PACIFIC POWER
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May 8, 2019

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: UE 352—PacifiCorp Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Reply Testimony and Exhibits of Etta P. Lockey, Timothy J. Hemstreet, Rick T. Link, Steven R. McDougal, and Judith M. Ridenour.

Please direct any informal correspondence and questions regarding this filing to Cathie Allen, Manager, Regulatory Affairs, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

Docket No. UE 352
Exhibit PAC/600
Witness: Etta P. Lockey

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Etta P. Lockey

May 2019

REPLY TESTIMONY OF ETTA P. LOCKEY

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Q. Are you the same Etta P. Lockey who previously provided testimony in this case on behalf of PacifiCorp d/b/a Pacific Power?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. I respond to the policy and regulatory issues raised in the opening testimonies of Public Utility Commission of Oregon Staff (Staff) witness Steve Storm, Oregon Citizens' Utility Board (CUB) witness William Gehrke, Alliance of Western Energy Consumers (AWEC) witness Bradley G. Mullins, and Calpine Energy Solutions, LLC (Calpine) witness Kevin C. Higgins.

Q. Please summarize your reply testimony.

A. PacifiCorp's wind repowering project produces net benefits to customers. No party to this proceeding has provided evidence disputing the prudence of wind repowering, nor challenging the company's underlying economic analysis. There is no basis for imposing a cost disallowance or cost recovery conditions.

Staff, CUB, and AWEC seek to disallow a rate base return on the undepreciated investment in wind turbine equipment replaced as part of the repowering project. Because wind repowering that qualifies for new Production Tax Credit (PTC) benefits requires the replacement of a significant amount of equipment this disallowance is substantial. It would shift a large share of the costs of wind repowering to PacifiCorp, even though customers already stand to gain tens of millions of dollars of benefits from this innovative project. This unbalanced and unreasonable outcome is contrary to ORS 469A.120(2), which dictates dollar-for-dollar recovery of the fixed costs of all prudent investments in resources, such as this, that are compliant with Oregon's renewable portfolio standard (RPS). Nor is this result mandated by ORS 757.355, because the underlying wind facilities remain used and useful.

Staff and CUB recommend that the Commission condition cost recovery by imputing PTC benefits in future ratemaking, effectively treating the PTC benefits forecast during resource acquisition analysis as a floor. To justify such conditions, these parties wrongly seek to convert the acknowledgment of PacifiCorp's 2017 Integrated Resource Plan (IRP) by the Public Utility Commission of Oregon (Commission) into a ratemaking order and inaccurately claim that the repowering project is not needed.

The treatment of PTC benefits in rates is governed by ORS 757.264, which requires the Commission to set rates based on annual PTC forecasts in the Transition Adjustment Mechanism (TAM). Staff's and CUB's proposal is contrary to this statute and outside the scope of the Renewable Adjustment Clause (RAC). In addition, the Commission has consistently rejected similar ratemaking proposals to impute wind capacity factors, and there is no justification for changing its approach here. And, as a practical matter, PTC benefits currently in rates are generally higher than those in PacifiCorp's economic analysis.

There is no basis for imposing other conditions proposed by CUB with respect to PTC qualification and construction cost over-runs. This case seeks cost recovery only after the repowered projects are in service, so these risks are moderated. Indeed, PacifiCorp has already started passing PTC benefits through to customers, effectively addressing CUB's underlying concern that these benefits are uncertain.

Finally, my testimony addresses the following topics:

- PacifiCorp intends to file a general rate case in 2020, and AWEC has not met its burden to justify a requirement conditioning approval of this RAC on PacifiCorp filing a general rate case several months sooner than currently planned.
- Contrary to AWEC's position, the company's proposal to implement cost recovery for repowering in two separate rate changes later this year is consistent with the spirit of the parties' stipulations in dockets UM 1330 and UE 339, as this approach minimizes the number of rate changes while also limiting regulatory lag and appropriately matching the costs and benefits of the project.
- PacifiCorp does not oppose Staff's recommendation for an affidavit attesting to the in-service dates of repowered wind facilities prior to rate effective dates for those facilities. If a facility is delayed past December 1, however, ORS 469A.120(2) provides for full recovery of costs incurred between the facility's in-service date and when it is reflected in rates. Staff's proposal fails to address this issue.
- PacifiCorp does not oppose Calpine's position on the scope of PacifiCorp's proposal to expand the RAC to apply to direct access customers. PacifiCorp also supports modifications to Calpine's proposal to better match costs and benefits for direct access customers in the five-year opt-out program.

II. PRUDENCE OF THE REPOWERING PROJECT

Q. Please summarize the repowering project.

A. Since 2016, PacifiCorp has expended significant time and resources on repowering its wind fleet to increase its energy output and renew PTC benefits for a decade. By the end of 2019, PacifiCorp will complete repowering of the nine wind facilities covered by this RAC filing, for a total of 773.5 megawatts (MW). As described in the opening testimony of PacifiCorp witness Mr. Rick T. Link, wind repowering will produce hundreds of millions of dollars in net benefits to customers, with further customer upside for additional Renewable Energy Certificates (RECs) generated by the incremental energy output from each facility.[1]

Q. Has any party provided evidence disputing these benefits or challenging the prudence of the repowering project?

A. No. In fact, Staff explicitly finds the projects to be prudent.[2]

Q. Has any party challenged the reasonableness of the costs of wind repowering?

A. No.

Q. In the 2019 TAM, did Staff propose to include the benefits of wind repowering in rates effective on January 1, 2019, months in advance of the projected in-service dates of the repowered facilities?

A. Yes, Staff made this proposal in its opening testimony in the 2019 TAM.[3] Through an all-party stipulation approved by the Commission, the company agreed to include the pro-rated PTC and net power cost benefits of repowering in the 2019 TAM. This reduced current rates by approximately $4.5 million on an Oregon-allocated basis.

Q. Staff notes that the Oregon-allocated repowering benefits in the 2019 TAM are $7.7 million, citing Order No. 18-421 issued in the 2019 TAM.[4] Please comment.

A. The 2019 TAM was settled in advance of the reply and final TAM updates. The stipulation includes a preliminary, approximate estimate of $7.7 million in wind

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[1] PAC/300, Link/3, 34; see also PAC/800, Link/5-6.
[2] Staff/100, Storm/56. While AWEC notes that it has not yet taken a position on prudence, AWEC/100, Mullins/4-5, in the 2019 TAM stipulation the parties all agreed to review the 2019 RAC on an expedited basis. *See In the Matter of PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421, at 4 (Oct. 26, 2018). It would be inconsistent with that agreement for AWEC to challenge prudence for the first time in its rebuttal testimony in this proceeding.
[3] *In the Matter of PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Staff/100, Gibbons/5-11.
[4] Staff/100, Storm/34.

repowering benefits, subject to revision in the TAM reply and final updates "based on changes to the scope or expected in-service dates of the repowering projects."[5] The in-service dates of the projects changed in the final TAM update, decreasing the Oregon-allocated repowering benefit to approximately $4.5 million ($4 million in incremental PTCs and $0.5 million in net power cost benefits). The Commission issued Order No. 18-421 before the final TAM update and referenced the preliminary benefit estimate in the stipulation.

Q. Has PacifiCorp also included the benefits of repowering in the 2020 TAM?

A. Yes. The benefits of repowering reduce rates in the 2020 TAM by $26.4 million on an Oregon-allocated basis.[6]

Q. In the RAC stipulation approved by the Commission in Order No. 07-072, did parties agree that recovery of variable costs and benefits in PacifiCorp's TAM and power cost adjustment mechanism (PCAM) would be conditioned on matching fixed cost recovery in the RAC?

A. Yes. The stipulating parties in that case, which included Staff, CUB and AWEC's predecessor, the Industrial Customers of Northwest Utilities (ICNU), agreed that "if the fixed costs of an eligible resource are not included in RAC charges, or otherwise included in rates, then the variable costs and cost offsets of the eligible resource likewise should not be included in the annual power cost update filings or power cost adjustment mechanisms."[7]

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[5] Docket No. UE 339, Order No. 18-421, Appendix A at 5.
[6] *In the Matter of PacifiCorp, dba Pacific Power, 2020 Transition Adjustment Mechanism,* Docket No. UE 356, PAC/100, Wilding/5. This figure reflects only the benefits of the repowered wind resources in this case and does not include the benefits of Dunlap or Glenrock III, which will be repowered in 2020.
[7] *In the Matter of Public Utility Commission of Oregon, Investigation of Automatic Adjustment Clause Pursuant to SB 838,* Docket No. UM 1330, Order No. 07-572, at 5 (Dec. 19, 2007).

Q. In spite of these facts, have parties to this case sought to partially disallow or condition PacifiCorp's fixed cost recovery for wind repowering?

A. Yes.

Q. What major adjustments do the parties propose?

A. Staff and CUB seek to disallow PacifiCorp's return on the undepreciated investment in the equipment replaced by repowering.[8] Staff quantifies this as a $5.4 million reduction to the October 1, 2019 increase of $14.0 million, and an $8.1 million reduction to the December 1, 2019 increase of $18.2 million;[9] in total, this adjustment would disallow 42 percent of the wind repowering costs PacifiCorp seeks to recover in the RAC.

AWEC makes an adjustment to plant balances for the replaced equipment, reducing the company's return of its investment. AWEC also proposes a regulatory asset approach, with one of its alternatives reflecting a carrying charge that is less than one-half of PacifiCorp's authorized rate of return.[10] AWEC quantifies its adjustments at $7.2 million.[11]

Staff and CUB also seek to condition cost recovery on a PTC "floor" that would guarantee the level of PTCs projected in the company's economic analysis. Staff proposes that customers receive 100 percent of any PTC benefits that exceed these projections through an adjustment to the PCAM. CUB proposes several other conditions on cost recovery, including a construction cost cap.

I respond to each of these proposed adjustments in my testimony below.

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[8] Staff/100, Storm/5, 66-67, 76; CUB/100, Gehrke/5-7.
[9] Staff/100, Storm/72.
[10] AWEC/100, Mullins/13-21.
[11] AWEC/100, Mullins/7, 12; AWEC/103.

Q. Is there any justifiable basis for these major disallowances and conditions?

A. No. The adjustments are unfounded and one-sided. In late 2016, PacifiCorp took decisive action to capture the benefits of wind repowering for its customers by acquiring safe-harbor equipment and assuming the risk of successfully delivering the repowering project to its customers. Since then, PacifiCorp has carefully managed the many different facets of this project. PacifiCorp is now positioned to complete the project on time and on budget,[12] and the project is already delivering benefits to Oregon customers through the 2019 TAM.

Under these circumstances, the parties' cost recovery adjustments and conditions are unreasonable. If adopted, they would discourage utility innovation at a time when customers need their utilities to take actions to prepare for a decarbonized future. And, because of the matching principle adopted in the RAC, a cost disallowance would jeopardize future inclusion of repowering benefits in the TAM.[13]

III. TREATMENT OF REPLACED EQUIPMENT

Q. Does wind repowering involve replacement of original plant equipment?

A. Yes. As described in the opening testimony of PacifiCorp witness Mr. Timothy J. Hemstreet, repowering involves replacing the machine head of repowered turbines, consisting of the nacelle, hub, and rotor.[14] While equipment replacement occurs

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[12] PAC/700, Hemstreet/1.

[13] In recommending the Commission disallow a rate base return on the undepreciated investment in the replaced equipment, after having already stipulated to 100 percent of the benefits of repowering in the 2019 TAM, the parties are effectively seeking to claim all of the benefits of wind repowering for customers while paying only a portion of the costs. The Commission's treatment of the Rolling Hills wind facility in the 2009 RAC exemplifies that if costs and benefits are not matched, the facility will be removed from rates entirely, consistent with the parties' agreement in the RAC stipulation. *See In the Matter of PacifiCorp, dba Pacific Power, 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, PPL/101, Kelly/5-6 (Aug. 22, 2008) (recommending the Commission exclude the Rolling Hills wind facility from both the RAC and the TAM, rather than adopt Staff's adjustment imputing a higher capacity factor and associated PTCs to this facility); Docket No. UE 200, Order No. 08-548, at 20 (Nov. 14, 2008) (excluding Rolling Hills from Oregon rates).

[14] PAC/200, Hemstreet/26.

routinely in plant overhauls and upgrades, wind repowering is unique in one respect: to qualify for a ten-year renewal of the PTC, at least 80 percent of the fair market value of the repowered turbine must be comprised of new equipment costs, requiring that a significant portion of the original wind equipment be upgraded and replaced.

Q. Has PacifiCorp's economic analysis of the benefits of wind repowering always assumed recovery of the return of and return on the replaced equipment?

A. Yes. By definition, wind repowering that qualifies for new PTC benefits requires replacement of a significant portion of the existing wind turbine. Recovery of and on the undepreciated costs of the replaced equipment is thus a key element of the wind repowering project. As explained by Mr. Link, all of PacifiCorp's net benefit calculations assume full cost recovery for the replaced equipment, including both a return of the original investment and a return on that investment.[15]

Q. Because the costs of the replaced equipment are already reflected in rates, how has PacifiCorp accounted for these costs in this filing?

A. As explained by PacifiCorp witness Mr. Steven R. McDougal, the RAC filing leaves base rates unchanged, effectively allowing an opportunity for continued recovery of and on the replaced equipment, and includes only the incremental costs of wind repowering.[16] This treatment is consistent with the limited scope of the RAC, and it is appropriate because the Commission will soon update the depreciation lives and rates for the replaced equipment in PacifiCorp's pending depreciation filing, docket UM 1968, and the company's upcoming general rate case.[17]

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[15] PAC/800, Link/6.
[16] PAC/900, McDougal/1-2.
[17] *See In the Matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1968 (Sep. 13, 2018); PAC/400, McDougal/7.

Q. Is continued recovery of the undepreciated costs of the replaced wind equipment authorized by Oregon's RPS?

A. Yes. Oregon's RPS includes a broad cost recovery provision, ORS 469A.120(2). The RPS is designed to facilitate the transition from fossil fuels to renewable energy resources, in part by allowing utilities to recover in rates "all prudently incurred costs associated with compliance" with the RPS.[18] The Commission has determined that this statutory section mandates dollar-for-dollar recovery of fixed capital costs in RPS-compliant resource investments.[19] The investment in the replaced wind equipment constitutes fixed capital costs of RPS-compliant resources.

Q. CUB asserts that ORS 757.355 precludes recovery of a rate of return on the replaced wind equipment because it is not presently used for the provision of utility services.[20] Do you agree?

