEDERATION

By: Paul S. S

Date: September 21, 2022

KLAMATH WATER USERS ASSOCIATION

By: Paul S. S

Date: September 21, 2022

SMALL BUSINESS UTILITY ADVOCATES

By: ______________________________

Date:______________________________

CALPINE ENERGY SOLUTIONS, LLC

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VITESSE, LLC

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PUBLIC UTILITY COMMISSION OF OREGON STAFF

By: */s/ Johanna Riemenschneider*

Date: 9/21/2022

PACIFICORP

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

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SMALL BUSINESS UTILITY ADVOCATES

By: Diane Henkels

Date: 9/21/22

CALPINE ENERGY SOLUTIONS, LLC

By: ______________________________

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VITESSE, LLC

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Date: ______________________________

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CALPINE ENERGY SOLUTIONS, LLC

By: ______________________________

Date: Sept. 21, 2022

PUBLIC UTILITY COMMISSION OF OREGON STAFF	**PACIFICORP**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
OREGON CITIZENS' UTILITY BOARD	**ALLIANCE OF WESTERN ENERGY CONSUMERS**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
WALMART INC.	**FRED MEYER AND QUALITY FOOD CENTERS**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
OREGON FARM BUREAU FEDERATION	**KLAMATH WATER USERS ASSOCIATION**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
SMALL BUSINESS UTILITY ADVOCATES	**CALPINE ENERGY SOLUTIONS, LLC**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
VITESSE, LLC	
By: [signature]	
Date: 9/21/2022	

APPENDIX A

Confidential—For Settlement Purposes Only

PacifiCorp Docket UE 399
Adjustments to Oregon-Allocated Results
Year Ending December 31, 2023

Adj. Ref.	Adjustments	Revenue Requirement Effect ($000)
	Reply Filed Revenue Requirement Increase	**$86,429**
S_0	Rate of Return - 7.11% Reflects settlement of capital structure, cost of preferred stock, and return on equity. This also reflects an update to the cost of long-term debt used in the Company's reply filing.	($16,659)
S_1	Vegetation/Wildfire Stipulation This adjustments modifies vegetation management and wildfire mitigation expenses in base rate in accordance with levels agreed upon in the settlement in principle reached.	($321)
S_2 & S_3	Jim Bridger Unit 1, Unit 2 and Common lives This adjustment reflects extending Oregon's depreciable lives for Jim Bridger Unit 1, Unit 2 and Common to December 31, 2029. The Company's calculation of updated depreciation rates reflects a reasonable approximation of new rates for purposes of extending lives in this GRC. All components of the deprecation rates will be updated in the Company's next depreciation study.	($12,255)
S_4	Black Box Adjustment This adjustment reflects a black box adjustment made to operations and maintenance expense.	($6,000)
8.11_S	Emissions Control Investment Return at Settlement capital structure and ROE This reflects the settlement level of capital structure and ROE on the Emissions Control Investment Adjustment.	$220
	Total Adjustments	**($35,016)**
	Adjusted Revenue Requirement Increase	**$51,413**

Confidential—For Settlement Purposes Only

PacifiCorp UE 399
Results of Operations
Year Ending December 31, 2023
($000)

	UE 399 Oregon Results per Company Filing (1)	Stipulated Adjustments (2)	2023 Adjusted (3)	Stipulated Revenue Requirement Increase (4)	Results at Reasonable Return (5)
1 **Operating Revenues**					
2 General Business Revenues	957,021	-	957,021	51,413	1,008,434
3 Interdepartmental	-	-	-		-
4 Special Sales	-	-	-		-
5 Other Operating Revenues	80,910	-	80,910		80,910
6 **Total Operating Revenues**	$1,037,931	$0	$1,037,931	$51,413	$1,089,344
7 **Operating Expenses**					
8 Steam Production	84,817	-	84,817		84,817
9 Nuclear Production	-	-	-		-
10 Hydro Production	12,195	-	12,195		12,195
11 Other Power Supply	19,245	-	19,245		19,245
12 Embedded Cost Differential	19,274	-	19,274		19,274
13 Transmission	116,475	-	116,475		116,475
14 Distribution	23,650	(310)	23,340		23,340
15 Customer Accounting	4,692	-	4,692	735	5,428
16 Customer Service & Info	-	-	-		-
17 Sales	63,204	-	63,204		63,204
18 Administrative & General	-	(5,583)	(5,583)		(5,583)
19 **Total Operation & Maintenance**	$343,553	($5,893)	$337,660	$735	$338,396
20 Depreciation	287,295	(13,022)	274,273		274,273
21 Amortization	34,357	-	34,357		34,357
22 Taxes Other Than Income	89,849	-	89,849	4,164	94,013
23 Income Taxes - Federal	16,684	5,476	22,160	9,324	31,484
24 Income Taxes - State	4,036	1,240	5,276	2,112	7,388
25 Income Taxes - Def Net	14,588	(2,821)	11,767		11,767
26 Investment Tax Credit Adj.	-	-	-		-
27 Misc Revenue & Expense	5	-	5		5
28 **Total Operating Expenses**	$790,366	($15,020)	$775,346	$16,335	$791,682
29 **Net Operating Revenues**	$247,565	$15,020	$262,585	$35,078	$297,662
30 **Average Rate Base**					
31 Electric Plant In Service	8,832,858	-	8,832,858		8,832,858
32 Plant Held for Future Use	-	-	-		-
33 Misc Deferred Debits	67,039	-	67,039		67,039
34 Elec Plant Acq Adj	700	-	700		700
35 Nuclear Fuel	-	-	-		-
36 Prepayments	11,117	-	11,117		11,117
37 Fuel Stock	37,220	-	37,220		37,220
38 Material & Supplies	81,633	-	81,633		81,633
39 Working Capital	13,615	8	13,622		13,622
40 Weatherization Loans	-	-	-		-
41 Misc Rate Base	(101)	-	(101)		(101)
42 **Total Electric Plant**	$9,044,079	$8	$9,044,087	$0	$9,044,087
43 Less:					
44 Accum Prov For Deprec	(3,565,615)	6,513	(3,559,102)		(3,559,102)
45 Accum Prov For Amort	(217,779)	-	(217,779)		(217,779)
46 Accum Def Income Tax	(643,329)	1,725	(641,604)		(641,604)
47 Unamortized ITC	(46)	-	(46)		(46)
48 Customer Adv For Const	(22,975)	-	(22,975)		(22,975)
49 Customer Service Deposits	-	-	-		-
50 Misc Rate Base Deductions	(414,777)	(504)	(415,281)		(415,281)
51 **Total Rate Base Deductions**	($4,864,520)	$7,733	($4,856,787)	$0	($4,856,787)
52 **Total Average Rate Base**	$4,179,559	$7,741	$4,187,300	$0	$4,187,300
53 **Rate of Return**	5.923%	0.348%	6.271%	0.838%	7.109%
54 **Implied Return on Equity**	7.025%	0.799%	7.825%	1.675%	9.500%

Confidential—For Settlement Purposes Only

PacifiCorp UE 399
Stipulated Adjustments to Oregon Results
Year Ending December 31, 2023
($000)

	Rate of Return	Black Box Adjustment	Vegatation/Wildfire Stipulation	Jim Bridger Unit 1, Unit 2 and Common lives	Emission Control Investment Return	Total Stipulated Adjustments
	S_0	S_4	S_1	S_2 & S_3	8.11_S	
1 **Operating Revenues**						
2 General Business Revenues	0	0	0	0	0	0
3 Interdepartmental	0	0	0	0	0	0
4 Special Sales	0	0	0	0	0	0
5 Other Operating Revenues	0	0	0	0	0	0
6 **Total Operating Revenues**	0	0	0	0	0	0
7 **Operating Expenses**						
8 Steam Production	0	0	0	0	0	0
9 Nuclear Production	0	0	0	0	0	0
10 Hydro Production	0	0	0	0	0	0
11 Other Power Supply	0	0	0	0	0	0
12 Embedded Cost Differential	0	0	0	0	0	0
13 Transmission	0	0	0	0	0	0
14 Distribution	0	0	(310)	0	0	(310)
15 Customer Accounting	0	0	0	0	0	0
16 Customer Service & Info	0	0	0	0	0	0
17 Sales	0	0	0	0	0	0
18 Administrative & General	0	(5,795)	0	0	212	(5,583)
19 **Total Operation & Maintenance**	0	(5,795)	(310)	0	212	(5,893)
20 Depreciation	0	0	0	(13,022)	0	(13,022)
21 Amortization	0	0	0	0	0	0
22 Taxes Other Than Income	0	0	0	0	0	0
23 Income Taxes - Federal	(889)	1,162	62	5,184	(43)	5,476
24 Income Taxes - State	(201)	263	14	1,174	(10)	1,240
25 Income Taxes - Def Net	0	0	0	(2,821)	0	(2,821)
26 Investment Tax Credit Adj.	0	0	0	0	0	0
27 Misc Revenue & Expense	0	0	0	0	0	0
28 **Total Operating Expenses**	(1,091)	(4,370)	(234)	(9,485)	160	(15,020)
29 **Net Operating Revenues**	1,091	4,370	234	9,485	(160)	15,020
30 **Average Rate Base**						
31 Electric Plant In Service	0	0	0	0	0	0
32 Plant Held for Future Use	0	0	0	0	0	0
33 Misc Deferred Debits	0	0	0	0	0	0
34 Elec Plant Acq Adj	0	0	0	0	0	0
35 Nuclear Fuel	0	0	0	0	0	0
36 Prepayments	0	0	0	0	0	0
37 Fuel Stock	0	0	0	0	0	0
38 Material & Supplies	0	0	0	0	0	0
39 Working Capital	(10)	(41)	(2)	60	2	8
40 Weatherization Loans	0	0	0	0	0	0
41 Misc Rate Base	0	0	0	0	0	0
42 **Total Electric Plant**	(10)	(41)	(2)	60	2	8
43 Less:						
44 Accum Prov For Deprec	0	0	0	6,511	2	6,513
45 Accum Prov For Amort	0	0	0	0	0	0
46 Accum Def Income Tax	0	0	0	1,725	0	1,725
47 Unamortized ITC	0	0	0	0	0	0
48 Customer Adv For Const	0	0	0	0	0	0
49 Customer Service Deposits	0	0	0	0	0	0
50 Misc Rate Base Deductions	0	0	0	(504)	0	(504)
51 **Total Rate Base Deductions**	0	0	0	7,731	2	7,733
52 **Total Rate Base**	(10)	(41)	(2)	7,792	3	7,741
53 **Revenue Requirement Effect**	(16,659)	(6,000)	(321)	(12,255)	220	(35,016)

Confidential—For Settlement Purposes Only

PacifiCorp UE 399
Cost of Capital
Year Ending December 31, 2023

Reply Cost of Capital (Refer to Page 2.0 of Exhibit PAC/2002)

	Capital Structure	Embedded Cost	Weighted Cost
DEBT%	47.740%	4.717%	2.252%
PREFERRED %	0.010%	6.750%	0.001%
COMMON %	52.250%	9.800%	5.121%
	100.000%		**7.373%**

Settlement Cost of Capital

	Capital Structure	Embedded Cost	Weighted Cost
DEBT%	49.990%	4.717%	2.358%
PREFERRED %	0.010%	6.750%	0.001%
COMMON %	50.000%	9.500%	4.750%
	100.000%		**7.109%**

Operating Revenue	**100.000%**
Operating Deductions	
Uncollectible Accounts	0.505%
Taxes Other - Franchise Tax	2.303%
Taxes Other - Resource Supplier	0.125%
PUC Fees Based on General Business Revenues	0.430%
Sub Total	96.637%
State Income Tax @ 4.54%	4.387%
Sub-Total	92.250%
Federal Income Tax @ 21%	19.373%
Net Operating Income	**72.878%**

Confidential—For Settlement Purposes Only

PacifiCorp UE 399
Deferral Amortization
Effective April 1, 2023

	December 2022	Amortization	Annual
Deferral Docket	**Balance**	**Period**	**Amortization**
UM 1964 Transportation Electrification Program	2,839,892	3 Years	978,604
UM 2134 Cedar Springs II	681,475	3 Years	234,831
UM 2186 TB Flats	17,900,662	3 Years	6,168,426
UM 2167 Renewable Energy Credits from Pryor Mountain	(364,127)	3 Years	(125,475)
UM 2142 Cholla Unit 4-Related Property Tax Expense	639,589	3 Years	220,063
UM 2063 COVID-19 Deferral	17,887,722	4 Years	4,664,754
UM 2201 Fly Ash Revenues	(1,700,000)	1 Year	(1,723,322)
Proposed Annual Amortization	**37,885,213**		**10,417,881**

APPENDIX B

Estimated General Rate Case Base Rates for UE 399 Stipulation

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,769,399,104	5,755,783,167	5,633,856,479	kWh	0.818 ¢	$46,084,946	0.919 ¢	$51,775,141
System Usage Charge								
Sch 200 related, per kWh	5,769,399,104	5,755,783,167	5,633,856,479	kWh	0.067 ¢	$3,774,684	0.078 ¢	$4,394,408
T&A and Sch 201 related, per kWh	5,769,399,104	5,755,783,167	5,633,856,479	kWh	0.079 ¢	$4,450,747	0.106 ¢	$5,971,888
Distribution Charge								
Basic Charge Single Family, per month	4,970,309	4,970,309	5,116,973	bill	$9.50	$48,611,244	$11.00	$56,286,703
Basic Charge Multi Family, per month	1,266,367	1,266,367	1,303,735	bill	$8.00	$10,429,880	$8.00	$10,429,880
Total Bills	6,236,676	6,236,676	6,420,708	bill				
Three Phase Demand Charge, per kW demand	16,025	16,025	15,686	kW	$2.20	$34,509	$2.20	$34,509
Three Phase Minimum Demand Charge, per month	1,373	1,373	1,414	bill	$3.80	$5,373	$3.80	$5,373
Distribution Energy Charge, per kWh	5,769,399,104	5,755,783,167	5,633,856,479	kWh	3.523 ¢	$198,480,764	4.337 ¢	$244,340,355
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	4,325,370,839	4,315,161,839	4,223,752,316	kWh	2.732 ¢	$115,392,913		
Second Block kWh (> 1,000)	1,444,028,265	1,440,621,328	1,410,104,163	kWh	3.207 ¢	$45,222,041		
Summer kWh			1,572,474,819	kWh			2.813 ¢	$44,233,717
Winter kWh			4,061,381,660	kWh			2.813 ¢	$114,246,666
Subtotal	5,769,399,104	5,755,783,167	5,633,856,479	kWh		$472,487,101		$531,718,640
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	4,325,370,839	4,315,161,839	4,223,752,316	kWh	0.021 ¢	$886,988	0.000 ¢	$0
Second Block kWh (> 1,000)	1,444,028,265	1,440,621,328	1,410,104,163	kWh	0.028 ¢	$394,829	0.000 ¢	$0
Subtotal						$473,768,918		$531,718,640
Schedule 201								
First Block kWh (0-1,000)	4,325,370,839	4,315,161,839	4,223,752,316	kWh	2.016 ¢	$85,150,847	2.016 ¢	$85,150,847
Second Block kWh (> 1,000)	1,444,028,265	1,440,621,328	1,410,104,163	kWh	2.705 ¢	$38,143,318	2.705 ¢	$38,143,318
Total	5,769,399,104	5,755,783,167	5,633,856,479	kWh		$597,063,083		$655,012,805
							Change	$57,949,722
Schedule No. 4 (Employee Discount)								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	13,311,491	13,311,491	13,029,509	kWh	0.818 ¢	$106,581	0.919 ¢	$119,741
System Usage Charge								
Sch 200 related, per kWh	13,311,491	13,311,491	13,029,509	kWh	0.067 ¢	$8,730	0.078 ¢	$10,163
T&A and Sch 201 related, per kWh	13,311,491	13,311,491	13,029,509	kWh	0.079 ¢	$10,293	0.106 ¢	$13,811
Distribution Charge								
Basic Charge Single Family, per month	10,775	10,775	11,093	bill	$9.50	$105,384	$11.00	$122,023
Basic Charge Multi Family, per month	480	480	494	bill	$8.00	$3,952	$8.00	$3,952
Total Bills	11,255	11,255	11,587	bill				
Three Phase Demand Charge, per kW demand	0	0	0	kW	$2.20	$0	$2.20	$0
Three Phase Minimum Demand Charge, per month	0	0	0	bill	$3.80	$0	$3.80	$0
Distribution Energy Charge, per kWh	13,311,491	13,311,491	13,029,509	kWh	3.523 ¢	$459,030	4.337 ¢	$565,090
Energy Charge - Schedule 200								
First Block kWh (0-1,000)	9,240,455	9,240,455	9,044,711	kWh	2.732 ¢	$247,102		
Second Block kWh (> 1,000)	4,071,036	4,071,036	3,984,798	kWh	3.207 ¢	$127,792		
Summer kWh			3,636,687	kWh			2.813 ¢	$102,300
Winter kWh			9,392,822	kWh			2.813 ¢	$264,220
Subtotal	13,311,491	13,311,491	13,029,509	kWh		$1,068,864		$1,201,300
TAM Adj for Other Revs (205)								
First Block kWh (0-1,000)	9,240,455	9,240,455	9,044,711	kWh	0.021 ¢	$1,899	0.000 ¢	$0
Second Block kWh (> 1,000)	4,071,036	4,071,036	3,984,798	kWh	0.028 ¢	$1,116	0.000 ¢	$0
Subtotal						$1,071,879		$1,201,300
Schedule 201								
First Block kWh (0-1,000)	9,240,455	9,240,455	9,044,711	kWh	2.016 ¢	$182,341	2.016 ¢	$182,341
Second Block kWh (> 1,000)	4,071,036	4,071,036	3,984,798	kWh	2.705 ¢	$107,789	2.705 ¢	$107,789
Total	13,311,491	13,311,491	13,029,509	kWh		$1,362,009		$1,491,430
Schedule 201 Employee Discount						($72,533)		($72,533)
Total Employee Discount						($340,502)		($372,858)
							Change	($32,356)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,179,290,680	1,169,546,266	1,133,686,986	kWh	0.723 ¢	$8,196,557	0.780 ¢	$8,842,758
System Usage Charge								
Sch 200 related, per kWh	1,179,290,680	1,169,546,266	1,133,686,986	kWh	0.061 ¢	$691,549	0.073 ¢	$827,591
T&A and Sch 201 related, per kWh	1,179,290,680	1,169,546,266	1,133,686,986	kWh	0.072 ¢	$816,255	0.098 ¢	$1,111,013
Distribution Charge								
Basic Charge								
Single Phase, per month	775,694	775,694	775,779	bill	$17.35	$13,459,766	$17.35	$13,459,766
Three Phase, per month	240,969	240,969	239,153	bill	$25.90	$6,194,063	$25.90	$6,194,063
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	1,142,229	1,142,229	1,106,759	kW	$1.40	$1,549,463	$1.65	$1,826,152
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	564,595	564,595	547,081	kW	$4.64	$2,538,456	$5.43	$2,970,650
Reactive Power Charge, per kvar	216,881	216,881	209,593	kvar	65.00 ¢	$136,235	65.00 ¢	$136,235
Distribution Energy Charge, per kWh	1,179,290,680	1,169,546,266	1,133,686,986	kWh	3.182 ¢	$36,073,920	4.023 ¢	$45,608,227
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	924,695,576	917,115,576	889,068,833	kWh	2.866 ¢	$25,480,713	2.807 ¢	$24,956,162
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153	kWh	2.128 ¢	$5,205,474	2.084 ¢	$5,097,842
Subtotal	1,179,290,680	1,169,546,266	1,133,686,986	kWh		$100,342,451		$111,030,459
TAM Adj for Other Revs (205)								
1st 3,000 kWh, per kWh	924,695,576	917,115,576	889,068,833	kWh	0.023 ¢	$204,486	0.000 ¢	$0
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153	kWh	0.017 ¢	$41,585	0.000 ¢	$0
Subtotal						$100,588,522		$111,030,459
Schedule 201								
1st 3,000 kWh, per kWh	924,695,576	917,115,576	889,068,833	kWh	2.197 ¢	$19,532,842	2.197 ¢	$19,532,842
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153	kWh	1.629 ¢	$3,984,830	1.629 ¢	$3,984,830
Total	1,179,290,680	1,169,546,266	1,133,686,986	kWh		$124,106,194		$134,548,131
							Change	$10,441,937
Schedule No. 23/723 - Composite General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	3,442,654	3,442,654	3,323,737	kWh	0.712 ¢	$23,665	0.768 ¢	$25,526
System Usage Charge								
Sch 200 related, per kWh	3,442,654	3,442,654	3,323,737	kWh	0.060 ¢	$1,994	0.072 ¢	$2,393
T&A and Sch 201 related, per kWh	3,442,654	3,442,654	3,323,737	kWh	0.071 ¢	$2,360	0.096 ¢	$3,191
Distribution Charge								
Basic Charge								
Single Phase, per month	685	685	682	bill	$17.35	$11,833	$17.35	$11,833
Three Phase, per month	703	703	697	bill	$25.90	$18,052	$25.90	$18,052
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	7,379	7,379	7,143	kW	$1.40	$10,000	$1.65	$11,786
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	2,821	2,821	2,732	kW	$4.58	$12,513	$5.36	$14,644
Reactive Power Charge, per kvar	2,717	2,717	2,599	kvar	60.00 ¢	$1,559	60.00 ¢	$1,559
Distribution Energy Charge, per kWh	3,442,654	3,442,654	3,323,737	kWh	3.133 ¢	$104,133	3.961 ¢	$131,653
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482	kWh	2.822 ¢	$50,922	2.764 ¢	$49,876
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255	kWh	2.095 ¢	$31,828	2.052 ¢	$31,175
Subtotal	3,442,654	3,442,654	3,323,737	kWh		$268,859		$301,688
TAM Adj for Other Revs (205)								
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482	kWh	0.022 ¢	$397	0.000 ¢	$0
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255	kWh	0.017 ¢	$258	0.000 ¢	$0
Subtotal						$269,514		$301,688
Schedule 201								
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482	kWh	2.130 ¢	$38,435	2.130 ¢	$38,435
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255	kWh	1.580 ¢	$24,004	1.580 ¢	$24,004
Total	3,442,654	3,442,654	3,323,737	kWh		$331,953		$364,127
							Change	$32,174

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	6,972,158	6,972,158	6,943,054	kW	$2.20	$15,274,719	$2.13	$14,788,705
System Usage Charge								
Sch 200 related, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.068 ¢	$1,338,557	0.072 ¢	$1,417,296
T&A and Sch 201 related, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.079 ¢	$1,555,088	0.096 ¢	$1,889,728
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	58,555	58,555	59,595	bill	$19.00	$1,132,305	$18.00	$1,072,710
Load Size 51-100 kW, per month	41,184	41,184	41,899	bill	$35.00	$1,466,465	$34.00	$1,424,566
Load Size 101-300 kW, per month	22,209	22,209	22,586	bill	$84.00	$1,897,224	$81.00	$1,829,466
Load Size > 300 kW, per month	621	621	631	bill	$119.00	$75,089	$115.00	$72,565
Load Size Charge								
≤ 50 kW, per kW	2,232,934	2,232,934	2,227,010	kW	$1.20	$2,672,412	$1.15	$2,561,062
51-100 kW, per kW	2,892,150	2,892,150	2,879,942	kW	$0.95	$2,735,945	$0.90	$2,591,948
101-300 kW, per kW	3,353,010	3,353,010	3,336,352	kW	$0.55	$1,834,994	$0.55	$1,834,994
>300 kW, per kW	259,546	259,546	257,628	kW	$0.35	$90,170	$0.35	$90,170
Demand Charge, per kW	6,972,158	6,972,158	6,943,054	kW	$4.03	$27,980,508	$3.89	$27,008,480
Reactive Power Charge, per kvar	657,847	657,847	651,033	kvar	65.00 ¢	$423,171	65.00 ¢	$423,171
Distribution Energy Charge, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.411 ¢	$8,090,397	0.401 ¢	$7,893,550
Energy Charge - Schedule 200								
All kWh, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	2.722 ¢	$53,581,657	2.618 ¢	$51,534,452
Subtotal	1,993,362,624	1,975,519,401	1,968,466,445	kWh		$120,148,701		$116,432,863
TAM Adj for Other Revs (205)								
All kWh, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	0.022 ¢	$433,063	0.000 ¢	$0
Subtotal						$120,581,764		$116,432,863
Schedule 201								
All kWh, per kWh	1,993,362,624	1,975,519,401	1,968,466,445	kWh	2.087 ¢	$41,081,895	2.087 ¢	$41,081,895
Total	1,993,362,624	1,975,519,401	1,968,466,445	kWh		$161,663,659		$157,514,758
							Change	($4,148,901)
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	104,177	104,177	102,993	kW	$2.14	$220,405	$1.67	$171,998
System Usage Charge								
Sch 200 related, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.064 ¢	$15,235	0.071 ¢	$16,901
T&A and Sch 201 related, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.075 ¢	$17,853	0.094 ¢	$22,376
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	164	164	167	bill	$25.00	$4,175	$18.00	$3,006
Load Size 51-100 kW, per month	214	214	217	bill	$43.00	$9,331	$31.00	$6,727
Load Size 101-300 kW, per month	380	380	385	bill	$100.00	$38,500	$71.00	$27,335
Load Size > 300 kW, per month	54	54	55	bill	$143.00	$7,865	$102.00	$5,610
Load Size Charge								
≤ 50 kW, per kW	6,569	6,569	6,511	kW	$1.40	$9,115	$1.00	$6,511
51-100 kW, per kW	15,968	15,968	15,692	kW	$1.15	$18,046	$0.80	$12,554
101-300 kW, per kW	66,331	66,331	65,414	kW	$0.70	$45,790	$0.50	$32,707
>300 kW, per kW	43,318	43,318	42,282	kW	$0.35	$14,799	$0.25	$10,571
Demand Charge, per kW	104,177	104,177	102,993	kW	$4.90	$504,666	$3.50	$360,476
Reactive Power Charge, per kvar	11,812	11,812	11,603	kvar	60.00 ¢	$6,962	60.00 ¢	$6,962
Distribution Energy Charge, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.069 ¢	$16,425	0.041 ¢	$9,760
Energy Charge - Schedule 200								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	2.696 ¢	$641,763	2.557 ¢	$608,675
Subtotal	24,061,378	24,061,378	23,804,268	kWh		$1,570,930		$1,302,169
TAM Adj for Other Revs (205)								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.022 ¢	$5,237	0.000 ¢	$0
Subtotal						$1,576,167		$1,302,169
Schedule 201								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	2.068 ¢	$492,272	2.068 ¢	$492,272
Total	24,061,378	24,061,378	23,804,268	kWh		$2,068,439		$1,794,441
							Change	($273,998)

PACIFIC POWER
State of Oregon
Billing Determinants
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Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 30/730 - Composite										
Large General Service - (Secondary)										
Transmission & Ancillary Services Charge										
per kW	3,224,408	3,224,408	3,324,307	kW	$2.52		$8,377,254	$2.52		$8,377,254
System Usage Charge										
Sch 200 related, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	0.065	¢	$769,042	0.071	¢	$840,031
T&A and Sch 201 related, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	0.076	¢	$899,188	0.093	¢	$1,100,322
Distribution Charge										
Basic Charge										
Load Size ≤ 200 kW, per month	179	179	176	bill	$494.00		$86,944	$437.00		$76,912
Load Size 201-300 kW, per month	2,582	2,582	2,539	bill	$144.00		$365,616	$127.00		$322,453
Load Size > 300 kW, per month	6,313	6,313	6,205	bill	$380.00		$2,357,900	$336.00		$2,084,880
Load Size Charge										
≤ 200 Kw, per kW					No Charge		$0	No Charge		$0
201-300 kW, per kW	669,986	669,986	692,354	kW	$1.75		$1,211,620	$1.55		$1,073,149
>300 kW, per kW	3,133,877	3,133,877	3,233,216	kW	$0.85		$2,748,234	$0.75		$2,424,912
Demand Charge, per kW	3,224,408	3,224,408	3,324,307	kW	$4.17		$13,862,360	$3.69		$12,266,693
Reactive Power Charge, per kvar	581,094	581,094	587,792	kvar	65.00	¢	$382,065	65.00	¢	$382,065
Energy Charge - Schedule 200										
Demand Charge, per kW	3,224,408	3,224,408	3,324,307	kW	$3.41		$11,335,887	$5.80		$19,280,981
All kWh, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	1.710	¢	$20,231,728	0.933	¢	$11,038,715
Subtotal	1,152,976,818	1,142,524,024	1,183,141,965	kWh			$62,627,838			$59,268,367
TAM Adj for Other Revs (205)										
All kWh, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	0.021	¢	$248,460	0.000	¢	$0
Subtotal							$62,876,298			$59,268,367
Schedule 201										
All kWh, per kWh	1,152,976,818	1,142,524,024	1,183,141,965	kWh	2.036	¢	$24,088,770	2.036	¢	$24,088,770
Total	1,152,976,818	1,142,524,024	1,183,141,965	kWh			$86,965,068			$83,357,137
								Change		($3,607,931)
Schedule No. 30/730 - Composite										
Large General Service - (Primary)										
Transmission & Ancillary Services Charge										
per kW	273,083	273,083	280,081	kW	$2.50		$700,203	$2.55		$714,207
System Usage Charge										
Sch 200 related, per kWh	95,500,340	95,500,340	98,439,365	kWh	0.064	¢	$63,001	0.071	¢	$69,892
T&A and Sch 201 related, per kWh	95,500,340	95,500,340	98,439,365	kWh	0.076	¢	$74,814	0.094	¢	$92,533
Distribution Charge										
Basic Charge										
Load Size ≤ 200 kW, per month	0	0	0	bill	$481.00		$0	$410.00		$0.00
Load Size 201-300 kW, per month	95	95	93	bill	$151.00		$14,043	$130.00		$12,090.00
Load Size > 300 kW, per month	546	546	538	bill	$393.00		$211,434	$339.00		$182,382.00
Load Size Charge										
≤ 200 Kw, per kW					No Charge			No Charge		
201-300 kW, per kW	25,038	25,038	26,123	kW	$1.65		$43,103	$1.40		$36,572
>300 kW, per kW	312,218	312,218	320,601	kW	$0.80		$256,481	$0.70		$224,421
Demand Charge, per kW	273,083	273,083	280,081	kW	$4.17		$1,167,938	$3.60		$1,008,292
Reactive Power Charge, per kvar	38,218	38,218	37,437	kvar	60.00	¢	$22,462	60.00	¢	$22,462
Energy Charge - Schedule 200										
Demand Charge, per kW	273,083	273,083	280,081	kW	$3.41		$955,076	$5.80		$1,624,470
All kWh, per kWh	95,500,340	95,500,340	98,439,365	kWh	1.692	¢	$1,665,594	0.900	¢	$885,954
Subtotal	95,500,340	95,500,340	98,439,365	kWh			$5,174,149			$4,873,275
TAM Adj for Other Revs (205)										
All kWh, per kWh	95,500,340	95,500,340	98,439,365	kWh	0.022	¢	$21,657	0.000	¢	$0
Subtotal							$5,195,806			$4,873,275
Schedule 201										
All kWh, per kWh	95,500,340	95,500,340	98,439,365	kWh	2.068	¢	$2,035,726	2.068	¢	$2,035,726
Total	95,500,340	95,500,340	98,439,365	kWh			$7,231,532			$6,909,001
								Change		($322,531)

PACIFIC POWER
State of Oregon
Billing Determinants
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Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	237,425,712	224,330,512	234,939,400	kWh	0.643 ¢	$1,510,660	0.676 ¢	$1,588,190
System Usage Charge								
Sch 200 related, per kWh	237,425,712	224,330,512	234,939,400	kWh	0.057 ¢	$133,915	0.091 ¢	$213,795
T&A and Sch 201 related, per kWh	237,425,712	224,330,512	234,939,400	kWh	0.089 ¢	$209,096	0.070 ¢	$164,458
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	5,576	5,576	5,586	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	974	974	976	bill	$360.00	$351,360	$410.00	$400,160
Three Phase Load Size > 300 kW, per customer	19	19	19	bill	$1,420.00	$26,980	$1,630.00	$30,970
Total Annual Bills	6,569	6,569	6,581					
Average Customers	7,981	7,981	7,995					
Monthly Bills	42,934	42,934	43,009					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	94,969	94,969	99,460	kW	$17.10	$1,700,766	$17.10	$1,700,766
Three Phase Load Size 51-300 kW, per kW	86,214	86,214	90,291	kW	$11.70	$1,056,405	$11.70	$1,056,405
Three Phase Load Size > 300 kW, per kW	8,433	8,433	8,832	kW	$7.20	$63,590	$7.20	$63,590
Single Phase, Minimum Charge	377	377	378	bill	$65.00	$24,570	$75.00	$28,350
Three Phase, Minimum Charge	1,457	1,457	1,460	bill	$105.00	$153,300	$120.00	$175,200
Distribution Energy Charge, per kWh	237,425,712	224,330,512	234,939,400	kWh	4.197 ¢	$9,860,407	4.988 ¢	$11,718,777
Reactive Power Charge, per kvar	211,414	211,414	221,412	kvar	65.00 ¢	$143,918	65.00 ¢	$143,918
Energy Charge - Schedule 200								
All kWh, per kWh	237,425,712	224,330,512	234,939,400	kWh	2.577 ¢	$6,054,388	2.528 ¢	$5,939,268
Subtotal	237,425,712	224,330,512	234,939,400	kWh		$21,289,355		$23,223,847
TAM Adj for Other Revs (205)	237,425,712	224,330,512	234,939,400	kWh	0.021 ¢	$49,337	0.000 ¢	$0
Subtotal						$21,338,692		$23,223,847
Schedule 201								
All kWh, per kWh	237,425,712	224,330,512	234,939,400	kWh	1.974 ¢	$4,637,704	1.974 ¢	$4,637,704
Option A Summer On Peak Adder, per On-peak kWh	19,903,136	18,805,380	19,694,711	kWh	4.989 ¢	$982,569	4.989 ¢	$982,569
Option B Summer On Peak Adder, per On-peak kWh	19,465,341	18,391,732	19,261,501	kWh	4.989 ¢	$960,956	4.989 ¢	$960,956
Summer Off Peak Adder, per Off-peak kWh	198,057,235	187,133,400	195,983,188	kWh	-0.992 ¢	($1,944,153)	-0.992 ¢	($1,944,153)
Total	237,425,712	224,330,512	234,939,400	kWh		$25,976,396		$27,861,551
							Change	$1,885,155

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	32,387	32,387	33,919	kWh	0.633 ¢	$215	0.666 ¢	$226
System Usage Charge								
Sch 200 related, per kWh	32,387	32,387	33,919	kWh	0.056 ¢	$19	0.090 ¢	$31
T&A and Sch 201 related, per kWh	32,387	32,387	33,919	kWh	0.088 ¢	$30	0.069 ¢	$23
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	2	2	2	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	1	1	1	bill	$360.00	$360	$400.00	$400
Three Phase Load Size > 300 kW, per customer	0	0	0	bill	$1,400.00	$0	$1,610.00	$0
Total Annual Bills	3	3	3					
Average Customers	4	4	4					
Monthly Bills	24	24	24					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	12	12	13	kW	$16.90	$220	$16.90	$220
Three Phase Load Size 51-300 kW, per kW	72	72	75	kW	$11.50	$863	$11.50	$863
Three Phase Load Size > 300 kW, per kW	0	0	0	kW	$7.10	$0	$7.10	$0
Single Phase, Minimum Charge	0	0	0	bill	$65.00	$0	$75.00	$0
Three Phase, Minimum Charge	0	0	0	bill	$105.00	$0	$120.00	$0
Distribution Energy Charge, per kWh	32,387	32,387	33,919	kWh	4.132 ¢	$1,402	4.911 ¢	$1,666
Reactive Power Charge, per kvar	81	81	85	kvar	60.00 ¢	$51	60.00 ¢	$51
Energy Charge - Schedule 200								
All kWh, per kWh	32,387	32,387	33,919	kWh	2.537 ¢	$861	2.489 ¢	$844
Subtotal	32,387	32,387	33,919	kWh		$4,021		$4,324
TAM Adj for Other Revs (205)	32,387	32,387	33,919	kWh	0.020 ¢	$7	0.000 ¢	$0
Subtotal						$4,028		$4,324
Schedule 201								
All kWh, per kWh	32,387	32,387	33,919	kWh	1.943 ¢	$659	1.943 ¢	$659
Option A Summer On Peak Adder, per On-peak kWh	2,715	2,715	2,843	kWh	4.989 ¢	$142	4.989 ¢	$142
Option B Summer On Peak Adder, per On-peak kWh	2,655	2,655	2,781	kWh	4.989 ¢	$139	4.989 ¢	$139
Summer Off Peak Adder, per Off-peak kWh	27,017	27,017	28,295	kWh	-0.992 ¢	($281)	-0.992 ¢	($281)
Total	32,387	32,387	33,919	kWh		$4,687		$4,983
							Change	$296

PACIFIC POWER
State of Oregon
Billing Determinants
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Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	85,374	85,374	87,270	kW	$2.45	$213,812	$2.45	$213,812
credit per kW of on-peak demand (OATT)	0	0	0	kW	($2.45)	$0	($2.45)	$0
System Usage Charge								
Sch 200 related, per kWh	14,646,249	14,646,249	14,971,570	kWh	0.059 ¢	$8,833	0.068 ¢	$10,181
T&A and Sch 201 related, per kWh	14,646,249	14,646,249	14,971,570	kWh	0.068 ¢	$10,181	0.088 ¢	$13,175
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$550.00	$0	$570.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$1,490.00	$17,880	$1,570.00	$18,840
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.30	$0	$1.25	$0
Facility Capacity > 4,000 kW, per kW	119,806	119,806	122,467	kW	$0.85	$104,097	$0.50	$61,234
Demand Charge, per kW of on-peak demand	85,374	85,374	87,270	kW	$4.33	$377,879	$3.49	$304,572
Reactive Power Charge, per kvar	5,446	5,446	5,567	kvar	60.00 ¢	$3,340	60.00 ¢	$3,340
Reactive Hours, per kvarh	12,609,400	12,609,400	12,889,479	kvarh	0.080 ¢	$10,312	0.080 ¢	$10,312
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	119,806	119,806	122,467	kW	$0.27	$33,066	$0.27	$33,066
Supplemental Reserves, per kW of Facility Cap.	119,806	119,806	122,467	kW	$0.27	$33,066	$0.27	$33,066
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	85,374	85,374	87,270	kW	$1.71	$149,232	$1.65	$143,996
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381	kWh	2.179 ¢	$136,283	2.160 ¢	$135,095
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189	kWh	2.179 ¢	$189,948	2.160 ¢	$188,291
Unscheduled Energy, per kWh	452,751	452,751	462,808	kWh		$20,584		$20,584
Subtotal	15,099,000	15,099,000	15,434,378	kWh		$1,308,513		$1,189,564
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381	kWh	0.025 ¢	$1,564	0.000 ¢	$0
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189	kWh	0.018 ¢	$1,569	0.000 ¢	$0
Subtotal						$1,311,646		$1,189,564
Schedule 201								
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381	kWh	2.374 ¢	$148,479	2.374 ¢	$148,479
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189	kWh	1.686 ¢	$146,972	1.686 ¢	$146,972
Total	15,099,000	15,099,000	15,434,378	kWh		$1,607,097		$1,485,015
							Change	($122,082)
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	138,992	138,992	135,695	kW	$3.25	$441,009	$3.11	$422,011
credit per kW of on-peak demand (OATT)	0	0	0	kW	($3.25)	$0	($3.11)	$0
System Usage Charge								
Sch 200 related, per kWh	12,828,129	12,828,129	12,903,938	kWh	0.058 ¢	$7,484	0.065 ¢	$8,388
T&A and Sch 201 related, per kWh	12,828,129	12,828,129	12,903,938	kWh	0.066 ¢	$8,517	0.084 ¢	$10,839
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	24	24	24	bill	$710.00	$17,040	$710.00	$17,040
Facility Capacity > 4,000 kW, per month	36	36	36	bill	$1,820.00	$65,520	$1,820.00	$65,520
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	28,166	28,166	28,792	kW	$1.25	$35,990	$1.25	$35,990
Facility Capacity > 4,000 kW, per kW	311,273	311,273	298,765	kW	$1.05	$313,703	$1.05	$313,703
Demand Charge, per kW of on-peak demand	138,992	138,992	135,695	kW	$3.03	$411,156	$1.88	$255,107
Reactive Power Charge, per kvar	144,234	144,234	137,544	kvar	55.00 ¢	$75,649	55.00 ¢	$75,649
Reactive Hours, per kvarh	48,770,928	48,770,928	45,614,133	kvarh	0.080 ¢	$36,491	0.080 ¢	$36,491
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	339,439	339,439	327,557	kW	$0.27	$88,440	$0.27	$88,440
Supplemental Reserves, per kW of Facility Cap.	339,439	339,439	327,557	kW	$0.27	$88,440	$0.27	$88,440
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	138,992	138,992	135,695	kW	$1.72	$233,395	$1.68	$227,968
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426	kWh	2.129 ¢	$99,242	2.079 ¢	$96,911
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512	kWh	2.129 ¢	$175,483	2.079 ¢	$171,362
Unscheduled Energy, per kWh	808,775	808,775	770,332	kWh		$31,982		$31,982
Subtotal	13,636,904	13,636,904	13,674,270	kWh		$2,129,541		$1,945,841
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426	kWh	0.024 ¢	$1,119	0.000 ¢	$0
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512	kWh	0.016 ¢	$1,319	0.000 ¢	$0
Subtotal						$2,131,979		$1,945,841
Schedule 201								
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426	kWh	2.259 ¢	$105,302	2.259 ¢	$105,302
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512	kWh	1.571 ¢	$129,490	1.571 ¢	$129,490
Total	13,636,904	13,636,904	13,674,270	kWh		$2,366,771		$2,180,633
							Change	($186,138)

PACIFIC POWER
State of Oregon
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Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 76R/776R								
Large General Service/Partial Requirements Service - Economic Replacement Power Rider								
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.087	$0	$0.087	$0
Primary	0	0	0	kW	$0.095	$0	$0.095	$0
Transmission	0	0	0	kW	$0.127	$0	$0.121	$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.161	$0	$0.129	$0
Primary	0	0	0	kW	$0.169	$0	$0.136	$0
Transmission	0	0	0	kW	$0.118	$0	$0.073	$0
Schedule No. 48/748 - Composite								
Large General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,310,991	1,310,991	1,394,562	kW	$2.78	$3,876,882	$2.78	$3,876,882
System Usage Charge								
Sch 200 related, per kWh	542,038,800	524,746,272	560,925,960	kWh	0.060 ¢	$336,556	0.070 ¢	$392,648
T&A and Sch 201 related, per kWh	542,038,800	524,746,272	560,925,960	kWh	0.070 ¢	$392,648	0.092 ¢	$516,052
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	1,111	1,111	1,109	bill	$580.00	$643,220	$580.00	$643,220
Facility Capacity > 4,000 kW, per month	12	12	13	bill	$1,600.00	$20,800	$1,600.00	$20,800
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,461,164	1,461,164	1,521,792	kW	$2.70	$4,108,838	$2.95	$4,489,286
Facility Capacity > 4,000 kW, per kW	154,726	154,726	245,208	kW	$0.80	$196,166	$1.30	$318,770
Demand Charge, per kW of on-peak demand	1,310,991	1,310,991	1,394,562	kW	$4.14	$5,773,487	$3.31	$4,616,000
Reactive Power Charge, per kvar	331,372	331,372	332,557	kvar	65.00 ¢	$216,162	65.00 ¢	$216,162
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,310,991	1,310,991	1,394,562	kW	$1.64	$2,287,082	$1.57	$2,189,462
On-Peak, per on-peak kWh	206,565,779	199,974,779	213,761,828	kWh	2.244 ¢	$4,796,815	2.156 ¢	$4,608,705
Off-Peak, per off-peak kWh	335,473,021	324,771,493	347,164,132	kWh	2.244 ¢	$7,790,363	2.156 ¢	$7,484,859
Subtotal	542,038,800	524,746,272	560,925,960	kWh		$30,439,019		$29,372,846
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	206,565,779	199,974,779	213,761,828	kWh	0.026 ¢	$55,578	0.000 ¢	$0
Off-Peak, per off-peak kWh	335,473,021	324,771,493	347,164,132	kWh	0.019 ¢	$65,961	0.000 ¢	$0
Subtotal						$30,560,558		$29,372,846
Schedule 201								
On-Peak, per on-peak kWh	206,565,779	199,974,779	213,761,828	kWh	2.461 ¢	$5,260,679	2.461 ¢	$5,260,679
Off-Peak, per off-peak kWh	335,473,021	324,771,493	347,164,132	kWh	1.774 ¢	$6,158,692	1.774 ¢	$6,158,692
Total	542,038,800	524,746,272	560,925,960	kWh		$41,979,929		$40,792,217
							Change	($1,187,712)
Schedule No. 48/748 - Composite								
Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	3,170,854	3,170,854	3,148,200	kW	$2.99	$9,413,118	$2.99	$9,413,118
System Usage Charge								
Sch 200 related, per kWh	1,493,674,734	1,493,674,734	1,477,893,837	kWh	0.059 ¢	$871,957	0.068 ¢	$1,004,968
T&A and Sch 201 related, per kWh	1,493,674,734	1,493,674,734	1,477,893,837	kWh	0.068 ¢	$1,004,968	0.088 ¢	$1,300,547
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	744	744	743	bill	$550.00	$408,650	$570.00	$423,510
Facility Capacity > 4,000 kW, per month	329	329	327	bill	$1,490.00	$487,230	$1,570.00	$513,390
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,478,553	1,478,553	1,551,718	kW	$1.30	$2,017,233	$1.25	$1,939,648
Facility Capacity > 4,000 kW, per kW	2,445,708	2,445,708	2,400,601	kW	$0.85	$2,040,511	$0.50	$1,200,301
Demand Charge, per kW of on-peak demand	3,170,854	3,170,854	3,148,200	kW	$4.33	$13,631,706	$3.49	$10,987,218
Reactive Power Charge, per kvar	757,050	757,050	727,257	kvar	60.00 ¢	$436,354	60.00 ¢	$436,354
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	3,170,854	3,170,854	3,148,200	kW	$1.71	$5,383,422	$1.65	$5,194,530
On-Peak, per on-peak kWh	565,736,213	565,736,213	559,759,125	kWh	2.179 ¢	$12,197,151	2.160 ¢	$12,090,797
Off-Peak, per off-peak kWh	927,938,521	927,938,521	918,134,712	kWh	2.179 ¢	$20,006,155	2.160 ¢	$19,831,710
Subtotal	1,493,674,734	1,493,674,734	1,477,893,837	kWh		$67,898,455		$64,336,091
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	565,736,213	565,736,213	559,759,125	kWh	0.025 ¢	$139,940	0.000 ¢	$0
Off-Peak, per off-peak kWh	927,938,521	927,938,521	918,134,712	kWh	0.018 ¢	$165,264	0.000 ¢	$0
Subtotal						$68,203,659		$64,336,091
Schedule 201								
On-Peak, per on-peak kWh	565,736,213	565,736,213	559,759,125	kWh	2.374 ¢	$13,288,682	2.374 ¢	$13,288,682
Off-Peak, per off-peak kWh	927,938,521	927,938,521	918,134,712	kWh	1.686 ¢	$15,479,751	1.686 ¢	$15,479,751
Total	1,493,674,734	1,493,674,734	1,477,893,837	kWh		$96,972,092		$93,104,524
							Change	($3,867,568)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2021
Forecast 12 Months Ended December 31, 2023

Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 - Composite								
Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,426,735	1,426,735	2,477,112	kW	$3.79	$9,388,254	$3.65	$9,041,459
System Usage Charge								
Sch 200 related, per kWh	837,259,000	837,259,000	1,545,235,788	kWh	0.058 ¢	$896,237	0.065 ¢	$1,004,403
T&A and Sch 201 related, per kWh	837,259,000	837,259,000	1,545,235,788	kWh	0.066 ¢	$1,019,856	0.084 ¢	$1,297,998
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	49	49	49	bill	$710.00	$34,790	$710.00	$34,790
Facility Capacity > 4,000 kW, per month	45	45	45	bill	$1,820.00	$81,900	$1,820.00	$81,900
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	45,876	45,876	50,938	kW	$1.25	$63,673	$1.25	$63,673
Facility Capacity > 4,000 kW, per kW	1,488,481	1,488,481	2,540,444	kW	$1.05	$2,667,466	$1.05	$2,667,466
Demand Charge, per kW of on-peak demand	1,426,735	1,426,735	2,477,112	kW	$3.03	$7,505,649	$1.88	$4,656,971
Reactive Power Charge, per kvar	17,440	17,440	18,385	kvar	55.00 ¢	$10,112	55.00 ¢	$10,112
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,426,735	1,426,735	2,477,112	kW	$1.72	$4,260,633	$1.68	$4,161,548
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821	kWh	2.129 ¢	$12,373,915	2.079 ¢	$12,083,311
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967	kWh	2.129 ¢	$20,524,155	2.079 ¢	$20,042,141
Subtotal	837,259,000	837,259,000	1,545,235,788	kWh		$58,826,640		$55,145,772
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821	kWh	0.024 ¢	$139,490	0.000 ¢	$0
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967	kWh	0.016 ¢	$154,244	0.000 ¢	$0
Subtotal						$59,120,374		$55,145,772
Schedule 201								
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821	kWh	2.259 ¢	$13,129,485	2.259 ¢	$13,129,485
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967	kWh	1.571 ¢	$15,144,879	1.571 ¢	$15,144,879
Total	837,259,000	837,259,000	1,545,235,788	kWh		$87,394,738		$83,420,136
							Change	($3,974,602)
Schedule No. 848 - Commercial								
Distribution Only Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand				kW				
System Usage Charge								
Sch 200 related, per kWh				kWh				
T&A and Sch 201 related, per kWh				kWh				
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$710.00	$0	$710.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$1,820.00	$21,840	$1,820.00	$21,840
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.25	$0	$1.25	$0
Facility Capacity > 4,000 kW, per kW	404,276	404,276	440,285	kW	$1.05	$462,299	$1.05	$462,299
Demand Charge, per kW of on-peak demand	400,368	400,368	436,029	kW	$3.03	$1,321,168	$1.88	$819,735
Reactive Power Charge, per kvar	0	0	0	kvar	55.00 ¢	$0	55.00 ¢	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand				kW				
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Subtotal				kWh		$1,805,307		$1,303,874
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Subtotal						$1,805,307		$1,303,874
Schedule 201								
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Total				kWh		$1,805,307		$1,303,874
Energy Delivered	274,597,000	274,597,000	286,470,860				Change	($501,433)

PACIFIC POWER
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Schedule	Actual 7/20-6/21 Units	Normalized 7/20-6/21 Units	Forecast 1/23 - 12/23 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 15 - Composite								
Outdoor Area Lighting Service								
No. of Customers	6,066	6,066	5,809					
Transmission & Ancillary Services Charge								
per kWh	8,475,916	8,475,916	8,259,954	kWh	0.079 ¢	$6,511	0.065 ¢	$5,346
System Usage Charge								
Sch 200 related, per kWh	8,475,916	8,475,916	8,259,954	kWh	0.031 ¢	$2,544	0.026 ¢	$2,121
T&A and Sch 201 related, per kWh	8,475,916	8,475,916	8,259,954	kWh	0.029 ¢	$2,426	0.028 ¢	$2,290
Distribution Charge								
Distribution Charge, per kWh	8,475,916	8,475,916	8,259,954	kWh	8.954 ¢	$737,460	7.735 ¢	$638,882
Energy Charge - Schedule 200								
per kWh	8,475,916	8,475,916	8,259,954	kWh	1.159 ¢	$95,635	0.940 ¢	$77,613
Subtotal	8,475,916	8,475,916	8,259,954	kWh		$844,575		$726,252
TAM Adj for Other Revs (205), per kWh	8,475,916	8,475,916	8,259,954	kWh	0.009 ¢	$743	0.000 ¢	$0
Subtotal						$845,318		$726,252
Schedule 201								
per kWh	8,475,916	8,475,916	8,259,954	kWh	0.845 ¢	$69,726	0.844 ¢	$69,726
Total	8,475,916	8,475,916	8,259,954	kWh		$915,044		$795,978
							Change	($119,067)
Schedule No. 51/751								
Street Lighting Service, Company-Owned System								
No. of Customers	1,105	1,105	1,108					
Transmission & Ancillary Services Charge								
per kWh	24,436,047	24,436,047	23,892,579	kWh	0.114 ¢	$27,123	0.078 ¢	$18,665
System Usage Charge								
Sch 200 related, per kWh	24,436,047	24,436,047	23,892,579	kWh	0.044 ¢	$10,598	0.030 ¢	$7,139
T&A and Sch 201 related, per kWh	24,436,047	24,436,047	23,892,579	kWh	0.042 ¢	$10,105	0.043 ¢	$10,279
Distribution Charge								
Distribution Charge, per kWh	24,436,047	24,436,047	23,892,579	kWh	11.768 ¢	$2,811,694	10.314 ¢	$2,464,277
Energy Charge - Schedule 200								
per kWh	24,436,047	24,436,047	23,892,579	kWh	1.674 ¢	$399,987	1.251 ¢	$298,838
Subtotal	24,436,047	24,436,047	23,892,579	kWh		$3,259,506		$2,799,198
TAM Adj for Other Revs (205), per kWh	24,436,047	24,436,047	23,892,579	kWh	0.009 ¢	$2,150	0.000 ¢	$0
Subtotal						$3,261,656		$2,799,198
Schedule 201								
per kWh	24,436,047	24,436,047	23,892,579	kWh	0.987 ¢	$235,901	0.987 ¢	$235,901
Total	0	0	23,892,579	kWh		$3,497,558		$3,035,099
							Change	($462,458)
Schedule No. 53/753								
Street Lighting Service, Consumer-Owned System								
No. of Customers	310	310	314					
Transmission & Ancillary Services Charge								
per kWh	10,736,096	10,736,096	11,451,780	kWh	0.038 ¢	$4,352	0.029 ¢	$3,321
System Usage Charge								
Sch 200 related, per kWh	10,736,096	10,736,096	11,451,780	kWh	0.015 ¢	$1,718	0.012 ¢	$1,374
T&A and Sch 201 related, per kWh	10,736,096	10,736,096	11,451,780	kWh	0.014 ¢	$1,603	0.014 ¢	$1,603
Distribution Charge								
Distribution Charge, per kWh	10,736,096	10,736,096	11,451,780	kWh	4.274 ¢	$489,449	3.706 ¢	$424,403
Energy Charge - Schedule 200								
per kWh	10,736,096	10,736,096	11,451,780	kWh	0.555 ¢	$63,557	0.449 ¢	$51,418
Subtotal	10,736,096	10,736,096	11,451,780	kWh		$560,679		$482,120
TAM Adj for Other Revs (205), per kWh	10,736,096	10,736,096	11,451,780	kWh	0.009 ¢	$1,031	0.000 ¢	$0
Subtotal						$561,710		$482,120
Schedule 201								
per kWh	10,736,096	10,736,096	11,451,780	kWh	0.830 ¢	$95,050	0.830 ¢	$95,050
Total	10,736,096	10,736,096	11,451,780	kWh		$656,760		$577,170
							Change	($79,590)
Schedule No. 54/754								
Recreational Field Lighting								
Transmission & Ancillary Services Charge								
per kWh	1,310,533	1,310,533	1,141,242	kWh	0.047 ¢	$536	0.037 ¢	$422
System Usage Charge								
Sch 200 related, per kWh	1,310,533	1,310,533	1,141,242	kWh	0.019 ¢	$217	0.016 ¢	$183
T&A and Sch 201 related, per kWh	1,310,533	1,310,533	1,141,242	kWh	0.018 ¢	$205	0.018 ¢	$205
Distribution Charge								
Basic Charge, Single Phase, per month	798	798	795	bill	$6.00	$4,770	$6.00	$4,770
Basic Charge, Three Phase, per month	431	431	429	bill	$9.00	$3,861	$9.00	$3,861
Distribution Energy Charge, per kWh	1,310,533	1,310,533	1,141,242	kWh	4.775 ¢	$54,494	4.021 ¢	$45,889
Energy Charge - Schedule 200								
per kWh	1,310,533	1,310,533	1,141,242	kWh	0.699 ¢	$7,977	0.579 ¢	$6,608
Subtotal	1,310,533	1,310,533	1,141,242	kWh		$72,060		$61,938
TAM Adj for Other Revs (205), per kWh	1,310,533	1,310,533	1,141,242	kWh	0.009 ¢	$103	0.000 ¢	$0
Subtotal						$72,163		$61,938
Schedule 201								
per kWh	1,310,533	1,310,533	1,141,242	kWh	0.830 ¢	$9,472	0.830 ¢	$9,472
Total	1,310,533	1,310,533	1,141,242	kWh		$81,635		$71,410
							Change	($10,225)
Subtotal Oregon	13,402,158,727	13,320,114,631	13,937,602,352			$1,242,687,942		$1,294,132,990
Employee Discount						($340,502)		($372,858)
TOTAL OREGON	**13,402,158,727**	**13,320,114,631**	**13,937,602,352**			**$1,242,347,440**		**$1,293,760,132**
Distribution Only Energy	274,597,000	274,597,000	286,470,860					
Total Energy Including Distribution Only	13,676,755,727	13,594,711,631	14,224,073,212					

Estimated General Rate Case Rate Impact for UE 399 Stipulation

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

		Pre	Pro			Present Revenues ($000)			Proposed Revenues ($000)			Change				
Line		Sch	Sch	No. of		Base		Net	Base		Net	Base Rates		Net Rates		Line
No.	Description	No.	No.	Cust	MWh	Rates	Adders[1]	Rates	Rates	Adders[1]	Rates	($000)	%[2]	($000)	%[2]	No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	535,059	5,633,856	$597,063	$9,738	$606,801	$655,013	($15,775)	$639,238	$57,950	9.7%	$32,437	5.35%	1
2	**Total Residential**			535,059	5,633,856	$597,063	$9,738	$606,801	$655,013	($15,775)	$639,238	$57,950	9.7%	$32,437	5.35%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	84,329	1,137,011	$124,438	$1,015	$125,453	$134,912	($2,547)	$132,365	$10,474	8.4%	$6,912	5.51%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,462	1,992,271	$163,732	$9,197	$172,929	$159,309	$13,707	$173,016	($4,423)	-2.7%	$87	0.05%	4
5	Gen. Svc. 201 - 999 kW	30	30	797	1,281,581	$94,197	$4,696	$98,893	$90,266	$8,663	$98,930	($3,930)	-4.2%	$37	0.04%	5
6	Large General Service >= 1,000 kW	48	48	190	3,584,056	$226,347	($15,493)	$210,854	$217,317	$2,330	$219,647	($9,030)	-4.1%	$8,793	4.02%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	6	29,109	$3,974	($120)	$3,854	$3,666	$19	$3,685	($308)	-4.1%	($169)	4.02%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	$1,805	$10	$1,815	$1,304	$0	$1,304	($501)	-27.8%	($511)	-28.16%	8
9	Agricultural Pumping Service	41	41	7,998	234,973	$25,981	($3,250)	$22,731	$27,867	($3,919)	$23,947	$1,885	7.3%	$1,216	5.35%	9
10	**Total Commercial & Industrial**			103,783	8,259,000	$640,474	($3,945)	$636,529	$634,641	$18,253	$652,893	($5,833)	-0.9%	$16,364	2.57%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	5,809	8,260	$915	$74	$989	$796	$213	$1,009	($119)	-13.0%	$19	1.95%	11
12	Street Lighting Service Comp. Owned	51	51	1,108	23,893	$3,498	$387	$3,885	$3,035	$926	$3,961	($462)	-13.2%	$76	1.95%	12
13	Street Lighting Service Cust. Owned	53	53	314	11,452	$657	$210	$867	$577	$306	$883	($80)	-12.1%	$17	1.95%	13
14	Recreational Field Lighting	54	54	102	1,141	$82	$27	$108	$71	$39	$110	($10)	-12.5%	$2	1.95%	14
15	**Total Public Street Lighting**			7,333	44,746	$5,151	$698	$5,849	$4,480	$1,484	$5,963	($671)	-13.0%	$114	1.95%	15
16	**Subtotal**			646,176	13,937,602	$1,242,688	$6,491	$1,249,179	$1,294,133	$3,961	$1,298,094	$51,445	4.1%	$48,915	3.92%	16
17	Emplolyee Discount			*966*	*13,030*	($341)	($6)	($346)	($373)	$9	($364)	($32)		($18)		17
17	Paperless Credit					($2,072)		($2,072)	($2,072)		($2,072)	$0		$0		17
18	AGA Revenue					$3,521		$3,521	$3,521		$3,521	$0		$0		18
19	COOC Amortization					$1,767		$1,767	$1,767		$1,767	$0		$0		19
20	**Total Sales with AGA**			646,176	13,937,602	$1,245,563	$6,486	$1,252,049	$1,296,976	$3,971	$1,300,946	$51,413	4.1%	$48,898	3.91%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Estimated General Rate Case Rate Adjustment Schedule Revenues for UE 399 Stipulation
PACIFIC POWER
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Description	Pre Sch No.	Pro Sch No.	OCAT 104 ($000)	Repl Mtr Def Adj 194 ($000)	Tax Act 195 ($000)	Deer Cr Def Adj 198 ($000)	RAC Defer. 203 ($000)	Sol. Inctv. 204 ($000)	Comm. Sol 207 ($000)	RMA 299 ($000)	RMA 299 ($000)	Total ($000)	Total ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				PRE							PRE	PRO	PRE	PRO
	Residential													
1	Residential	4	4	$3,259	$1,859	($3,549)	$845	$282	$1,746	$225	$5,070	($17,183)	$9,738	($15,775)
2	**Total Residential**			$3,259	$1,859	($3,549)	$845	$282	$1,746	$225	$5,070	($17,183)	$9,738	($15,775)
	Commercial & Industrial													
3	Gen. Svc. < 31 kW	23	23	$674	$387	($750)	$159	$57	$330	$34	$125	($2,763)	$1,015	($2,547)
4	Gen. Svc. 31 - 200 kW	28	28	$929	$498	($877)	$279	$100	$598	$60	$7,610	$13,049	$9,197	$13,707
5	Gen. Svc. 201 - 999 kW	30	30	$531	$295	($500)	$179	$64	$372	$38	$3,717	$8,215	$4,696	$8,663
6	Large General Service >= 1,000 kW	48	48	$1,132	$717	($1,219)	$466	$179	$968	$108	($17,844)	$1,111	($15,493)	$2,330
7	Partial Req. Svc. >= 1,000 kW	47	47	$21	$6	($10)	$4	$1	$8	$1	($150)	$9	($120)	$19
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	$10	$0	$0	$0	$0	$0	$0	$0	$0	$10	$0
9	Agricultural Pumping Service	41	41	$122	$82	($164)	$33	$12	$66	$7	($3,407)	($3,955)	($3,250)	($3,919)
10	**Total Commercial & Industrial**			$3,419	$1,984	($3,520)	$1,120	$413	$2,340	$248	($9,949)	$15,667	($3,945)	$18,253
	Lighting													
11	Outdoor Area Lighting Service	15	15	$5	$1	($6)	$0	$0	$0	$0	$74	$218	$74	$213
12	Street Lighting Service Comp. Owned	51	51	$21	$4	($22)	$1	$0	$1	$0	$383	$942	$387	$926
13	Street Lighting Service, Cust Owned	53	53	$5	$2	($4)	$1	$0	$1	$0	$205	$306	$210	$306
14	Recreational Field Lighting	54	54	$1	$0	($1)	$0	$0	$0	$0	$26	$39	$27	$39
15	**Total Public Street Lighting**			$31	$7	($33)	$1	$1	$3	$0	$688	$1,505	$698	$1,484
16	**Subtotal**			$6,709	$3,850	($7,102)	$1,967	$695	$4,090	$474	($4,191)	($11)	$6,491	$3,961
17	Employee Discount			($2)	($1)	$2	($0)	($0)	($1)	($0)	($3)	$10	($6)	$9
18	**Total**			$6,707	$3,849	($7,100)	$1,966	$695	$4,089	$473	($4,194)	($2)	$6,486	$3,971

Estimated General Rate Case Rate Adjustment Schedule Rates for UE 399 Stipulation
PACIFIC POWER
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Description	Pre Sch No.	Pro Sch No.	OCAT 104 ¢/kWh	Repl Mtr Def Adj 194 ¢/kWh	Tax Act 195 ¢/kWh	Deer Cr Def Adj 198 ¢/kWh	RAC Defer. 203 ¢/kWh	Sol. Inctv. 204 ¢/kWh	Comm. Sol 207 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh	RMA Sec 299 ¢/kWh	RMA Pri 299 ¢/kWh	RMA Trn 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				PRE							PRE	PRE	PRE	PRO	PRO	PRO
	Residential															
1	Residential	4	4	0.54%	0.033	(0.063)	0.015	0.005	0.031	0.004	0.090			(0.305)		
	Commercial & Industrial															
2	Gen. Svc. < 31 kW	23	23	0.54%	0.034	(0.066)	0.014	0.005	0.029	0.003	0.011	0.011		(0.243)	(0.243)	
3	Gen. Svc. 31 - 200 kW	28	28	0.54%	0.025	(0.044)	0.014	0.005	0.030	0.003	0.382	0.382		0.655	0.655	
4	Gen. Svc. 201 - 999 kW	30	30	0.54%	0.023	(0.039)	0.014	0.005	0.029	0.003	0.290	0.290		0.641	0.641	
5	Large General Service >= 1,000 kW	48	48	0.54%	0.020	(0.034)	0.013	0.005	0.027	0.003	(0.372)	(0.465)	(0.575)	0.031	0.031	0.031
6	Partial Req. Svc. >= 1,000 kW	47	47	0.54%	0.020	(0.034)	0.013	0.005	0.027	0.003	(0.372)	(0.465)	(0.575)	0.031	0.031	0.031
7	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	0.54%	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	Agricultural Pumping Service	41	41	0.54%	0.035	(0.070)	0.014	0.005	0.028	0.003	(1.450)	(1.450)		(1.683)	(1.683)	
	Lighting															
9	Outdoor Area Lighting Service	15	15	0.54%	0.036	(0.077)	0.006	0.004	0.012	0.003	3.520			10.338		
10	Street Lighting Service HPS	51	51	0.54%	0.044	(0.093)	0.006	0.005	0.012	0.003	4.570			11.249		
11	Street Lighting Service	53	53	0.54%	0.017	(0.037)	0.006	0.002	0.012	0.001	1.790			2.673		
12	Recreational Field Lighting	54	54	0.54%	0.023	(0.047)	0.006	0.003	0.012	0.002	2.290			3.422		

Estimated Rate Spread and Rates for Schedule 203 Renewable Resource Deferral Adjustment for April 1, 2023

PACIFIC POWER
Calculation of Proposed Change to Renewable Resource Deferral Supply Service Adjustment - Schedule 203

FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Description	Sch No.	MWh*	Generation Rate Spread	Proposed Schedule 203 Rate Adder (¢/kWh)	Proposed Schedule 203 Additional Revenues ($000)	Total Proposed Sch 203 Rates for Tariff (¢/kWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Residential						
1	Residential	4	5,633,856	43.2%	0.049	$2,761	0.054
2	**Total Residential**		5,633,856			$2,761	
	Commercial & Industrial						
3	Gen. Svc. < 31 kW	23	1,137,011	8.2%	0.046	$523	0.051
4	Gen. Svc. 31 - 200 kW	28	1,992,271	14.2%	0.046	$916	0.051
5	Gen. Svc. 201 - 999 kW	30	1,281,581	9.0%	0.045	$577	0.050
6	Large General Service >= 1,000 kW	48	3,584,056	23.7%	0.042	$1,505	0.047
7	Partial Req. Svc. >= 1,000 kW	47	29,109		0.042	$12	0.047
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	0		-	$0	-
9	Agricultural Pumping Service	41	234,973	1.6%	0.044	$103	0.049
10	**Total Commercial & Industrial**		8,259,000			$3,637	
	Lighting						
11	Outdoor Area Lighting Service	15	2,108		0.033	$1	0.037
12	Street Lighting Service Comp. Owned	51	8,373		0.033	$3	0.038
13	Street Lighting Service Cust. Owned	53	11,452		0.033	$4	0.035
14	Recreational Field Lighting	54	1,141		0.033	$0	0.036
15	**Total Lighting**		23,074	0.1%	0.033	$8	
16	**Subtotal**		13,915,931	100.0%		$6,405	
17	Emplolyee Discount					($2)	
18	**Total Sales with Employee Discount**					$6,404	

* Includes lighting tariff MWh

Estimated Rate Spread and Rates for Schedule 192 Deferred Accounting Adjustment for April 1, 2023

PACIFIC POWER
Calculation of Proposed Deferred Accounting Adjustment - Schedule 192

FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Description	Sch No.	MWh*	Proposed Base Revenues	Equal Percentage Rate Spread	Proposed Schedule 192 Rates (¢/kWh)	Proposed Schedule 192 Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Residential						
1	Residential	4	5,633,856	$655,013	50.8%	(0.006)	($338)
2	**Total Residential**		5,633,856	$655,013			($338)
	Commercial & Industrial						
3	Gen. Svc. < 31 kW	23	1,137,011	$134,912	10.5%	(0.006)	($68)
4	Gen. Svc. 31 - 200 kW	28	1,992,271	$159,309	12.4%	(0.004)	($80)
5	Gen. Svc. 201 - 999 kW	30	1,281,581	$90,266	7.0%	(0.004)	($51)
6	Large General Service >= 1,000 kW	48	3,584,056	$217,317	16.9%	(0.003)	($108)
7	Partial Req. Svc. >= 1,000 kW	47	29,109	$3,666		(0.003)	($1)
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	286,471	$1,304		(0.003)	($9)
9	Agricultural Pumping Service	41	234,973	$27,867	2.2%	(0.006)	($14)
10	**Total Commercial & Industrial**		8,259,000	$634,641			($330)
	Lighting						
11	Outdoor Area Lighting Service	15	2,108	$796		(0.010)	($0)
12	Street Lighting Service Comp. Owned	51	8,373	$3,035		(0.010)	($1)
13	Street Lighting Service Cust. Owned	53	11,452	$577		(0.010)	($1)
14	Recreational Field Lighting	54	1,141	$71		(0.010)	($0)
15	**Total Lighting**		23,074	$4,480	0.3%	(0.010)	($2)
16	**Subtotal**		13,915,931	$1,294,133	100.0%		($671)
17	Emplolyee Discount			($373)			$0
18	**Total Sales with Employee Discount**			$1,296,976			($670)

* Includes Distribution Only consumer MWh and lighting tariff MWh

Rate Spread and Estimated Rates for Schedule 193 COVID-19 Deferred Accounting Adjustment for April 1, 2023

PACIFIC POWER
Calculation of Proposed COVID-19 Deferred Accounting Adjustment - Schedule 193

FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

Line No.	Description	Sch No.	MWh*	Settled Rate Spread	Proposed Schedule 193 Rates (¢/kWh)	Proposed Schedule 193 Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)
	Residential					
1	Residential	4	5,633,856	73.9%	0.061	$3,437
2	**Total Residential**		5,633,856			$3,437
	Commercial & Industrial					
3	Gen. Svc. < 31 kW	23	1,137,011	11.5%	0.047	$534
4	Gen. Svc. 31 - 200 kW	28	1,992,271	5.5%	0.013	$259
5	Gen. Svc. 201 - 999 kW	30	1,281,581	2.3%	0.008	$103
6	Large General Service >= 1,000 kW	48	3,584,056	5.8%	0.008	$287
7	Partial Req. Svc. >= 1,000 kW	47	29,109		0.008	$2
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	286,471		0.008	$23
9	Agricultural Pumping Service	41	234,973	1.1%	0.021	$49
10	**Total Commercial & Industrial**		8,259,000			$1,257
	Lighting					
11	Outdoor Area Lighting Service	15	2,108		0.007	$0
12	Street Lighting Service Comp. Owned	51	8,373		0.007	$1
13	Street Lighting Service Cust. Owned	53	11,452		0.007	$1
14	Recreational Field Lighting	54	1,141		0.007	$0
15	**Total Lighting**		23,074	0.03%	0.007	$2
16	**Subtotal**		13,915,931	100.00%		$4,695
17	Emplolyee Discount					($2)
18	**Total Sales with Employee Discount**					$4,694

* Includes Distribution Only consumer MWh and lighting tariff MWh

Estimated Deferral Amortizations Rate Impact April 1, 2023

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2023

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
												Base Rates		Net Rates		
Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	535,059	5,633,856	$655,013	($15,775)	$639,238	$655,013	($9,916)	$645,097	$0	0.0%	$5,859	0.9%	1
2	**Total Residential**			535,059	5,633,856	$655,013	($15,775)	$639,238	$655,013	($9,916)	$645,097	$0	0.0%	$5,859	0.9%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	84,329	1,137,011	$134,912	($2,547)	$132,365	$134,912	($1,558)	$133,355	$0	0.0%	$989	0.8%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,462	1,992,271	$159,309	$13,707	$173,016	$159,309	$14,803	$174,112	$0	0.0%	$1,096	0.6%	4
5	Gen. Svc. 201 - 999 kW	30	30	797	1,281,581	$90,266	$8,663	$98,930	$90,266	$9,291	$99,558	$0	0.0%	$628	0.6%	5
6	Large General Service >= 1,000 kW	48	48	190	3,584,056	$217,317	$2,330	$219,647	$217,317	$4,014	$221,331	$0	0.0%	$1,685	0.8%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	6	29,109	$3,666	$19	$3,685	$3,666	$33	$3,698	$0	0.0%	$14	0.8%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	$1,304	$0	$1,304	$1,304	$14	$1,318	$0	0.0%	$14	1.1%	8
9	Agricultural Pumping Service	41	41	7,998	234,973	$27,867	($3,919)	$23,947	$27,867	($3,781)	$24,086	$0	0.0%	$139	0.6%	9
10	**Total Commercial & Industrial**			103,783	8,259,000	$634,641	$18,253	$652,893	$634,641	$22,817	$657,457	$0	0.0%	$4,564	0.7%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	5,809	8,260	$796	$213	$1,009	$796	$213	$1,009	$0	0.0%	$1	0.1%	11
12	Street Lighting Service Comp. Owned	51	51	1,108	23,893	$3,035	$926	$3,961	$3,035	$928	$3,963	$0	0.0%	$3	0.1%	12
13	Street Lighting Service Cust. Owned	53	53	314	11,452	$577	$306	$883	$577	$310	$887	$0	0.0%	$3	0.4%	13
14	Recreational Field Lighting	54	54	102	1,141	$71	$39	$110	$71	$39	$111	$0	0.0%	$0	0.3%	14
15	**Total Public Street Lighting**			7,333	44,746	$4,480	$1,484	$5,963	$4,480	$1,491	$5,970	$0	0.0%	$7	0.1%	15
16	**Subtotal**			646,176	13,937,602	$1,294,133	$3,961	$1,298,094	$1,294,133	$14,392	$1,308,525	$0	0.0%	$10,430	0.8%	16
17	Emplolyee Discount			*966*	*13,030*	($373)	$9	($364)	($373)	$6	($367)	$0		($3)		17
17	Paperless Credit					($2,072)		($2,072)	($2,072)		($2,072)	$0		$0		17
18	AGA Revenue					$3,521		$3,521	$3,521		$3,521	$0		$0		18
19	COOC Amortization					$1,767		$1,767	$1,767		$1,767	$0		$0		19
20	**Total Sales with AGA**			646,176	13,937,602	$1,296,976	$3,971	$1,300,946	$1,296,976	$14,397	$1,311,373	$0	0.0%	$10,427	0.8%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules