PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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July 28, 2017

VIA ELECTRONIC FILING

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

Attn: Filing Center

RE: LC 67 – PacifiCorp's Reply Comments

PacifiCorp d/b/a Pacific Power submits for filing its Reply Comments on PacifiCorp's 2017 Integrated Resource Plan.

Please direct any questions on this filing to Natasha Siores at (503) 813-6583.

Sincerely,

Etta Lockey
Vice President, Regulation

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's **Reply Comments** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated July 28, 2017.

Jennifer Angell
Jennifer Angell
Supervisor, Regulatory Operations

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

LC 67

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2017 Integrated Resource Plan.	PACIFICORP'S REPLY COMMENTS

I. INTRODUCTION AND SUMMARY

PacifiCorp d/b/a Pacific Power filed its 2017 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (Commission) on April 4, 2017. On June 23, 2017, the following stakeholders submitted written comments on PacifiCorp's 2017 IRP: Commission Staff (Staff), Renewable Northwest (RNW), the Oregon Department of Energy (ODOE), the Industrial Customers of Northwest Utilities (ICNU), the Renewable Energy Coalition (the Coalition), the Citizens' Utility Board of Oregon (CUB), the Northwest Energy Coalition (NWEC), the Northwest and Intermountain Power Producers (NIPPC), Sierra Club, and National Grid USA.

PacifiCorp looks forward to continuing to work with stakeholders in their review of the 2017 IRP. In these reply comments, PacifiCorp:

- Summarizes the Commissions standards for IRP acknowledgment, and explains how the 2017 IRP and the associated action plan meets these standards.
- Recognizes the importance and need for parties' and Commission's on-going review of the Energy Vision 2020 projects, and provides an overview of these projects and explains its efforts to complete the necessary analysis and share it with IRP stakeholders in real-time during the public input process.
- Explains that the Energy Vision 2020 projects are part of the company's least-cost,

least-risk plan to meet system load, are consistent with long-standing treatment of other resource alternatives, and are appropriately considered as part of the IRP.

- Responds to claims that an early coal-plant retirement might provide a lower cost alternative to building new transmission by explaining that it is not physically possible to interconnect 1,100 MW of new wind resources in the area of the proposed new Aeolus substation (Medicine Bow, WY) by retiring the Dave Johnston plant, which provides critical voltage support to the existing 230-kV transmission system from the plant's location near the existing Windstar substation (Glenrock, Wyoming). PacifiCorp also outlines the significant benefits associated with the new transmission line that are not factored into parties' comments. Specifically, the new transmission line will: (1) relieve congestion and increase transmission capacity across Wyoming, allowing interconnection of new generation resources and greater flexibility in managing existing resources; (2) provide critical voltage support to the transmission system; (3) improve system reliability; and (4) reduce energy and capacity losses.
- Responds to parties' comments on PacifiCorp's coal-unit analysis by summarizing how its fleet-wide modeling approach complies with the Commission's direction, noting that the IRP is the appropriate forum to evaluate these issues. PacifiCorp also explains that one party's recommendation to perform unit-by-unit analysis is flawed because the proposed analysis of individual units ignores the system-wide cost impacts assessed in the IRP. Such an approach is inconsistent with long-term resource planning principles.
- Addresses parties' comments on demand-side management (DSM) resources, explaining that the preferred portfolio includes all available cost-effective energy

efficiency, and that despite claims to the contrary, is consistent with findings in the Northwest Power and Conservation Council (NPCC) Seventh Power Plan.

- Replies to parties' initial comments on renewable portfolio standard (RPS) compliance, front office transactions (FOTs), load forecasts and the 2017 IRP load-and-resource balance, demand response, smart grid, distributed system planning, Clean Power Plan (CPP) modeling, storage, resource sufficiency demarcation, capacity value, the flexible reserve study, stochastic parameters and risk metrics, natural gas price forecasts, and access to computer models.

II. OVERVIEW OF THE 2017 IRP

A. The 2017 IRP Satisfies the Commission's Standards for Acknowledgement

The Commission will acknowledge a utility's IRP if the plan meets the substantive and procedural requirements for least-cost planning and is "reasonable at the time that acknowledgement is given."[1] In an IRP, the Commission "looks at the reasonableness of individual actions in the context of the entire plan."[2] "The Commission generally does not address the need for specific resources, but rather determines whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk."[3]

The Commission's IRP guidelines require that the IRP:

- Evaluate all resources on a consistent and comparable basis;
- Consider risk and uncertainty;

[1] *In the Matter of Public Utility Commission of Oregon Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at 2 (Jan. 8, 2007) (corrected by Order No. 07-047).
[2] *Id.* at 25.
[3] *In the Matter of Idaho Power Company 2009 Integrated Resource Plan*, Docket No. LC 50, Order No. 10-392 at 2 (Oct. 11, 2010).

- Select a portfolio of resources with the best combination of expected costs and associated risks and uncertainty for the utility and its customers; and
- Be consistent with the long-run public interest as expressed in Oregon and federal energy policies.[4]

PacifiCorp's 2017 IRP and action plan complies with the Commission's requirements for resource planning and ensures that PacifiCorp will provide adequate and reliable electricity supply at a reasonable cost "consistent with the long-run public interest."[5] The economic benefits of the near-term, time-limited Energy Vision 2020 projects included in the 2017 IRP preferred portfolio are bolstered by the extension of federal wind production tax credits (PTCs). These major resource investments will provide significant savings to customers over the resource lives, making them a critical element of PacifiCorp's least-cost, least-risk plan to meet system load that is consistent with the long-run public interest, while ensuring compliance with state and federal regulatory obligations.[6] In addition, while the 2017 IRP measures for known compliance obligations, the time-limited economic benefits of the Energy Vision 2020 projects also present a "no regrets" strategy to meeting potential future obligations, such as those articulated by Governor Kate Brown and other Oregon policymakers.[7]

The selection of the preferred portfolio was supported by more than 200 Planning and Risk (PaR) studies. Each PaR study includes 50 iterations of system performance, which

[4] Order No. 07-002 Appendix A at 1-2 (corrected by Order No. 07-047).
[5] *Id.* at 7.
[6] *Id.* at 2 (Commission will acknowledge and IRP if it is reasonable); *id.* at 5 (Guideline 1(c): "The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.").
[7] Governor Kate Brown Joins Pacific Leaders Committed to Participating in International Climate Change Conference, June 13, 2017, http://www.oregon.gov/newsroom/Pages/NewsDetail.aspx?newsid=2103.

equates to over 10,000 simulations of potential 20-year system dispatch outcomes.[8] The preferred portfolio was selected after evaluating 39 different cases. The portfolios were developed from 88 different supply-side resource options, including thermal generation resources; a broad spectrum of renewables, including wind, solar, and geothermal resources; and several different types of storage resources. PacifiCorp also analyzed its ability to meet system load with firm market transactions, and included robust transmission analysis when producing and evaluating resource portfolios that can reliably and cost-effectively meet customer demand with manageable risk.

PacifiCorp retained a reputable third-party to assess demand-side resource potential over the 2017-2036 time frame, which served as the basis for updated DSM resource cost and performance inputs. DSM resources continue to play a key role in PacifiCorp's resource mix. Over the first 10 years of the planning horizon, accumulated acquisition of new energy efficiency resources meets 88 percent of forecasted load growth from 2017 through 2026 (up from 86 percent in the 2015 IRP).

Although the 2017 IRP uses a 20-year planning horizon, the Commission has historically focused on the action plan, which identifies the specific resource actions PacifiCorp intends to undertake in the next two to four years.[9] The key resource actions in the 2017 IRP action plan include the following items that are the cornerstones of the company's proposed Energy Vision 2020 projects:

- **Action Item 1a**: PacifiCorp's plan to upgrade, or "repower," existing wind resources because it provides net benefits to customers by increasing energy production, reducing operating costs, and requalifying PacifiCorp's existing wind resources for PTCs, which expire 10 years after a facility's original

[8] Order No. 07-002 at 5 (IRP must analyze resource portfolios over 20-year planning horizon).
[9] *Id.* at 12.

commercial operation date. To achieve the full PTC benefits, PacifiCorp must complete the wind repowering project by the end of 2020.

- **Action Items 1c and 2a**: The acquisition of at least 1,100 MW of new Wyoming wind resources that will capture a time-limited resource opportunity arising from the expiration of PTCs. The proposed wind resources will be acquired in conjunction with a new 140-mile, 500 kV transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to a new annex substation, Bridger/Anticline, which will be located near the existing Jim Bridger substation (Aeolus-to-Bridger/Anticline line). The transmission resource is necessary to relieve existing congestion and will enable interconnection of the proposed wind resources into PacifiCorp's transmission system. The proposed wind resources net of PTC benefits, when combined with the transmission resource, are expected to provide economic benefits for PacifiCorp's customers, if both resources are operational by the end of 2020.

Upon being placed in service, these resources will be used to meet system load requirements and will continue to meet system load requirements through their respective lives. Completion of these projects by the end of 2020 will ensure the repowered and new wind will qualify for the full value of PTCs and will defer the need for other, higher-cost resource alternatives. PacifiCorp's modeling indicates that the early acquisition of these resources represents the least-cost, least-risk approach to serving customers.

B. The Energy Vision 2020 Projects in the Preferred Portfolio Provide Substantial Customer Benefits and Mitigate Future Regulatory Risk

1. Overview of wind repowering.

Recent advancements in wind generation technology, including innovations in wind turbine design and control systems, allow modern wind turbines to generate greater energy from available wind resources. To take advantage of these recent technologies, the 2017 IRP's action plan includes repowering most of PacifiCorp's Wyoming wind fleet (Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap); the Marengo I and Marengo II facilities in Washington; and the Leaning Juniper facility in Oregon. These facilities currently represent a total of 905 MW.

Consistent with its 2017 IRP action plan, PacifiCorp has since updated its economic analysis and expanded the scope of the wind repowering project to include the 94 MW Goodnoe Hills facility located in Washington.[10] Also consistent with the action plan, PacifiCorp will continue to evaluate repowering the Foote Creek project, which is also consistent with the 2017 IRP action plan.

Wind repowering involves the installation of new rotors with longer blades and new nacelles with higher-capacity generators. Longer blades increase the wind-swept area of the wind turbine and allow it to produce more energy at lower wind speeds. The nacelle is the housing that sits atop the tower and contains the gear box, low- and high-speed shafts, generator, controller, and brake. The new nacelles will include sophisticated control systems and more robust mechanical and generator components necessary to handle the greater loads that come with longer blades. Together, the new rotors and nacelles are estimated to increase wind project generation from 13 to 35 percent depending on the project, assuming the projects continue operating within the limits of their current large-generator interconnection agreements.

The innovative technologies available with the new wind turbines provide for greater control of power quality and voltage, allowing PacifiCorp to more easily integrate the energy from the wind facilities into the transmission system and support the reliability of the grid. The new equipment also reduces future operating costs and extends the useful life of each wind plant by approximately 10 years. With Goodnoe Hills included in the wind repowering scope, over the current life of the repowered facilities, incremental annual energy production

[10] *See* 2017 IRP, Volume I, Chapter 9, Action Plan and Resource Procurement, Table 9.1 – 2017 IRP Action Plan, Item 1a "by September 2017, complete technical and economic analysis of other repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e. Foote Creek 1 and Goodnoe Hills)."

exceeds 500 gigawatt hours (GWh). Over the extended life, the incremental annual energy production exceeds 3,100 GWh. Importantly, because the wind repowering project involves efficiency improvements to existing facilities, these benefits can be achieved without the costs and complexity of permitting and constructing entirely new facilities.

PacifiCorp's economic analysis in the 2017 IRP demonstrates that repowering provides substantial customer benefits. The 2017 IRP analysis also demonstrates that the new wind and transmission projects result in base-case present-value customer savings of $35 million before accounting for the significant increase in incremental energy expected from the repowered wind facilities beyond the end of the 20-year IRP-planning time frame. When accounting for these additional benefits, the base-case present-value customer savings rises to over $350 million. In the updated analysis recently made available to parties in this docket, customer savings based on costs and projected benefits extended out through 2050 are $359 million, assuming medium natural gas and medium carbon dioxide (CO_2) prices. Conservatively, these benefits do not assign any value to the incremental renewable-energy credits (RECs) that will be produced by the repowered wind facilities. Over the remaining life of these assets, present-value benefits improve by an additional $11 million for every dollar assigned to the incremental RECs that will be generated after repowering.

PacifiCorp analyzed the wind repowering project under many different scenarios, each with varying natural gas and CO_2 policy assumptions. Importantly, in every scenario analyzed, wind repowering provides customer benefits relative to non-repowering.

The economic benefits of repowering are bolstered by the fact that the repowered facilities are able to requalify for federal PTCs. To ensure the repowered facilities are eligible for 100 percent of available PTC benefits, in December 2016, PacifiCorp purchased new wind turbine generator equipment sufficient to satisfy Internal Revenue Service (IRS) "safe harbor" provisions requiring at least five percent of the expected cost of repowering to be incurred in 2016. These 2016 "safe-harbor equipment" purchases allow the repowered wind facilities to qualify for 100 percent of the value of available PTCs, assuming commercial operation by the end of 2020.

2. Overview of new wind and transmission resources.

The action plan in the 2017 IRP advances PacifiCorp's commitment to low-cost clean energy with the proposed addition of at least 1,100 MW of new wind resources by the end of 2020. These new zero-emission wind resources will rely on a new 140-mile, 500 kV transmission line segment and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to a new annex substation, Bridger/Anticline, which will be located near the existing Jim Bridger substation.

The transmission project and the new wind resources are mutually dependent. The wind resources will rely on the transmission line for interconnection to PacifiCorp's transmission system. In turn, the transmission line is supported by the key economic attributes of the wind resources—zero-fuel-cost generation that lowers net power costs and provides 10 years of PTCs. The wind resources also generate RECs, which can be used to meet the RPS targets in Oregon and the company's other service territory states. The wind resources will facilitate de-carbonization of PacifiCorp's resource portfolio, mitigating long-term risk associated with potential future state and federal policies targeting CO_2 emissions reductions from the electric sector.

The transmission project also provides significant benefits to customers. The Aeolus-to-Bridger/Anticline line is a sub-segment of the company's Energy Gateway West transmission project, and is an integral component of the long-term transmission plan for the region. PacifiCorp, with stakeholder involvement, has pursued permitting of the Energy Gateway West transmission project, which includes the Aeolus-to-Bridger/Anticline line, since 2008. This transmission investment will relieve congestion on the current transmission system in eastern Wyoming, provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, enhance PacifiCorp's ability to comply with mandated reliability and performance standards, reduce line losses, and create the potential for further increases to the transfer capability across the Aeolus-to-Bridger/Anticline line with the construction of additional segments of the Energy Gateway project in the future.

The 2017 IRP analysis, which assumes repowering of existing wind resources, demonstrates that the new wind resources will provide the cost savings necessary to support construction of this key transmission project and provide economic benefits for customers. The 2017 IRP analysis demonstrates that the new wind and transmission projects result in base-case present-value customer savings of $21 million. In the updated analysis recently made available to parties in this docket, PacifiCorp analyzed the new wind and transmission as standalone investments (*i.e.*, in isolation from the wind repowering project) with costs and projected benefits extended out through 2050 to align with the assumed life of the new wind assets. This economic analysis shows customer savings of $137 million under medium natural gas and medium CO_2 price assumptions. As is the case with wind repowering economic analysis, these benefits conservatively do not assign any value to the incremental RECs that will be produced by the new wind. Over the remaining life of these assets, present-value benefits would improve by an additional $26 million for every dollar assigned to the incremental RECs that will be generated by the new wind resources.

In addition to being least-cost, the resources described in the preferred portfolio, including the 1,100 MW of new wind by 2020, are also least-risk. Based on current load expectations, portfolio modeling performed for the 2017 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term.

PacifiCorp has included the 1,100 MW of additional wind resources in its preferred portfolio as cost-effective system resources that will be used to serve system load, and not as resources necessary for RPS compliance. These resources, however, will also contribute to PacifiCorp's ability to meet state renewable energy targets in Oregon, Washington, California and Utah, as well as meet the growing desire for renewable energy resources in local jurisdictions PacifiCorp serves.[11]

C. The 2017 IRP Public Process was Robust, but Did Not Include Discussion of the Energy Vision 2020 Project Until the End Because the Resource Opportunities Emerged Late in the Public Process

Integrated resource planning requires extensive public involvement in the development and review of the plan.[12] To that end, beginning in June 2016, PacifiCorp organized five state meetings and held seven public meetings to facilitate information sharing and collaboration, and to set expectations for the 2017 IRP. The public process covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Based on public feedback provided through this

[11] Salt Lake City, Utah; Park City, Utah; Moab, Utah; Summit County, Utah; Portland, Oregon; Multnomah County, Oregon; and Hood River, Oregon have local ordinances, resolutions, or climate plans calling for increases in the delivery of electricity from renewable energy resources.
[12] Order No. 07-002 at 8.

process and in the 2015 IRP process, the 2017 IRP included process and modeling improvements. In response to stakeholder feedback received during the 2015 IRP, PacifiCorp incorporated in its 2017 IRP comprehensive analysis of how its resource plan meets winter peak-load obligations. Efficiencies gained through improvements to the resource development process better positioned PacifiCorp to develop additional studies requested by stakeholders during the public input process. PacifiCorp and stakeholders identified and requested alternative modeling scenarios that were informed by the initial and intermediate analysis that was reviewed during the public input process. This improved process in the 2017 IRP enabled PacifiCorp to develop additional Regional Haze compliance cases and alternative environmental policy cases in response to stakeholder requests. Results from some of these studies led PacifiCorp to consider additional scenarios, which directly influenced the resource mix in the preferred portfolio.

In December 2016, PacifiCorp concluded that repowering wind units could generate cost savings if implemented on at least a subset of wind facilities in the fleet. To preserve the repowering option for application at additional facilities and to preserve the option to qualify new wind facilities for the full value of PTCs, subject to further review and analysis, PacifiCorp made safe harbor wind equipment purchases at that time.

PacifiCorp completed its additional review and expanded economic analysis of wind repowering in early 2017, toward the end of the IRP's pre-filing process. In February 2017, PacifiCorp finalized its IRP analysis of wind repowering. PacifiCorp incorporated repowering into the IRP process as the portfolio option referred to as OP-REP. PacifiCorp rescheduled the February 2017 public input meeting to the first of March to enable the company to complete and share its wind repowering analysis. PacifiCorp expedited its analysis of wind repowering to ensure its inclusion in the 2017 IRP, even though this resource opportunity emerged just a few months before the IRP's filing date; simultaneously, PacifiCorp was also completing its analysis of 24 sensitivity cases and eight core cases initially presented in the January 2017 public input meeting.

Also in late 2016 and early 2017, PacifiCorp continued to study and refine its resource portfolios, all of which contained new Wyoming wind resources. In reviewing these resource portfolios, it became clear that the amount of Wyoming wind included in these resource portfolios were limited by transmission constraints. The presence of the Wyoming wind resources in these initial portfolios led PacifiCorp to assess whether additional wind resources enabled by sub-segments of Energy Gateway West would further lower system costs. Consequently, after the January public input meeting, PacifiCorp incorporated the Aeolus-to-Bridger/Anticline line as a specific sensitivity case in its broader Energy Gateway sensitivity analysis. In late February, PacifiCorp's modeling of four Energy Gateway transmission sensitivities indicated there were potential benefits to including the Aeolus-to-Bridger/Anticline line in the portfolio. At the March 2017 public input meeting, PacifiCorp presented this analysis to stakeholders, along with next steps that communicated PacifiCorp's intention to further refine key assumptions for this sensitivity case.

While the pre-filing stakeholder review process of Energy Vision 2020 projects was necessarily limited by the timing of PacifiCorp's analysis, it was in customers' interest to consider these resources and ultimately include them in the 2017 IRP. PacifiCorp explicitly chose to share the results of its analysis with stakeholders as they were being produced. Given the time-sensitivity of these resource opportunities, delaying the IRP to allow additional pre-filing review was not a viable option. Instead, PacifiCorp expeditiously completed the necessary analysis and shared it with IRP stakeholders in real-time.

Filing of the 2017 IRP on April 4, 2017, signals a new stage in the stakeholder review process, not the end of it. PacifiCorp supports a meaningful and robust review of the Energy Vision 2020 projects and all other aspects of its IRP in this docket. PacifiCorp has not executed any agreements committing PacifiCorp to move forward with development of the Energy Vision 2020 projects other than the December 2016 purchases of wind turbine safe harbor equipment to preserve the option of qualifying wind resources for the full value of federal PTCs.

III. REPLY TO PARTIES' OPENING COMMENTS

A. Energy Vision 2020

1. Least-cost planning requires PacifiCorp to determine the least-cost, least-risk combination of resources to serve customers even without an immediate resource need.

The 2017 IRP preferred portfolio includes the Energy Vision 2020 projects as the least-cost, least-risk approach to serving customers. This approach obviates the need for more expensive resources alternatives and facilitates construction of a key transmission segment. Because the Energy Vision 2020 project is supported by economic need and because wind repowering and new wind and transmission resources are not intended to meet an immediate need for additional generation, Staff suggests that the "normal standards of IRP review may not be relevant" to the 2017 IRP.[13] According to Staff, if the IRP "establishes the fact that PacifiCorp can reliably meet projected load with available resources, it also

[13] Staff's Initial Comments at 1.

makes clear that there is no need for further resource analysis or acquisition to fulfill the least-cost planning goals."[14]

Contrary to Staff's claim, there is no basis to assume that if PacifiCorp is resource sufficient, it can satisfy its least-cost planning obligations by simply doing nothing. In Order No. 89-507, the Commission defined least-cost planning as an "approach to utility planning [that] requires consideration of all known resources for meeting the utility's load[.]"[15] The goal of obtaining a least-cost, least-risk portfolio "is most likely to be attained if all the options available for providing service are considered and if all the costs are considered."[16] Least-cost planning must therefore focus on the best combination of resources to serve load over the entirety of the 20-year planning period. Here, the preferred portfolio was selected over competing portfolios that did not acquire new PTC-eligible resources during the limited window when those resources are available. It would be inconsistent with least-cost planning principles for PacifiCorp to select a higher-cost, higher-risk portfolio simply because it did not include, or even consider, opportunities to procure PTC-eligible new resources within the context of its IRP.

Staff's position is also contrary to the specific direction it provided to PacifiCorp just last year. PacifiCorp's 2015 IRP Update (filed March 31, 2016) indicated that there may be a time-limited opportunity to acquire cost-effective renewable resources to provide economic

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[14] *Id.* at 2.

[15] *In the Matter of the Investigation into Least-Cost Planning in Oregon,* Docket No. UM 180, Order No. 89-507 at 2 (Apr. 20, 1989).

[16] *Id.* at 2; *see also* Order No. 07-047 Appendix A at 1-2 ("[P]rimary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."); *id.* at 5 (Guideline 4(l) requires that the IRP include "selection of a portfolio that represents the best combination of cost and risk for the utility and its customers."); Order No. 89-507 at 2 (the IRP must result in the "selection of that mix of options which yields, for society over the long-run, the best combination of expected costs and variance of costs.").

benefits to customers.[17] PacifiCorp did not request acknowledgment of the 2015 IRP Update, and when PacifiCorp proposed an RFP to test the market for economically beneficial renewable resources, Staff objected.[18] Staff argued that without a request for acknowledgment there was no opportunity for the Commission and stakeholders to test PacifiCorp's proposed acquisition of new renewable resources. By "disregard[ing] typical long-term resource planning processes," Staff argued PacifiCorp did not "justify the case for the economic need for new renewable resources[.]"[19] PacifiCorp has now included economically beneficial resources in its 2017 IRP—to provide the analytical support Staff requested last year—yet Staff now claims that economically beneficial resources do not belong in an IRP.

It is reasonable and consistent with least-cost planning to acquire resources before the point when the utility is resource deficient. Certainly "just-in-time" procurement is usually not in customer's economic interest, and the Commission has previously recognized that early action can be least-cost. In Order No. 17-019, the Commission found that PacifiCorp's current acquisition of RECs to satisfy its future RPS compliance obligation was prudent based on Staff's analysis that, "Under every scenario, early acquisition of RECs was less expensive than just-in-time acquisition."[20] In other words, obtaining RECs at today's prices was prudent because it allowed PacifiCorp to avoid paying higher prices in the future. Here, PacifiCorp's thorough portfolio analysis demonstrates that the preferred portfolio is the least-

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[17] PacifiCorp 2015 IRP Update at 55-56.

[18] Order No. 16-188, Appendix A at 6. Staff recognized that the "time-sensitive need for the RFP resources is not based in energy or capacity gaps as is typical of IRP planning, but built on the case of lost opportunity related to the currently anticipated decline of the federal PTC starting in 2017."

[19] *In the Matter of the Northwest and Intermountain Power Producers Coalition Petition for Temporary Rulemaking,* Docket No. UM 1771, Order No. 16-188, Appendix A at 7 (Apr. 25, 2016).

[20] *In the Matter of PacifiCorp d/b/a Pacific Power, Update to Schedule 203, Renewable Resource Deferral Supply Service Adjustment*, Docket No. UE 313, Order No. 17-019, Appendix A at 5 (Jan. 24, 2017).

cost, least-risk combination of resources because the early acquisition of PTC-eligible renewable generation provides all-in economic benefits for customers by deferring the need for other resource options in the future. If taking early action is the least-cost, least-risk option, then doing so is consistent with the Commission's principles for least-cost planning even if there is no immediate need for additional resources.

The Commission has also recognized that generation resources can provide customer benefits even when the plant's output is not required to serve an immediate resource need. In Order No. 87-1017, the Commission found that a new generating plant was useful to customers even though its output would not be needed for six to eight years because the plant provided customer benefits resulting from additional reserves, increased flexibility, and increased margins on sales for resale.[21] The Commission noted that, "Although six years is a considerable period of time, the period is sufficiently short that, the Commission finds that the plant will be necessary to meet load within a reasonable period of time."[22] The Commission did not penalize the utility "for not precisely matching the timing of its construction of new energy facilities to the need of its customers" because it is "extremely difficult for a utility to perfectly match completion of a facility with the arrival of the need for the power."[23] Although the Commission's discussion in Order No. 87-1017 was made in the context of the used and useful standard, the underlying policy principle applies here—early acquisition is not inherently unreasonable or indicative of poor planning; indeed, early acquisition may, in fact, be the most prudent course of utility action. Here, the new

[21] *In the Matter of Portland General Electric*, Docket No. UE 47, Order No. 87-1017, 86 P.U.R.4th 463 (1987) (finding Colstrip 4 was used and useful even though the plant was brought online during a period of energy surplus).
[22] *Id.*
[23] *Id.*

renewable resources will be used to meet system load, deferring market purchases over the near-term and deferring the need for future, higher-cost resources over the long-term.

Moreover, PacifiCorp's selection of the least-cost mix of supply-side resources is conceptually identical to the IRP's treatment of demand-side resources. The Commission requires least-cost planning to evaluate all resources on a consistent and comparable basis, including both supply- and demand-side resources.[24] When evaluating DSM resources, PacifiCorp's analysis is not limited by a need for additional DSM. Rather, PacifiCorp plans to acquire all cost-effective DSM resources, even if they are not strictly required to meet an immediate need.

When assessed on comparable footing, PacifiCorp's investment in DSM is similar to the level of proposed investment associated with the Energy Vision 2020 project. Over the last 10 years, PacifiCorp's nominal spend on total system Class 2 DSM (energy efficiency) is approximately $979 million. Accounting for inflation so that this can be compared to the initial capital proposed with the Energy Vision 2020 projects, this equates to over $1.1 billion (2020 dollars). PacifiCorp's most recent estimate of in-service capital for the Energy Vision 2020 project is approximately $3.2 billion (total system). However, these projects are expected to have a 30-year life (both repowered and new wind) or a 62-year life (new transmission). The 10-year levelized revenue requirement for these assets, which is more comparable to the last 10-years of spend on Class 2 DSM, totals $1.1 billion—equal to the cost of acquiring cost-effective Class 2 DSM resources over the most recent 10-year period.

Further, other regulatory commissions have recognized the customer benefits resulting from similar proposals to acquire least-cost, least-risk renewable resources before

[24] Order No. 07-002 at 3.

there is a specific resource need. In January 2017, the Minnesota Public Utilities Commission (MPUC) approved Xcel Energy's IRP, which included the acquisition of 1,000 MW of new wind resources by 2019. In this proceeding, the MPUC noted that 1,000 MW of wind was "least-cost even through Xcel does not show a planning capacity deficit until the mid-2020s because it will provide incrementally lower-cost energy, thereby reducing system costs."[25]

ICNU also criticizes the 2017 IRP because there is a "lack of actual new resource 'needs' for Oregon customers."[26] ICNU claims that the Commission's administrative rules strictly require the IRP to focus on only resources that are needed.[27] Like Staff, ICNU's interpretation of resource need is far too narrow in the context of integrated resource planning. First, as ICNU itself cites, the Commission's rules require an IRP to determine a utility's "long-term resource needs," and then identify the "best portfolio of resources to meet those needs."[28] The resources reflected in the 2017 IRP action plan are intended to provide economic benefits for customers and satisfy a *long-term* resource need by deferring the acquisition of more costly resource alternatives in the future.

Second, ICNU points to Order No. 16-071 from PacifiCorp's 2015 IRP where the Commission noted that one of the key elements of an IRP is "a finding of resource need, focusing on the first 10 years of a 20-year planning period" and then identifying the resources to meet the identified resource need.[29] ICNU's reliance on this language is misplaced, however, because there is nothing in Order No. 16-071 to suggest that least-cost

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[25] *In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan*, Docket No. E-002/RP-15-21, at 7 (Jan. 11, 2017).
[26] ICNU Opening Comments at 6.
[27] *Id.* at 6-8.
[28] OAR 860-027-0400(2).
[29] Order No. 16-071 at 2 (emphasis added).

planning is now limited to only resource need. In that same order, the Commission acknowledged an action item related to purchasing unbundled RECs for RPS compliance even though PacifiCorp had no need for additional RECs until 2027.[30] And, as noted above, the Commission subsequently found that PacifiCorp prudently acquired unbundled RECs even though there was no immediate or near-term need for additional RECs.

As Staff observes in its comments, the utility industry is currently in a time of transition, with both rapidly evolving technologies and changing regulatory environments.[31] It is not, however, consistent with long-term resource planning or in customers' interests for PacifiCorp to halt resource development in light of a changing policy and regulatory landscape, particularly when halting resource development would forgo the opportunity to pursue cost-effective renewable resources and further decarbonize PacifiCorp's resource portfolio. PacifiCorp cannot pass on opportunities like the current time-sensitive opportunity presented in this IRP, which include heavily discounted renewable resources in the hope that there may be a better opportunity in the future or simply because the future is uncertain. PacifiCorp must plan for the future based on the best information available today, taking into consideration the inherent uncertainties that are present in today's planning environment.

Staff and ICNU also note that ongoing conversations regarding PacifiCorp's inter-jurisdictional cost allocation process indicate the need to possibly consider how resources will be selected and included within rates. These parties comment that the inter-jurisdictional cost allocation methodology could affect how east-side resource benefits are reflected in Oregon rates.[32] Stakeholders involved in the inter-jurisdictional cost allocation process are

[30] *Id.* at 4.
[31] Staff's Initial Comments at 2.
[32] Staff's Initial Comments at 2; ICNU Opening Comments at 6.

aware of PacifiCorp's Energy Vision 2020 projects and the decision whether to move forward with Energy Vision 2020 will occur before conclusion of the current inter-jurisdictional allocation process. Therefore stakeholders in that process will be able to consider any potential implications of the Energy Vision 2020 projects on inter-jurisdictional cost allocations. Ongoing issues around the inter-jurisdictional cost allocation process are being discussed in separate proceedings in Oregon, and the IRP is not the appropriate forum to raise regional cost-allocation or rate-recovery issues.

2. PacifiCorp's reply to parties' comments on repowering.

CUB, NWEC, and RNW recommend that the Commission acknowledge repowering.[33] RNW noted that it "is encouraged by the 2017 IRP selection of a portfolio that hopefully marks the beginning of a substantial transition towards more energy efficiency and cleaner resources."[34] CUB qualifies its support, arguing that the benefits from extending the life of these resources should be given little weight.[35] As noted in the 2017 IRP, however, even without extending the life of the wind turbines, repowering provides substantial customer benefits, as CUB acknowledges.[36]

Staff is encouraged that PacifiCorp analyzed whether repowering its wind fleet could be economic for customers, but expressed concern that minor changes in assumptions could lead to significantly different results.[37] Staff does not dispute that every scenario used for the sensitivity analysis produced an economic benefit—so even if changing assumptions alters

[33] CUB Opening Comments at 6, NW Energy Coalition Comments at 11; Comments of Renewable Northwest at 19.
[34] Comments of Renewable Northwest at 19.
[35] CUB Opening Comments at 5.
[36] *Id*.
[37] Staff's Initial Comments at 3.

the calculated benefits, not a single scenario shows that wind repowering is higher cost compared with non-repowering over the life of the repowered resources.

Staff is also concerned that this project is not driven by any need and solely on its economic merits.[38] As discussed above, the purpose of an IRP is to identify a least-cost, least-risk portfolio. It would be fundamentally inconsistent with the purpose of least-cost planning if PacifiCorp pursued a higher-cost, higher-risk portfolio that did not include wind repowering simply because the additional generation was not immediately needed. And the opportunity presented by repowering is time-limited—if PacifiCorp waited, it would be unable to achieve the substantial customer savings anticipated from repowering.

ODOE appears generally supportive of the repowering investment, but expressed a desire for additional information relating to the permitting requirements associated with repowering so that ODOE could assess whether those requirements may cause risk or delays to implementation.[39] Because repowering does not affect the foundations or towers at the existing facilities, PacifiCorp does not anticipate construction-related permitting requirements associated with repowering that could cause additional risk or delay project implementation. After discussions with representatives from Wyoming and the respective Washington and Oregon counties, it is anticipated that the repowering modifications can be covered by amendments to the project's conditional use permit. Although wind repowering influences a larger wind-swept area, discussions with the governing agency have identified no additional avoidance measures or mitigation requirements.

ICNU requests that the Commission not acknowledge repowering, but for

[38] *Id.* at 1-2.
[39] Opening Comments of the Oregon Department of Energy at 4-5, 7.

unpersuasive reasons.40 First, ICNU argues that PTCs are not free and PacifiCorp has not factored in the societal costs of those tax expenditures that are borne by taxpayers and society as a whole.[41] This concern is inconsistent with Commission precedent and practice, and ultimately detrimental to customers. In docket UM 1056, where the Commission adopted its IRP guidelines, the Commission made clear that the when analyzing portfolios, the "key cost metric" should be the present-value revenue requirement (PVRR).[42] One party recommended that the Commission use "total resource cost," instead of "PVRR," because using "total resource cost" would remove subsidies, like PTCs, from the analysis.[43] The Commission rejected this recommendation and affirmed that resource planning must examine the costs to the utility and "the utility should consider funding available from other sources—for example . . . federal tax credits."[44] Thus, the PTCs must be included in the analysis and should not be stripped out, as recommended by ICNU.

Second, ICNU also argues that because repowering is a "purely economic project" and does not meet an immediate resource need, the Commission should treat the investment as it would a PacifiCorp investment in a merchant plant and assign greater risk to PacifiCorp.[45] But repowering is not at all like investing in a merchant plant. These facilities serve customers today and will continue to serve customers once repowered. It is therefore appropriate for these facilities to continue to be treated like every other used and useful utility investment. There is no basis for ICNU's proposal to effectively treat the repowering project as if it were an unregulated merchant plant that is not serving customers.

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[40] ICNU Opening Comments at 2.
[41] *Id* at 2-3.
[42] Order No. 07-002 at 6-7.
[43] *Id.* at 7.
[44] *Id.* at 15.
[45] ICNU Opening Comments at 4.

Third, ICNU questions whether the repowering project will be able to qualify for federal PTCs because, according to ICNU, the IRS guidance indicating repowering qualifies for PTCs may change or be held unlawful.[46] ICNU cites no authority for this argument, which amounts to little more than speculation. PacifiCorp does not anticipate that the PTCs, as currently structured, will change or be held unlawful.

NIPPC argues that the Commission should decline to acknowledge the wind repowering projects because PacifiCorp has not provided sufficient economic analysis, and if PacifiCorp does move forward, it should be required to open the process to a competitive bid, which should include using the repowering as a benchmark resource in the 2017R RFP.[47] Contrary to NIPPC's claim, PacifiCorp's IRP contains robust and detailed economic analysis justifying the repowering decision. PacifiCorp has further updated this analysis, which was recently provided to parties in this proceeding. Notably, NIPPC fails to provide any description of the analysis that it claims is lacking. In addition, there is no basis for including repowering as a benchmark resource in the 2017R RFP. NIPPC is essentially arguing that this is a binary, "either/or" decision PacifiCorp should either repower existing resources or acquire new resources. This argument fails to recognize that repowering existing wind facilities does not preclude PacifiCorp from pursuing procurement of cost-effective new wind resources enabled by new transmission. Based on the all-in economic customer savings associated with the Energy Vision 2020 project, PacifiCorp plans to pursue both time-limited opportunities.

Sierra Club recommends that the Commission decline to acknowledge repowering, arguing that rather than spending significant funds to tear down existing resources with

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[46] *Id*.
[47] Northwest and Intermountain Power Producers Coalition's Comments at 11.

effectively no incremental customer benefit, PacifiCorp should invest in new cost-effective renewable energy projects.[48] Sierra Club's conclusion that repowering provides only a marginal customer benefit relies on the exclusion of the PTC benefits, which drive the investment decision. When PTCs are accounted for, repowering provides substantial benefits and, as Sierra Club concedes, accounting for PTCs is "a legitimate, if not entirely standard, business practice."[49]

3. PacifiCorp's reply to parties' comments on the new wind and transmission resources.

RNW recommends acknowledgement of the 2017 IRP, including the new wind and transmission resources, and notes that the renewable resources in the preferred portfolio may provide even higher economic benefit than what is reflected in PacifiCorp's analysis because PacifiCorp assumed no incremental REC value.[50]

Staff expressed three concerns related to the proposed wind and transmission resources. First, Staff claims that because the new resources are not needed to serve an immediate need, it is "implausible to consider these projects as less risky than the option of acquiring no resources."[51] Staff provides no analysis demonstrating that forgoing PTC-eligible resources is less risky than moving forward with the PTC-eligible new wind resources. In other words, Staff ignores any opportunity costs to customers of inaction. Notably, the 2017 IRP contains numerous portfolios that did not include the new wind and transmission investments—Staff's preferred approach—and the preferred portfolio outperformed those competing portfolios. Without any analysis, Staff cannot reasonably

[48] Sierra Club Comments at 24-25.
[49] *Id.*
[50] Comments of Renewable Northwest at 14.
[51] Staff's Initial Comments at 3.

claim that doing nothing is the least-cost, least-risk option, particularly given the time-limited opportunity presented by the PTCs.

Second, Staff notes that the $2.5 billion new wind and transmission project is only projected to yield minor economic benefits to customers, and only under a limited range of economic conditions. Specifically, the project would not be economic if natural gas prices stay low through 2036.[52] But the only scenario in the 2017 IRP where the new wind and transmission resources are non-economic is the low gas scenario. In every other scenario, PacifiCorp's analysis shows that the new resources provide customer benefits and the upside associated with higher natural gas prices far exceeds any potential downside if natural gas prices remain low through the life of the assets. Moreover, Staff does not recognize that PacifiCorp's analysis conservatively assigns no incremental value to the RECs generated by the new wind facilities and does not consider incremental benefits associated with the new transmission line, which will relieve congestion for existing resources, provide critical voltage support, enhance PacifiCorp's ability to comply with mandated reliability and performance standards, and provide an opportunity for further increases to the future transfer capability out of wind-rich regions of Wyoming with construction of additional segments of Energy Gateway. Since Staff filed its initial comments, PacifiCorp completed an updated economic analysis, which was presented at the July 10, 2017 public meeting and recently filed in this docket. This updated analysis, which isolates the benefits of the new wind and transmission investments from wind repowering, shows that with medium natural gas and medium CO_2 price assumptions, the present-value customer benefits total $137 million when calculated from the change in system costs over the life of the new wind resources.

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[52] *Id.* at 2; *see also* ICNU Opening Comments at 5.

Third, Staff indicated that it would like to know the extent to which the economics of these projects rely on the existence of the Clean Power Plan.[53] As noted above, natural gas prices have a greater impact on the economics of the wind and transmission resources than CO_2 pricing. PacifiCorp's updated analysis specifically included scenarios without any incremental CO_2 policy (*i.e.*, scenarios assuming a zero CO_2 price), and the only scenarios where the new resources are not economic are those with low natural gas prices when paired with zero or medium CO_2 price assumptions.

CUB recommends that the Commission not acknowledge the new wind and transmission resources. First, CUB argues that PacifiCorp's analysis overstates the benefits of these resources by combining them with the wind repowering.[54] To clarify, the portfolio that included the new wind and transmission resources (GW-4) was presented at the March public input meeting and showed benefits above the draft preferred portfolio (OP-NT3), even without wind repowering (OP-REP). When combined in the final screening stage, the portfolio that included both wind repowering and the new wind and transmission resources (FS-GW4) showed greater benefits than the portfolio that included wind repowering on its own (FS-REP). As discussed above, PacifiCorp's updated analysis isolates the benefits of the new wind and transmission from the wind repowering project and shows present-value customer benefits totaling $137 million.

Second, CUB claims that it may be lower cost to retire the Dave Johnston coal plant to free-up transmission, instead of building the new line.[55] Other parties also suggest that the new transmission resource could be unnecessary if PacifiCorp retired coal plants to free-up

[53] Staff's Initial Comments at 3.
[54] CUB Opening Comments at 6-7.
[55] *Id.* at 7-8.

existing transmission.[56] While the 750 MW of incremental transfer capability across the Aeolus-to-Bridger/Anticline transmission line is of similar magnitude to the 762 MW capacity of the Dave Johnston plant, this argument fails to recognize limitations on interconnecting new generators due to voltage instability on the 230-kV transmission system. Regardless of the economics, it is simply not physically possible to interconnect 1,100 MW of new wind resources by retiring the Dave Johnston plant. The 762 MW Dave Johnston plant provides critical voltage support to the 230-kV transmission system and without that support, the company could not integrate the level of economic wind resources selected in the preferred portfolio.

Moreover, the Dave Johnston plant is one of the lowest variable-cost assets on PacifiCorp's system and operationally, provides flexibility that facilitates PacifiCorp's ability to import low-cost renewable energy from California through the energy imbalance market (EIM). The plant also provides significant system capacity needed to satisfy PacifiCorp's 13 percent target planning reserve margin (PRM) and provides fault current support to maintain "stiffness" of the grid which is necessary to support system voltages. If Dave Johnston retired at the end of 2020 (approximately three years out), there would be limited time to procure potential replacement resource alternatives capable of delivering energy and capacity benefits comparable to those provided by the Dave Johnston plant and could necessarily increase PacifiCorp's reliance on market purchases. Retiring Dave Johnston by the end of 2020 would also create substantial upward pressure on customer rates due to the accelerated depreciation resulting from early retirement.

The Aeolus-to-Bridger/Anticline line will also provide additional benefits that would

[56] *See, e.g.*, NW Energy Coalition Comments at 6; Sierra Club Comments at 28, 39.

not be realized simply by retiring the Dave Johnston plant. The new transmission line will: (1) relieve congestion and increase transmission capacity across Wyoming, allowing interconnection of new generation resources and greater flexibility in managing existing resources; (2) provide critical voltage support to the transmission system; (3) improve system reliability; and (4) reduce energy and capacity losses.

Currently, PacifiCorp's transmission system in southeastern Wyoming is operating at capacity, which limits transfer of existing resources from eastern Wyoming. Also, due to limited fault current in the southeastern portion of the transmission system, which indicates a weak grid, interconnection of additional resources in this prime wind region is precluded to maintain grid stability. The transmission project will not only increase the transfer capability from east to west by 750 MW, but will also improve the fault current providing "stiffness" to the grid. This will allow interconnection of additional wind facilities in and around the proposed Aeolus substation, which is not possible today.

In addition, under certain operating conditions, voltage control issues have limited the ability to add additional resources, particularly wind facilities, in southeastern Wyoming. The proposed transmission project will solve the voltage control issues and allow up to approximately 1,270 MW of additional wind generation to be interconnected into the transmission system.

The transmission project will also increase system reliability. The transmission grid can be affected in its entirety by what happens on an individual transmission line or path. For example, the transmission system between eastern and central Wyoming is composed of several individual transmission lines or line segments. A single outage on any of the individual lines or line segments due to storm, fire, or other interference can and does cause significant reductions in transmission capacity and can negatively impact PacifiCorp's ability to serve customers. Line outages require PacifiCorp to significantly curtail generation resources to stabilize system voltages and require less efficient re-dispatch of system resources to meet network load requirements. If there is a line outage, the redundancy provided by the proposed transmission line will allow PacifiCorp to continue to meet native load-service obligations and continue to meet other contractual obligations to third parties. Strengthening this path and increasing system redundancy with the new transmission line will benefit all customers by reducing the risk of outages and inefficient dispatch resulting from those outages.

In addition, the transmission resource will improve PacifiCorp's ability to perform required maintenance without significant operational impacts to the system, and will reduce impacts to customers during planned and forced system outages. Transmission line and substation maintenance windows are currently limited because the system is operating at capacity. By relieving congestion and providing additional transmission paths, the transmission resource will allow greater flexibility.

The transmission resource will reduce energy and capacity losses on the transmission system, and has the potential to provide significant cost savings over time. Generally, the addition of a new transmission path in parallel with existing lines, like the proposed Aeolus-to-Bridger/Anticline line, will reduce the energy and capacity losses by reducing the impedance of the transmission system. Reduced line losses mean more efficient delivery of energy and capacity at reduced costs.

Further, PacifiCorp modeled and evaluated a number of Regional Haze cases that assumed a range of coal unit retirement assumptions and incorporated stakeholder feedback.

In the first stage of the 2017 IRP portfolio development process, PacifiCorp identified least-cost, least-risk Regional Haze case adopted for further portfolio analysis. The 1,100 MW of new Wyoming wind and Aeolus-to-Bridger/Anticline line included in the 2017 IRP preferred portfolio was selected as part of the least-cost, least-risk preferred portfolio reflecting the least-cost, least-risk Regional Haze compliance alternatives and associated early coal unit retirement assumptions.

Third, CUB recommends against acknowledgement of the transmission line because PacifiCorp did not propose an RFP process for the transmission line.[57] CUB contends that there are potential non-utility owners who would build the transmission line because in other areas of the country that have regional transmission operators (RTO) there are non-utility transmission providers. Based on PacifiCorp's past experience, there are no non-utility transmission providers that would bid into an RFP to construct the proposed transmission resource. The RTO markets CUB refers to in its comments are not comparable to the transmission market in the western U.S.

NWEC supports acknowledgment of the new wind resources, but not the new transmission project.[58] NWEC "recognizes the importance of the [proposed wind] acquisitions, and believes PacifiCorp has made a strong case for a major new clean energy investment."[59] According to NWEC, the "economic case presented by PacifiCorp regarding the benefits of repowering and new wind procurement is convincing."[60] But NWEC is concerned that the new wind and transmission resources and management of the coal fleet

[57] CUB Opening Comments at 8.
[58] NW Energy Coalition Comments at 11.
[59] *Id.* at 6.
[60] *Id.*

are not effectively aligned.[61] As discussed above, however, the 2017 IRP has fully explored other alternatives for coal plant retirements—but the analysis demonstrates that the least-cost, least-risk approach to compliance with the Regional Haze requirements for coal plants includes the acquisition of the new wind and transmission resources. Without the transmission project, PacifiCorp cannot interconnect the wind resources, so non-acknowledgment of the transmission project is effectively non-acknowledgment of both.

NWEC expresses concern that the new and repowered wind facilities may unreasonably duplicate resources when there is diminishing demand being met with increased energy efficiency.[62] NWEC also believes that the IRP must more fully explore technologies such as demand response, storage, and solar instead of investing in new resources. As described above, the 2017 IRP included all cost-effective DSM resources in the preferred portfolio, and the least-cost, least-risk combination of resources still included the new wind and transmission resources. Moreover, the 2017 IRP includes robust consideration of demand response, storage, and solar resources, but none of those resources outperformed the substantial customer benefits derived from the new wind and transmission resources associated with Energy Vision 2020.

ODOE acknowledges that the preferred portfolio including the transmission resource has “overwhelming” PVRR benefits from “increased transfer capability of the line itself, increased export capability for wind combined with lower wind installed cost assumptions, reduced losses on parallel lines resulting in increased annual energy flows, avoided de-rating during times of outages on nearby portions of the transmission system, and finally

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[61] *Id.*
[62] *Id.* at 7-8.

incremental benefits in the EIM."[63] ODOE also acknowledges that PacifiCorp performed additional sensitivity analysis involving the new transmission resource, at stakeholder's request.[64] While ODOE does not take a position on acknowledgment, it does request additional explanation for PacifiCorp's decision to move forward with the new wind and transmission resources, "when delaying the build of some renewable resources could reduce risk to ratepayers."[65] ODOE would also like a more thorough analysis and description of the potential timeline risks associated with the preferred portfolio. In response to ODOE's request for more information regarding potential timeline risks, PacifiCorp offers that for the Energy Vision 2020 projects the on-going regulatory review and approval processes currently underway is a key risk to achieving an operational date of the end of 2020. In particular, it is critical that PacifiCorp receive a certificate for public convenience and necessity (CPCN) in the first quarter of 2018 from the Wyoming Public Service Commission for the transmission project with sufficient time to allow PacifiCorp to obtain necessary rights-of-way and maintain the critical-path construction schedule for the transmission project. Timing is critical for both the new wind and transmission projects. These assets must achieve commercial operation by the end of 2020 to qualify for the full benefits of the PTCs and maintain favorable economics. Thus, PacifiCorp must move quickly, particularly on the new transmission, which will take several years to fully permit, obtain the necessary rights-of-way, and construct. To complete construction of the new wind and transmission by December 31, 2020, PacifiCorp has requested expedited review of its CPCN applications.

Because of the time-sensitivity of the new wind and transmission projects, PacifiCorp

[63] Opening Comments of the Oregon Department of Energy at 8.
[64] *Id.*
[65] *Id.* at 9.

is conducting its 2017R request for proposals (RFP) process simultaneously with its CPCN applications and on-going review of these investments by parties participating in PacifiCorp's 2017 IRP process. Although unusual, this approach is necessary in this case. If PacifiCorp waited until the conclusion of the 2017R RFP to seek CPCNs, or similarly, waited for conclusion of review of PacifiCorp's 2017 IRP to issue its 2017R RFP, the new wind and transmission projects could not be completed by the end of 2020, and customers would lose significant PTC benefits. Specific to the new wind and transmission projects, PacifiCorp will actively mitigate construction delay risk and has demonstrated experience delivering similar high-voltage transmission projects. To allow the new wind and transmission projects to move forward, PacifiCorp has pursued specific wind projects that will be benchmark resources in the 2017R RFP.

ICNU also reiterates its argument that the new wind and transmission resource do not respond to a need for new resources.[66] As discussed above, this fact does not change how the resources should be evaluated in the context of an IRP.

NIPPC states that "PacifiCorp appropriately recognizes the costs of renewable resources have dramatically dropped, and early acquisition may provide customers with the greatest benefits at the lowest cost."[67] But NIPPC does not support the decision to limit renewable resource acquisition to only Wyoming wind, which NIPPC claims has not been supported with adequate analysis.[68] The Coalition takes the same position as NIPPC and supports NIPPC's recommendation.[69] The preferred portfolio in the 2017 IRP includes PTC-

[66] ICNU Opening Comments at 5.
[67] Northwest and Intermountain Power Producers Coalition's Comments at 5.
[68] *Id.* at 2.
[69] Renewable Energy Coalition's Comments at 9.

eligible wind resources located in the wind-rich region of Wyoming as part of the least-cost, least-risk combination of resources to serve customers.

NIPPC and the Coalition cannot simply substitute a different type of resource in a different location and expect the same results. PacifiCorp's preferred portfolio is supported by extensive analysis, which assessed but did not identify significant potential for near-term opportunities to procure other types of renewable resources that might be capable of delivering energy and capacity to other locations on PacifiCorp's system. A broad range of renewable resource alternatives—both type and location—were considered in the portfolio development process. This finding is substantiated by results of PacifiCorp's 2016R RFP, issued in 2016 to test the market for potential acquisition of renewable resources after filing the 2015 IRP Update. Through this competitive solicitation, PacifiCorp received proposals for over 6,000 MW of renewable resources. PacifiCorp ultimately chose not to move forward with any of these projects because none provided all-in economic benefits for customers.

NIPPC notes that while the new transmission line may relieve local area congestion, it is unclear whether it will increase transfer capability west of the Jim Bridger plant without displacing existing resources.[70] The Aeolus-to-Bridger/Anticline line is not designed to increase the transfer capability west of the Jim Bridger plant, so NIPPC's concern is misplaced. The customer benefits provided by the new line relate to its critical role in bolstering the transmission system east of the Jim Bridger plant and enabling interconnection of PTC-eligible wind resources that will be used to serve system load once placed in service.

[70] Northwest and Intermountain Power Producers Coalition's Comments at 4-5.

B. Coal Resource Analysis

1. PacifiCorp's coal fleet modeling and analysis complies with the Commission's prior direction.

PacifiCorp's modeling of its coal fleet has evolved over the last several IRP proceedings in response to Commission and stakeholder input, and PacifiCorp views the IRP proceeding as the appropriate forum to analyze these issues. In PacifiCorp's 2013 IRP proceeding, PacifiCorp presented analysis addressing the potential investments that would be required at coal-fired generating plants.[71] In that case, parties criticized PacifiCorp's analysis and recommended that PacifiCorp analyze more flexible compliance alternatives, including the transmission implications for specific investments decisions. To address parties' concerns and provide more transparency on model inputs/outputs and scenarios, PacifiCorp proposed a separate process to develop parameters for coal investment analyses and allow the company to seek acknowledgment of emissions control investments or alternatives for specific units.[72]

In its order acknowledging the 2013 IRP, the Commission "recognize[d] the additional coal analysis that PacifiCorp provided in this proceeding and PacifiCorp's willingness to establish a separate proceeding to address coal investments."[73] To further refine the coal fleet analysis, the Commission directed the participants to schedule several workshops to determine the parameters of coal analyses in future IRPs. Following those workshops, in Order No. 14-296, the Commission adopted Staff's recommendation for future coal analysis that would be used in PacifiCorp's 2015 IRP.

In the 2015 IRP, PacifiCorp implemented the modeling refinements that grew out of

[71] Order No. 14-252 at 5.
[72] *Id.*
[73] *Id.* at 5.

the 2013 IRP and the Commission found that PacifiCorp complied with its "requests and directives" from the 2013 IRP and acknowledged the four action items related to coal resources.[74]

PacifiCorp's 2017 IRP includes the same analysis and modeling approach that was used in the 2015 IRP, and approved by the Commission. Based on that approved analytic methodology, the 2017 IRP preferred portfolio does not include any incremental selective catalytic reduction (SCR) equipment. Avoiding installation of SCR equipment will save customers hundreds of millions of dollars and retain compliance-planning flexibility associated with the Clean Power Plan and other potential state and federal environmental policies. As in past IRPs, the 2017 IRP studied a range of Regional Haze compliance scenarios, reflecting potential bookend alternatives that consider early retirement outcomes as a means to avoid installation of expensive SCR equipment. By the end of the planning horizon, PacifiCorp assumes 3,650 MW of existing coal capacity will be retired.

The 2017 action plan has one item related to coal resources, Action Item 5, and that item includes only further study and monitoring of developments that impact the economics of PacifiCorp's coal units for inclusion in future IRPs.

2. PacifiCorp's reply.

Staff supports PacifiCorp's coal resource action items for limiting the cost and risk to customers from the installation of SCR equipment for Regional Haze compliance: "Analysis presented by PacifiCorp in both previous IRPs and the current IRP consistently indicates that avoidance of [SCRs] is a least-cost, least-risk approach to managing the coal fleet."[75]

ODOE also supports PacifiCorp's coal resource modeling as an improvement over

[74] Order No. 16-071 at 2-3, 7-8.
[75] *Id*.

prior IRPs, stating that the "Regional Haze compliance scenarios were clearly identified, and the process for evaluation explained."[76] ODOE agreed that the "choice of one Regional Haze scenario (RH-5) to use as a base case moving forward into formulating the core cases was a very good one, and much less confusing than how Regional Haze compliance was treated in previous IRP development cycles" and that the "sensitivity cases were well-explained and stakeholders had input on the implementation of the cases."[77]

NWEC also supports PacifiCorp's decision not to make further SCR equipment for its coal fleet.[78]

Sierra Club is the only party that challenges PacifiCorp's coal resource modeling and recommends that the Commission decline to acknowledge Action Item 5. Sierra Club argues that the 2017 IRP is not least-cost, least-risk because it does not include the retirement of non-economic coal resources. Sierra Club claims that approximately 40 percent of PacifiCorp's coal units are uneconomic on a prospective basis, even without meeting required environmental compliance obligations.[79] Sierra Club's analysis is flawed. Sierra Club performs a unit-by-unit analysis to determine whether each individual unit is economic without examining how the retirement of individual unit(s) impacts the system as a whole. In other words, each analysis implicitly assumes that the coal unit being studied is the only one that would be retired. Proper analysis, however, would need to assess the economic impact of each unit that is retired on the next unit analyzed. In addition, Sierra Club's analysis fails to consider the operational impacts of retiring so many coal units. From an operational

[76] Opening Comments of the Oregon Department of Energy at 3.
[77] *Id*.
[78] NW Energy Coalition Comments at 11.
[79] Sierra Club Comments at 3.

perspective, it is untenable to simply retire 40 percent of the coal units, as Sierra Club recommends.

Relatedly, Sierra Club argues that PacifiCorp's analysis only considers the continued viability of coal units in the face of considerable capital investments, like SCRs, instead of engaging in a continual process to evaluate whether coal units remain economic compared to available alternatives.[80] Sierra Club argues that the Commission must direct PacifiCorp to analyze as part of its fundamental planning process the viability of each individual coal unit and demonstrate that continued operation is in the customers' interest. This is a major change to the coal methodology the Commission adopted in 2014, after an extensive review. Sierra Club's proposal should not be considered without additional justification, analysis, and support.

Sierra Club also claims that PacifiCorp failed to include a Regional Haze case that allows endogenous coal unit retirements, despite agreeing to include such a case as part of a settlement reached with Sierra Club in 2016.[81] On the contrary, PacifiCorp conducted seven Regional Haze cases, including an endogenous case (RH-6) as explicitly referenced and defined in the 2016 settlement, that evaluated early retirement versus installation of SCR equipment on the coal plants facing Regional Haze compliance obligations. This Regional Haze case was analyzed among the same market price and greenhouse gas policy assumptions applied to PacifiCorp's analysis of other Regional Haze cases. PacifiCorp fully met its obligations under the 2016 settlement.

Sierra Club claims that despite repeated requests from stakeholders going back years, PacifiCorp continues to withhold tools and data that are necessary to assess the viability of its

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[80] *Id.* at 8.
[81] *Id.* at 8-9.

coal resources.[82] Sierra Club argues that PacifiCorp has a strategy of hindering the valuation of its coal fleet. This claim is at odds with the record in prior IRP cases, where the Commission has found that PacifiCorp's 2015 IRP responded directly to its requirements when acknowledging the 2013 IRP.[83] Moreover, PacifiCorp has worked with Sierra Club and other stakeholders to allow them access and training to the same tools and modeling used by PacifiCorp. The reality of modeling, operating, and delivering electricity supply across a multi-state vertically integrated energy system is that complex tools are required to ensure that PacifiCorp meets its obligations to provide risk-adjusted, least-cost planning, operation, and delivery of electricity for customers. PacifiCorp remains committed to continually improving the analytical support it provides to stakeholders with limited resources.

Sierra Club claims that PacifiCorp's modeling in the 2017 IRP cannot meet enforceable Clean Air requirements.[84] Sierra Club also claims that PacifiCorp's long-term planning assumes that it will prevail in litigation against the U.S. Environmental Protection Agency (EPA) and will therefore have a lower compliance obligation that is currently required by EPA.[85] This is inaccurate. PacifiCorp developed a range of compliance scenarios working with stakeholders and selected the least-cost, least-risk compliance portfolio as its benchmark for the core case and sensitivity analysis that followed in development of the preferred portfolio. PacifiCorp will continue to update its assumptions and scenarios in future IRP cycles and working with stakeholders, taking into account the then-current policy, rulemaking and litigation outcomes as appropriate.

Sierra Club argues that PacifiCorp is unwilling to demonstrate the basis of its

[82] *Id.* at 4.
[83] Order No. 16-071 at 2-3.
[84] Sierra Club Comments at 18.
[85] *Id.* at 21.

Regional Haze alternatives.[86] This is also not the case. PacifiCorp began discussing its Regional Haze compliance obligations and the wide range of cases it planned to assess as early as the second public input meeting in July and continued to discuss and incorporate stakeholder feedback on Regional Haze alternatives that would be studied in the IRP at subsequent public input meetings, including an endogenous retirement scenario (RH-6) at the request of Sierra Club.

C. Demand-Side Management

1. Parties' comments.

Staff finds PacifiCorp's overall position on Class 2 DSM acceptable but has several questions: (1) what amount of the reduction in total energy savings relative to the 2015 IRP is forecast for Oregon specifically; (2) how the avoided cost methodology is used to determine the value and selection of energy efficiency pursued in Oregon and how it relates to the new avoided costs values proposed to the ETO; (3) further clarity regarding the amount of Oregon-specific energy efficiency winter and summer peak reduction; and (4) how historical over-achievement of IRP targets by the ETO are considered in energy efficiency forecasts in the 2017 IRP.

ODOE believes the investments in Class 1 and Class 2 DSM are well aligned with the NPCC's Seventh Power Plan and a "win-win" for customers.

CUB and NWEC do not recommend acknowledgment of Action Item 4a, Class 2 DSM. CUB is concerned about PacifiCorp's proposal to reduce energy efficiency due to reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives because these factors have little to do with cost effectiveness. NWEC

[86] *Id.* at 22.

does not believe that PacifiCorp's proposed reduction in energy efficiency goals relative to the 2015 IRP is properly justified, noting that the NPCC Seventh Power Plan plans shows cost-effective energy efficiency opportunities growing. NWEC is concerned about the level of energy efficiency in Oregon compared to other states.

Sierra Club believes that PacifiCorp's projections of Class 2 DSM are substantially underestimated and contrary to the trend of expanding energy efficiency programs. Sierra Club notes that basing projections on a potential study does not adequately provide long-term projections. Sierra Club also believes PacifiCorp's approach for assessing cost-effectiveness of energy efficiency resources has limitations in transmission and distribution (T&D) deferral credit (or avoided cost), the application of the 20 percent consideration credit, and operation and maintenance costs.

2. PacifiCorp's reply.

While energy efficiency remains the primary cost-effective resource used to meet incremental load growth over the next 10 years, PacifiCorp understands stakeholders' interest in better understanding the decrease in energy efficiency selections relative to the 2015 IRP. PacifiCorp notes that the selected Oregon energy efficiency in the 2017 IRP preferred portfolio decreased less than two percent over the 20-year study period when compared to the 2015 IRP preferred portfolio and actually increased 22 percent over the first 10 years of the study period (2017 through 2026). Oregon energy efficiency selection increased an average of 42 percent during the period 2017 through 2020 (the action plan period).[87] PacifiCorp updates its energy efficiency supply curves for each IRP to reflect updated information on the cost and availability of energy efficiency resources since the previous assessment. As the

[87] See response to OPUC Data Request 55(a), July 5, 2017.

past several IRP cycles have shown, the available energy efficiency potential is not static, but fluctuates based on changes in the market, the emergence of new technologies, improvements to building codes and equipment efficiency standards, and updated load forecasts.

PacifiCorp has not reduced its commitment to procuring cost-effective energy efficiency as CUB suggests in its comments. PacifiCorp's models continue to select all of the cost-effective energy efficiency available. Reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives impact the level of energy efficiency that can be procured cost-effectively as these resources complete with other resources, including demand-side resources, on a least-cost/least-risk basis for resource selection. As CUB notes in its comments, energy efficiency should be acquired to the extent that it is cost-effective, and PacifiCorp's models are consistent with this premise.

ODOE and NWEC both reference the NPCC Seventh Power Plan, but reach different conclusions about its relation to PacifiCorp's 2017 IRP. While PacifiCorp cautions against direct comparison between its 2017 IRP and a power plan for the entire Northwest region, the company notes that NWEC's claim that the Seventh Power Plan shows growing energy efficiency resource opportunity is not supported by the data. The 4,300 average megawatts of new energy efficiency resources in the NPCC Seventh Power Plan[88] represents a 27 percent reduction in 20-year cost-effective energy efficiency savings relative to the over 5,900 average megawatts identified in the NPCC Sixth Power Plan.[89]

The NPCC Seventh Power Plan supports the 2017 IRP's finding that less cost-effective energy efficiency is available than in previous analyses, and further illustrates why it is not appropriate to base future projections of cost-effective energy efficiency resources,

[88] *Seventh Northwest Conservation and Electric Power Plan*, p. 1-2.
[89] *Sixth Northwest Conservation and Electric Power Plan*, p. 4.

or the cost to acquire those resources, on historical resource acquisition levels, as suggested by Sierra Club. As the NPCC Seventh Power Plan describes:

> In the NPCC Sixth Power Plan, the Council estimated the residential sector to offer nearly 2,700 average megawatts of potential energy efficiency at less than $100 per megawatt-hour. The NPCC Seventh Power Plan estimates 1,600 average megawatts of potential but also includes the addition of many new measures. The decrease in potential from the Sixth Power Plan is primarily driven by programmatic accomplishments and improvements in codes and federal standards. For example, in the Sixth Power Plan, there were nearly 400 average megawatts of potential from LED backlit televisions. Television savings identified in the Sixth Plan have already been captured. As older televisions are replaced, the savings from the purchase of new televisions are incorporated as load reductions—the NPCC Seventh Power Plan sets at zero the remaining potential for televisions. Another 220 average megawatts were identified in the NPCC Sixth Power Plan for residential new construction shell upgrades. With the improvement of energy codes across all states in the region, this potential is now significantly decreased and electric use forecasts for future new homes has similarly been decreased where the savings are now required and thus being realized (no longer potential) as a matter of statute or code.[90]

Sierra Club's suggestion that energy efficiency resources in PacifiCorp's IRP should be held flat at historical acquisition levels rather than based on a potential study has several flaws. First, it fails to account for the market dynamics that can affect available energy efficiency potential, some of which are highlighted by NPCC in the passage above. Second, it fails to recognize the many factors that affect the cost-effectiveness of energy efficiency resources as compared to supply-side resource alternatives—acquiring energy efficiency resources at levels significantly higher than what the IRP deemed cost-effective could drive additional costs to PacifiCorp customers. PacifiCorp continues to work with ETO to improve alignment between IRP energy efficiency targets and actual acquisition. Third, the suggestion seems to be in direct conflict with the Commission's IRP guidelines for

[90] *Seventh Northwest Conservation and Electric Power Plan*, p. 12-22.

conservation—that a utility should conduct periodic potential studies and include best cost/risk portfolio conservation resources in its action plan.[91]

Parties' questions about the cost-effectiveness of energy efficiency resources are timely, as PacifiCorp recently completed its 2017 Class 2 DSM Decrement Study, which provides the basis of cost-effectiveness analysis, consistent with the 2017 IRP, for states where the company delivers energy efficiency programs.[92] PacifiCorp provided comparable values to the ETO for incorporation into its avoided-cost calculations. PacifiCorp is currently working with the ETO to improve alignment of the ETO's methodology with the value to PacifiCorp's system. PacifiCorp understands that Staff plans to begin a stakeholder process to review Oregon energy efficiency avoided-cost methodology, and PacifiCorp plans to actively participate in that process.

At the August 25-26, 2016 2017 IRP public input meeting, PacifiCorp described the methodology for assessing cost-effectiveness of energy efficiency resources in the 2017 IRP, including why the methodology differs by state.[93] As explained during that presentation, each state in which PacifiCorp operates provides its own guidance on how to assess the cost-effectiveness of energy efficiency programs. For example, as Sierra Club notes, Oregon and Washington primarily view energy efficiency programs from a total resource cost perspective, including an additional ten percent credit, consistent with the methodology of the NPCC. However, other states do not recognize this 10 percent credit, and including the credit for all states, as Sierra Club suggests, would create a disconnect between the levels of

[91] Guideline 6, Order No. 07-002.
[92] The study is available on the Company's website at the following URL: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/2017/PacifiCorp_Class2_DSM_Decrement_Study.pdf
[93] 2017 Integrated Resource Plan Public Input Meeting 3, August 25-26, 2016, Slide 127.

energy efficiency deemed cost-effective in the IRP and what could be delivered cost-effectively per state-specific guidance.

Sierra Club also questions the value of the T&D deferral credit applied to energy efficiency resources, pointing out that the 2017 IRP value of $13.56/kW-year is lower than the value applied in the 2015 IRP and the credit applied in the NPCC Seventh Power Plan. Energy efficiency's ability to defer T&D investment is highly dependent on the unique characteristics of a given utility's system, and variation should be expected, both between utilities and for different vintages of studies for a given utility. The T&D deferral value used in the 2017 IRP is derived from an updated assessment of load growth and planned T&D investments to serve new load, specific to PacifiCorp's system. In contrast, the NPCC Seventh Power Plan's T&D deferral credit dates back to 2008, when load forecasts showed higher expected growth rates relative to today, and is an average of values from several utilities, many of which may no longer be accurate.

D. RPS Compliance

1. Parties' comments.

Staff anticipates that the benefits of the RECs and capital costs of the new wind projects will affect the RPS incremental cost calculation in the future. Staff does not expect PacifiCorp to deviate from its approved 2016 Renewable Portfolio Standard Implementation Plan (RPIP) for the five year period from 2017-2021. In the 2017 IRP, PacifiCorp states that it will use unbundled RECs for compliance but plans to complete the installation of new supply-side resources by 2020. Because PacifiCorp uses a first-in-first-out REC retirement structure, RECs from these new resources will likely not be used for compliance with the RPS during the term of the 2016 RPIP.

NWEC believes that the increase in renewable resources earlier in the planning period and the coal retirements will help put Oregon on track for meeting statutory GHG emissions reduction goals and put PacifiCorp in a better position should there be higher than expected carbon prices or new GHG requirements.

2. PacifiCorp's reply.

PacifiCorp's RPIP was refiled at the Commission's directive to address the new RPS requirements resulting from the passing of Senate Bill (SB) 1547 (2016). The refiled RPIP presented a number of scenarios, one of which showed the benefits of competitively priced near-term procurement opportunities. Unlike the analysis presented in the RPIP, the new supply side resources identified in the 2017 IRP are not being driven by a need to comply with the Oregon RPS—these are cost-effective system resources that will be used to meet customer load, with the added benefit of contributing to state RPS targets.

The RPIP analysis and results will be updated in December 2017 to align with PacifiCorp's most recently acknowledged IRP, and could deviate from the acknowledged 2017-2021 RPIP. In light of SB 1547's more flexible REC retirement rules, which eliminate the first-in, first-out requirement, PacifiCorp will not always follow a first-in, first-out methodology. It is therefore possible that RECs from the new supply-side resources would be retired for compliance toward the end of the 2017-2021 period. PacifiCorp acknowledges that if RECs from the new supply-side resources are retired for Oregon RPS compliance, there will be an impact on the RPIP incremental cost calculation. PacifiCorp also anticipates an impact to the RPIP cost calculation once the Commission completes the AR 610 rulemaking, which will include revisions to the Oregon RPS Incremental Cost Calculation.

PacifiCorp agrees with NWEC's comments regarding the benefits and risk mitigation associated with adding renewables in the first 10 years of its preferred portfolio.

E. Front Office Transactions

1. Parties' comments.

Staff agrees with PacifiCorp that there is likely not a capacity deficit looming in 2021 and load can reliably be met with the existing resource fleet and FOTs, and this is the least-cost, least-risk strategy. Staff expects that PacifiCorp will notify the Commission if it anticipates or experiences market changes which could alter its action plan. NWEC questions what the reliance on FOTs does for resource adequacy if the incidences of exceeding the FOT planning limit continue more frequently. ODOE requests a more in-depth analysis of reliance on FOTs, particularly in the summer. In the next IRP, ODOE would like to see an analysis of energy efficiency and direct load control (DLC) explored as a hedge against high levels of market purchases.

2. PacifiCorp's reply.

PacifiCorp will continue to seek and review the most current regional and northwest studies available on resource adequacy and present its findings and assessment of FOT limits in future IRP cycles. The FOT limits in PacifiCorp's IRP are planning limits imposed to ensure that PacifiCorp's preferred portfolio does not rely market purchases beyond those limits. In application, on a day-to-day basis, operational circumstances may necessitate higher or lower FOT purchases based on economics and overall system conditions. PacifiCorp notes that it included in its 2017 IRP portfolio development process a specific core case specifically targeting DLC resources (DLC-1). Results of this case to other cases can be used to assess the impact of DLC on FOTs in the portfolio. PacifiCorp welcomes

ODOE's input during the public input meeting stakeholder process to inform potential sensitivities that might be run in future IRP cycles.

F. Load Forecasting and Load and Resource Balance

1. Parties' comments.

Staff believes that PacifiCorp's load and resource balance is comprehensive and thorough, which indicates that PacifiCorp has ample capacity to meet projected load in the IRP timeframe without any new major resources. Staff questions whether issues from past IRPs have been resolved in this IRP, specifically: (1) whether PacifiCorp can reliably meet its winter peak in its west balancing authority area (BAA) given the limited transmission between the two BAAs; (2) whether forecasts reflect decreased loads due to customer-owned solar; and (3) whether the forecasts reflect decreased loads due to customers opting for direct access.

ODOE notes that PacifiCorp performed a winter peak analysis for the first time in the 2017 IRP which will allow PacifiCorp to report winter load and resource balances. ODOE encourages PacifiCorp to return to the high–private generation scenario and run additional analysis in the next IRP.

2. PacifiCorp's reply.

PacifiCorp can reliably meet its winter peak obligations in the west BAA, relying on east-to-west transmission, and within known firm transmission constraints. As with past IRPs, these constraints cannot be abrogated and are applicable to all IRP studies. The 13 percent Planning Reserve Margin (PRM) provides additional support that unforeseen events would not prevent efficient and economic operation as presented in the system-level optimization results of all studies.

The load forecasts in the IRP reflect decreased loads due to customer-owned solar generation. The private solar generation forecast is taken from the 2016 Private Generation Long-Term Resource Assessment (2017-2036) study prepared by Navigant Consulting, Inc. included in the 2017 IRP Volume II, Appendix O, Private Generation Study. This study estimated private generation penetration levels specific to PacifiCorp's six-state territory, including a break-down of anticipated private solar growth in each state. PacifiCorp's 2017 IRP load and resource balance treats base case private generation penetration levels as a reduction in load. As noted by Staff, the 2017 IRP presents private generation as a separate load component in Volume I, Chapter 5 – Load and Resource Balance, pages 91-92. Private solar generation is rolled into the "private generation" rows of "Table 5.14 – Summer Peak – System Capacity Loads and Resources without Resource Additions", and "Table 5.15 – Winter Peak – System Capacity Loads and Resources without Resource Additions".

Customers opting for direct access are removed from the load forecast as appropriate based on the term of their selected program.

In response to ODOE's comments, PacifiCorp will continue to assess trends in private generation and will continue to work with stakeholders in the public input meeting process to establish sensitivities for future IRP cycles.

G. Demand Response

1. Parties' comments.

Staff is concerned that PacifiCorp seems to plan long lead times for demand response development, particularly in Oregon, even though PacifiCorp has solid experience in other areas of its system. Staff is concerned that PacifiCorp's study is not transparent and PacifiCorp may not be using full efforts to pilot and acquire cost-effective demand response as identified in the demand response potential study and as required by SB 1547. Staff noted that it may seek revisions to the narrative and to the study's structure in future IRPs.

2. PacifiCorp's reply.

PacifiCorp's Demand-Side Resource Potential Assessment for 2017-2036, performed by Applied Energy Group (AEG), includes extensive detail on the methodology, inputs, and results of the assessment of demand response resource potential.[94] The methodology and format of the final report are materially the same as in previous IRP cycles, and PacifiCorp presented and discussed the results of this study with stakeholders at the August 25-26, 2016 public input meeting. PacifiCorp will continue to update this study in future IRP cycles and is open to feedback from Staff on ways to improve the study.

PacifiCorp included new demand response programs as resource options in the 2017 IRP beginning in 2019, factoring in the time required for regulatory approval and program ramp-up if resources were deemed cost-effective in the 2017 IRP. While the resource need does not occur until 2028, the 2017 IRP identified significantly more new cost-effective demand response over the long-term than in the 2015 IRP.

As PacifiCorp's Oregon Irrigation Load Control Pilot has demonstrated, having experience with a given program design in one jurisdiction does not necessarily translate to a scalable, cost-effective design in another geographical area. PacifiCorp will continue to assess potential demand response options to determine whether pilot programs are warranted.

H. Smart Grid

1. Parties' comments.

Staff requested information about interrelationship between advanced metering

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[94] PacifiCorp's Demand-Side Resource Potential Assessment for 2017-2036, completed by AEG, can be found at: http://www.pacificorp.com/es/dsm.html

infrastructure (AMI) and planning and resource applications in PacifiCorp's reply comments. Staff expressed concern that PacifiCorp has not indicated how the rollout of AMI in Oregon folds into the IRP and has not presented the costs or savings of this project in the 2017 IRP.

2. PacifiCorp's reply.

PacifiCorp's load forecast uses econometric models that rely on historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes. Any variations in customer usage from behavioral changes resulting from programs such as AMI installation will therefore be captured and reflected in the load forecast in future IRP cycles. In addition, PacifiCorp will continue to update its Smart Grid study found in the 2017 IRP, Volume II, Appendix E, in future IRP cycles.

I. Distribution System Planning

Staff stated that it plans to explore issues around distribution system planning and provide process recommendations in its final comments regarding next steps for investigating, defining, and potentially implementing distribution system planning (DSP). PacifiCorp provides the following responses to Staff's questions as follows.

- How does PacifiCorp envision improving the connection between planning for and investing in a distribution system that is needed to efficiently, reliably and safely manage higher levels of distributed energy resources (DERs)?
    - PacifiCorp believes that the long-term planning process appropriately reflects the results of distribution investments, energy efficiency programs and additions of private generation resources. Planning for the reliability and safety of the distribution system requires a shorter and more dynamic

planning process and should remain separate and distinct from the long-term IRP process.

- Does PacifiCorp see benefit in reassessing and possibly reworking the current regulatory processes connecting locational value dockets (e.g., Resource Value of Solar (UM 1716) and Energy Storage (UM 1751)), distribution infrastructure planning, the Smart Grid Report and the IRP?
  - PacifiCorp believes that what Staff refers to as the locational value dockets will help to further inform the long-term IRP load and resource forecasting process, but maintains that DSP should remain separate from, yet inform, the long-term IRP planning process due to the short-term and dynamic requirements of investments in the distribution system. The Smart Grid Report is already a component of the IRP process.
- Would greater, more comprehensive regulatory guidance related to DSP enable more efficient prioritization of company action and resources toward grid modernization goals?
  - The company has a robust distribution system planning process that efficiently prioritizes distribution system improvements for service reliability, grid modernization, renewables integration and load growth using historical demand profiles and a locally focused perspective on future trends and customer behaviors. Distribution system planning is conducted on a periodic basis to identify potential electrical infrastructure needs in the respective planning area. Due to the dynamic nature of distribution feeders, distribution planning studies typically evaluate a

forward-looking five-year period and area sub-transmission studies are conducted for a 10-year period. The construction cycles for distribution system solutions are typically short, allowing for the underlying assumptions to develop and be validated before committing to a project. Because of the geographically specific nature of distribution system planning and the need for shorter lead time, more dynamic distribution system investment, the distribution system planning process is fundamentally distinct and separate from the long-term Integrated Resource Planning process.

- In addition, the existing distribution system planning process currently considers and evaluates a wide range of technologies and solutions that could be labeled "traditional" or "alternative" as solutions to a projected need. To further inform the grid modernization aspects of distribution system planning, the company filed the draft 2017 Pacific Power Smart Grid Annual report in docket UM-1667 that focuses on technologies and processes that can be readily integrated in an affordable manner with the existing electrical grid infrastructure. The 2017 Smart Grid Annual Report included in the 2017 IRP (Volume II, Appendix E) contains an example of how the company's distribution system planning process considers and evaluates "alternative" resource solutions solar, solar plus energy storage and DSM to enhance the solutions evaluation to efficiently invest in the distribution system.

- Could greater transparency of location specific aspects of distribution system resources and load lead to greater adoption of cost-effective DERs than currently reflected in IRP planning assumptions and potentially lessen the cost of system operations?
    - PacifiCorp believes that the locational value dockets will help to further inform the long-term IRP load and resource forecasting process, but maintains that DSP should remain separate, yet inform, from the long-term IRP process due to the short-term and dynamic requirements of investment in the distribution system.

J. Clean Power Plan Modeling

1. Parties' comments.

Staff applauded PacifiCorp's extensive efforts to model CPP compliance in conjunction with other environmental regulatory requirements, and noted that it will seek additional information regarding how the CPP may have informed modeling runs, portfolio selection and preferred resource acquisition.

RNW believes that PacifiCorp's consideration of the CPP in the 2017 IRP was appropriate.

2. PacifiCorp's reply.

Staff notes that PacifiCorp assumes a WECC-wide compliance agreement between states, or that all states adopt the same CPP compliance approach, including whether states choose to adopt EPA's New Source Complement option, but that this level of coordination does not exist. PacifiCorp chose to model the CPP in this way as a simplifying assumption because to do otherwise would have involved significant unpredictability and a potentially endless number of scenarios involving different states' individual choices regarding CPP compliance. This would have become unworkable, and this simplifying assumption did not have a significant impact on modeling results. In addition, PacifiCorp does not think it unreasonable or unrealistic to assume that, for its own system modeling, PacifiCorp states could potentially agree on allowing PacifiCorp to adopt a system-approach to CPP compliance.

Even though the IRP was not filed until April 4, 2017, to complete the extensive modeling required to file by April planning assumptions had to be finalized at the end of 2016. PacifiCorp is aware that since that time, President Trump signed an executive order regarding the CPP. Accordingly, PacifiCorp will continue to consider and evaluate the use of CPP modeling in future IRP cycles.

K. Storage

1. Parties' comments.

NWEC is pleased that PacifiCorp is making improvements to storage analytics a priority.

National Grid encourages the Commission to require PacifiCorp to perform a study of the benefits of building regional pumped-hydro storage projects to serve the needs of Oregon, Washington, and California.

2. PacifiCorp's reply.

PacifiCorp developed two energy storage sensitivity studies in the 2017 IRP, including a study for battery storage and a study for compressed air energy storage, and appreciates NWEC's comments on this issue. PacifiCorp will continue to work with stakeholders and evaluate energy storage in future IRP cycles.

PacifiCorp's IRP planning process also includes an update to its Bulk Energy Storage study conducted by external consultants. For the 2017 IRP, this study included the pumped-hydro storage projects discussed in National Grid's comments. This study informs the costs associated with pumped-hydro storage projects that are then modeled in the IRP to compete for resource selection with other supply-side resources. PacifiCorp continues to stay actively informed about the benefits of pumped-hydro storage projects but does not agree the IRP process is the appropriate place to conduct a regional pumped-hydro storage study as National Grid suggests. PacifiCorp will continue to model pumped-hydro storage projects in future IRP cycles.

L. Resource Sufficiency Demarcation

1. Parties' comments.

The Coalition provides two recommendations related to the resource position used to calculate avoided cost prices. First, the Coalition opposes acknowledgement of the fact that, under the preferred portfolio, PacifiCorp would not acquire its next major thermal resource until 2029. The Coalition argues that this date is speculative and that PacifiCorp will likely acquire a major baseload capacity resource well before 2029.[95]

Second, based on PacifiCorp's proposal to acquire 1,100 MW of PTC-eligible Wyoming wind resources by 2021, the Coalition argues that PacifiCorp is renewable-resource deficient in 2021.[96] The Coalition also argues that if a proposed renewable resource requires additional transmission investment, as is the case of the proposed Wyoming wind resources, then Oregon QFs should be paid for both the avoided generation and avoided

[95] Renewable Energy Coalition's Comments at 11-12.
[96] *Id.* at 9-10.

transmission costs.[97] The Coalition expresses confusion over whether PacifiCorp is proposing a modification of the Commission's methodology for determining when the company is resource sufficient for purposes of calculating avoided costs.[98]

2. PacifiCorp's reply.

PacifiCorp's current avoided cost prices are differentiated based on whether the company is considered resource sufficient or resource deficient.[99] During the deficiency period, capacity provided by a QF allows PacifiCorp to defer or avoid a future resource acquisition, so avoided cost prices include a capacity payment. When PacifiCorp has sufficient resources to serve load, however, a QF does not allow PacifiCorp to avoid capacity costs and the avoided cost price does not include a capacity payment. For avoided cost pricing, PacifiCorp is resource sufficient until the next major resource acquisition identified in its IRP.[100] For renewable avoided cost pricing, PacifiCorp is resource sufficient until the next acquisition of a renewable resource that is required to meet PacifiCorp's RPS obligation.[101]

The Coalition provides no analytical support for its claim that the 2017 IRP is inaccurate because they believe PacifiCorp will acquire a new thermal resource before 2029. Instead, the Coalition speculates that PacifiCorp will require new thermal resources before

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[97] *Id.* at 10-11.
[98] *Id*.
[99] *In the Matter of the Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 05-584 at 26 (May 13, 2005) ("In a period of resource deficiency, the historical calculation of avoided costs has included both the variable and fixed costs of a planned resource in order to reflect the actual deferral or avoidance of that resource. In a period of resource sufficiency, however, the historical calculation of avoided costs has included only the variable costs of operating an existing resource, reflecting the inability of a resource sufficient utility to defer or avoid a resource when QF generation is committed.").
[100] *In the Matter of Public Utility Commission of Oregon Investigation into Determination of Resource Sufficiency,* Docket No. UM 1396, Order No. 10-488 (Dec. 22, 2010).
[101] *In the Matter of Public Utility Commission of Oregon Investigation into Determination of Resource Sufficiency,* Docket No. UM 1396, Order No. 11-505 at 9 (Order No. 11-505) (Dec. 13, 2011).

2029 due to uncertainties, such as future environmental regulations and planned coal plant retirements. Every uncertainty identified by the Coalition is factored into the analytics and modeling for the 2017 IRP. With consideration of these uncertainties, PacifiCorp's preferred portfolio shows it does *not* require a new thermal resource before 2029. The Coalition did not identify any uncertainty that PacifiCorp did not already consider in the 2017 IRP. The Coalition also failed to provide any substantive criticism of PacifiCorp's modeling of these uncertainties.

Moreover, the 2017 IRP is consistent with previous IRPs. The first thermal resource acquisition identified in the acknowledged 2015 IRP and 2015 IRP Update in 2028. The 2017 IRP has delayed that sufficiency period by one year, which is driven by an updated load-and-resource balance and selection of least-cost, least-risk resources to meet system load through the 20-year planning time frame. The consistency between the results of the 2015 and 2017 IRPs validates PacifiCorp modeling.

The purpose of the IRP is to produce a long-term resource plan based on the best available evidence at the time the plan is prepared. The robust analysis included in the 2017 IRP is based on the best available evidence and demonstrates that PacifiCorp will not need a new thermal resource until 2029.

As to the Coalition's second argument, for purposes of determining renewable avoided-cost pricing, PacifiCorp's planned acquisition of 1,100 MW of Wyoming wind resources does not indicate that the company is renewable resource deficient in 2021. As noted above, the Commission has found that "[r]enewable QFs willing to sell their output and cede their RECs to the utility allow the utility to avoid building (or buying) renewable generation *to meet their RPS requirements*."[102] Thus, "[t]hese QFs should be offered an avoided cost stream that reflects the costs that utility will avoid."[103] The sufficiency/deficiency demarcation for renewable avoided cost prices is tied directly to whether a QF will allow PacifiCorp to avoid an RPS compliance cost and should not necessarily be tied to the presence of a renewable resource in the preferred portfolio that is added as part of the least-cost, least-risk plan to meet system load.

Moreover, Oregon QFs that do not interconnect with or use PacifiCorp's Wyoming transmission system to deliver energy and capacity in the same time frame as the proposed wind resources would not partially displace or defer any of the 1,100 MW of new wind resources. PacifiCorp's modeling demonstrates that new wind resources located in Wyoming and coupled with the Aeolus-to-Bridger/Anticline line provide net benefits to retail customers. PacifiCorp would therefore pursue these resources even if new QF projects were added to the system in Oregon. If a new Oregon QF does not result in the company avoiding either the new wind or transmission resources, then Oregon's avoided-cost prices should not assume that either resource is avoided.

Finally, PacifiCorp is not proposing in this IRP to modify the Commission's long-standing policy for determining resource sufficiency/deficiency periods for purposes of determining avoided-cost pricing. PacifiCorp's 2017 IRP demonstrates that if no further procurement activity were pursued, it would meet its Oregon RPS obligations through 2028, based on the metrics that the Commission has consistently applied to determine whether PacifiCorp is resource sufficient—whether a QF will allow PacifiCorp to avoid RPS

[102] Order No. 11-505 at 9 (emphasis added).
[103] *Id*.

compliance costs. PacifiCorp is resource sufficient for non-renewable avoided cost prices through 2029.

PacifiCorp recognizes that the acquisition of resources driven by the economic benefits they offer for customers, rather than resource acquisition strictly based on a traditional demonstration of need, may present new issues for Commission consideration. In Order No. 17-239, issued on July 7, 2017 (after the Coalition filed its IRP comments), the Commission indicated that it would hold workshops to address these issues.[104] Based on the fact that these issues may be further examined, the Commission should not consider changes to its existing policy here.

M. Capacity Value for Expiring QF Contracts

1. Parties' comments.

The Coalition claims that PacifiCorp has improperly modeled capacity contributions from existing QFs and PacifiCorp has therefore ignored a directive from the Commission in Order No. 16-174 to work with stakeholders to determine how to value the capacity contribution provided by existing QFs when they renew their contracts.[105]

2. PacifiCorp's reply.

Contrary to the Coalition's allegations, PacifiCorp's 2017 IRP modeling is directly responsive to the Commission's ruling in Order No. 16-174. In docket UM 1610, the Coalition and several other parties recommended that avoided costs account for the capacity value provided by existing QFs.[106] The Coalition argued that PacifiCorp's IRP modeling

[104] *In the Matter of PacifiCorp, d/b/a Pacific Power Investigation into Schedule 37 – Avoided Cost Purchases from Qualifying Facilities of 10,000 kW or Less*, Docket No. UM 1794, Order No. 17-239 at 3 (July 7, 2017).
[105] Renewable Energy Coalition's Comments at 3-9.
[106] *In the Matter of the Public Utility Commission of Oregon Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 16-174 at 19 (May 13, 2016).

improperly assumed that QFs will renew their contracts, thereby extending PacifiCorp's resource sufficiency period, without compensating the existing QFs for allowing PacifiCorp to defer future resource acquisitions.[107] In Order No. 16-174, the Commission directed PacifiCorp to work with the parties to address this issue in its 2017 IRP.[108]

As PacifiCorp communicated to stakeholders during the public input process—and as acknowledged by the Coalition[109]—the 2017 IRP no longer assumes that QF contracts are renewed.[110] As a result, the deficiency period in the 2017 IRP is based on the assumption that existing QFs will not renew their contracts. When an existing QF renews its contract, it will receive the same capacity payment that would be received by a new QF. The Commission has already found that this fully compensates QFs for their capacity contributions;[111] therefore, PacifiCorp's 2017 IRP complies with Order No. 16-174.

N. Planning Reserve Margin Study

1. Parties' comments.

Staff is generally satisfied with the procedures PacifiCorp used in the PRM study as well as the selected 13 percent target PRM, but will work with PacifiCorp to clarify certain details.

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[107] *Id.*
[108] *Id.*
[109] REC submitted written feedback to the Company during its IRP public input process in which it stated: "We asked, at an IRP stakeholder meeting, about the Company's assumption regarding the renewal of QF contracts. In all past IRPs, including the last IRP (LC 62) PacifiCorp assumed that all small existing QF contracts renew and stay in the existing resource stack. **PacifiCorp has changed their assumption in this 2017 IRP, and is now assuming that they do not renew.**"
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/RECComments_FeedbackForm_02_21_17.pdf (emphasis added).
[110] To be clear, in prior IRPs, PacifiCorp assumed that large QFs would not renew their contracts. Thus, in the 2017 IRP, both large and small QF contracts are treated the same.
[111] Order No. 16-174 at 19.

2. PacifiCorp's reply.

PacifiCorp will continue to assess and study its PRM modeling assumption in future IRP cycles.

O. Flexible Reserve Study (FRS)/Wind & Solar Capacity Contribution Study

1. Parties' comments.

Staff notes that it has sought discovery regarding the data sources and calculation used in the FRS and expects that PacifiCorp is justified in attributing different levels of regulation reserves to load, wind, solar, and non-variable energy resources based on the data sources, methods, and calculations employed. ODOE appreciates the consistent use of the capacity factor approximation method and noted the expanded wind integration study. In the next IRP, ODOE would like to see validation of the capacity factor contribution for both west and east. ODOE notes that there is a concern that some QFs in the west BAA may be financially harmed if the reduction in capacity contribution has been overestimated.

2. PacifiCorp's reply.

PacifiCorp appreciates Staff's support on the FRS and the new methodology used to determine the regulation reserves necessary to reliably manage variations in the loads and resources on PacifiCorp's system. PacifiCorp provided workpapers containing the data sources and calculations used in the FRS with the 2017 IRP filing.[112]

PacifiCorp also appreciates ODOE's comments on its capacity factor approximation method used in the Wind & Solar Capacity Contribution Study. PacifiCorp notes that the Wind & Solar Capacity Contribution Study used the same methodology for east and west resources and for wind and solar resources consistent with the company's approach in the

[112] *See* the non-confidential data discs, folder Appendix F.

2015 IRP. PacifiCorp provided workpapers containing the study calculations used in the Wind & Solar Capacity Contribution Study with the 2017 IRP filing.[113] PacifiCorp will continue to update this study in future IRP cycles and seek stakeholder feedback during its public input process.

P. Modeling and Stochastic Parameters

1. Parties' comments.

Staff notes that PacifiCorp appears to be appropriately considering a wide range of variables in its studies and notes a few assumptions related to the in-service dates that it is continuing to assess through discovery. Staff explains that PacifiCorp's model and portfolio evaluation appears to be robust and developed with a level of complexity well suited to the IRP process. Staff indicated that it will work with PacifiCorp to better understand the data source used in the stochastic parameter analysis and better understand the regional scale modeling, in particular understanding why missing price data were "blanked" for natural gas prices, but interpolated for electricity. ODOE believes that PacifiCorp's resource development process has improved from the 2015 IRP. RNW recommends that the Commission acknowledge the preferred portfolio and summarized what it describes as PacifiCorp's rigorous three-phase selection process.

2. PacifiCorp reply.

In each IRP planning cycle, PacifiCorp identifies and implements advancements to continuously improve its modeling and planning assumptions. In the 2017 IRP, some key advancements include a winter-peak analysis, improved portfolio development process and stakeholder involvement, modeling of the CPP and development and incorporation of solar

[113] *See* the non-confidential and confidential data discs, folder Appendix N.

integration costs as part of its FRS. A number of supplemental studies were also updated as described in more detail on pages 14-15 of the 2017 IRP, Volume I, Executive Summary, and included in the 2017 IRP in Volume II. PacifiCorp appreciates Staff's request for further clarification on certain modeling assumptions and is actively working with Staff on those items through the discovery process.

Regarding Staff's request to understand why missing price data were "blanked" for natural gas prices, but interpolated for electricity, PacifiCorp offers the following clarification: As described in the 2017 IRP, Volume II, Appendix H – Stochastic Parameters, page 151, missing prices are interpolated for secondary (illiquid) markets, but not for primary markets. A missing primary market price (gas or electricity) would be left blank, although this is not explicitly stated for electricity. Missing natural gas prices are treated the same way, except that there are no secondary markets in the analysis, and so interpolation is not a possibility.

As summarized by RNW, PacifiCorp followed an improved three-phase preferred portfolio selection process that consisted of the following: (1) Regional Haze case screening; (2) eligible case screening; and (3) final screening for preferred portfolio selection. This approach enabled PacifiCorp to evaluate more combinations of resources when comparing the relative cost and risk among different portfolio options. This was achieved by initially working with stakeholders to evaluate a comprehensive range of regional haze compliance cases under different market-price and environmental-policy scenarios and then using stochastic-risk metrics to evaluate the relative performance of alternative compliance outcomes. Results from this analysis established coal-unit retirement assumptions for subsequent core case and sensitivity case studies, addressing stakeholder feedback from the

2015 IRP requesting that portfolios considered for selection as the preferred portfolio be compared among common Regional Haze compliance assumptions.

Q. Risk Metrics

1. Parties' comments.

Staff expresses concerns about the use of the upper tail statistics for measuring risk and questions the justification for use of the five percent metric and views the five percent value as potentially arbitrary. Staff also notes that while the variability of portfolio cost around the expected value is a reasonable measure for the severity or intensity of risk, it does not capture the probability of an event occurring, and that both should be considered to understand the amount of risk represented by a portfolio.

2. PacifiCorp's reply.

PacifiCorp welcomes a specific proposal from Staff to establish an alternative risk metric that satisfies the Commission's guidelines and that it believes is less arbitrary. PacifiCorp assessed upper-tail stochastic risk in all of its IRPs (2003, 2004, 2006, 2008, 2011, 2013, 2015 and 2017). As described in the 2017 IRP, Chapter 7, Modeling and Portfolio Evaluation Approach, pages 166-169, for each Monte Carlo iteration, PaR generates a set of natural gas prices, electricity prices, loads, hydroelectric generation and thermal outages. While all stochastic outcomes in the 2017 IRP meet all requirements and constraints, the upper-tail mean PVRR represents the five percent of least-favorable (*i.e.*, worst-case) iterations of each study.

This stochastic risk is conservatively incorporated into the PVRR assessment of every case by adding five percent of the upper tail mean PVRR to the mean PVRR, resulting in a "risk-adjusted PVRR." The risk-adjusted PVRR represents the long-term cost performance for a portfolio, accounting for the potential for a high-cost, low-probability outcomes and its associated impact on an expected-value basis.

As an accepted and explicit risk measure derived from stochastic outcomes, PacifiCorp believes that incorporating upper-tail risk allows for the consideration of skewed distributions in projected system costs among different resource portfolios and reasonably represents the risks inherent in portfolio performance. As a portfolio driver, this measure allows a resource mix with less volatility across stochastic iterations to compete with a portfolio that may be exceptionally favorable but only within a very narrow range of parameters. This approach tends to support the selection of a portfolio that is robust across a range of possible futures.

R. Natural Gas Resource Analysis

1. Parties' comments.

Regarding the natural-gas-fired resource selected in 2029, Staff appreciates that PacifiCorp will continue to evaluate potential long-term supply alternatives, including energy storage and new potential technologies across the planning horizon.

2. PacifiCorp's reply.

As noted by Staff, PacifiCorp will continue to evaluate potential long-term supply alternatives, including energy storage and new potential technologies in future IRP cycles.

S. Natural Gas Forecast

1. Parties' comments.

The Coalition argues that the Commission should direct PacifiCorp to use an independent third-party gas forecast.

2. PacifiCorp's reply.

PacifiCorp used three underlying natural gas forecasts as shown in the 2017 IRP, Chapter 7, page 154: (1) the October 2016 official forward price curve (OFPC) base case; (2) a high-price scenario; and (3) a low-price scenario. Each of these forecasts is based upon independent third-party sources. PacifiCorp has not deviated from past principles in developing its gas price outlook. The 2017 IRP reflects a lower natural gas price forecast that consistent with changing price dynamics brought about by structural shifts in natural gas markets. PacifiCorp's continued use of an expert third-party forecast is reasonable.

PacifiCorp describes the OFPC development process in the 2017 IRP, Chapter 7, pages 152-153. PacifiCorp does not pay an expert third-party forecaster to produce customized forecasts. Instead, PacifiCorp subscribes to two expert third-party forecasting services to receive multi-client "off-the-shelf" base and scenario forecasts, with supporting data, on a regular basis. Both forecasting services employ natural gas experts, are well established in energy market research and analytics, and serve hundreds of clients, many of which are Fortune Global 500 companies. PacifiCorp is merely one of many subscribers and has no influence on forecast development.

The U.S. Energy Information Administration's (EIA) natural gas price forecasts, as published in its 2016 Annual Energy Outlook, were reviewed as part of PacifiCorp's OFPC development process but not selected because the EIA's reference and scenario outlooks were outliers compared to either of the expert third-party forecasts.

T. Access to Computer Models

1. Parties' comments.

The Coalition argues that Staff and stakeholders should be allowed to use, at low cost or no cost, any computer models relied upon in the IRP process. To support its position, the Coalition pointed to the 2015 IRP review when Sierra Club's expert acquired the capacity expansion model and identified modeling constraints that PacifiCorp did not present to stakeholders.

2. PacifiCorp reply.

PacifiCorp has continued its practice started in the 2015 IRP of providing data discs with its 2017 IRP filing, which include modeling inputs and outputs, results and assumptions. The data discs allow stakeholders to review the same information produced by PacifiCorp's models including input, outputs, and PacifiCorp's processing of the outputs to generate summary files.

The 2017 IRP is a public process that allows for feedback and comments from many stakeholders. However, due to proprietary nature of the software, PacifiCorp is unable to provide license rights to the modeling software, and is not aware of any other utility that provides this service to stakeholders in an IRP process. Given the complexities of the models, PacifiCorp has continued to work with stakeholders to address these issues by being as transparent as possible.

In response to the Coalition's specific example, in the 2015 IRP, PacifiCorp established certain fixed coal retirement dates as discussed in the 2015 IRP and part of the three Regional Haze scenarios modeled at that time. Similarly, in the 2017 IRP, Regional Haze scenarios and assumptions were discussed in the 2017 IRP public input meeting process and stakeholder comments lead the company to add case Regional Haze case 6 (RH-6) where selected coal units were allowed to retire endogenously.

IV. CONCLUSION

PacifiCorp's 2017 IRP complies with the Commission's standards and guidelines. The 2017 IRP includes robust portfolio modeling and prudent planning assumptions that lead to selection of a least-cost, least-risk preferred portfolio. The 2017 IRP also includes an action plan that is consistent with the long-term public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group and continues to support stakeholder participation throughout the IRP development process to foster constructive dialogue.

PacifiCorp requests that the Commission acknowledge the 2017 IRP and the 2017 IRP action plan.

Respectfully submitted this 28th of July, 2017

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