A. No. First, because ORS 469A.120(2) is a more recent and specific statute, its provisions appear to control the issue of cost recovery of the replaced equipment, not ORS 757.355. But even if that were not the case, based on my understanding of Oregon laws and regulations, the provisions of ORS 757.355 are nevertheless inapplicable, because the replaced wind equipment is not associated with a plant that is retired and no longer used and useful. Post-repowering, PacifiCorp's wind facilities will remain fully operational, and the replaced equipment is reasonably

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[18] *See In the Matter of PacifiCorp, dba Pac. Power 2011 RPS Compliance Report*, Docket No. UM 1 606, Order No. 12-435, App. A at 5 (Nov. 15, 2012) (citing SB 838's preamble that it is "necessary for Oregon's electric utilities to decrease their reliance on fossil fuels for electricity generation and to increase their use of renewable energy sources" as policy of SB 838).
[19] *In the Matter of Portland General Electric Company and PacifiCorp, dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation*, Docket No. UM 1662, Order No. 15-408, at 7 (Dec. 18, 2015) (analyzing ORS Section 469A.120(2)).
[20] CUB/100, Gehrke/5-7.

related to the facilities as a whole. Furthermore, if the Commission were to interpret ORS 757.355 to bar recovery of individual cost components in a used and useful plant, this could disincentivize the company from undertaking routine maintenance and upgrades as part of optimizing its resources. Applying such a standard to this case would create uncertainty for utilities when they seek to modernize facilities through removal and replacement of existing equipment.

Q. Has the Commission previously allowed rate base recovery of replaced or abandoned equipment associated with an investment that was used and useful?

A. Yes. In Order No. 99-697 in docket UG 132, the Commission declined to apply the used and useful standard to individual expenditures for a large-scale information technology project, concluding instead that the used and useful inquiry should "focus on the project as a whole."[21] In that case, the utility initially pursued a customized software program but eventually abandoned this approach in favor of different software.[22] The Commission found the expenditures on the initial effort were reasonably related to the end product. Therefore, the Commission determined that pursuit of both software programs "should be considered as part of the same project[,]" and the project, as a whole, was "used and useful in providing utility service."[23]

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[21] *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 51-52 (Nov. 12, 1999).
[22] *Id.* at 45-49.
[23] *Id.* at 51-52, 54.

Q. Is this consistent with how the Commission has treated PacifiCorp's generation plant upgrades in the past?

A. Yes. PacifiCorp's 2010 rate case, docket UE 217, included turbine upgrades at Hunter Unit 1 and Huntington Unit 1, both of which replaced the existing turbine with a new turbine that used the latest technologies to increase efficiency.[24] Similarly, in PacifiCorp's 2013 rate case, docket UE 263, the company requested approval of a turbine upgrade at Jim Bridger Unit 2.[25] No party raised concerns about the recovery of replaced equipment under ORS 757.355 in either proceeding, and the full costs of these upgrades were ultimately included in rates without objection.[26]

Q. Does Staff explain the basis for its proposed disallowance with respect to the replaced equipment?

A. Not entirely. Staff merely states that it would be unfair to obligate ratepayers to pay the return of as well as return on the replaced equipment just because this issue is being raised in a RAC rather than a general rate case.[27]

Q. Do you agree with Staff's characterization?

A. No. PacifiCorp's proposal involves leaving the replaced equipment in rate base and recovering the incremental cost of repowering through the RAC on an interim basis. Staff wrongly implies that if this issue were addressed in a rate case rather than the RAC, the Commission would remove the replaced equipment from rate base. This is not accurate. As described above, replacing the old equipment is necessary to qualify

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[24] *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 217, PPL/1102, Page 8.6.14 (Mar. 1, 2010).
[25] *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 263, PAC/400, Ralston/2 (Mar. 1, 2013).
[26] *See* Docket No. UE 217, Order No. 10-473, at 3 (Dec. 14, 2010); Docket No. UE 263, Order No. 13-474, at 2 (Dec. 18, 2013).
[27] Staff/100, Storm/66-67.

the wind repowering project for PTCs, and Staff's recommendation would severely penalize the Company for taking an action that delivers substantial PTC benefits to customers.

Q. AWEC takes issue with PacifiCorp's proposal to leave base rates unchanged and include only incremental costs of repowering in the RAC.[28] How do you respond?

A. As Mr. McDougal explains, PacifiCorp's proposal to leave base rates unchanged is a fair and reasonable way to address cost recovery of the replaced equipment on an interim basis.[29] While AWEC claims this proposal is too complex, AWEC proposes an even more complex solution: AWEC attempts to retroactively account for past accumulated depreciation, creates a regulatory asset under ORS Section 757.140(2), uses a sinking fund method for amortizing the regulatory asset balance over a period of seven or nine years, and applies a pre-tax or post-tax carrying charge depending on the amortization period.[30]

IV. PROPOSED CONDITIONS ARE UNWARRANTED

Q. Please describe the conditions Staff and CUB propose with respect to PTC guarantees.

A. Staff recommends the Commission "impute values of net PTC benefits" in each annual TAM filing to be "no less than the net PTC benefits included in the company's economic analyses supporting these wind repowering projects."[31] For purposes of

[28] *See* AWEC/100, Mullins/14-17.
[29] PAC/900, McDougal/1-2.
[30] *See* AWEC/100, Mullins/17-20.
[31] Staff/100, Storm/58-59.

establishing this PTC floor, it is not clear whether Staff seeks to rely on the economic analysis from the 2017 IRP or on a more recent vintage.[32] Staff further recommends exempting benefits of wind repowering from the deadband, sharing, or earnings test provisions in PacifiCorp's annual PCAM.[33]

CUB similarly recommends the Commission set the PTC benefits projected in this proceeding as "a floor on PTCs included in rates."[34]

Q. On what basis do Staff and CUB seek to impose conditions on cost recovery for wind repowering?

A. Notably, Staff and CUB do not seek cost recovery conditions on the basis that wind repowering is imprudent. Instead, they claim that conditions are justified because repowering is driven purely by economic opportunity rather than need.[35] They also rely on the Commission's order acknowledging PacifiCorp's 2017 IRP, because the Commission observed that recovery could be structured to hold PacifiCorp to the economic projections in its original IRP analysis.[36]

Q. Do these arguments support imposition of a PTC floor or other cost recovery conditions?

A. No. As explained by Mr. Link in his reply testimony, (1) wind repowering should be evaluated through the lens of utility asset management, not resource need;[37] (2) wind repowering does help fill an established need for uncommitted resources, as identified

[32] *See* Staff/100, Storm/59, 75.
[33] *See* Staff/100, Storm/2, 58, 75-76.
[34] CUB/100, Gehrke/5.
[35] Staff/100, Storm/56, 58; CUB/100, Gehrke/5.
[36] Staff/100, Storm/56 (quoting Order No. 18-138 at 8); CUB/100, Gehrke/4 (quoting Order No. 18-138 at 8).
[37] PAC/800, Link/13.

in the 2017 IRP;[38] and (3) the Commission itself caveated that its conditions on acknowledgment do not dictate ratemaking treatment.[39]

Q. Is there an Oregon statute that governs how PTCs are to be included in rates?

A. Yes. ORS 757.264 requires that utilities forecast PTC benefits on an annual basis. The statute provides that "the Public Utility Commission shall allow those forecasts to be included in rates through any variable cost forecasting process established by the Commission."

Q. As a result of ORS 757.264, does PacifiCorp include annual PTC forecasts in the TAM?

A. Yes. PacifiCorp includes annual PTC benefit forecasts in the TAM; issues relating to PTC benefits are therefore addressed in the TAM, not the RAC.

Q. Is the PTC floor proposed by Staff and CUB contrary to ORS 757.264?

A. Yes. The statute requires the Commission to set rates based on PacifiCorp's annual PTC forecast in the TAM, not impute PTC benefits in the RAC based on a ten-year forecast.

Q. On the whole, are the PTC benefits for repowering in the 2019 and 2020 TAM higher than the PTC benefits in the company's economic analysis for wind repowering?

A. Yes. PTC benefits are primarily a function of a wind facility's capacity factor. As noted in Mr. Hemstreet's opening testimony, the capacity factors used in PacifiCorp's economic analysis for wind repowering are based on cumulative historical averages.[40]

[38] PAC/800, Link/13-14.
[39] PAC/800, Link/3.
[40] *See* PAC/200, Hemstreet/13-14.

In the 2019 TAM, the company proposed to use the same historical averages to forecast wind plant performance and PTCs.[41] Staff and AWEC objected, however, and the parties stipulated on an approach that uses a 50/50 blend of (1) the P50 production estimates when each wind facility was initially developed; and (2) cumulative historical averages. To avoid controversy, the company continued this approach in the 2020 TAM on a non-precedential basis.[42] For all but two of the wind facilities (McFadden Ridge and Seven Mile Hill II), the 50/50 blend produces higher capacity factors—and therefore higher PTCs—than the cumulative historical average. Thus, to the extent there is any difference between the PTC forecasts in the 2019 and 2020 TAM and the company's repowering economic analysis, it is because Staff and AWEC proposed these changes and they are beneficial to customers on an overall basis.

Q. Staff and CUB claim that there is a need for a PTC benefit floor because of the risk of wind underperformance. Do you agree that this risk warrants the proposed condition?

A. No. As described by Mr. Hemstreet in his opening testimony, PacifiCorp worked with an expert consultant, relying on extensive data history from these facilities, including millions of data points from the operational record, to generate the capacity factors.[43] In other words, unlike the construction of a new wind facility, capacity factors for the repowering project incorporate actual production history. In addition, PacifiCorp negotiated mechanical availability guarantees with the manufacturers of

[41] Docket No. UE 339, PAC/100, Wilding/39.
[42] Docket No. UE 356, PAC/100, Wilding/32.
[43] PAC/200, Hemstreet/13.

the new wind equipment, GE and Vestas, including liquidated damage provisions if the turbines fail to meet guaranteed availability.[44]

Q. Does Staff acknowledge that PacifiCorp has managed the capacity factor risk associated with its wind repowering economic forecasts?

A. Yes.[45]

Q. In the 2019 TAM, did AWEC agree that the PTC forecasts used in PacifiCorp's repowering analysis were reasonable and accurate?

A. Yes. AWEC noted that "the capacity factors assumed in the repowering proposal were the result of engineering studies that were based on the most recent data available to PacifiCorp."[46] Therefore, AWEC opined that "there is no reason to doubt the accuracy of those assessments in the long term."[47] This supports the company's position that the risk of wind underperformance is insufficient to justify Staff's and CUB's proposed PTC floor.

Q. Is there any Commission precedent for imputing capacity factors as Staff and CUB effectively propose?

A. No, the Commission has consistently rejected such an approach. In PacifiCorp's 2009 RAC proceeding, the Commission denied a proposal by Staff to impute a higher capacity factor to the Glenrock facility in determining net variable power costs, based on an outdated CH2M Hill study that had since been superseded.[48] The Commission stated:

[44] PAC/200, Hemstreet/18.
[45] *See* Staff/100, Storm/55-56.
[46] Docket No. UE 339, AWEC/100, Mullins/7.
[47] *Id.*
[48] Order No. 08-548, at 4-5, 21.

> Although the estimated capacity factor at the time of project approval is dispositive for purposes of prudency review, it is not dispositive for purposes of forecasting resource availability for ratemaking purposes. The most recent reliable data should be used to set rates for the test period[.] . . .[49]

Similarly, in PacifiCorp's 2016 TAM proceeding, docket UE 296, the Commission approved the company's proposal to use actual production data to develop capacity factors for wind purchase power agreements, over the objection of ICNU.[50] ICNU had recommended using the original capacity factor forecasts, because actual generation had been lower than expected when the wind resources were acquired.[51] In rejecting ICNU's recommendation, the Commission found that "[f]orty-eight months of actual operation is sufficient for deriving a reasonable forecast of expected wind generation at a site that is superior to the long-range forecasts provided by the project owners."[52]

Q. As part of the PTC floor described above, Staff proposes tracking 100 percent of the wind repowering benefits in the PCAM.[53] Is this approach reasonable?

A. No. PacifiCorp does not support the PCAM's deadbands, sharing bands, and earnings test, in part because PacifiCorp wants to provide customers 100 percent of all variable cost offsets, such as the wind repowering benefits in this case. However, Staff proposes the removal of the deadbands and sharing bands as part of the PTC floor. There is no justification to modify the PCAM in this proceeding.

[49] *Id.* at 21.
[50] *In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 6-7 (Dec. 11, 2015).
[51] *Id.* at 6-7.
[52] *Id.* at 7.
[53] Staff/100, Storm/2, 58, 75-76.

Q. Staff describes various risks relating to qualification for PTCs,[54] and CUB recommends several conditions to address PTC qualification and other risks. What are CUB's conditions?

A. Citing to the repowering stipulations in the Wyoming and Idaho pre-approval cases, CUB recommends PacifiCorp bear the risk of PTC qualification, meaning, if a turbine does not qualify for PTC benefits, the value of the PTC would nevertheless be imputed to customers.[55] CUB also recommends that all liquidated damages received by PacifiCorp under the contractual provisions with the wind manufacturers "flow back to customers[,]" for example, if the equipment is not installed on schedule.[56]

Q. Is it appropriate to look to stipulations from the pre-approval cases as a model for this docket, which seeks cost recovery for fully operational, repowered facilities?

A. No. The Wyoming and Idaho stipulations were executed more than one year ago, when the repowering project was still under development. This case seeks cost recovery after the nine facilities in this case are fully repowered. As described by Mr. Hemstreet, PTC qualification risk is minimal at this point, as these facilities will be in service more than one year in advance of the PTC qualification deadline.[57] Furthermore, the company has already included the PTC benefits of repowering in Oregon rates through the 2019 TAM.

[54] Staff/100, Storm/51-53.
[55] CUB/100, Gehrke/8.
[56] CUB/100, Gehrke/8.
[57] PAC/200, Hemstreet/25.

Q. What other condition does CUB recommend?

A. CUB recommends imposing a construction cost cap, imputing the construction costs forecast in this proceeding, to prevent customers from bearing any risk with respect to construction cost overruns.[58]

Q. Is this condition warranted?

A. No. As described by Mr. Hemstreet in his opening testimony, under the contracts negotiated with the turbine manufacturers, the majority of construction costs are now fixed, which substantially reduces the risk of cost overruns.[59] Therefore, the risk of construction cost overruns is low and CUB's proposed condition is unwarranted.

Q. Does the RAC include provisions for handling the difference between cost estimates in the company's filing and final costs?

A. Yes. Section 6(e) of the RAC stipulation provides that if any cost element in the RAC cannot be finally verified by the final round of RAC testimony, PacifiCorp will make a filing within 8 months of the initial filing, or by December 1, to reflect the then-current costs or costs estimates. If the update reflects a cost reduction, then this will reduce RAC rates before the January 1, effective date; if the update reflects a cost increase, then section 6(f) of the RAC stipulation controls.[60]

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[58] CUB/100, Gehrke/7. CUB also signals that it may request a condition on safe harbor PTC equipment, if there is risk that the equipment purchased in 2016 has deteriorated due to storage conditions. CUB asks the company to address various questions in reply testimony related to the safe harbor equipment. CUB/100, Gehrke/10-11. Mr. Hemstreet addresses this issue in his reply testimony. PAC/700, Hemstreet/7-9.
[59] PAC/200, Hemstreet/24-25.
[60] *See* Order No. 07-572, Appendix A, at 5.

Under section 6(f) of the RAC stipulation, the parties support the use of deferred accounting if prudent costs are higher than projected costs in the record, or if actual capital costs cannot be verified by December 1.[61]

Q. Does the company intend to follow these provisions of the RAC, modified as necessary to track the special schedule in this RAC filing and address Order No. 18-423 in docket UM 1909 relating to deferrals for capital costs?[62]

A. Yes. PacifiCorp intends to file final cost updates one month in advance of the October 1 and December 1 rate effective dates (i.e., on September 1 and November 1). If the updated costs are lower than those included in the company's surrebuttal testimony, the updated costs will be used to set rates. If the updated costs are higher, or costs remain unknown, rates will be set using the costs in the surrebuttal testimony. The company will then seek recovery of the cost increase in its next general rate case or RAC filing through whatever mechanism the Commission develops to replace deferred accounting and provide 100 percent capital cost recovery for renewable resource investment, as required by ORS 469A.120(2).

Q. Are these provisions of the RAC in conflict with CUB's request for a construction cost cap?

A. Yes. The RAC provides for a true-up to cover the actual, prudent costs of a renewable resource, whether it is higher or lower than the cost estimates filed in the RAC.

[61] *Id.* at 5-6.
[62] *In the Matter of Public Utility Commission of Oregon, Investigation of the Scope of the Commission's Authority to Defer Capital Costs*, Docket No. UM 1909, Order No. 18-423, at 1, 8 (Oct. 29, 2018).

V. PACIFICORP'S NEXT GENERAL RATE CASE

Q. Please describe AWEC's proposal regarding the timing of PacifiCorp's next general rate case.

A. AWEC recommends conditioning the approval of this RAC filing on the company filing a general rate case within six months.[63]

Q. On what basis does AWEC argue for this condition?

A. In docket UM 1330, the parties' stipulation authorizes the Commission to condition approval of a rate change in the RAC on filing of a general rate case within six months. The Commission may impose this condition, however, only if it makes a finding either that the costs "have been collected for a reasonable period of years" or that good cause exists.[64] AWEC argues that here, good cause exists because PacifiCorp is "currently earning returns exceeding its authorized return on equity" and because the company still owes customers a material sum of tax savings from tax reform.[65]

Q. Has AWEC established good cause?

A. No. The concern at issue in docket UM 1330 was that the company might delay filing a new rate case for an extended period of time, *e.g.*, for three years, as the witness for ICNU (now AWEC) articulated.[66] The good cause exception was intended only for extraordinary circumstances. The factors AWEC relies on here do not amount to extraordinary circumstances, particularly given PacifiCorp's

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[63] AWEC/100, Mullins/22-23.
[64] Order No. 07-572, Appendix A, at 7. *See also id.* at 6 (joint testimony describing this provision of the stipulation).
[65] AWEC/100, Mullins/23-25.
[66] Order No. 07-572, at 8.

transparent intent to file a rate case in 2020 for rates effective beginning January 1, 2021, as AWEC itself acknowledges.[67] In the absence of such extraordinary circumstances, mandating a particular general rate case filing date in this case is inconsistent with the terms of the RAC stipulation approved in docket UM 1330.[68]

VI. MULTIPLE RATE CHANGES

Q. How does PacifiCorp propose to implement rate changes in this RAC?

A. As Mr. McDougal and I explain in our opening testimony, the company proposes to implement cost recovery in two separate rate changes, with rate effective dates on October 1, 2019, and December 1, 2019, respectively, in order to accommodate the expected in-service completion dates for the repowered wind projects.[69] This approach minimizes the number of rate changes while also limiting regulatory lag and appropriately matching costs and benefits.[70]

Q. How does this staggered approach more closely match costs and benefits?

A. While the RAC typically addresses both the costs and the benefits of renewable projects, as part of the settlement of the 2019 TAM the parties agreed to reflect net power cost benefits associated with wind repowering in the 2019 TAM.[71] This creates a timing difference, as the benefits are distributed to customers over the course of 2019, beginning on January 1, whereas the company does not begin recovering the costs of repowering a particular wind facility until the rate effective

[67] AWEC/100, Mullins/25; *see also* Order No. 18-421 at 8 (noting PacifiCorp's commitment to file a general rate case before January 2021).
[68] *See* Order No. 07-572, Appendix A, at 7.
[69] PAC/100, Lockey/4; PAC/400, McDougal/3.
[70] PAC/100, Lockey/4; PAC/400, McDougal/3.
[71] PAC/100, Lockey/6.

date for that project in the RAC.[72] The staggered approach proposed by PacifiCorp therefore allows a closer matching of costs and benefits, and less regulatory lag, for the four facilities that will be in service by October 1, 2019 (Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, and Glenrock I).[73]

Q. AWEC argues the company's proposed approach is inconsistent with the stipulations in the RAC (docket UM 1330) and the 2019 TAM (docket UE 339).[74] Do you agree?

A. No. First, while the parties in docket UM 1330 stipulated to annual update filings on April 1 of each year, that stipulation also contemplated "a Party may propose an alternative design" for this schedule to reflect material changes in circumstances, such as material changes to annual power cost update filings.[75] Consistent with this flexibility to accommodate material changes, in docket UE 339, the parties stipulated to a modified schedule in 2019 to allow for an earlier filing date (January 2 instead of April 1).[76] Importantly, the parties also agreed to support an expedited procedural schedule to allow for a rate effective date for the RAC of July 1, 2019, which was the earliest expected in-service date at the time.[77] The purpose of modifying the schedule was "to match costs and benefits of resources in rates," as the Commission noted in its order approving the 2019 TAM stipulation.[78]

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[72] PAC/100, Lockey/6-7.
[73] PAC/400, McDougal/3.
[74] AWEC/100, Mullins/21-22.
[75] Order No. 07-572, Appendix A, at 3.
[76] Order No. 18-421, Appendix A, at 4.
[77] *Id.*
[78] Order No. 18-421, at 3.

Based on subsequent changes to in-service dates, it is now necessary for PacifiCorp to modify the rate effective dates in the RAC to honor the parties' agreement in the 2019 TAM "that the RAC rates will not reflect any repowering project costs until the project is in service."[79] The company's proposal to stagger the rate effective dates in October and December rather than proposing a new single rate effective date results in better alignment with the in-service dates of the plants and more effectively matches costs and benefits in rates, consistent with the spirit of the parties' stipulations in dockets UM 1330 and UE 339.[80]

VII. IN-SERVICE AFFIDAVIT

Q. Please describe Staff's recommendation regarding an affidavit that a resource is in service.

A. Staff recommends the Commission require PacifiCorp's Chief Executive Officer sign an affidavit attesting that each repowered wind facility included in this RAC was placed in service prior to each facility's rate effective date.[81]

Q. Does PacifiCorp object to this recommendation?

A. No.

Q. How does Staff recommend the company proceed in the event that completion of repowering at a particular facility is delayed beyond that facility's rate effective date?

A. Staff recommends that in case of delay beyond October 1, 2019, at a facility with a rate effective date of October 1, 2019, the facility's rate effective date be moved to

[79] *Id.* at 4.
[80] Mr. McDougal's reply testimony addresses AWEC's claim regarding the revenue requirement impact of the proposed two-step rate change. PAC/900, McDougal/14-15.
[81] Staff/100, Storm/57.

December 1, 2019. For any facility that is not in service by December 1, 2019, Staff recommends cost recovery for that facility occur in a future RAC proceeding or general rate case.[82]

Q. Do you agree with this approach to address unexpected delay?

A. In part. PacifiCorp agrees that it is reasonable to move the rate effective date from October 1 to December 1 for delayed facilities. For facilities that are not in service by December 1, section 6(f) of RAC stipulation covers this kind of delay by allowing deferred accounting between the time a resource goes into service and when it comes into rates through a RAC or general rate case. In light of Order No. 18-423, the company will seek recovery of the costs associated with delayed cost recovery through whatever mechanism the Commission develops to replace deferred accounting and provide 100 percent capital cost recovery for renewable resource investment, as required by ORS 469A.120(2).

VIII. CALPINE DIRECT ACCESS PROPOSALS

Q. What did PacifiCorp propose in its initial filing with respect to direct access customers?

A. As explained in my opening testimony, PacifiCorp recommends expanding the RAC rate schedule to apply to direct access customers, because direct access customers subject to the 2019 TAM are already receiving the benefit of PTCs associated with repowering through a reduction in their transition adjustment charge or an increase in their transition adjustment credit.[83]

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[82] Staff/100, Storm/57.
[83] PAC/100, Lockey/5.

Q. Do other parties support this proposal?

A. Yes, both Staff and CUB support PacifiCorp's proposal.[84]

Q. What does Calpine recommend with respect to expanding the RAC to direct access customers?

A. Calpine appears to support PacifiCorp's proposal in general, but recommends several modifications.[85]

Q. What is Calpine's first recommended modification?

A. Calpine requests that direct access customers who began taking five-year opt-out service prior to the effective date of the 2019 TAM (January 1, 2019) be excluded, since those customers are not receiving the benefit of PTCs in their transition adjustments.[86]

Q. Does PacifiCorp support Calpine's position?

A. Yes. Calpine's position is consistent with how PacifiCorp intended to implement its proposal.

Q. What is Calpine's second recommended modification?

A. Calpine requests that direct access customers taking five-year opt-out service on or after January 1, 2019, who are therefore subject to the 2019 RAC under PacifiCorp's proposal, should not also be subject to any future RACs for additional renewable generation costs, absent evidence that the changes to their transition adjustments in the 2019 TAM reflected projected increases in PTC benefits from such future projects.[87] In other words, unless there is evidence those direct access customers are

[84] Staff/100, Storm/73; CUB/100, Gehrke/12.
[85] *See* Calpine Solutions/100, Higgins/9.
[86] Calpine Solutions/100, Higgins/4, 9-11, 13.
[87] Calpine Solutions/100, Higgins/4, 11, 13.

already receiving credit for expected additional renewable projects during their five year transition window, they should not be subject to any future costs associated with such projects either.

Q. What is PacifiCorp's position in regards to Calpine's second recommendation?

A. PacifiCorp's position is that direct access customers in the five-year opt-out program should be subject to rate changes in the RAC during the five-year opt-out period, in the same manner that they are subject to changes in Schedule 200. However, PacifiCorp recognizes that the costs and PTC benefits of resource included in a future RAC should be matched for the direct access customers in the five-year opt-out program. To the extent direct access customers in the five-year opt-out program are subject to a rate increase in a RAC, a tariff rider could be used to reflect the incremental PTC benefits for the direct access customers in the five-year opt-out program.

Q. What is Calpine's third recommended modification?

A. Calpine requests that direct access customers participating in the five-year opt-out program be excluded from the RAC charges once their respective five-year transition periods have passed, since such customers should at that point no longer be subject to incremental costs of new PacifiCorp generation, including repowered wind facilities under the RAC.[88]

Q. Does PacifiCorp agree with Calpine's position?

A. Yes, this is also consistent with PacifiCorp's proposal.

[88] Calpine Solutions/100, Higgins/4, 9, 11-12, 13.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 352
Exhibit PAC/700
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Timothy J. Hemstreet

May 2019

REPLY TESTIMONY OF TIMOTHY J. HEMSTREET

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Q. Are you the same Timothy J. Hemstreet who previously provided testimony in this case on behalf of PacifiCorp d/b/a Pacific Power?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My reply testimony provides an update on the current status of implementation of the wind repowering project and responds to issues and recommendations raised in the opening testimony of the Public Utility Commission of Oregon Staff (Staff) witness Mr. Steve Storm, and Oregon Citizens' Utility Board (CUB) witness Mr. William Gehrke.

Q. Please summarize your reply testimony.

A. PacifiCorp's wind repowering project is proceeding on schedule and on budget to deliver substantial net benefits to customers. The recommendations of Staff and CUB to condition PacifiCorp's cost recovery to avoid potential "harm" to customers are without merit and would penalize the company for pursuing what no party has disputed to be a prudent project that will benefit customers.[1]

CURRENT PROJECT STATUS

Q. Please provide an update on the status of implementation of the wind repowering project.

A. Since December 28, 2018, when the company's initial filing was submitted to the Public Utility Commission of Oregon (Commission), PacifiCorp has completed all contracting related to implementation of the project and repowering efforts are now

[1] *See e.g.*, Exhibit CUB/100, Gehkre/5.

underway at seven of the nine facilities included in this filing. Repowering work will begin at the remaining two facilities later this summer.

Q. Have significant construction activities already been completed?

A. Yes. Foundation retrofits have been completed at the Leaning Juniper facility and foundation retrofits are underway at the Goodnoe Hills facility. Additionally, turbine retrofit work is proceeding at the Glenrock I and Leaning Juniper facilities.

Q. Is the wind repowering project on schedule to be completed by the in-service dates identified in the company's filing in this proceeding?

A. Yes. PacifiCorp's wind repowering project is proceeding on schedule and all facilities are anticipated to be placed in service consistent with the timing provided in my opening testimony, and ahead of their respective October 1, 2019, and December 1, 2019, rate effective dates.

Q. Is the wind repowering project on budget?

A. Yes, the project is currently on budget and forecast to be completed consistent with the cost estimates included in the company's filing. Foundation retrofit work has been completed at Leaning Juniper and is more than 50 percent complete at Goodnoe Hills with costs at these facilities remaining on budget. This is significant because foundation retrofit work is one of the few aspects of the repowering project that presents a risk of unforeseen underground conditions (that could result in increased costs). The retrofit work at the other facilities now underway also remains on budget and without unforeseen underground conditions to-date.

WIND PRODUCTION ESTIMATES AND PRODUCTION TAX CREDIT (PTC) IMPUTATION

Q. What risk related to wind production estimates are raised by the parties?

A. Staff states that customers face "quantity risk" which he defines as the risk that actual generation from the repowered facilities will be less than forecast resulting in lower PTCs than estimated.[2] CUB recommends that the Commission set a "PTC floor" that would guarantee that customers receive at least the projected value of the PTC benefit from the wind repowering project that was included in the company's economic analysis.[3]

Q. Does the company agree with these recommendations?

A. No, these extraordinary conditions unreasonably penalize the company for prudently operating its existing generation facilities. PacifiCorp's use of actual historical generation data, combined with the conservative use of this data to determine forecasted energy production for the repowered facilities should give the Commission confidence that the company's forecast of customer benefits associated with PTCs is accurate. A PTC floor, which is effectively an imputation of a set capacity factor, inappropriately shifts risk to PacifiCorp for situations beyond the company's control, such as extreme weather events, wind conditions that deviate from the prior operational history, or other unforeseen circumstances.

Q. Is Staff's fear of "quantity risk" valid?

A. No. As described in my opening testimony,[4] the company's estimate of the energy

[2] OPUC/100, Storm/54.
[3] CUB/100, Gehrke/3.
[4] PAC/200, Hemstreet/12-13.

production (and thus capacity factors) for the repowered facilities is based on the extensive historical data of the currently-operating wind facilities.[5] This data includes actual curtailments, as well as planned and unplanned outages experienced at each of the facilities. Relying on the actual production history is more conservative and likely more accurate than relying upon estimates of how these impacts may affect energy production following repowering.

Q. Does the company's use of actual historical data to forecast energy production appropriately apportion risk between the company and customers?

A. Yes. As explained in my opening testimony, the energy estimates developed by the company are intentionally conservative to reduce risk to customers.[6] As further detailed in my opening testimony, technological advances that will be installed as part of the wind repowering project are likely to reduce turbine down-time, but these improvements to availability (compared to historical availability) were not included in the company's energy estimates.[7] As a result, energy production could be more than estimated and the "quantity risk" alleged by Staff is unlikely. It is also important to note that availability guarantees further protect customers from the alleged risk that repowering will not increase generation as expected. The service and maintenance contracts that the company has entered into for the repowered facilities include availability guarantees that require the service providers to compensate the company for lost generation as a result of failing to meet guaranteed availability targets. Thus,

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[5] PAC/200, Hemstreet/13-14.
[6] PAC/200, Hemstreet/13-14.
[7] PAC/200, Hemstreet/14.

customers are protected from risks that equipment down time will hamper production, and thus PTC benefits.

Q. Have any of the parties raised issues with the manner in which the company estimated the expected energy production that would result from the wind repowering project?

A. No.

Q. What is the impact to customers if energy production, and thus PTC value, is less than the company's estimates?

A. As discussed in Mr. Rick T. Link's opening testimony, the wind repowering project is forecast to provide present-value revenue requirement differential (PVRR(d)) benefits under all evaluated price-policy scenarios, with project-wide benefits evaluated in February 2018 ranging between $121 million to $466 million.[8] Given this range of substantial benefits, I believe customers will still benefit even if energy production, and thus PTC value, is less than the company's estimates. Setting a PTC floor will not result in increased forecast accuracy and would penalize the company for deviations, however reasonable and normal, from the estimated customer benefit.

Q. Are there any other reasons that setting a PTC floor is inappropriate?

A. Yes. Setting a PTC floor requires the company to hold customers harmless and bear the associated risk from natural, variable wind conditions that are beyond its control. While there is no reason to expect long-term wind conditions to deviate substantially from past experience, differences in future frequency, duration, and intensity of wind

[8] PAC/300, Link/3.

speed conditions will impact performance of the repowered turbines (and the resulting PTC Value). It is unfair for the company to unilaterally bear this risk.

If the Commission were to adopt a PTC floor, it would only be fair to also adopt the corollary, *i.e.*, that the company should solely benefit from any energy and PTC value produced from the repowered wind facilities that surpass the values included in the company's economic analysis.

Q. Has the Commission ever mandated that the company guarantee production and PTC values for the company's wind facilities?

A. To my knowledge, the Commission has never adopted a mechanism that requires the company to guarantee the generation output from its wind facilities. In fact, and as discussed in greater detail in the reply testimony of Ms. Etta P. Lockey, the Commission has consistently rejected this approach.[9]

Q. Do you have other concerns with a PTC floor condition?

A. Yes. Imposing a PTC floor could have unintended consequences because it is possible that the company could operate the wind facilities differently than it has historically and forecast in the company's economic analysis and create less PTC value, but still deliver equivalent or greater benefits to customers. This could occur if market conditions signal a dispatch of the facilities that is different than historic but that is more economic for customers. For instance, curtailment of the facilities during certain market and load/resource conditions could be more economic than running the facilities. Additionally, curtailment could be warranted under some conditions if it reduced equipment failure or maintenance requirements, thereby saving operational

[9] PAC/600, Lockey/16-17.

costs. A PTC floor would dictate the operational regime of the facilities to produce the highest PTC value, even if that regime doesn't provide the greatest benefit to customers.

Q. Could a PTC floor condition create other problems?

A. Yes. Parties have been unclear in articulating how the PTC value would be determined. Specifically, it is unclear if a PTC floor would require that a certain energy production floor be mandated, or simply that the PTC value in the company's economic analysis be guaranteed to customers. Because the value of the PTC for customers depends on the company's effective federal and state corporate tax rate, providing a PTC floor could require that the company hold customers harmless should these corporate tax rates be reduced. This would have the unreasonable effect of benefiting customers due to reduced income tax collected through rates, while also requiring the company to hold the PTC value constant for customers.

Q. Are economic backstops for the wind repowering project necessary?

A. No. No party has argued that the wind repowering project is imprudent, or that the wind repowering project presents risk factors different from normal resource acquisition that would warrant adoption by the Commission of extraordinary rate making conditions.

PROJECT COSTS

Q. What does CUB recommend with regard to project costs?

A. CUB recommends that cost recovery be subject to a construction cost cap to protect customers from the risk of construction cost overruns.[10]

[10] CUB/100, Gehrke/7.

Q. Is a construction cost cap appropriate?

A. No. First, as discussed in more detail in the reply testimony of company witness Mr. Link, there is a near-term need basis for the project in addition to economic benefits.[11] Second, construction costs are on budget and consistent with the cost caps set by other state commissions. There is therefore nothing to indicate that setting a cap here is necessary.

Q. Has any other state established construction cost caps for the wind repowering project?

A. Yes. PacifiCorp agreed to the imposition of cost caps in Wyoming and Idaho pursuant to settlement stipulations as part of project pre-approval proceedings.[12] The cost recovery agreed to in those states allows the company full recovery of its costs for the wind repowering project up to (and in some cases above) its estimated filed costs. In addition, those settlement stipulations provided the company with continued recovery of and a return on the company's investment in the wind turbine generator equipment that will be removed from service. In addition, the cost caps were set to mitigate the inherent risk to customers associated with cost pre-approval (*e.g.*, costs are not certain at the time of a pre-approval proceeding resulting in the possibility that rates could be set too high if costs are ultimately lower than estimated). This level of uncertainty does not exist in this proceeding because contracts have been finalized, equipment has been purchased, construction has commenced, and the facilities will be in service by the rate effective date. As discussed above, the project is on budget and

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[11] PAC/800, Link/3-6, 12-14.
[12] *See, e.g.*, CUB/103. The Utah Department of Public Utilities also imposed a cost-cap on its pre-approval pursuant to its Report and Order dated May 25, 2018 issued in Docket No. 17-035-39; such order reserved consideration of any adjustment to the rate of return on the retired assets for a future proceeding.

repowering the facilities is expected to be completed consistent with the estimated in-service dates provided by the company. Therefore, the mitigation of customer risk that cost caps sought to achieve in those pre-approval proceedings is not necessary here.

Q. Does CUB make any other recommendations that could limit the company's recovery of wind repowering project costs?

A. Yes. CUB recommends that any liquidated damages received pursuant to the contracts between the company and its vendors flow back to customers through the RAC.[13]

Q. Do you agree with this proposal?

A. No. While the company intends to credit customers for any liquidated damages received from vendors, how these damages are tracked depends on the reason damages are paid and thus the damages will be returned to customers outside of the RAC. For example, liquidated damages received because equipment fails to meet the specified availability will be returned to customers through the company's net power costs whereas liquidated damages related to construction of the project will flow back to customers by reducing final construction costs. Because there are already processes in place to pass liquidated damages back to customers, there is no need to address liquidated damages in the RAC filing.[14]

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[13] CUB/100, Gehrke/8.
[14] Similarly, as discussed in greater detail in the reply testimony of Mr. Steven R. McDougal, any salvage proceeds received by the company will also flow back to customers by crediting the accumulated depreciation reserve and reducing the net plant balance.

CONDITION OF SAFE HARBOR EQUIPMENT

Q. CUB states that "the company has not met its burden of proof to justify recovery of the entirety of safe harbor PTC capital expenditures".[15] Can you summarize CUB's concerns?

A. CUB alleges that because the safe harbor PTC equipment was acquired in 2016, but will not be installed until 2019 (or 2020 for later facilities) the equipment may have degraded while in storage such that it will not provide full value to customers when placed in rates.[16] As a result, CUB states that it may not be appropriate for customers to pay the full value of this equipment.[17]

Q. Are there particular concerns CUB expresses?

A. Yes, CUB states that "it is specifically concerning that some of the safe harbor PTC capital may be currently stored outside and exposed to the elements".[18]

Q. Do you share CUB's concerns?

A. No. CUB is correct that PacifiCorp's safe harbor equipment purchases are stored outside. However, this is appropriate and common industry practice for qualified safe harbor equipment that is awaiting installation. The company has taken all necessary steps to protect the equipment. For example, portions of the equipment are shrink-wrapped to reduce the potential for foreign material to enter the nacelles, and transition points in the nacelle housings have gaskets to keep out the elements. I would also note that PacifiCorp's wind facilities, where the equipment is ultimately

[15] CUB/100, Gehrke/8.
[16] CUB/100, Gehrke/8-9.
[17] CUB/100, Gehrke/10.
[18] CUB/100, Gehrke/10.

destined to be in service for a 30-year expected asset life, are located outdoors, and this equipment is designed for those conditions.

Q. Would it be practical to store the equipment indoors?

A. No. The company's safe harbor nacelles weigh upwards of 145,000 pounds, and require a 275 ton crane with 100 feet of boom height to lift them onto transport trucks that have 13 axles. Because of the weight of the equipment itself, and the space and height required to load the equipment onto trucks that require a significant amount of space to maneuver, it is impractical to store the equipment indoors.

Q. Are the company's safe harbor equipment purchases covered by any warranties or service agreements?

A. Yes. The equipment manufacturers, General Electric and Vestas, have provided warranties for the equipment; the company also has service agreements with these entities.

Q. Does outside storage or delayed installation of the safe harbor equipment impact the equipment warranty or reduce General Electric's or Vestas' obligations with respect to attaining contractual availability guarantees?

A. No. The equipment warranty covers a two-year period following *installation* of the turbines, and whether the equipment was in storage prior to installation for an extended time does not impact the warranty. Further, there are no allowances under the company's service agreements with General Electric or Vestas for the safe harbor equipment to perform any differently than would be expected from equipment that was stored indoors prior to installation.

Q. Are there maintenance requirements for the safe harbor equipment while it is in storage?

A. Yes. The equipment manufacturers have technical specifications for maintenance of idle equipment that must be performed while it is in storage to ensure the equipment will perform satisfactorily when installed.

Q. Is the company's safe harbor equipment being maintained consistent with these technical specifications and requirements?

A. Yes. The company has contracted for this equipment to be maintained consistent with the applicable manufacturer specifications prior to installation, and inspections and maintenance are performed consistent with these requirements.

Q. Do you understand what "burden of proof" CUB believes the company must meet with respect to the safe harbor equipment?

A. No. CUB does not articulate what standard they believes the company must meet in order to justify full recovery of the company's expenditures related to the safe harbor equipment, nor does CUB point out how the company's storage of the equipment deviates from standard industry or prudent utility practice.[19] Absent clarification from CUB the company in unable to further respond to these arguments.

Q. Does this conclude your reply testimony?

A. Yes.

[19] CUB/100, Gehrke/10.

Docket No. UE 352
Exhibit PAC/800
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Rick T. Link

May 2019

REPLY TESTIMONY OF RICK T. LINK

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Q. Are you the same Rick T. Link who previously provided testimony in this case on behalf of PacifiCorp d/b/a Pacific Power?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. I respond to the opening testimonies of Public Utility Commission of Oregon Staff (Staff) witness Steve Storm, Oregon Citizens' Utility Board (CUB) witness William Gehrke, and Alliance of Western Energy Consumers (AWEC) witness Bradley Mullins. The parties do not challenge the prudence of PacifiCorp's decision to repower its wind fleet, nor the implementation of repowering in the nine wind facilities in this filing. Each party, however, proposes disallowances or conditions on cost recovery. The economics of wind repowering are compelling for customers, who have already benefitted from significant, repowering-related cost reductions in the 2019 Transition Adjustment Mechanism (TAM). Full recovery of repowering costs is essential to a reasonable result, and imposing conditions on that recovery is unwarranted.

Q. Please summarize your reply testimony.

A. PacifiCorp's extensive economic analysis demonstrates substantial net benefits from repowering its wind resources. Since the 2017 Integrated Resource Plan (IRP), and consistent with direction from the Public Utility Commission of Oregon (Commission), PacifiCorp has updated its economic analysis three times for new cost, performance, load, price and policy inputs. The IRP analysis and all subsequent updates consistently show that customers will be better off with repowering. No party to this case has contested PacifiCorp's economic analysis, challenged the results, or provided alternative analysis.

The central economic analysis that informed PacifiCorp's decision to repower its wind facilities is the modeling PacifiCorp prepared in February 2018 to account for tax reform, among other changes. This analysis demonstrates:

- Under the medium price-policy case, net customer benefits for the total repowering project range from $180 million to $204 million, analyzed over the 20-year IRP planning period.[1]

- Net customer benefits for the total repowering project increase to $273 million when analyzed over a 30-year period, accounting for a substantial increase in incremental energy beyond 2036.

- Accounting for just the nine wind facilities included in the 2019 RAC, estimated net benefits range from $138 million to $155 million under the medium price-policy case, analyzed over a 20-year period.

- The value of the Production Tax Credits (PTC) is $24 per megawatt-hour (MWh), or $1.2 billion in PTC benefits for the entire project, and $957 million for the nine wind facilities in this case.

The August 2018 update to this analysis verifies that the benefits of repowering have remained constant since February and, in most cases, have improved. Over a 20-year period, the August 2018 update shows increased net benefits for all facilities under the medium price-policy scenario, with all facilities now showing a net benefit. This includes the Leaning Juniper facility, where updated cost-and-performance information significantly improve the economics of repowering this facility.

In all cases, the estimated net benefits reflect PacifiCorp's continued recovery of the undepreciated wind equipment replaced by the repowering project, and

[1] All dollar amounts are stated on a total company basis, unless otherwise noted.

continued recovery of a return on this equipment at PacifiCorp's authorized rate of return. This simply assumes that the substantial benefits of repowering are matched in rates with the full costs necessary to produce these benefits.

The Commission's order acknowledging PacifiCorp's 2017 IRP, Order No. 18-138, does not support the Staff or intervenor adjustments. In the order, the Commission qualified its acknowledgement of PacifiCorp's Energy Vision 2020 projects by reserving the right to impose conditions ensuring that the benefits are not less than IRP projections. The Commission issued this order when the projects were still early in development and, with respect to wind repowering, the impact of federal income tax changes were unknown.

Sixteen months later, the company is well into implementing repowering and it has mitigated and managed the project development risks. Because the parties do not challenge prudence and the undisputed economic analysis shows significant net benefits from repowering, the facts and conditions of the 2017 IRP acknowledgement are not at issue here. Importantly, the Commission made clear that it was not setting rates or pre-judging ratemaking issues in the IRP order.

Finally, while Staff argues that there is no near-term system resource need for repowering, this is not the correct lens through which to evaluate the prudence of repowering, which is more appropriately reviewed as a utility asset management decision. Under that framework, the proper question is whether repowering existing wind facilities constitutes an economically beneficial use of the underlying plant. PacifiCorp's economic analysis shows that the answer is unequivocally yes. In any event, modeling conducted for the 2017 IRP establishes a near-term resource need, and repowering forms part of the least-cost, least-risk portfolio of resources that meet this established need.

II. ECONOMIC ANALYSIS DEMONSTRATES NET BENEFITS

Q. Has any party to this case disputed the validity or results of PacifiCorp's extensive economic analysis of wind repowering, or presented alternative analysis?

A. No.

Q. Can you briefly summarize how PacifiCorp's economic analysis evolved during and after the pendency of the 2017 IRP?

A. Yes. PacifiCorp analyzed wind repowering in the development of its 2017 IRP. This analysis supported including repowering in the preferred portfolio. Since the 2017 IRP was filed in April 2017, PacifiCorp has updated its economic analysis three times for new cost, performance, load, price and policy inputs.

First, in July 2017, PacifiCorp filed new economic modeling for its Energy Vision 2020 projects, including repowering, with updates to assumptions, inputs, and methodology. PacifiCorp developed this economic analysis to support a series of concurrent pre-approval filings made with the Wyoming Public Service Commission, the Utah Public Service Commission, and the Idaho Public Utilities Commission. The company filed this analysis in the Oregon 2017 IRP docket so that all parties would have access to the same information in the ongoing review of the 2017 IRP.

Second, in February 2018, PacifiCorp updated its economic modeling to account for changes in the federal tax rate for corporations and to update cost-and-performance information. This February 2018 analysis supplanted the previous analysis entirely, which predated tax code reforms. The 2017 IRP Update, filed with the Commission on May 1, 2018, reflects this February 2018 analysis.

Third, in August 2018, PacifiCorp conducted a limited update to determine how more recent changes in modeling assumptions affect facility-by-facility results relative to those included in the February 2018 analysis. This targeted reassessment indicated projected net customer benefits remain similar to those calculated previously and confirmed the repowering project is prudent.

Q. What is the primary economic analysis PacifiCorp relies on to support wind repowering in this case?

A. The February 2018 modeling is the central economic analysis PacifiCorp relied upon in deciding to repower its wind fleet. This analysis represents the most recent full-fledged analysis of wind repowering, using nine different price-policy scenarios, a facility-by-facility review, and taking into account numerous sensitivities. To verify the sustained and, in most cases, improving economics of repowering, PacifiCorp also relied on the August 2018 analysis.

Q. Please summarize the repowering benefits established in the February 2018 economic analysis.

A. The February 2018 analysis demonstrates that under the medium price-policy case, net benefits for the total repowering project range from \$180 million to \$204 million, when analyzed over the 20-year IRP planning period.[2] When analyzing over a

[2] PAC/300, Link/35 (displaying total project estimated benefits in Table 6, using medium natural-gas and medium CO_2 price-policy assumptions). This range demonstrates that the estimated benefits are consistently positive and substantial using different modeling methodologies. *See id.* at 10-11 (explaining differences among the SO model and PaR).

30-year period to take the full life of the repowering project into account, including a substantial increase in incremental energy beyond 2036, the medium price-policy case shows $273 million in net benefits for the total project.[3]

A reasonable estimate of the benefits of the nine facilities included in this case using the 20-year analysis ranges from $138 million to $155 million.[4]

The February 2018 analysis also indicates that the value of PTCs is $24/MWh, with a sum total of $1.2 billion in net PTC benefits for the entire project. This translates into $957 million in PTC benefits for the nine facilities included in this filing.

Q. As discussed by PacifiCorp witness Ms. Etta P. Lockey, parties have challenged recovery of a return on the undepreciated equipment replaced by repowering.[5] Are the estimated benefits for customers net of a return of and return on the replaced equipment?

A. Yes. All of PacifiCorp's economic modeling assumes that the company continues to recover the return of and return on the equipment replaced by repowering. This produces a balanced outcome in which customers receive significant benefits, net of these and other costs, while PacifiCorp is made whole for its innovative and prudent investment in wind repowering.

[3] PAC/300, Link/39 (displaying total project estimated benefits in Table 7, using the change in annual nominal revenue requirement through 2050).
[4] *See id.* at 30 (displaying project-by-project estimated benefits in Table 2, using medium natural-gas and medium CO_2 price-policy assumptions, and analyzing over a 20-year period).
[5] *See* PAC/600, Lockey/8-12.

III. IRP ACKNOWLEDGMENT

Q. Did the Commission acknowledge repowering in the 2017 IRP?

A. Yes, at the Special Public Meeting on December 11, 2017, the Commission acknowledged the 2017 IRP, including the action items related to PacifiCorp's Energy Vision 2020 projects (which includes repowering along with new wind and transmission), with conditions.[6] In particular, the Commission directed PacifiCorp to update its analysis supporting wind repowering as part of the 2017 IRP Update.[7] The Commission also clarified that risk of proceeding with these Energy Vision 2020 projects remains with PacifiCorp unless and until the Commission completes a prudence review and authorizes recovery. In so doing, the Commission noted that it could "hold PacifiCorp to the cost and benefit projections in its analysis[]" as a potential means of mitigating customer risk exposure.[8]

Q. Please provide some context for the Commission's order.

A. Because of the critical timelines associated with qualification for PTCs, the company pursued IRP acknowledgment and pre-approvals of the Energy Vision 2020 projects concurrently with the development of these projects. The uncertainty around some key project inputs led to concerns about potential project risk. While most of these concerns focused on the new wind and transmission projects, with respect to wind repowering, the federal income tax law changes passed in December 2017 raised questions about the economics of the project.

[6] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan*, Docket No. LC 67, Order No. 18-138, at 1, 12 (Apr. 27, 2018) ("Order No. 18-138").
[7] *Id.* at 8.
[8] *Id*.

Q. Did PacifiCorp update its economic analysis of wind repowering to take into account federal income tax changes, consistent with the Commission's direction in the 2017 IRP acknowledgment order?

A. Yes. As noted above, PacifiCorp developed its February 2018 analysis and included it in the 2017 IRP Update. This analysis confirmed that wind repowering continues to provide significant net benefits to customers after accounting for changes in the federal income tax law.

Q. In the 16 months that have passed since IRP acknowledgement, has the company managed and mitigated other project risks raised in the IRP process, such as the risk of construction cost overruns or delays?

A. Yes. PacifiCorp witness Mr. Timothy J. Hemstreet testifies that repowering of the wind facilities in this case is on schedule and on budget.[9]

Q. Does PacifiCorp's robust economic analysis also address concerns about project risk?

A. Yes. As described in my opening testimony, PacifiCorp's analysis accounts for a significant range of risks by reviewing nine different price and policy scenarios, measured over a 20-year and 30-year time frame. PacifiCorp reviewed the economics of repowering on a total-project and facility-by-facility basis and tested the results with several different sensitivities. In virtually every case, wind repowering shows substantial net benefits to customers, demonstrating the risk-resilient nature of the wind repowering project.

[9] PAC/700, Hemstreet/1.

Q. In its testimony, Staff focuses on the results of the July 2017 analysis and a PacifiCorp presentation to the Commission in September 2017, not the February 2018 analysis. Why does Staff take this approach?

A. While it is not entirely clear, it appears that Staff views the 2017 IRP order as setting a floor on repowering benefits based on the then most current analysis—which it claims is the July 2017 analysis and the September 2017 presentation.

Q. Is this approach correct?

A. No. Prudence reviews are based on the most recent information the company has at the time it makes a decision to move forward with a project, not on historical, outdated analysis. In this case, the February 2018 analysis, as validated by the August 2018 analysis, was the analysis that the company relied upon for its decision to repower its wind facilities.

Q. Does the IRP order create a floor on repowering benefits for ratemaking purposes as both Staff and CUB[10] allege?

A. No. In the acknowledgment order, the Commission simply noted that it retains the right to impose conditions on recovery if appropriate.[11] As the Commission explained elsewhere in the Order:

> Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. The question of whether a specific investment made by a utility in its planning process *was prudent* will be fairly examined in the subsequent rate proceeding. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our subsequent examination of whether the utility's resource investment *is prudent* and should be recovered from customers.[12]

[10] CUB/100, Gehrke/5.
[11] Order No. 18-138 at 8.
[12] *Id.* at 3 (emphasis added).

In other words, when the prudence of a utility action is challenged, the Commission's acknowledgement decision and any conditions imposed during the resource planning process is one factor used to inform the prudence review. Here, however, no party even challenges the prudence of wind repowering, given the substantial value proposition for customers. Therefore, the Commission's conditions on acknowledgement in docket LC 67 do not dictate ratemaking treatment, and Staff's and CUB's efforts to convert the acknowledgement order into a ratemaking order are improper.

Q. In its testimony, Staff includes two slides from the September 14, 2017 presentation.[13] Were these slides based on the first update to the IRP analysis filed in July 2017?

A. Yes.

Q. Staff describes the content of these slides in its testimony. Do you agree with Staff's summary?

A. Not entirely. Staff claims that Figure 3 on slide four shows that, on an annual revenue requirement basis, repowering does not show a net cost for any year prior to 2029.[14] The updated analysis in July 2017 includes a more granular depiction of annual revenue requirement impacts in Figure 3.2.[15] This shows small increases in revenue requirement in certain years until 2021 when repowering is fully implemented.

[13] Staff/100, Storm/30-36.
[14] Staff/100, Storm/32.
[15] PacifiCorp's 2017 Integrated Resource Plan, Energy Vision 2020 Update at 19 (July 28, 2017).

Q. Why is this distinction important?

A. Staff appears to be relying on Figure 3 on slide four to support the argument that PacifiCorp's economic analysis in July and September of 2017 showed no net revenue requirement costs from repowering before 2029, so PacifiCorp must now demonstrate that the benefits in the TAM are greater than the costs in the RAC.[16] This argument is incorrect for a number of reasons. First, as explained above, the 2017 IRP acknowledgment order did not impose a floor on wind repowering benefits. Second, it is inappropriate to look to the July 2017 analysis in determining the prudence of wind repowering, because it was superseded by the company's February 2018 economic analysis. Third, as just noted, the July 2017 analysis does not show that there are no net costs in post-wind repowering revenue requirement until 2029. Fourth, PacifiCorp's revenue requirement economic analysis does not forecast the rate impacts of wind repowering because it does not consider base rates. Instead, the analysis simply reviews the revenue requirement differential with and without wind repowering. While the revenue requirement analysis provides an indication of how wind repowering will impact rates all else equal, it does not forecast specific rate changes relative to current base rates.

[16] Staff/100, Storm/62-63 (noting that the company's proposed RAC revenue requirement produces a rate increase of approximately $5 million in 2019, which when compared with the $7.7 million in benefits in the TAM "adequately validates the general result depicted in Figure 3 for calendar 2019; i.e. that wind repowering benefits exceed costs.") As explained in Ms. Lockey's reply testimony, in the final TAM update, the repowering benefits are approximately $4.5 million PAC/600, Lockey/5.

IV. REPOWERING AND SYSTEM NEED

Q. Staff asserts "that PacifiCorp is making these wind repowering investments at this time due to the [net customer] benefits . . . , including the availability of the PTC[.]"[17] What point is Staff making in this statement?

A. It is my understanding that Staff is reiterating a position it took on the issue of system need during the 2017 IRP proceeding, a position that was fully litigated without resolution. Specifically, Staff appears to be asserting that PacifiCorp does not have a "near-term and clearly identified capacity or RPS compliance need" for repowering and therefore that the Commission should take extraordinary steps in this proceeding to mitigate customer risk.[18] CUB takes a similar position in its testimony to justify imposition of a floor on PTC benefits.[19]

Q. Is Staff's and CUB's focus on system need appropriate in the context of reviewing the prudence of the wind repowering project?

A. No. Repowering involves upgrading and optimizing an existing resource to reduce customer costs, so system resource need is not a requisite finding to approve cost recovery of the wind repowering project. Staff's and CUB's argument that PacifiCorp should not repower its existing wind facilities in the absence of a system resource need is effectively an argument that the company should not optimize its system resources in real time to minimize costs simply because the activity is not required to serve customers.

[17] Staff/100, Storm/19.
[18] *Id.* at 19-20, 56-59.
[19] CUB/100, Gehrke/5.

Q. Did CUB file comments in the 2017 IRP contesting the applicability of the "need" standard to wind repowering for the reasons just stated?

A. Yes. In its comments on Staff's Public Meeting Memorandum in docket LC 67, CUB observed that "repowering of existing wind facilities" is more properly evaluated as a form of utility asset management:

> Utilities are generally expected to manage their rate[]-based assets in the best interest of customers. This means utilities take opportunities for off-system sales when the revenue can be used to offset rates. The Energy Imbalance Market is a form of asset management, where the utility adds remote dispatch functionality to a plant. This added functionality allows the plant to participate in the EIM and therefore generate revenue to offset costs. Repowering plants is not new. Utilities have repowered hydro plants to increase production. PGE upgraded two low pressure turbines at Boardman in 2000 by installing new rotors to increase efficiency. *In such a case, the question of need rests with the original investment in the plant. Once that investment is made and is found to be prudent, repowering can be viewed through the lens of whether it is an economically beneficial use of the underlying plant.*[20]

Q. Do you agree with Staff's and CUB's implication that there is no near-term system resource need for wind repowering?

A. No. In developing the load-and-resource-balance for the 2017 IRP, PacifiCorp incorporated a 13 percent target planning reserve margin to calculate its total projected resource obligations over the planning period. PacifiCorp's existing, committed resources were insufficient to meet these obligations, even in the near term.[21] By definition, therefore, the company faced a near-term resource need.

The IRP evaluated a wide range of resources that could help meet this need, such as gas-fired resources, uncommitted front office transactions, and renewable

[20] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan*, Docket No. LC 67, Oregon Citizens' Utility Board's Comments on Staff's Recommendations, at 9-10 (Oct. 30, 2017) (emphasis added; paragraph structure altered).
[21] *See* 2017 IRP p.17 (even with both repowering and front office transactions incorporated into the preferred portfolio, projecting an energy shortfall during on-peak hours in the summer of 2022).

resources, including the wind repowering project. All of these resources competed on an equal basis, and none of the model runs that include repowering achieved a planning reserve margin above 13 percent. The preferred portfolio resulting from this analysis included the wind repowering project. This means that repowering is part of the optimal (least-cost, least-risk) mix of resources for fulfilling a resource need in the IRP.

Q. Staff implies that in docket LC 67, the Commission found there was no system need for the wind repowering project.[22] Do you agree with this characterization of the Commission's 2017 IRP order?

A. No. In docket LC 67, the issue presented to the Commission was whether there was a system need for the collective set of Energy Vision 2020 projects, which includes new wind and transmission projects in addition to the wind repowering project. In that proceeding, the need discussion was primarily focused on new wind projects, not repowering. In any event, in Order No. 18-138, the Commission did not find there was no need for the Energy Vision 2020 projects, let alone no need for the wind repowering project specifically. In fact, the Commission left the issue of need explicitly unresolved.[23]

[22] Staff/100, Storm/19 ("As the wind repowering projects are motivated by potential economic benefits to customers and not by meeting some near-term and clearly identified capacity or RPS compliance need, the Commission included language that makes clear that it will appropriately mitigate risks to customers regarding a number of uncertainties associated with the wind repowering projects.").
[23] Order No. 18-138 at 9 ("[W]e do not definitively resolve questions surrounding need[.]"); *id.* at 11 (adding conditions to PacifiCorp's 2017 IRP Action Plan to help address various questions in future IRPs regarding front office transactions, including "whether displacing FOTs could constitute a resource need").

V. DECISION TO REPOWER LEANING JUNIPER

Q. Staff notes that Leaning Juniper "appears to be more marginal" than most of the other wind facilities in the wind repowering project.[24] Why did PacifiCorp include Leaning Juniper in the project?

A. As explained in my opening testimony, after completing the February 2018 economic analysis, PacifiCorp evaluated alternative equipment suppliers.[25] This resulted in changed cost-and-performance assumptions for Leaning Juniper, namely, a reduction in the capital cost to repower Leaning Juniper and an increase in expected annual energy output from this facility.[26]

The updated modeling in August 2018 reflected these changes and yielded improved projections for repowering Leaning Juniper. Specifically, under the most conservative price-policy assumption of low natural gas prices and low CO_2 prices, the results in the February 2018 analysis projected that Leaning Juniper could range from \$3-\$6 million in customer costs; the updated analysis in August 2018 projected \$4-\$5 million in customer benefits from repowering this facility.[27]

Q. Does this conclude your reply testimony?

A. Yes.

[24] Staff/100, Storm/46.
[25] PAC/300, Link/47.
[26] *Id.* at 47, 50.
[27] *Id.* at 50 (Table 12).

Docket No. UE 352
Exhibit PAC/900
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Steven R. McDougal

May 2019

REPLY TESTIMONY OF STEVEN R. MCDOUGAL

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ATTACHED EXHIBITS

Q. Are you the same Steven R. McDougal who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My reply testimony responds to ratemaking issues and proposed revenue requirement calculations raised in the opening testimonies of Public Utility Commission of Oregon (Commission) staff (Staff) witness Steve Storm, Alliance of Western Energy Consumers (AWEC) witness Bradley G. Mullins, and Oregon Citizens' Utility Board (CUB) witness William Gehrke.[1]

Q. Please summarize your testimony.

A. Staff, AWEC and CUB each propose adjustments to reduce PacifiCorp's cost recovery for the undepreciated investment in the equipment replaced by the wind repowering project. There is no regulatory or policy justification for these adjustments, as discussed in the reply testimony of PacifiCorp witness Ms. Etta Lockey.[2] My testimony explains Staff's and AWEC's differing approaches for implementing such an adjustment and illustrates fundamental problems inherent in each approach.

I demonstrate the reasonableness of PacifiCorp's proposal to leave base rates unchanged and thereby allow continued cost recovery of the replaced equipment at

[1] CUB has not proposed a specific approach for its proposed adjustment removing the return on the replaced equipment, nor quantified its adjustment. Therefore, I do not provide specific testimony in reply to CUB. Because CUB's adjustment is similar to Staff's and AWEC's, however, my testimony supporting the company's approach to cost recovery for the replaced wind equipment is generally applicable in reply to CUB's testimony.
[2] PAC/600, Lockey/1-2, 4-12.

PacifiCorp's authorized rate of return. I highlight that PacifiCorp's revenue requirement increase in the Renewable Adjustment Clause (RAC) is limited to the incremental costs of wind repowering, which is consistent with the defined scope of the RAC and its interim nature.

I explain why other revenue requirement adjustments proposed by Staff related to net salvage accruals and capital additions are unwarranted from a ratemaking perspective. Finally, I rebut AWEC's proposal to update to a single rate change on December 1, 2019 in this case and show that, contrary to Oregon law, this proposal would not permit PacifiCorp to recover its full costs associated with the wind repowering project.

II. RESPONSE TO STAFF'S REVENUE REQUIREMENT RECOMMENDATIONS

Q. What is Staff's primary revenue requirement recommendation?

A. Staff recommends that the Commission disallow the return on equity in the wind equipment replaced by the wind repowering project.[3] Staff's adjustment reduces PacifiCorp's proposed October 1, 2019 and December 1, 2019 RAC revenue requirement by $5.4 million and $8.1 million, respectively.[4] Together, this adjustment reduces PacifiCorp's RAC from $32.2 million to $18.7 million.

Q. How does PacifiCorp respond to this recommendation?

A. As stated in the reply testimony of company witness Ms. Etta P. Lockey, the continued return of and return on the replaced equipment is an integral component of

[3] Staff/100, Storm/5, 66-67, 76.
[4] Staff/100, Storm/72.

wind repowering.[5] Staff agrees that wind repowering is a prudent investment and contests neither the reasonableness of the costs nor the company's evidence that wind repowering provides net benefits to customers.[6] For these reasons, the Commission should allow PacifiCorp to recover the full costs of the replaced equipment at its allowed rate of return.

Q. Staff contends that, even though this is a RAC proceeding, it is "unfair" not to consider costs currently in base rates.[7] Please respond.

A. PacifiCorp agrees that, in calculating the RAC revenue requirement, it is reasonable to consider costs currently in base rates to ensure that customers are not being charged twice for the same costs. Here, PacifiCorp accounted for costs in base rates by reflecting only the incremental costs of wind repowering in the RAC, because the return of and return on the replaced wind equipment is already reflected in base rates.

Q. Does Staff accept PacifiCorp's approach for the return of (as opposed to the return on) PacifiCorp's replaced wind equipment?

A. Yes. Staff states that the RAC is "not intended to true-up PacifiCorp's rate base[.]"[8] Therefore, Staff leaves the replaced equipment in rates so that PacifiCorp may recover a return of its investment, but Staff calculates a downward adjustment in the RAC to effectively back-out the return on equity of the replaced wind equipment.[9]

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[5] *See* PAC/600, Lockey/7-8.
[6] Staff/100, Storm/56.
[7] Staff/100, Storm/66-67, 76.
[8] Staff/100, Storm/66, 76.
[9] *See* Staff/100, Storm/67, 72.

Q. You testify that it is unreasonable to remove the return on the replaced equipment given the benefits to customers from the wind repowering project. Does Staff also overstate the cost offset in the RAC for the return on the replaced equipment?

A. Yes. To calculate its adjustment, Staff first attempts to determine the amount currently in rates for the replaced wind equipment.[10] While PacifiCorp has identified the undepreciated net book value of the plant amount for the replaced equipment at $587 million (or $157 million on an Oregon-allocated basis), Staff proposes instead to determine the amount reflected in rates at the time of PacifiCorp's last rate case, docket UE 263, in 2013.

Wind plant-specific revenue requirement information is not available from PacifiCorp's filing in docket UE 263 because, under Federal Energy Regulatory Commission (FERC) accounting, wind plant is combined with other categories of plant, so PacifiCorp did not separately break out values for plant in service, accumulated deferred income taxes, and associated costs such as depreciation expense. In addition, since docket UE 263 was resolved by a settlement stipulation, there are no specific dollar amounts for the repowered wind facilities reflected in the final order in that case.[11]

Staff therefore approximates the amount in rates for the replaced equipment by taking the 2017 replaced equipment balance of $642 million and increasing it to $740 million.[12] Staff's calculation is simplistic and appears to overstate 2013 plant

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[10] Staff/100, Storm/65-66.
[11] *See In the Matter of PacifiCorp, dba Pacific Power, Request for a Gen. Rate Revision*, Docket No. UE 263, Order No. 13-474 (Dec. 18, 2013).
[12] Staff/100, Storm/65-66.

balances by leaving out various inputs, such as accumulated deferred income tax, the impacts of the tax reform act, and capital additions. By increasing the plant balances to inflated 2013 levels for the removed equipment, Staff unfairly increases its adjustment for removing the equity return on this equipment.

Q. Staff recommends that the RAC be reduced to offset the ongoing net salvage accrual in current rates for the equipment removed as a result of the wind repowering project.[13] Do you agree that an adjustment should be made to the RAC revenue requirement?

A. No. Staff points to the fact that the company has assumed no salvage value for the removed equipment.[14] To be clear, Staff is referring to the conservative assumption PacifiCorp made for purposes of its wind repowering economic analysis. As PacifiCorp witness Mr. Timothy J. Hemstreet states in his opening testimony, the company intends to maximize the salvage value of the replaced equipment and pass these benefits on to customers.[15] From an accounting perspective, this will be accomplished by crediting the accumulated depreciation reserve and reducing the net plant balance.

Q. Will PacifiCorp address net salvage value and accruals for the replaced wind equipment in its current depreciation filing, docket UM 1968?

A. Yes. There is no need to address this issue here because salvage values and accruals will be reviewed and reset in docket UM 1968 as necessary to address the replaced wind equipment. There is no risk that PacifiCorp will over accrue net salvage in the

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[13] Staff/100, Storm/70-71, 76.
[14] Staff/100, Storm/21-22, 70.
[15] PAC/200, Hemstreet/26-27.

replaced wind equipment because all amounts accrued in rates will be credited to the customers in resetting depreciation rates in docket UM 1968.

Q. Staff objects to PacifiCorp including small, on-going capital additions in calculating average rate base because they are added after the proposed effective date of the RAC.[16] Is Staff's adjustment appropriate?

A. No, and it is inconsistent with Staff's position in the 2019 Transition Adjustment Mechanism (TAM) that rates effective January 1, 2019 should reflect wind repowering benefits.[17] Projected capital additions should be included during the period over which the average rate base is calculated. To apply Staff's approach, PacifiCorp would need to use a beginning rate base methodology, which would eliminate both capital additions and accumulated depreciation. This approach would result in a higher net rate base and a higher revenue requirement.

Q. Do you concur with Staff's adjustment to include the PUC fee, adding $42,000 to the October 1, 2019 RAC increase and $55,000 to the December 1, 2019 RAC increase?[18]

A. Yes.

[16] Staff/100, Storm/63-65.
[17] *In the Matter of PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Staff's Opening Testimony, Staff/100, Gibbens/10-11 (June 11, 2018).
[18] Staff/100, Storm/72.

III. RESPONSE TO AWEC'S REVENUE REQUIREMENT RECOMMENDATIONS

Q. Like Staff, does AWEC also object to PacifiCorp continuing to recover the costs of the equipment replaced by the wind repowering project by leaving current amounts in base rates?

A. Yes.[19] PacifiCorp's fundamental response to AWEC's adjustment is therefore the same—because the wind repowering project is prudent and provides net benefits to customers, the Commission should allow continued recovery of the costs of the replaced equipment now in base rates.

Q. How is AWEC's adjustment different than Staff's adjustment?

A. As discussed above, Staff does not adjust the return of the replaced wind equipment or the return on the non-equity components of the investment in the replaced wind equipment. AWEC's approach is broader and more complicated in many respects. First, AWEC significantly decreases the amount of the recoverable investment in the original wind equipment by offsetting past accumulated depreciation. Second, AWEC offsets past accumulated depreciation for all original wind equipment, whether it was replaced or not. Third, AWEC removes *all* components of the return on investment, not just the equity return. Fourth, AWEC transfers these costs from base rates to a regulatory account with alternative carrying charges and amortization periods, utilizing a sinking fund approach.[20] On AWEC's Table 1, AWEC's total adjustment nets to approximately $7.2 million.[21] As discussed below, however,

[19] AWEC/100, Mullins/17-21.
[20] *See* AWEC/100, Mullins/17-21; AWEC/104, Mullins/1; AWEC/105, Mullins/1.
[21] AWEC/100, Mullins/7.

AWEC does not clearly quantify the impact to PacifiCorp of AWEC's regulatory asset recommendations. For example, AWEC's proposal to apply a reduced carrying charge to the regulatory asset would result in an additional disallowance of $18 million.

Q. Why is AWEC's proposal to selectively reset the accumulated depreciation of the replaced wind equipment unreasonable?

A. The RAC is an automatic adjustment mechanism to capture the incremental costs of renewable energy investments in rates on an interim basis until the next general rate case. Reopening base rates to true up past costs or benefits unrelated to the wind repowering project appears to violate the rule against retroactive ratemaking. It is also beyond the scope of the RAC and raises issues that belong in a general rate case proceeding. AWEC's proposal effectively penalizes the company for pursuing wind repowering by imposing an improper true-up for past accumulated depreciation, an adjustment which AWEC would not have proposed absent wind repowering.

Q. Why do you refer to AWEC's proposal as a selective update?

A. AWEC proposes to reduce the costs of the replaced equipment for past accumulated depreciation,[22] while ignoring updates that go the other way, such as past capital additions that have increased rate base. Additionally, the Tax Reform Act enacted in 2017 lowered PacifiCorp's combined federal and state tax rate and changed the accumulated deferred income taxes on existing wind facilities.

[22] AWEC/100, Mullins/12.

Q. Why is it reasonable for PacifiCorp to simply rely on costs currently embedded in rates for the return of and return on the replaced equipment?

A. The Commission approved these costs in PacifiCorp's last rate case, docket UE 263.[23] There is no justification for the selective, retroactive true-up of these costs in the RAC, especially because PacifiCorp already has filed to update its depreciation rates for wind repowering (including the replaced equipment) in docket UM 1968, and PacifiCorp intends to file a general rate case in 2020 to implement these depreciation rates.

Q. AWEC claims that the Joint Testimony supporting the stipulation in docket UM 1330 supports its adjustment because it provides that "'customers' rates will reflect both the reduction in rate base due to depreciation and the current forecast of all costs within the upcoming calendar year.'"[24] Do you agree with this interpretation?

A. No. This statement is referring to how resource costs are handled after they are approved for recovery in the RAC if those costs are not promptly incorporated in base rates. It has nothing to do with the issue here, which is whether cost elements in base rates should be trued-up against actual costs when considering whether to include a resource in the RAC in the first place.

Q. Is AWEC's calculation of its accumulated depreciation true-up overstated?

A. Yes. AWEC's adjustment as calculated in Exhibit AWEC/103 is significantly

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[23] *In the Matter of PacifiCorp, dba Pacific Power, Request for a Gen. Rate Revision*, Docket No. UE 263, Order No. 13-474 (Dec. 18, 2013).

[24] AWEC/100, Mullins/10 (quoting *In the Matter of Public Utility Commission of Oregon, Investigation of Automatic Adjustment Clause pursuant to SB 838*, Docket No. UM 1330, Joint Parties/100, Dahlgren, et al./6 (Nov. 29, 2007)).

overstated. The $7.7 million adjustment in Exhibit AWEC/103 is derived by calculating the decrease in the annual pretax rate of return due to the additional depreciation expense accumulated since docket UE 263 using a gross plant base of $1,626 million, which is the investment of both replaced equipment and non-replaced equipment. The non-replaced wind equipment is not impacted by wind repowering and there is no principled basis for including it in AWEC's adjustment. The gross plant of the replaced equipment is $955 million. Accordingly, at most, AWEC's adjustment should be limited to $4.5 million, derived from this calculation: [($955 million/$1,626 million) x $7.7 million].

Q. AWEC proposes to establish a regulatory asset under ORS 757.140(2)(b) for recovery of the undepreciated net book value of the replaced wind equipment using a sinking fund method for amortization.[25] Please explain how PacifiCorp accounted for the replaced equipment and why this accounting method makes sense.

A. PacifiCorp has followed the same FERC accounting approach here as it would apply in any other plant upgrade, which is to remove the gross book value of the removed equipment from both gross plant, by crediting FERC account 101, and accumulated depreciation, by debiting FERC account 108. This results in the same net book value of the removed equipment before and after removal and allows PacifiCorp to earn a return on the net book value until fully depreciated. This also reduces the complexities of identifying and allocating additional rate base items such as accumulated deferred income taxes and possible complications associated with

[25] AWEC/100, Mullins/17-21.

identifying excess deferred income tax balances and issues.

Q. AWEC claims that under PacifiCorp's FERC accounting approach, the company will over recover depreciation expense for its repowered resources pending the reset of depreciation rates in docket UM 1968.[26] Please respond.

A. AWEC is effectively advocating that depreciation rates be reset now for the wind repowering project, an exercise that is outside the scope of the RAC, and disregards the pendency of docket UM 1968, where depreciation rates are scheduled to be reset when that docket resumes this fall.[27]

Q. AWEC recommends that "the Commission allow PacifiCorp to recover 100% of the unrecovered plant balances removed from service" through wind repowering. Do AWEC's proposals in this case implement this recommendation?

A. No. As described above, AWEC improperly and retroactively adjusts the plant balances for accumulated depreciation to reduce PacifiCorp's cost recovery by $7.7 million. AWEC's regulatory asset approach further reduces PacifiCorp's cost recovery for its replaced equipment.[28]

Q. Please explain AWEC's regulatory asset approach using the alternative interest rates and amortization periods AWEC proposes.[29]

A. AWEC is proposing two alternative approaches for its proposed regulatory asset approach in Exhibits AWEC/104 and AWEC/105.[30] In Exhibit AWEC/104, AWEC

[26] *See* AWEC/100, Mullins/13, 17.
[27] *See In the Matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates*, Docket No. UM 1968.
[28] *See* AWEC/104, Mullins/1; AWEC/105, Mullins/1.
[29] AWEC/100, Mullins/19-20.
[30] *See* AWEC/104, Mullins/1; AWEC/105, Mullins/1.

proposes a pre-tax carrying charge of 3.49 percent, which is less than one-half of PacifiCorp's current pre-tax rate of return of 9.24 percent, with an amortization period of seven years. Under this approach, PacifiCorp's cost recovery would be reduced by approximately $18 million on a net present value basis.

Q. Please comment on AWEC's approach in Exhibit AWEC/105.

A. In Exhibit AWEC/105, AWEC proposes a pre-tax carrying charge of 9.24 percent, which aligns with PacifiCorp's pre-tax rate of return, with an amortization period of nine years. In concept, PacifiCorp agrees that this approach could properly compensate PacifiCorp for both the return of and return on the unrecovered investment.[31]

Q. Do you have any concerns about AWEC's approach in Exhibit AWEC/105?

A. Yes. AWEC has incorrectly calculated interest in its amortization schedule, and as a result, the approach in Exhibit AWEC/105 would not provide PacifiCorp full cost recovery. Exhibit PAC/901 uses Exhibit AWEC/105 to demonstrate the problem with AWEC's calculation of average rate base, which AWEC uses to calculate the return or "interest" in its amortization table.

Exhibit PAC/901 shows how AWEC calculated the average rate base compared to what the average rate base would be based on the beginning and ending rate base balances in AWEC's amortization schedule. AWEC's amortization schedule shows the asset, or principal, first-year beginning balance of $152,955,677 and the ending balance of $141,328,485. Based on this, the beginning/ending average

[31] *See* AWEC/100, Mullins/20-21.

balance for the first year is $147,142,081.[32] Yet, AWEC's interest calculation used in its amortization schedule is based on an average balance of $140,641,570.[33] As can be seen, AWEC is calculating the return on an average balance, $140,641,570, that is actually less than the average of the beginning and ending principal balance, $147,142,081.

Just as concerning, AWEC has determined that the first-year average balance, $140,641,570, is actually lower than the first year's ending balance, $141,328,485, as shown in AWEC's amortization schedule. AWEC has understated the interest component in its amortization schedule, which would result in PacifiCorp being under compensated.

Q. Do you have any concerns about the amortization period that AWEC has chosen to use in Exhibit AWEC/105?

A. Yes. AWEC advocates for an amortization period of nine years in Exhibit AWEC/105, which was chosen to "set the regulatory asset recovery to be roughly equal to the current level or rate recovery" in order to "promote rate stability."[34] As I describe above, AWEC's proposal does not provide PacifiCorp with full cost recovery, and an amortization period of nine years will increase rates. In order to eliminate any incremental rate impacts, the amortization period would need to be close to 20 years.

[32] [($152,955,677+$141,328,485)/2].
[33] [($152,955,677 - $24,628,214/2)].
[34] AWEC/100, Mullins/20.

Q. Do you agree with AWEC's rationale for consolidating the revenue requirement of the two annual increases so that a single annual period applies to the December 1, 2019 update in this RAC filing?[35]

A. No. PacifiCorp has requested two rate effective dates to match the recovery of costs with the in-service dates of the repowered projects. This is similar to the 2019 TAM, which used various in-service dates in calculating the net power cost and production tax credit benefits associated with repowering.[36] Each RAC effective date is independent of the other and considers only the costs of the projects associated with that effective date. As stated in my opening testimony, the first rate effective date of October 1, 2019 is for the Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, and Glenrock I facilities.[37] The second rate effective date is for the Goodnoe Hills, High Plains, McFadden Ridge, Marengo I and Marengo II facilities.[38] There is no crossover in the identification of the costs of these facilities. Each set of facilities is separate and has its own revenue requirement and its own rate effective date.

Q. AWEC claims that PacifiCorp has overstated the RAC increase by approximately $141,000 by combining the disparate revenue requirement increases when the increases are not in fact additive.[39] Please respond.

A. AWEC's proposal incorrectly recalculates the October 1, 2019 increase that was calculated using the twelve-month period of October 2019 through September 2020. Since the increase was calculated using that twelve-month period and a 13 month

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[35] AWEC/100, Mullins/21-22.
[36] *See In the Matter of PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421, at 4 n.5 (Oct. 26, 2018); *see also id.* at Appendix A, p.5.
[37] PAC/400, McDougal/3.
[38] PAC/400, McDougal/3.
[39] AWEC/100, Mullins/22.

average rate base, resetting rates before the end of the 12 months would eliminate PacifiCorp's opportunity for full cost recovery. By resetting on December 1, the company will under-recover its revenue requirement for October and November 2019. AWEC's proposal would provide full cost recovery only if the revenue requirement were calculated on a monthly basis, or if beginning rate base were used.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 352
Exhibit PAC/901
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Steven R. McDougal

PacifiCorp Summary of AWEC's Average Rate Base Calculation

May 2019

PacifiCorp Summary of AWEC's Average Rate Base Calculation

Year 1 Average Investment Calculation Comparison for AWEC 105			
	AWEC		
Beginning Balance		152,955,677	From AWEC 105
Year 1 amortization	(24,628,214)		From AWEC 105
Divided by 2	2		From AWEC 105
One-half of amortization		(12,314,107)	From AWEC 105
Average Balance used by AWEC		140,641,570	
	Corrected		
Beginning Balance	152,955,677		From AWEC 105
Ending Balance	141,328,485		From AWEC 105
Sum of Beg. and End. Balance		294,284,162	
Divided by 2		2	
Average Balance based on AWEC's Amortization Table		147,142,081	

Docket No. UE 352
Exhibit PAC/1000
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Judith M. Ridenour

May 2019

REPLY TESTIMONY OF JUDITH M. RIDENOUR

TABLE OF CONTENTS

ATTACHED EXHIBITS

Q. Are you the same Judith M. Ridenour who provided direct testimony in this docket?

A. Yes.

PURPOSE OF REPLY TESTIMONY

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

A. I present a revised rate spread, rate calculation and tariff reflecting changes made in response to the recommendations presented by Calpine Solutions (Calpine) in its opening testimony.

SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. I show that removing five-year opt-out direct access customers who began service under that program prior to 2019 from the proposed renewable adjustment clause (RAC) results in no change to the overall rate increase of $14.0 million or 1.1 percent on October 1, 2019, followed by an incremental increase of $18.2 million or 1.4 percent on December 1, 2019. I explain why it is necessary to adjust the rate spread and rate calculations to remove the load for these five-year opt-out customers and the minor effect on the proposed rates.

REVISED RATE SPREAD AND RATE CALCULATION

Q. Please describe the changes made to rate spread and rates in response to the recommendations of Calpine.

A. As described in the reply testimony of company witness Ms. Etta Lockey,[1] the company has agreed that the RAC adjustment will not apply to five-year opt-out

[1] *See* PAC/600, Lockey/25-27.

direct access customers who began taking service under the company's five-year opt-out program prior to January 1, 2019. To account for this, the associated load must be removed from the forecast when calculating rate spread and rates in order to assure full recovery of approved RAC costs.

Q. Have you modified the RAC tariff to reflect this change in applicability?

A. Yes. Exhibit PAC/1001 shows the proposed modification to the applicability language in the proposed RAC tariff.

Q. Have you prepared exhibits which show the revised rate spread and rate calculation?

A. Yes. Columns 4 and 5 of Exhibit PAC/1002 show the adjusted forecast load and the corresponding adjusted generation rate spread based on the removal of forecast load for the excluded five-year opt-out customers. The adjusted generation rate spread has been calculated as the spread of revenues from present Schedule 201, Net Power Costs rates multiplied by the adjusted forecast load. Exhibit PAC/1002 also shows the revised proposed rates for the RAC adjustment for both the October 1 and December 1 proposed rate changes.

Q. Why is it necessary to remove the excluded five-year opt-out direct access load from the forecast and from the calculation of the generation rate spread?

A. If the RAC adjustment does not apply to these five-year opt-out direct access customers then the load for those customers must be removed from the rate spread and rate calculations in order to completely collect the RAC revenue requirement in a fair and equitable manner from all other customers.

The RAC revenue requirement is not related to the forecast load. In other words, the RAC revenue requirement is not reduced when any particular customers are excluded from paying the costs. Therefore the forecast load used to calculate the RAC adjustments must exclude the load for the excluded five-year opt-out customers or the RAC adjustment rates would be set too low and the total RAC revenue requirement would not be collected.

When the excluded five-year opt-out load is removed from the forecast used in rate calculation, that load must also be removed in the calculation of the generation rate spread. If the generation rate spread was not adjusted, the same revenue requirement would be allocated to the rate schedules and only the other customers on those specific schedules now excluding five-year opt-out customers would pay the revenue requirement no longer being paid by the five-year opt-out customers. The revenue requirement not collected from the five-year opt-out customers should instead be collected from all other customers on all rate schedules on a generation rate spread basis.

Removing the forecast load for the five-year opt-out customers who will be excluded from paying the surcharge from both the rate spread and rate calculations fairly collects the total RAC revenue requirement from all other customers on a generation-based rate spread.

Q. How does the proposed change affect the RAC adjustment rates?

A. The proposed change increases rates for all rate schedules by a very small amount from the rates presented in the company's corrected RAC filing submitted on March 7, 2019. For example, the proposed residential RAC adjustment for October 1 increases 0.002 cents per kilowatt-hour from 0.111 to 0.113 cents per kilowatt-hour.

The rates for other customers increase from 0.001 to 0.004 cents per kilowatt-hour for both the proposed October 1 and December 1 rate changes.

Q. What is the overall rate impact of the rates proposed in this reply filing?

A. The overall effect of the proposed rates in this reply filing has not changed from the company's corrected filing. It is a rate increase of 1.1 percent, on a net basis, effective October 1, 2019 followed by an incremental increase of 1.4 percent, on a net basis, effective December 1, 2019. The rate change by customer rate schedule varies only slightly from the rate impacts in the company's corrected filing due to the small shift in revenue recovery between rate schedules. Exhibit PAC/1003 shows the effect of PacifiCorp's proposed rates by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. Page 1 of the exhibit shows the proposed October 1 rate change. Page 2 of the exhibit shows the proposed incremental December 1 rate change.

Q. What is the updated estimated monthly impact to an average residential customer?

A. The estimated monthly impact to the average residential customer using 900 kilowatt-hours per month is $1.06 beginning October 1 plus an additional $1.35 beginning December 1. The total monthly bill increase for this customer from present rates is $2.41.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 352
Exhibit PAC/1001
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Judith M. Ridenour

Proposed Tariff Schedule 202, Renewable Adjustment Clause

May 2019

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 202

RENEWABLE ADJUSTMENT CLAUSE
SUPPLY SERVICE ADJUSTMENT

Purpose

This schedule recovers, between rate cases, the costs to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission.

This adjustment is to recover the actual and forecasted revenue requirement associated with the prudently incurred costs of resources, including associated transmission, that are eligible under Senate Bill 838 (2007) and in service as of the date of the proposed rate change. The revenue requirement includes the actual return of and grossed up return on capital costs of the renewable energy source and associated transmission at the currently authorized rate of return, forecasted operation and maintenance costs, forecasted property taxes, forecasted energy tax credits, and other forecasted costs not captured in the Transition Adjustment Mechanism (TAM). The revenue requirement for Oregon will be calculated using the forecasted inter-jurisdictional allocation factors based on the same 12-month period used in the TAM. (D)

Applicable

To all Residential consumers and Nonresidential consumers except consumers who began service under the five-year cost of service opt-out program described in Schedule 296 before January 1, 2019. (C)
|
(C)

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Schedule	Charge	
4	0.113 cents per kWh	(I)
5	0.113 cents per kWh	
15	0.086 cents per kWh	
23, 723	0.108 cents per kWh	
28, 728	0.111 cents per kWh	
30, 730	0.106 cents per kWh	
41, 741	0.110 cents per kWh	
47, 747	0.097 cents per kWh	
48, 748	0.097 cents per kWh	
50	0.071 cents per kWh	
51, 751	0.112 cents per kWh	
52, 752	0.086 cents per kWh	
53, 753	0.037 cents per kWh	
54, 754	0.063 cents per kWh	(I)

(continued)

Special Conditions

1. The Company will file this schedule by April 1 of each year, as necessary, for proposed charges relating to new eligible resources and updating all charges already included on this schedule.

2. The Company will make an update filing within eight (8) months of the date of the initial filing, or by December 1, to reflect then-current, prudently-incurred actual resource costs or forecasted costs where appropriate, if the cost elements of an eligible resource cannot be verified as of the date of the final round of testimony in the proceeding initiated April 1. If the updated costs are lower than the projected costs in the record of the proceeding, the update will contain sufficient information to support a reduction in the proposed charges before the January 1 effective date. The Company will be allowed to defer for later commission review and incorporation into rates the cost differences between the projected costs in the record and the updated prudently incurred cost elements if (a) such cost elements are higher than the projected costs in the record or (b) if actual capital costs cannot be verified until after December 1.

3. Costs recovered in this schedule will be allocated across customer classes using the applicable forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kilowatt-hour to each applicable rate schedule.

4. The dates and provisions listed in the special conditions above may be modified if approved by (N)
the Commission. (N)

Docket No. UE 352
Exhibit PAC/1002
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Judith M. Ridenour

Renewable Adjustment Clause, Rate Spread and Rate Calculation

May 2019

PACIFIC POWER
STATE OF OREGON
RENWABLE ADJUSTMENT CLAUSE - RATE SPREAD AND RATE CALCULATION
FORECAST 12 MONTHS ENDING DECEMBER 31, 2019

						Proposed Schedule 202				
					Present	October 1 Rates		December 1 Adder		Total Dec 1
Line No.	Description	Sch No.	No. of Cust	MWh	Generation Rate Spread	Rates ¢/kWh	Revenues $	Rates ¢/kWh	Revenues $	Rates ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
							(4)*(6)		(4)*(8)	(6)+(8)
	Residential									
1	Residential	4	506,345	5,401,764	43.7638%	0.113	$6,103,993	0.147	$7,940,593	0.260
2	**Total Residential**		506,345	5,401,764			$6,103,993		$7,940,593	
	Commercial & Industrial									
3	Gen. Svc. < 31 kW	23	80,663	1,139,223	8.8255%	0.108	$1,230,361	0.141	$1,606,304	0.249
4	Gen. Svc. 31 - 200 kW	28	10,452	1,972,036	15.6673%	0.111	$2,188,960	0.144	$2,839,732	0.255
5	Gen. Svc. 201 - 999 kW	30	866	1,328,571	10.0707%	0.106	$1,408,285	0.138	$1,833,428	0.244
6	Large General Service >= 1,000 kW	48	194	2,824,435	19.6391%	0.097	$2,739,702	0.126	$3,558,788	0.223
7	Partial Req. Svc. >= 1,000 kW	47	6	49,859		0.097	$48,363	0.126	$62,822	0.223
8	Agricultural Pumping Service	41	7,982	222,624	1.7448%	0.110	$244,886	0.142	$316,126	0.252
9	**Total Commercial & Industrial**		100,163	7,536,748			$7,860,558		$10,217,201	
	Lighting									
10	Outdoor Area Lighting Service	15	6,305	9,058	0.0558%	0.086	$7,790	0.112	$10,145	0.198
11	Street Lighting Service	50	225	7,713	0.0392%	0.071	$5,476	0.092	$7,096	0.163
12	Street Lighting Service HPS	51	815	19,940	0.1598%	0.112	$22,333	0.145	$28,913	0.257
13	Street Lighting Service	52	35	404	0.0025%	0.086	$347	0.111	$448	0.197
14	Street Lighting Service	53	273	9,678	0.0253%	0.037	$3,581	0.047	$4,549	0.084
15	Recreational Field Lighting	54	104	1,345	0.0061%	0.063	$847	0.082	$1,103	0.145
16	**Total Public Street Lighting**		7,757	48,138			$40,375		$52,254	
17	Employee Discount			*16,976*			($4,796)		($6,239)	
18	**Total**		614,265	12,986,650			$14,000,130		$18,203,809	

Docket No. UE 352
Exhibit PAC/1003
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Judith M. Ridenour

Estimated Effect of Proposed Price Changes

May 2019

RAC - October 1, 2019

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 ENDING DECEMBER 31, 2019

Line No.	Description	Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates	Present Revenues ($000) Adders[1]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[1]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates %[2]	Change Net Rates ($000)	Change Net Rates %[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	506,345	5,401,764	$622,951	$5,618	$628,569	$629,055	$5,618	$634,673	$6,104	1.0%	$6,104	1.0%	1
2	**Total Residential**		506,345	5,401,764	$622,951	$5,618	$628,569	$629,055	$5,618	$634,673	$6,104	1.0%	$6,104	1.0%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	80,663	1,139,223	$126,459	$5,228	$131,687	$127,689	$5,228	$132,917	$1,230	1.0%	$1,230	0.9%	3
4	Gen. Svc. 31 - 200 kW	28	10,452	1,972,036	$181,356	$3,235	$184,591	$183,545	$3,235	$186,780	$2,189	1.2%	$2,189	1.2%	4
5	Gen. Svc. 201 - 999 kW	30	866	1,328,571	$108,386	$1,196	$109,582	$109,795	$1,196	$110,991	$1,409	1.3%	$1,409	1.3%	5
6	Large General Service >= 1,000 kW	48	195	3,221,037	$226,762	($9,688)	$217,074	$229,502	($9,688)	$219,814	$2,740	1.2%	$2,740	1.3%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	49,859	$5,615	($154)	$5,461	$5,664	($154)	$5,510	$49	1.2%	$49	1.3%	7
8	Agricultural Pumping Service	41	7,982	222,624	$25,966	($1,230)	$24,736	$26,211	($1,230)	$24,981	$245	0.9%	$245	1.0%	8
9	**Total Commercial & Industrial**		100,164	7,933,350	$674,544	($1,413)	$673,131	$682,406	($1,413)	$680,993	$7,862	1.2%	$7,862	1.2%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,305	9,058	$1,167	$216	$1,383	$1,175	$216	$1,391	$8	0.7%	$8	0.6%	10
11	Street Lighting Service	50	225	7,713	$861	$169	$1,030	$867	$169	$1,036	$6	0.7%	$6	0.6%	11
12	Street Lighting Service HPS	51	815	19,940	$3,513	$721	$4,234	$3,536	$721	$4,257	$23	0.7%	$23	0.5%	12
13	Street Lighting Service	52	35	404	$53	$9	$62	$53	$9	$62	$0	0.0%	$0	0.0%	13
14	Street Lighting Service	53	273	9,678	$611	$121	$732	$614	$121	$735	$3	0.5%	$3	0.4%	14
15	Recreational Field Lighting	54	104	1,345	$112	$21	$133	$113	$21	$134	$1	0.9%	$1	0.8%	15
16	**Total Public Street Lighting**		7,757	48,138	$6,317	$1,257	$7,574	$6,358	$1,257	$7,615	$41	0.7%	$41	0.5%	16
17	**Total Sales before Emp. Disc. & AGA**		614,266	13,383,252	$1,303,812	$5,462	$1,309,274	$1,317,819	$5,462	$1,323,281	$14,007	1.1%	$14,007	1.1%	17
18	Employee Discount				($484)	($3)	($487)	($489)	($3)	($492)	($5)		($5)		18
19	**Total Sales with Emp. Disc**		614,266	13,383,252	$1,303,328	$5,459	$1,308,787	$1,317,330	$5,459	$1,322,789	$14,002	1.1%	$14,002	1.1%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		614,266	13,383,252	$1,305,767	$5,459	$1,311,226	$1,319,769	$5,459	$1,325,228	$14,002	1.1%	$14,002	1.1%	21

1 Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
2 Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

RAC - December 1, 2019

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 ENDING DECEMBER 31, 2019

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
Line		Sch	No. of		Base		Net	Base		Net	Base Rates		Net Rates		Line
No.	Description	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)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	506,345	5,401,764	$629,055	$5,618	$634,673	$636,995	$5,618	$642,613	$7,940	1.3%	$7,940	1.3%	1
2	**Total Residential**		506,345	5,401,764	$629,055	$5,618	$634,673	$636,995	$5,618	$642,613	$7,940	1.3%	$7,940	1.3%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	80,663	1,139,223	$127,689	$5,228	$132,917	$129,296	$5,228	$134,524	$1,607	1.3%	$1,607	1.2%	3
4	Gen. Svc. 31 - 200 kW	28	10,452	1,972,036	$183,545	$3,235	$186,780	$186,385	$3,235	$189,620	$2,840	1.6%	$2,840	1.5%	4
5	Gen. Svc. 201 - 999 kW	30	866	1,328,571	$109,795	$1,196	$110,991	$111,628	$1,196	$112,824	$1,833	1.7%	$1,833	1.7%	5
6	Large General Service >= 1,000 kW	48	195	3,221,037	$229,502	($9,688)	$219,814	$233,061	($9,688)	$223,373	$3,559	1.5%	$3,559	1.6%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	49,859	$5,664	($154)	$5,510	$5,727	($154)	$5,573	$63	1.5%	$63	1.6%	7
8	Agricultural Pumping Service	41	7,982	222,624	$26,211	($1,230)	$24,981	$26,527	($1,230)	$25,297	$316	1.2%	$316	1.3%	8
9	**Total Commercial & Industrial**		100,164	7,933,350	$682,406	($1,413)	$680,993	$692,624	($1,413)	$691,211	$10,218	1.5%	$10,218	1.5%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,305	9,058	$1,175	$216	$1,391	$1,185	$216	$1,401	$10	0.9%	$10	0.7%	10
11	Street Lighting Service	50	225	7,713	$867	$169	$1,036	$874	$169	$1,043	$7	0.8%	$7	0.7%	11
12	Street Lighting Service HPS	51	815	19,940	$3,536	$721	$4,257	$3,565	$721	$4,286	$29	0.8%	$29	0.7%	12
13	Street Lighting Service	52	35	404	$53	$9	$62	$54	$9	$63	$1	1.9%	$1	1.6%	13
14	Street Lighting Service	53	273	9,678	$614	$121	$735	$619	$121	$740	$5	0.8%	$5	0.7%	14
15	Recreational Field Lighting	54	104	1,345	$113	$21	$134	$114	$21	$135	$1	0.9%	$1	0.8%	15
16	**Total Public Street Lighting**		7,757	48,138	$6,358	$1,257	$7,615	$6,411	$1,257	$7,668	$53	0.8%	$53	0.7%	16
17	**Total Sales before Emp. Disc. & AGA**		614,266	13,383,252	$1,317,819	$5,462	$1,323,281	$1,336,030	$5,462	$1,341,492	$18,211	1.4%	$18,211	1.4%	17
18	Employee Discount				($489)	($3)	($492)	($495)	($3)	($498)	($6)		($6)		18
19	**Total Sales with Emp. Disc**		614,266	13,383,252	$1,317,330	$5,459	$1,322,789	$1,335,535	$5,459	$1,340,994	$18,205	1.4%	$18,205	1.4%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		614,266	13,383,252	$1,319,769	$5,459	$1,325,228	$1,337,974	$5,459	$1,343,433	$18,205	1.4%	$18,205	1.4%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules