ITEM NO. 3

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: February 27, 2018

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: February 12, 2018

TO: Public Utility Commission

FROM: Lance Kaufman LK

THROUGH: Jason Eisdorfer and John Crider JE JC

SUBJECT: PACIFIC POWER: (Docket No. UM 1824) Update on Staff's investigation into PacifiCorp's Oregon specific cost allocation issues.

STAFF RECOMMENDATION:

None.

DISCUSSION:

Issues

This report provides an update on Staff's investigation into PacifiCorp's Oregon specific cost allocation issues. The report includes background on PacifiCorp's cost allocations, describes the allocation issues currently under investigation, identifies potential evaluation criteria for cost allocation methods, and identifies the next steps in the investigation.

Discussion and Analysis

Background
PacifiCorp provides electric distribution service to customers in six states, California, Oregon, Washington, Idaho, Utah, and Wyoming. PacifiCorp formed in 1910 as Pacific Power and Light (PP&L), serving electric customers in Oregon and Washington. In 1987 PacifiCorp acquired Utah Power and Light (UP&L). At the time, PacifiCorp provided service as PP&L in California, Idaho, Montana, Oregon, Washington, and Wyoming. Utah Power and Light provided service in Idaho, Utah, and Wyoming.

The Oregon Public Utility Commission (OPUC) approved the merger between PP&L and UP&L in Order No. 88-767. In this order, the Commission approved a stipulation regarding cost allocation guidelines. These guidelines directed parties to develop an agreement on how to allocate the joint costs and benefits of the merger, and provided that if agreement on an allocation issue cannot be reached, the method of allocation will be determined by the Commission based on the guidelines in the stipulation. The stipulation also states "Pacific agrees, however, that its shareholders will assume all risks that may result from less than full system cost recovery if interdivisional allocation methods differ among the merged company's jurisdictions."[1]

Since then, PacifiCorp's rates in Oregon have utilized the following allocation methodologies:

- Accord Method Pre-1998
- Modified Accord 1998 to 2005
- Revised Protocol 2005 to 2011 adopted in Order 05-021
- 2010 Protocol 2011 to 2016 adopted in Order No. 11-244
- 2017 Protocol 2016 to present adopted in Order No. 16-319

When the 2017 Protocol was adopted in Order 16-319, the Commission also resolved to open an investigation into Oregon specific allocation issues. Order No. 16-319 notes that the Oregon specific investigation is intended to:

1. Conduct detailed analysis on a reasonable allocation method for the company and its Oregon Customers;
2. Progress simultaneously with the multi-state process (MSP) workgroup;
3. Address allocation issues due to the passage of Senate Bill 1547 (SB 1547);
4. Explore allocation approaches consistent with cost-causation principles; and
5. Explore allocation approaches that make sense for Oregon customers.

The Commission opened its investigation, docketed as UM 1824, via Order No. 17-124. In its order, the Commission directed Staff to begin the investigation as a non-contested case and anticipated that parties would identify key Oregon-specific issues. The Commission also underscored a difference of opinion between Oregon and PacifiCorp's other state jurisdictions regarding the use of a rolled-in method of allocation and considerations arising from SB 1547. The Commission also conveyed its expectation that the Company would cooperate in answering all relevant requests for information from all participants. Finally, the Commission intended for the Oregon-specific investigation to culminate in a long-term Oregon resolution of underlying issues.

---

[1] OPUC Order No 88-767 at Page 6.

Staff filed a status report in this docket on September 22, 2017, describing the content of the first three workshops and the analysis performed in the first six months of the investigation. Following the publication of Staff's status report, in a letter filed September 25, 2017, PacifiCorp requested guidance from the Commission regarding various issues involved in this investigation.

On October 11, 2017, Administrative Law Judge (ALJ) Rowe issued a Scheduling Memorandum that directed the parties to discuss PacifiCorp's request for clarification. Parties met to discuss the matters raised by PacifiCorp on October 27, 2017. Staff filed a memo in this docket on November 2, 2017, requesting that the Commission defer until 2018 its consideration of the issues raised by PacifiCorp. Staff stated that the review would benefit from occurring within the context of a concrete proposed cost allocation methodology. The Commission adopted Staff's proposal in Order No. 17-456.

The purpose of this investigation is to explore allocation options that are consistent with cost causation, equitable for Oregon customers, and accommodate divergent state energy policies. The progression of this investigation in parallel with Docket No. UM 1050 will allow the investigation to inform Oregon parties during MSP discussions.

Parties have continued to make progress in this investigation following the September 22, 2017, Staff report. Parties have since held four separate workshops, at which the parties addressed many of the issues raised by PacifiCorp in its September 25 letter. Specifically, at the workshops:

1. Parties continued to refine and explore allocation options;
2. Parties developed a list of Oregon-specific allocation issues;
3. Parties discussed the concept of cost causation and explored how the various allocation proposals under consideration aligned with cost causation;
4. Parties discussed potential ways to evaluate allocation options; and
5. Parties developed a tentative timeline to maintain parallel progress with the general MSP workgroup.

Allocation options under consideration

As discussed in more detail below, Parties are currently contemplating the merits of the following general allocation approaches:

1. Rolled-in with variants
2. Hybrid/control area approach
3. "Sudoku" flow based approach (proposed by ICNU)
4. PacifiCorp's Strawman

High-level descriptions of those four general approaches are as follows:

1. Rolled-in with variants "rolled-in" refers to an allocation method that sums all costs for resources (fixed and variable costs) and allocates the resources' total costs based on each state's share of system loads. The current allocation approach in the 2017 Protocol is a variant of rolled-in. This approach has been accepted as a temporary agreement by Oregon, Utah, Idaho, and Wyoming. Staff has submitted a detailed information request set that is designed to reveal, up through 2026 or 2030, the yearly Oregon generation, transmission, and overhead-share revenue requirements according to a number of variations of rolled-in methodologies.

   Initial analysis shows that the rolled-in approach, including the 2017 Protocol variant, allocates substantially more costs to Oregon when compared to the Hybrid control area approach.

2. Hybrid-control area approach Oregon, Washington, and California load service territories are located within the Western Control Area (WCA). WCA incorporates the hydro and thermal assets in the Northwest plus the Bridger coal complex in Wyoming along with the transmission interconnection from Bridger to the Northwest. The WCA generation and transmission (G&T) capacity, including area purchase contracts, is sufficient to meet PacifiCorp Northwestern current loads. As such, the hybrid-control area approach only recognizes WCA G&T fixed costs in determining Oregon's allocated costs.

   The coal assets recognized by this approach for Oregon cost inclusion are limited to the Bridger assets plus the small Colstrip units in Montana. Washington has employed a variation of this approach for many years. The hybrid approach results in a smaller coal portfolio for Oregon relative to Rolled-in and the Strawman Proposal.

3. "Sudoku" flow based approach This approach was initially proposed by ICNU. It involves determining the sources of all the states' power through the use of power flow models, and then having the shares of the costs of those resources more or less equated to each states' respective shares of the outputs from those sources. This model may reveal that the Eastern Control Area (ECA) loads receive more benefit from WCA resources than the WCA receives from ECA resources.

4. PacifiCorp Strawman At the December 12-13 Broad Review Workgroup meeting, PacifiCorp presented its Strawman proposal to participants. The central feature of the Strawman is a realignment of PacifiCorp's coal fleet to assign whole coal units to western states while assigning shares of coal units to eastern states. This approach will allow PacifiCorp to make investments within units that are consistent with the state energy policy of customers that will bear the cost of those investments. The system will continue to be planned and operated on a system basis. New generation will be assigned to states using a subscription method to accommodate state energy policy. A locational marginal pricing model will be used to value generation and as a basis for assigning net power costs. The realignment of coal plants shifts substantial jurisdictional costs across states and time. An offsetting cost adjustment is made to realign the net present value of jurisdictional costs with those that are forecasted under the 2017 Protocol.

Oregon Specific Issues
The Oregon specific issues in this investigation follow two general themes: equitable sharing of system costs and benefits, and accommodating divergent state energy policies within a single system.

Equity related issues:

1. Oregon Interpretation of Cost Causation;
2. Transmission Allocation;
3. Equitable compensation for Klamath Dam removal; and
4. Oregon used-and-useful standards.

Divergent state energy policy:

5. Excluding post 2030 coal costs and benefits from rates;
6. Evaluating the cost of coal resource replacement under various alternatives;
7. Addressing the treatment of recent and future coal investments;
8. Continued operation of coal plants after 2030;
9. Inclusion of coal resources in valuation of post 2030 power costs;
10. Incorporation of post 2030 cost forecasts into pre 2030 rates;
11. Renewable Portfolio Standard compliance;
12. Details on subscription process under Oregon regulatory framework;
13. Details on how nodal pricing would integrate with Oregon power cost framework;
14. Treatment of depreciation differential resulting from non-Oregon states extending lives of coal plants;
15. Carbon reporting under various allocation schemes; and
16. Public perception of coal closures under subscription.

See Attachment A for further description of each issue. Parties have extensively discussed cost causation in response to PacifiCorp's September 25, 2017, letter. This discussion is reported on in the following section.

Cost Causation Principles

The Commission has highlighted cost causation as an important evaluation criteria for future allocation mechanisms. Staff generally understands the cost causation principle to be that costs should be assigned or allocated to the customers that cause them. The cost causation principle appears in the NARUC Guidelines on cost allocations, which define cost allocation as:

> ...the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).[2]

The NARUC Guidelines also provide the following cost allocation principle:

> (1) To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided....(5) The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.[3]

These principles are reasonably applied to jurisdictional allocations as well as non-regulated allocations. The first principle of maximizing direct assignment highlights cost causation as the dominant consideration in allocating costs. The fifth principle highlights that the most direct cost drivers should be used.

Parties have discussed how the cost causation principle applies to PacifiCorp's cost allocations. There continues to be disagreement on how to interpret and apply the cost causation principle. Parties generally agree that subscription to new investments is consistent with cost causation. However, subscription only addresses cost causation of new fixed costs. It does not provide a cost causation basis for allocating the fixed costs

---

[2] NARUC Guidelines for Cost Allocations and Affiliate Transactions https://pubs.naruc.org/pub.cfm?id=539BF2CD-2354-D714-51C4-0D70A5A95C65 accessed February 5, 2018

[3] NARUC Guidelines for Cost Allocations and Affiliate Transactions https://pubs.naruc.org/pub.cfm?id=539BF2CD-2354-D714-51C4-0D70A5A95C65 accessed February 5, 2018

of existing resources. Under the Strawman Proposal, the cost of existing resources are effectively allocated based on the 2017 protocol.[4] Staff did not illicit a clear explanation of what PacifiCorp considered to be the cost causation basis for allocating existing plant using the 2017 protocol.

If PacifiCorp had utilized the subscription model historically, there could have existed a basis for directly assigning existing plant to states. PacifiCorp has stated that it is not possible to identify how it would have assigned resources had it been following subscription when they were acquired.

Absent direct assignment, the cost causation principle advocates identifying primary cost drivers. Rolled in, hybrid, and Sudoku allocation models each rely on cost drivers to allocate the costs of existing generation. For example, the past and present rolled-in allocation methods (such as the 2017 Protocol) have allocated costs using shares of 12 month coincident peak and shares of annual energy to calculate allocation factors. These factors are consistent with a "current" cost causation perspective and do not reflect historic cost drivers.

However, variants of rolled-in employed in Oregon (such as the 2017 Protocol) consider, through the embedded cost differential (ECD), the lower average cost of PPL's pre-merger hydro assets. The embedded cost differential allocates costs and benefits in a manner similar to a subscription type approach for northwestern hydro assets, with rolled in treatment of all other assets.

The Hybrid approach considers geography to be the primary indicators of cost causation. Accordingly, the northwestern jurisdictions would primarily be responsible for costs associated with its geographic control area, i.e., the western control area (WCA). The main geographic distinction of the Hybrid model is the separate western and eastern control areas. That separation partially reflects the fact that FERC does not consider PacifiCorp's system to be sufficiently integrated to qualify as a single control area. However, transmission capabilities do allow generation to be far removed from consumers and PacifiCorp has considerable west to east power transfer capability but much less in the opposite direction.

The Sudoku model relies on actual power flows as cost drivers. Each driver should be thoroughly evaluated within the context of PacifiCorp's historic, existing, and future system and regulatory environment.

---

[4] This is because the Strawman equalization adjustment adjusts jurisdictional costs to be consistent with the 2017 Protocol.

The PacifiCorp Strawman Proposal includes a nodal pricing model to accommodate state subscription. The concept of nodal pricing has not been fully developed and parties can consider the cost causation basis for it once the concepts have been more fully flushed out.

Within the general MSP discussion other states have indicated concern that SB 1547 is causing system costs for PacifiCorp. Staff has not yet seen analysis showing the impact that SB 1547 will have on overall system costs. However, to the extent that SB 1547 increases or decreases system costs, those costs and benefits should be allocated to Oregon.

Evaluation criteria for allocation options
Staff's investigation to date has been focused on gathering information regarding allocation alternatives. This investigation is intended to result in a long term resolution of allocation issues. In order to accomplish this, Staff intends to develop a comprehensive and thorough set of evaluation criteria for each allocation alternative. The orders requiring and opening this investigation provide the following evaluation criteria:

- Be consistent with cost causation principles;
- Be consistent with Oregon law, including SB 1547; and
- Make sense for Oregon customers.

Consistent with cost causation principles
This memo has provided a preliminary analysis of the cost causation basis for the allocation options currently under consideration, from Staff's perspective. The preliminary analysis shows that there is a cost causation conceptual basis for each alternative. Future work on this evaluation criterion should further decompose the cost drivers and explore the economic and equity implications of each driver. Staff also intends to analyze overlapping principles underlying the four alternatives. For example, further analysis of cost causation principles may show that the Sudoku model is consistent with the principles underlying Utah's preference for rolled-in, because both methods allocate system wide costs using energy based cost drivers.

Consistent with Oregon Law
All decisions made by the Commission must be consistent with Oregon law. The allocation methods under consideration may deviate from Commission policy.[5] To the extent that Staff proposes a method that deviates from Commission policy, Staff will

[5] For example Staff is continuing to evaluate whether the Strawman Proposal's nodal pricing mechanism and subscription process is consistent with Commission policy.

make specific policy recommendations to the Commission to align policy with its proposal.

Make sense for Oregon customers
One appropriate interpretation for the requirement that an allocation method make sense is that the allocation method be equitable to Oregon. Future workshops should include discussion of appropriate criteria for evaluating the equity of allocation mechanisms.

The order opening Docket No. UM 1050 provides additional criteria that may be relevant to the extent that allocations evaluated in this Docket are incorporated into the MSP proceeding:

- Determine an allocation methodology that will allow PacifiCorp an opportunity to recover its prudently incurred costs associated with its investment in generation;
- Ensure that Oregon's share of PacifiCorp's costs is equitable in relation to other states; and
- Meet the public interest standard in Oregon.[6]

There is some overlap between the MSP criteria and the UM 1824 criteria.

Timeline and coordination with MSP
The Commission has directed this investigation to progress in parallel with the MSP. Staff sees two major benefits arising from parallel progress:

- New Oregon specific issues can be identified and explored in Docket No. UM 1824 as they arise in the MSP; and
- Results of Docket No. UM 1824 can inform Oregon parties as they participate in the MSP.

PacifiCorp intends to have completed the Strawman Proposal by March 27, 2018. The MSP is anticipated to transition into a negotiation phase by the following meeting on May 8, 2018. This transition will result in fewer new Oregon specific issues and a greater need for formalized analysis of allocation alternatives. As such, Staff intends to draft a formal report of its investigation and report back to the Commission at a future public meeting once the larger MSP process has progressed.

Conclusion

---

[6] Order No. 02-193.

This investigation has progressed successfully as an informal investigation. Parties have agreed that the process can continue on an informal basis as long as there continues to be reasonable cooperation.

PROPOSED COMMISSION MOTION:

None.

Attachment A

1. Oregon Interpretation of Cost causation

Cost causation principles were called out by the Commission as a necessary basis for allocation approaches. For this reason cost causation is explored extensively in the main body of this memo. Non-Oregon parties have also raised cost causation principles as important principles for an allocation mechanism. It may be useful for parties to understand how other state cost causation principles may differ from Oregon.

2. Transmission Allocation

Transmission is an important expense that may have been overlooked in previous MSP analysis. Specifically, Staff has three concerns. First, transmission costs driven by load growth may not have been factored into load growth analysis of previous MSP analysis.[7] Second, terminal nodes of transmission, including terminal substations, may currently be assigned as system resources while they primarily provide local benefit. Third, nodal pricing models may result in some states receiving disproportional value from new transmission. This suggests that rolled-in transmission allocation may no longer be feasible. Staff also notes that PacifiCorp has substantially more West to East transmission capacity than it does East to West transmission capacity.

3. Equitable compensation for Klamath Dam removal

In Docket No. UE 219 PacifiCorp has shown that the removal of the Klamath dams is the least cost and least risk solution to the relicensing needs of the Klamath Project. Oregon and California are bearing the burden of removing the Klamath dams. However, customers from all PacifiCorp's jurisdictions have received benefits from the Klamath Project and will benefit from the removal of the Klamath dams. Staff will evaluate how future allocation mechanisms would reflect the investment made by Oregon in the removal of the Klamath dams.

4. Clarification of Oregon used and useful standards

The Industrial Customers of Northwest Utilities have requested that analysis of Oregon's used and useful be included as part of this investigation. Further analysis of the used and useful standard may help parties to identify which allocation mechanisms are fair and equitable to Oregon customers.

5. Excluding coal costs and benefits from rates post 2030

---

[7] Such as the analysis presented in Idaho Public Utility Commission *In the Matter of the Investigation of Inter-Jurisdictional Issues Affecting PacifiCorp DBA Utah Power & Light Co.* Direct Testimony of Gregory N. Duvall at page 16 http://www.puc.idaho.gov/fileroom/cases/elec/PAC/PACE0203/company/20030930DUVALL%20DIRECT.PDF

Section 1 part 2 of SB 1547 states "On or before January 1, 2030, an electric company shall eliminate coal-fired resources from its allocation of electricity." Any long term allocation mechanism for PacifiCorp must be compatible with this requirement.

6. Evaluating the cost of coal replacement under various alternatives

The alternative allocation options under consideration attribute different levels of coal generation to Oregon. For example, Strawman Proposal aligns a larger portion of PacifiCorp's coal generation capacity to Oregon relative to costs allocated in both rolled-in and the hybrid approach. Each allocation method also has varying amounts of non-coal resources. A complete alternatives analysis should include estimates of coal replacement resource costs.

7. Addressing the treatment of coal investments not currently in ratebase

PacifiCorp's Straw Proposal includes a type of equalization adjustment which is based on a forecasted value of generation resources. Some of these generation resources have substantial investments that have not been acknowledged by the Commission in a PacifiCorp IRP. These investments have not yet been brought before the Commission for inclusion in PacifiCorp's rate base. PacifiCorp's proposed equalization adjustment may make it difficult for the Commission to disentangle the costs and benefits of these investments from rates in the event that the Commission does not find them prudent.

8. Continued operation of coal plants after 2030

PacifiCorp has indicated that it may continue to operate coal plants that have been fully depreciated by Oregon rate payers after 2030. PacifiCorp's proposed equalization adjustment may transfer costs and benefits of post 2030 coal operations into pre-2030 rates. However, the equalization adjustment does not appear to include value associated with post 2030 operation of coal plant ascribed to Oregon. This seems to be inconsistent treatment.

9. Inclusion of coal resources in valuation of post 2030 power costs

PacifiCorp is contemplating a nodal pricing system that will allow coal resources to influence the amount of net power costs paid by Oregon. PacifiCorp has indicated that this is consistent with SB 1547: however Staff intends to continue to evaluate whether nodal pricing is consistent with SB 1547.

10. Incorporation of post 2030 cost forecasts into pre 2030 rates

One allocation mechanism under consideration in this docket is PacifiCorp's MSP Straw Proposal. PacifiCorp's proposal includes a type of equalization adjustment which is based on a forecasted value of generation resources.

11. Renewable Portfolio Standard compliance

Under the 2017 Protocol PacifiCorp expects to have sufficient Oregon allocated RECs to meet RPS requirements and PacifiCorp has not found that the RPS requirements have substantially increased Oregon rates. However, the allocation alternatives under consideration may result in different allocations of RECs. A thorough evaluation of the allocation alternatives should also consider how RPS requirements are met.

12. Details on subscription process under Oregon regulatory framework

PacifiCorp's Straw Proposal includes a subscription process for new resources. Staff does not have a clear understanding of how the subscription process will integrate with Oregon's regulatory framework. Staff needs to clarify with PacifiCorp how its subscription concept will function. This should include an understanding of when Oregon subscribes, who makes subscription decisions, how these decisions are made, and who is at risk if a new plant is over or under subscribed to.

13. Details on how nodal pricing would integrate with Oregon power cost framework

PacifiCorp's Straw Proposal includes a nodal pricing process for new resources. Staff does not have a clear understanding of how the nodal pricing process will integrate with Oregon's regulatory framework. The nodal pricing mechanism has been described as a method of using actual operation decisions to allocate actual costs. Parties need to explore how the nodal pricing mechanism would work in a forecasted power cost framework like the Transition Adjustment Mechanism (TAM).

14. Treatment of depreciation differential resulting from non-Oregon states extending lives of coal plants

In 2007 PacifiCorp filed applications with Oregon and other jurisdictions to extend the depreciable lives of coal generation plants. The Oregon Commission did not extend the life of coal assets while non-Oregon jurisdictions did extend such lives. As a result, PacifiCorp has recovered more investment on coal plants from Oregon relative to other states. Any realignment of coal plants should account for the incremental depreciation recovered from Oregon customers.

15. Carbon reporting under various allocation schemes

PacifiCorp may be subject to local or national carbon emission restrictions. Any allocation scheme should address the cost of complying with coal related carbon requirements.

16. Public perception of coal closures under subscription

The January 26, 2018 Commissioner Forum included a discussion of the public perception of Oregon energy policy causing the closure of Wyoming coal facilities, and subsequently undermining local Wyoming economies. While SB 1547 does not obligate PacifiCorp to close coal plants, Staff agrees that there may be a public perception issue associated with closure under a realignment paradigm. While public perception does not directly impact Oregon rate payers, there may be indirect customer impacts such as additional legislative changes.