PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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October 30, 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 Response Comments

PacifiCorp d/b/a Pacific Power submits for filing its Response 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 **Response Comments** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated October 30, 2017.

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 RESPONSE 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. PacifiCorp appreciates the active participation of Commission Staff and other parties throughout the 2017 IRP process, which included multiple opportunities to submit written comments and to participate in workshops.

Parties filed written comments on June 23, 2017; PacifiCorp filed reply comments July 28, 2017, and also filed a supplemental informational filing on that date. Parties were given the opportunity to file additional response comments to PacifiCorp's informational filing on August 24, 2017, and Staff filed its final comments and recommendation on October 6, 2017. In addition to written comments, there were several stakeholder and commissioner workshops, including PacifiCorp's presentation at the May 30, 2017 public meeting; commissioner workshops on July 10, 2017, and September 14, 2017; and a stakeholder workshop on August 17, 2017.

PacifiCorp agrees with Staff that "the IRP is a tool to help identify and determine the amount and timing of any new resource acquisition that best serves the needs of utility customers."[1] PacifiCorp and Staff diverge, however, when it comes to Staff's narrow view of the usefulness and applicability of this planning tool, which does not align with the Commission's recent statements that "how utilities characterize need and assess risk and uncertainty" within the IRP process and how the Commission integrates that analysis into its review "must evolve"[2] in response to the current planning environment. Contrary to Staff's assertions, PacifiCorp's 2017 IRP fits within the existing IRP framework and appropriately responds to the complexities, both economic and regulatory, that exist today and will continue into the future. Staff's opposition to the renewables action items has ventured into interpretations and applications of the IRP that diverge from PacifiCorp's interpretation and Commission precedent.

PacifiCorp's 2017 IRP is consistent with its long-standing consideration of the value of renewable energy resources—the Energy Vision 2020 resources represent a continuation of this trajectory, which has included PacifiCorp's voluntary programs, renewable portfolio standard (RPS) compliance programs, and investments in renewable resources over the past 10 years. The 2017 IRP, and specifically, Energy Vision 2020, represents a continuation of PacifiCorp's investments in renewable energy resources.

In these final comments, PacifiCorp:

- Expresses its willingness to conduct the additional coal analysis requested by Staff, which includes an additional 25 System Optimizer (SO) model runs.
- Explains that the Energy Vision 2020 projects are a necessary part of PacifiCorp's least-cost, least-risk plan because they will fill an energy and capacity need by displacing front office transactions (FOTs) in addition to providing substantial economic and non-

[1] Staff Final Comments at 3.
[2] *In the Matter of Portland Gen. Elec. Co.*, Docket No. LC 66, Order No. 17-386 at 14 (Oct. 09, 2017).

economic benefits to customers. Staff uses an extremely narrow and unprecedented interpretation of short-term capacity need to reach the conclusion that the Energy Vision 2020 projects fall outside of the Commission's established IRP process. PacifiCorp also clarifies that the Commission already has authority to consider the regulatory and policy risks associated with carbon, and has done so on numerous occasions.

- Provides updated results of the wind repowering component of the Energy Vision 2020 projects.
- Corrects Staff's one-sided analysis regarding the risks and benefits of the Energy Vision 2020 projects.
- Clarifies that, because the Energy Vision 2020 projects are within the existing IRP framework, there is no need to create a new type of IRP acknowledgment in this proceeding. Although PacifiCorp is intrigued by Staff's proposal for conditions on the acknowledgement of the renewable action items that effectively amount to pre-approval, PacifiCorp has serious concerns about this type of prudence analysis in the IRP review and acknowledgment context. PacifiCorp is open to further discussions with Staff and parties on this topic in a generic policy setting.

II. COAL RESOURCE ACTIONS

PacifiCorp agrees to conduct the significant and time-consuming coal analysis requested by Staff, which includes an additional 25 SO model runs. The requested analysis will require establishing as many as 24 unique data sets to reflect specific cost assumptions associated with each hypothetical coal-unit retirement scenario that includes complex interactions with other coal-generating units and affected contractual arrangements. PacifiCorp anticipates that it will take several months to develop the required data sets for each scenario and to apply those data sets to new SO model runs.

Staff believes this additional coal unit analysis will "provide transparency for stakeholders and could help further optimize PacifiCorp's system costs."[3] As PacifiCorp explained at the September 14, 2017 workshop, the unit-by-unit type of analysis that Staff proposes will require significant work to produce and will not give a complete, portfolio-level view of the economics of PacifiCorp's coal portfolio. The structure of the proposed unit-by-unit analysis requested by Staff does not capture system cost impacts that would result with early retirements at more than one facility. Results from these studies will therefore provide limited insight into a least-cost, least-risk resource portfolio. With hypothetical retirement dates assumed to occur at the end of 2022, portfolio impacts from these simulations are unlikely to influence the 2017 IRP action plan, which identifies specific resource actions required over the next two-to-four years.

Despite these concerns, PacifiCorp is willing to perform the additional SO model runs requested by Staff. PacifiCorp estimates it can produce these 25 runs by June 2018, which aligns with the beginning of the stakeholder process for the 2019 IRP. This will also allow the new analysis to inform subsequent analysis in the 2019 IRP by providing coal-unit screening studies early in the public-input process. The requested SO model runs will require further supplemental analysis regarding transmission and system balancing, based on the identification of any economic retirement, or a combination thereof, that may occur. In addition, PacifiCorp reiterates its willingness to work with stakeholders through a workshop process to address issues raised in this proceeding related to the company's analysis of its coal resources.

[3] Staff Final Comments at 30.

III. THE IRP FRAMEWORK AND ENERGY VISION 2020

A. The Energy Vision 2020 Projects Are Properly Part of PacifiCorp's Least-Cost, Least-Risk Resource Plan Consistent with the Commission's Existing IRP Framework

1. The 2017 IRP satisfies the Commission's standards for acknowledgment within the Commission's existing IRP framework.

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."[4] PacifiCorp's 2017 IRP and action plan comply with the Commission's requirements for resource planning and ensure that PacifiCorp will provide customers with the least-cost, least-risk electricity supply "consistent with the long-run public interest."[5]

The Energy Vision 2020 projects included in the 2017 IRP preferred portfolio are an essential element to this least-cost, least-risk plan. The Energy Vision 2020 projects are linked to the extension of federal wind production tax credits (PTCs), making them a time-limited opportunity to provide substantial customer savings, while also serving current and future capacity and energy needs. In addition, the time-limited economic benefits of the Energy Vision 2020 projects provide a "no regrets" hedge against future state or federal carbon regulation.

The key actions in the 2017 IRP action plan include the following items that are the cornerstones of the proposed Energy Vision 2020 projects:

- **Action Item 1a**: PacifiCorp's plan to upgrade, or "repower," existing wind resources and provide 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 commercial operation

[4] *In the Matter of Pub. Util. Comm'n of Or. Investigation into Integrated Resource Planning,* Docket No. UM 1056, Order No. 07-002 at 2 (Jan. 8, 2007) (corrected by Order No. 07-047).
[5] *Id.* at 7.

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 kilo-volt (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 new 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.

2. The Energy Vision 2020 projects will meet an identified need.

Staff concludes that there is no need for the proposed resources because Staff does not perceive a need within the two- to four-year action plan period.[6] But the Energy Vision 2020 projects will meet a current energy and capacity need otherwise filled by uncommitted FOTs.

a. The Energy Vision 2020 projects meet a current capacity and energy need

Staff notes that the new Energy Vision 2020 resources would largely displace FOTs in the near-term.[7] Staff argues that this displacement involves "the layering of resource upon resource,"[8] thereby transforming the IRP process into a reevaluation of "all existing resources" and "all alternatives to these existing resources."[9] But Staff mistakes the nature of the displaced resource at issue. FOTs are not committed resources—they are proxy resources that represent future procurement activity to help PacifiCorp cover short positions. While solicitation for FOTs can be made years, quarters, or months before, most transactions are made months ahead or

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[6] *See* Staff Final Comments at 13.
[7] *Id.* at 14.
[8] *Id.* at 18.
[9] *Id.* at 24.

less.[10] The Energy Vision 2020 projects would not supplant committed resources, as Staff suggests, but instead replace placeholder resources with less expensive, firm resource commitments. The Energy Vision 2020 projects would therefore fill an identified resource gap.

The Energy Vision 2020 projects leverage PTCs to provide least-cost, committed resources that would otherwise be procured at some later date and without the substantial savings to customers in the form of a 70 percent discount to the capital costs, and as discussed above does not results in "layering" of resources or "paying for twice the resources."[11]. Because these resources are more than "purely" economic opportunities, there is no need for the Commission to undertake a radical revision of the IRP process to reconsider "all existing resources."[12]

Staff also appears to object to the displacement of FOTs on the basis that PacifiCorp receives no rate of return for market transactions.[13] This fact is irrelevant because it incorrectly assumes that PacifiCorp will own the new wind resources, an outcome that will be known only after the conclusion of the Commission-approved 2017R request for proposals (2017R RFP) process, which provides no guarantee the company will own all, some, or any of these resources. But even assuming that PacifiCorp were to own the Energy Vision 2020 wind resources, those resources are more cost effective than FOTs *even including the cost of capital*. A higher-cost resource should not be selected merely to forego providing an opportunity for shareholders to earn a rate of return.

Staff argues that, if there is a capacity need, it is not clear what the exact quantity of that need is.[14] But Staff's comments include PacifiCorp data indicating that, without available FOTs,

[10] 2017 IRP at 141.
[11] *See* Staff Final Comments at 10.
[12] *Id.* at 24.
[13] *Id.* at 14.
[14] *Id.* at 18.

PacifiCorp will have an approximately 1,000 mega-watt (MW) capacity deficit by 2019, and the capacity deficit increases over the remaining course of the 20-year planning horizon.[15] PacifiCorp quantified a near-term capacity need and Staff's argument to the contrary is confusing and unfounded. Even if Staff's assertion that a capacity need is a predicate to inclusion of the Energy Vision 2020 resources in the 2017 IRP, PacifiCorp has made the necessary showing.

Similar to Staff's misconstrued position regarding a lack of need for these resources, Staff's public statements also seemed to ignore that PacifiCorp's 2017 IRP preferred portfolio would both add new resources and shut down coal-fired resources. Staff publicly stated that "PacifiCorp has not presented a plan to add renewables and remove dirtier resources…[h]ad the company come forward with a plan of adding and also removing, that might have been something we could have worked with."[16] PacifiCorp's 2017 IRP preferred portfolio does exactly this—in addition to adding resources including the Energy Vision 2020 projects, it also includes retirement of 3,650 megawatts of coal-fired generation by the end of the study period in 2036. In the near-term it includes 667 megawatts of coal-fired generation retiring by the end of 2020.[17]

[15] *Id.* at 16.
[16] *Oregon Regulators May Deflate PacifiCorp's $3.5B Renewables Plan,* Portland Business Journal, August 31, 2017.
[17] Specifically, retirement of Naughton Unit 3 (280 megawatts) and Cholla Unit 4 (387 megawatts). PacifiCorp will continue to evaluate retirement dates of its coal-fired generation in future IRPs and IRP Updates.

b. PacifiCorp has consistently described the current and future need for the Energy Vision 2020 projects

Contrary to Staff's characterization,[18] PacifiCorp has maintained that the Energy Vision 2020 resources will contribute to current and future needs. Staff claims that PacifiCorp's filings in docket UM 1802 indicate that the new wind resources are purely economic resources not needed to meet load requirements.[19] To reach this conclusion, Staff relies on PacifiCorp's statement that, without the PTCs, the new wind resources would not be part of PacifiCorp's least-cost, least-risk preferred portfolio. Staff reasons that, because PacifiCorp has no intention of acquiring an alternative resource in the near-term in lieu of PTC-eligible wind resources, the wind resources do not meet a resource need.[20] Staff's logic does not hold. PacifiCorp's analysis demonstrates that acquiring the new wind resources now, when they are PTC-eligible, will prevent or defer the need for a more expensive resource in the future, while also replacing more expensive market transactions in the near-term. The PTCs affect the timing and economics of the new resource, not the need for the resource. The fact that the Energy Vision 2020 resources are a time-limited opportunity does not inherently indicate that they are disconnected from a resource need. PacifiCorp's testimony in docket UM 1802 is consistent with its position here.

Staff further claims that in docket UM 1802 PacifiCorp argued that it had no capacity need until 2028.[21] But PacifiCorp's argument in docket UM 1802 related to the treatment of the new Wyoming wind resources in the context of avoided cost pricing. For purposes of determining an avoided cost of capacity, PacifiCorp argued that the new Wyoming wind resources should not be considered deferrable because there is no reasonable methodology to

[18] Staff Final Comments at 17 ("PacifiCorp's filings in Docket No. UM 1802 reveal the Wyoming wind proposal for what it truly is, a claimed, potential economic opportunity and not a necessary resource acquisition to meet load requirements.").
[19] *Id*.
[20] *Id.*
[21] *Id.*

account for PTCs. The Commission does not consider FOTs when determining the avoided cost of capacity. PacifiCorp's argument in docket UM 1802 focused on the deferability of the wind resources, and not how those resources will displace FOTs, which was not relevant in that avoided cost proceeding.[22]

3. Staff employs an extremely narrow interpretation of short-term capacity needs within the two- to four-year period, which is inconsistent with the long-term nature of the IRP.

Staff argues that the Energy Vision 2020 projects are not consistent with "need-based IRP planning" because they represent "a purely economic opportunity."[23] But Staff's initial premise is mistaken—the IRP is not narrowly focused on meeting short-term capacity need. Staff's characterization of need is inconsistent with the Commission's statements that the IRP process is the appropriate forum to balance near-term opportunities with long-term risks,[24] utilities' overarching obligation to include major investments in their IRPs,[25] and the regular inclusion of other aspects of least-cost, least-risk planning not associated with meeting a specific need.[26] The Commission previously found that economic opportunities can impact the timing of resource acquisition.[27] The purpose of an IRP is to identify the least-cost, least-risk resource portfolio; in PacifiCorp's 2017 IRP, the least-cost, least-risk portfolio includes the Energy Vision 2020 projects.

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[22] *See 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) (avoided capacity costs based on next deferrable resource); *In the Matter of Public Utility Commission of Oregon, Investigation Into Resource Sufficiency Pursuant to Order No. 06*-538, Docket No. UM 1396, Order No. 11-505 at 6 (Dec. 13, 2011).

[23] Staff Final Comments at 13.

[24] Order No. 17-386 at 14.

[25] *In the Matter of PacifiCorp, dba Pacific Power, Request for a Gen. Rate Revision*, Docket No. UE 246, Order No. 12-493 at 33 (Dec. 20, 2012).

[26] *Id.* at 33 (concluding that emission control investments are properly included in IRPs).

[27] *In the Matter of PacifiCorp Resource and Market Planning Program (RAMPP-7)*, Docket No. LC 31, Order No. 03-508 at 16 (Aug. 25, 2003).

Staff relies on Order No. 89-507 for its narrow definition of the IRP framework as strictly need-based over a limited timeframe. Staff concludes "that need is fundamental to major resource acknowledgment" because one of the components a utility can usefully consider in the IRP process is how to "bridge the gap between expected loads and resources."[28] Yet, the gap between expected loads and resources described in Order No. 89-507 is merely one in a long list of critical considerations relevant to the IRP process. In that same order, the Commission emphasized that the IRP's scope is much broader: "*The primary goal* must be least-cost to the utility and its ratepayers consistent with the *long-run* public interest."[29]

And since that 1989 decision, the IRP process has "increased [in] scope and complexity" in order to "adapt" to the changing industry landscape and long-term planning horizons.[30] In Portland General Electric's (PGE's) 2016 IRP, the Commission "challenge[d] utilities and stakeholders not to view [the] IRP guidelines as pre-established checklists but rather to proactively adapt their assessment of risk and uncertainty as industry evolution comes into greater focus."[31] PGE, the Commission noted, had properly "met this challenge" by planning for the early acquisition of time-sensitive wind resources (also reliant on PTCs) to meet long-term RPS requirements.[32] While not acknowledging PGE's action item as proposed,[33] the Commission specifically recognized that "expiring tax incentives represent a time-limited opportunity that could significantly benefit customers" and requested that PGE resubmit an action plan that considers short-term impacts and long-term risks, including renewable resource

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[28] Staff Final Comments at 13 (citing *In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 8 (Apr. 20, 1989)).
[29] Order No. 89-507 at 7 (emphasis added).
[30] *See* Order No. 17-386 at 14.
[31] *Id.*
[32] *Id.* at 15.
[33] *Id*. Unlike PacifiCorp's more robust all-in economic analysis, "PGE primarily justified the size, timing, and expected technology characteristics of its proposed acquisition on the basis of projected long-term RPS compliance savings." *Id.*

portfolio diversity and alignment with near-term system needs, strategies for avoiding or mitigating front-loaded rate impacts, [and] resource sizing that maintains long-term optionality[.]"[34] The Commission underscored that the IRP is the proper forum for balancing "near- and long-term tradeoffs and the assessment of long-term risks" and that existing "IRP guidelines and policies continue to provide the necessary framework to address these new challenges."[35] In rejecting Staff's nearly identical position in PGE's IRP, the Commission made clear that it did not intend to limit the IRP process to consideration of only near-term needs.

Staff's position is also contradicted by the Commission's requirement that utilities "fully evaluate all major investments that have implications for the utility's resource mix" in the IRP, even if the investment is not tied to meeting a specific capacity or energy need.[36] For this reason, emission control investments are included in the IRP even though they are not tied to a near-term need. Similarly, PacifiCorp's selection of demand-side resources is not tethered to a specific need, but must be included in least-cost planning. Staff distinguishes demand-side resources on the grounds that they are a low-risk portfolio component, and that the "analysis necessary to determine cost-effectiveness focuses on the near-term[.]"[37] But there is no basis for Staff's implicit suggestion that the IRP should only consider what it perceives as low-risk proposals, or only near-term risks.[38] On the contrary, the IRP's 20-year planning horizon makes the process particularly appropriate for "the assessment of long-term risks."[39] The Commission's review is

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[34] Order No. 17-386 at 3.
[35] *Id.* at 14.
[36] Order No. 12-493 at 33 ("If a utility seeks rate recovery of a significant investment that has not been included in an IRP, we will hold the utility to the same level of rigorous review required by the IRP to demonstrate the prudence of the project.").
[37] Staff Final Comments at 15 ("[U]nlike DSM, [Energy Vision 2020's projects] have an economic case that rests primarily on assumptions decades into an uncertain future and are subject to extensive risks.").
[38] *In the Matter of Idaho Power Co. 2009 Integrated Resource Plan*, Docket No. LC 50, Order No. 10-392 at 2 (Oct. 11, 2010).
[39] Order No. 17-386 at 14.

much broader than mere need: where a decision "can significantly impact the rates paid by customers[,]" it is appropriately included in the IRP process.[40]

The IRPs' 20-year planning horizon would be meaningless if utilities were prohibited from taking timely action to account for future needs, as Staff's position suggests.[41] The logical extension of Staff's emphasis on the two- to four-year action period would be continual "just-in-time" resource acquisition. But "just-in-time" procurement is usually not in customers' economic interest; on the contrary, the Commission has recognized that early action can be least-cost.[42] In Order No. 17-019, the Commission found that PacifiCorp's early acquisition of RECs to satisfy its future RPS compliance obligation was prudent, relying on Staff's analysis that early acquisition lead to better economic outcomes for customers.[43] The Commission recently noted that the "unique attributes of renewable resources, *including available tax credits* and changes within the electricity markets . . . may favor earlier action than would be required for traditional resource investments."[44]

Even assuming the Energy Vision 2020 resources were only based on an economic opportunity, this reasoning has already formed the basis for the Commission's acknowledgement of a proposed resource: in PacifiCorp's 2003 IRP, the Commission acknowledged proposed wind resources that were included "based on economic merit, not potential RPS requirements."[45] The Commission later approved PacifiCorp's proposal to acquire additional wind installations earlier

[40] Order No. 12-493 at 33.
[41] Order No. 07-002 at 5 (IRP must analyze resource portfolios over 20-year planning horizon).
[42] *See, e.g., In the Matter of PacifiCorp, dba Pacific Power, Petition for Waiver of Competitive Bidding Guidelines*, Docket No. UM 1374, Order No. 08-376 (July 17, 2008) (approving RFP waiver for Chehalis and noting that the plant was being acquired 4 years early and would increase near term rates).
[43] *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).
[44] Order No. 17-386 at 13-14 (emphasis added).
[45] Order No. 03-508 at 16.

than planned, where the earlier acquisition became economic.[46] Thus, early acquisition of economic resources was deemed consistent with the resource planning framework and with prudent utility management.

4. The Commission already has authority to consider and mitigate carbon risk to customers.

PacifiCorp noted at an IRP workshop that the Energy Vision 2020 projects will provide emission-free generation and help decarbonize PacifiCorp's resource portfolio. Based on this statement, Staff argues that considering decarbonization strategies in an IRP would be a "momentous change in our values for examination of utility action," requiring a comprehensive reassessment of the Commission's authority to regulate carbon.[47] Contrary to Staff's statement, the fact that the Energy Vision 2020 projects provide an additional benefit and contribute to decarbonizing PacifiCorp's resource portfolio does not require a comprehensive overhaul of the IRP, nor is consideration of the risks associated with carbon a new factor in the IRP process.

Wind resources will facilitate decarbonization of PacifiCorp's resource portfolio and mitigate long-term risk associated with potential future state and federal policies targeting carbon dioxide emissions reductions from the electric sector.[48] But the central inquiry remains identifying the least-cost, least-risk resource portfolio in the long-term customer interest. There is no reason to conduct a comprehensive overhaul merely because these least-cost, least-risk resources *also* provide decarbonization benefits.

[46] *In the Matter of Pacific Power & Light (dba PacifiCorp) Request for Proposals in Compliance with Competitive Bidding Guidelines established by Order No. 91-1383*, Docket No. UM 1118, Order No. 04-091 at 17 ("The Commission agrees that economic wind installations should be moved up.").
[47] Staff Final Comments at 27.
[48] PacifiCorp Reply Comments at 9.

Staff is similarly incorrect that "[d]ecarbonization represents a major shift for utility planning."[49] The Commission has repeatedly considered the implications of carbon in IRP proceedings.[50] In PGE's 2010 IRP, the Commission deemed one portfolio option superior in part because "it mitigate[d] the risk of future carbon regulation" by closing the Boardman coal plant, and thereby contributed to the decarbonization of PGE's resource portfolio.[51] Neither Staff nor the Commission suggested that the decarbonization benefits of this decision triggered a wholesale reassessment of the Commission's authority to mitigate carbon risk or to oversee decarbonization efforts. And again in PGE's 2016 IRP, the Commission adopted Staff's recommendation to require PGE's next IRP to specifically study decarbonization.[52] Staff also previously explicitly argued that resource planning's risk assessment should consider the "long-term price stability," provided by wind resources, in part, because they reduce the "risk of further regulation of CO_2 and other pollutants."[53]

Considering carbon and decarbonization is embedded in the Commission's responsibility for ensuring that a least-cost plan is "consistent with Oregon's energy policy."[54] Possible decarbonization benefits are therefore already part of the Commission's IRP review process. To the extent Staff is recommending that the Commission examine broader regulation of carbon, PacifiCorp agrees that the Commission lacks statutory authority to undertake a wholesale regulation of carbon emissions, but regulation of carbon emissions is distinct from considering and mitigating customer risk associated with carbon.

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[49] Staff Final Comments at 27.
[50] *In the Matter of Pub. Util. Comm'n of Or. Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process*, Docket No. UM 1302, Order No. 08-339 (June 30, 2008) (adopting Guideline 8 explicitly requiring the consideration of carbon regulation in IRP planning).
[51] *In the Matter of Portland Gen. Elec. Co. 2009 Integrated Resource Plan*, Docket No. LC 48, Order No. 10-457 at 15 (Nov. 23, 2010).
[52] Order No. 17-386 at 19.
[53] Order No. 04-091 at 8.
[54] Order No. 07-002 at 2.

PacifiCorp's IRP does not require the Commission to expand the scope of its jurisdiction beyond the well-established treatment of carbon risks in utility resource planning. The Commission explicitly addressed its legal authority to consider external environmental costs in utility planning and determined that it can "require utilities to consider in their least-cost plans the likelihood that external costs may be internalized in the future."[55] Under the Commission's own precedent, there is no bar to considering the decarbonization benefits provided by the Energy Vision 2020 resources. Based on long-standing precedent dating back over 25 years, the Commission's review of a plan containing decarbonization benefits is an established aspect of the IRP process that PacifiCorp recognizes and factors into its business planning and is therefore not "a momentous change in our values for examination of utility action[,]"[56] nor is it fair to say that utilities have only just recently started to take into consideration the value of renewable resources to their customers.[57] There is therefore no need to conduct a wholesale reevaluation of the Commission's authority to consider decarbonization in the context of utility planning.

B. Staff's Analysis of the Energy Vision 2020 Projects—Especially Regarding Risk to Customers—Is One-Sided and Ignores PacifiCorp's Thorough Analysis in This Proceeding

1. PacifiCorp's analysis includes both benefits and risks to customers.

In arriving at its least-cost, least-risk portfolio, PacifiCorp systematically modeled the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting a target planning reserve margin.[58] In assessing relative portfolio risk, PacifiCorp modeled customer rate impacts in a range of scenarios, accounting for this risk while balancing the

[55] *Re Guidelines for the Treatment of External Environmental Costs*, Docket No. UM 424, Order No. 93-695, 142 P.U.R. 4th 465, 468 (May 17, 1993).
[56] Staff Comments at 27.
[57] *Oregon Regulators May Deflate PacifiCorp's $3.5B Renewables Plan,* Portland Business Journal, August 31, 2017.
[58] 2017 IRP at 143.

potential customer benefits. In the vast majority of modeling scenarios, resource portfolios that included the Energy Vision 2020 projects were superior to those that did not. PacifiCorp's robust scenario analysis demonstrates that the Energy Vision 2020 projects are not only least-cost, they are also least-risk.

PacifiCorp recently provided an updated and expanded economic analysis for the wind repowering component of its Energy Vision 2020 projects in Utah Docket No. 17-03-39.[59] Please see Attachment A that includes the tables and figures from the updated and expanded economic analysis. The updated and expanded analysis demonstrates the following:

- The wind repowering project will produce present-value net customer benefits, based on updated economic analysis over the remaining life of the repowered wind facilities, ranging between \$360 million to \$635 million, and shows net customer benefits in all of the scenarios analyzed.
- Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between \$1.38 billion and \$1.65 billion, which compares to present-value project costs totaling \$1.02 billion.
- These net and gross customer benefits are conservative, as they do not account for additional incremental energy output that will be generated with the installation of equipment that only recently has been verified to be available for repowering of certain wind facilities.
- When measured over a 20-year period, the present value of net customer benefits from wind repowering range between \$90 million and \$214 million, which does not account for the value of incremental energy output that will increase significantly beyond 2036.

[59] The updated analysis is provided as an attachment to these comments.

- Project-by-project analysis confirms that the proposed scope of the project, including just over 999 MW of existing wind resource capacity, is appropriate and will maximize customer benefits.
- Tax-policy sensitivity analysis confirms that net customer benefits persist even if the corporate federal income tax rate were reduced from 35 percent to 25 percent.

The modeling tools and methodologies used to develop the economic analysis supporting the wind repowering project are robust. The wind repowering project will replace equipment at existing wind facilities with modern technology to improve efficiency, increase energy production, extend the operational life, reduce run-rate operating costs, reduce net power costs, and deliver substantial federal PTC benefits that will be passed on to customers.

2. Staff simply assumes inaction is less risky, without substantively disputing PacifiCorp's robust scenario analysis.

Staff claims that "new major resources . . . do not need to be acquired to provide reliable service to customers in a least-cost, least-risk manner[,]"[60] but this claim merely assumes a conclusion that is plainly disproven by PacifiCorp's IRP—the Energy Vision 2020 projects provide customers with the least-cost, least-risk portfolio.

In asserting, without analysis, that the status quo yields superior outcomes, Staff discounts the availability of a lower-cost, lower-risk alternative.[61] To the extent that Staff assumes inaction is less risky than action, this assumption lacks either logical or factual support. There is nothing about inaction that makes it preferable to action when objectively considering relative risk. For Energy Vision 2020, the vast majority of modeling scenarios result in customer

[60] Staff Final Comments at 16.
[61] *Id.* (stating without analysis that inaction will allow for the least-cost, least-risk path).

benefits.[62] Declining to pursue the Energy Vision 2020 projects results in a likely opportunity cost—that is, a likely customer *loss*. Staff's recommendation would be substantially more likely to achieve a less favorable outcome for ratepayers in the form of increased costs and increased risk—an inexplicable result inadequately justified by Staff's preference for inaction over action.

PacifiCorp seeks to develop new resources and repowering of existing resources now because the PTCs make this the least-cost, least-risk option to serve current capacity and energy needs, while also providing RECs to meet future RPS requirements. This analysis accounts for any time delays, and the need for early acquisition is inextricably linked to the unique and time-limited opportunity of the PTCs. Waiting will forego a valuable opportunity, delaying the acquisition of necessary resources until they would be purchased at greater expense to customers.

3. Staff's analysis addresses potential risks associated with missing forecasted outcomes but ignores potential benefits associated with outperforming forecasted outcomes.

In opposing the Energy Vision 2020 projects, Staff does not substantively contest that the proposal provides the least-cost resource portfolio. Instead, Staff myopically focuses on a limited set of potential risks of underperforming forecasted outcomes while failing to acknowledge the risks of inaction, the possibility that the projects might *outperform* forecasted outcomes, and the other benefits the proposal entails.[63] Staff's specific focus on this limited set of potential risks also overlooks who bears the risk; unless and until the company seeks cost recovery, it bears all risk associated with moving forward with the Energy Vision 2020 projects. Staff emphasizes the possibility that the Energy Vision 2020 projects could underperform.[64] But Staff fails to account for the possibility of variance in both directions: it is possible that the

[62] PacifiCorp's 2017 IRP Informational Filing at 16, 23.
[63] Staff Final Comments at 21-22.
[64] *Id.* at 22.

Energy Vision 2020 projects could *outperform* expectations. The fact that a resource choice could either underperform or outperform is precisely why prudence review occurs separate from the long-term planning process and focuses not on the outcome, but on what was reasonably known at the time of the decision.[65]

Staff includes five sensitivities and provides a hypothetical estimate of potential impact to the benefits analysis including: (1) a capacity factor shortfall of one percent; (2) an assumption that the PTC value does not grow at inflation; (3) the commercial operation date is missed by less than one year; (4) there is a one percent construction cost overrun; and (5) there is a one dollar energy price shortfall at the start of the price curve. Staff's hypothetical is based on an arbitrary $2.5 billion project cost and wind resources totaling 1,270 megawatts. While the assumptions made by Staff in this hypothetical are high level and do not account for any system optimization, each of these items has a corresponding potential benefit or upside that is largely ignored in Staff's examination as discussed below.

Staff's analysis of the PTC assumes that the realized production of the wind output will be lower than expected, but ignores the possibility that it could be higher than expected. Similarly, Staff's analysis ignores the possibility that there could be fewer scheduled and forced outages than expected. Applying Staff's approach, as shown in the table below, if a one percent increase in capacity factor is assumed (from 41.5 percent to 42.5 percent), there would be a corresponding $70 million of additional customer benefit.

Staff's analysis also assumes that the individual PTCs are less valuable than expected, but does not explore the possibility that the individual PTCs may be more valuable than expected.

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[65] *In the Matter of Portland General Electric Co. Application to Amortize the Boardman Deferral*, Docket No. UE 196, Order No. 10-051 at 6 (Feb. 11, 2010) ("In a prudence review, the Commission examines the objective reasonableness of a utility's actions at the time the utility acted: 'Prudence is determined by the reasonableness of the actions 'based on information that was available (or could reasonably have been available) at the time.'").

There are two inflation adjustments assumed in PacifiCorp's PTC valuation. One is dictated by legislation, inflating PTC values by two percent from the time of a project's commercial online date. The other inflation adjustment depends on the IRS's annually updated value per KWh, as expressed by Staff. Removing only the IRS's annually published inflation adjustment as suggested by Staff and estimated conservatively by PacifiCorp at two percent, PacifiCorp estimates a $33 million decrease in economic value from PTCs, not the $100 million calculated by Staff. If, however, the IRS publishes annually refreshed PTC values based on an inflation rate greater than the conservative two percent assumption, and the two percent inflation escalates at the same rate, the value of PTCs will increase, yielding additional customer benefits. An increase in inflation rate comparable in magnitude to the suggested elimination of both of the two percent conservative assumptions would increase inflation to four percent and increase PTC values in aggregate by an estimated $127 million.

Staff analyzes the possibility that the Energy Vision 2020 projects are delayed, but does not consider the additional benefits if these projects are delivered on-time and/or ahead of schedule. The company's approach to the Energy Vision 2020 wind projects is to mitigate risk and ensure that appropriate off-ramps exist in the project review, approval, and implementation processes before significant capital outlays or commitments are made in case the necessary approvals are not received, project economic benefits erode, or the associated benefits are placed at risk. With timely regulatory reviews and approvals, and successful transmission rights of way acquisition, PacifiCorp expects it will successfully meet the requirements necessary to ensure eligibility for 100 percent of the PTC and receive net power costs and wholesale wheeling revenue benefits available through the projects. While some risks may materialize during implementation of the projects, PacifiCorp anticipates other benefits may become available (for example, savings on project costs), resulting in the forecasted net benefits being achieved.

Staff ignores the possibility that the Energy Vision 2020 projects could have construction cost savings. Staff provides a rough estimate of $50 million increased costs based on an assumed one percent cost overrun. In response to PacifiCorp's request for supporting analysis, Staff clarified the estimated value is actually $40 million increased costs and not the $50 million included in Staff's table. However, generation projects may experience construction cost savings for a variety of reasons, including favorable contract negotiations, reduced costs due to unanticipated favorable site conditions, reduced equipment expenses, and other previously unrecognized opportunities in the bidding and lead-up to signed construction contracts final scoping process and the follow-on design and construction process. Case-by-case project risks will continually be identified, assessed, monitored, and mitigated to maintain project schedule and cost. PacifiCorp developed an ongoing strategy of engagement with stakeholders including permitting agencies, local authorities, and property owners to identify risks and develop mitigation plans. Construction contracts will have guaranteed milestones and liquidated damages included to motivate contractors to complete the projects on time.

Staff's analysis ignores the possibility that energy prices may be higher than anticipated. The Energy Vision 2020 projects were studied under a range of price-policy scenarios. The projected official forward price curve yields the expected benefits of $137 million in the Medium Gas, Medium CO2 scenario. Staff's analysis assumes the forward price curve started one dollar lower at $29 per megawatt-hour versus $30 per megawatt-hour. Assuming a one dollar corollary price increase to $31 per megawatt-hour, an additional benefit of $70 million would occur applying Staff's approach. Again, this approach does not take into account total system optimization that would serve to mitigate price-contingent impacts and is therefore misleading. The table below presents Staff's sensitivity results and the company's alternative scenarios, with the exception of the commercial operation date assumption described in the section above.

	Risk/Harm		Benefit[2]	
Sensitivity	Amount of Sensitivity (Change)	Impact ($ million)	Amount of Sensitivity (Change)	Impact ($ million)
Capacity Factor Shortfall	One percent CF decrease (41.5% -> 40.5%)	70	One percent CF increase (41.5% -> 42.5%)	70
PTC Value Decrease	IRS refresh does not grow with inflation[1]	100	IRS refresh grows at 4% inflation[3]	130
Construction Cost Overrun	One percent cost overrun	40	One percent cost savings	40
Energy Price Shortfall	One dollar price shortfall	70	One dollar price increase	70

[1,3] For consistency, Staff's value of $100 million is given, and not PacifiCorp's restated value of $33 million. Consequently, PacifiCorp's benefit impact ($130 million) is also given based on a calculation consistent with Staff's treatment.

[2] Values have been rounded to the nearest $10 million, in keeping with Staff approach

Staff does not justify this unbalanced treatment of the relative risks and benefits, and ignores that in the vast majority of scenarios customers substantially benefit. Again, Staff assumes that action is necessarily riskier than inaction and that customers will wholly bear the risks. Staff ignores the opportunity cost of failing to move forward, particularly as these resources must be procured either now—with the benefit of PTCs—or later. Staff's assessment of Energy Vision 2020's relative risks also does not recognize that PacifiCorp's analysis conservatively assigns no incremental value to the RECs generated by the new wind facilities. Nor does PacifiCorp's analysis 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. These are substantial non-economic benefits entirely overlooked by Staff's analysis.

Staff compares Energy Vision 2020 to PGE's 2017 Annual Update Tariff, arguing that both involve "essentially speculation to approve an investment that has very real risk of costing customers."[66] Staff's analogy misses the mark. In PGE's case, the Commission denied a long-term natural gas hedging proposal, finding its value uncertain, its risks great, and the alternatives in the best interests of customers.[67] The Commission also appeared particularly troubled by the analysis provided by PGE, which comprised a single analysis using one set of assumptions based on a 30-year forecast.[68] That the Commission found this particular cost-benefit balance inappropriate in a ratemaking case is irrelevant to the merits of an IRP proposal involving a different utility's acquisition of a different resource that is supported by completely different and substantially more comprehensive economic and risk analysis.

To the extent that Staff objects to the particular risk balance of the Energy Vision 2020 projects, Staff fails to present substantive analysis challenging these projects' likely customer benefits. As reflected in PacifiCorp's robust scenario analysis, the Energy Vision 2020 projects provide the least-cost, least-risk portfolio to serve current and future customer need.

4. Energy Vision 2020 resources provide capacity contributions and serve as effective prices hedges.

In addition to meeting energy and capacity needs, the Energy Vision 2020 projects provide significant reliability and hedging benefits. But Staff inappropriately dismisses these benefits, arguing that: (1) a wind resource's "capacity contribution will be less than its nameplate capacity[;]" (2) "the wind may not blow [during] any particular hour[;]" and (3) wind fails to provide an effective hedge value.[69] These objections overlook the analysis incorporated in PacifiCorp's 2017 IRP, the Commission's treatment of wind's reliability benefits, and Staff's prior statements concerning the hedge value of variable energy resources (VERs).

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[66] Staff Final Comments at 14.
[67] *In the Matter of Portland Gen. Elec. Co. 2017 Annual Power Cost Update*, Docket No. UE 308, Order No. 17-088 at 5-6 (Mar. 15, 2017).
[68] *Id.* at 6.
[69] Staff Final Comments at 24-26.

While wind resources do not replace FOTs on a one-for-one basis, PacifiCorp's analysis accounted for wind's relative capacity contribution. Even accounting for the difference between the wind resources' nameplate capacities and capacity contributions, the alternative modeling scenarios consistently showed net benefits from replacing FOTs with the Energy Vision 2020 projects, given the opportunity to make use of time-sensitive PTCs.

Wind provides acknowledged reliability benefits that are incorporated into avoided-cost calculations through the capacity contribution adjustment.[70] It would be inconsistent to assume wind's reliability benefits for one purpose but not for another. Moreover, the innovative technologies available with new wind turbines provide greater control over power quality and voltage, thereby improving grid reliability. Staff fails to justify its dismissal of these projects' reliability benefits in particular, and of wind's reliability benefits in general.

Staff also disregards the reliability benefits of the proposed transmission line. The Aeolus-to-Bridger/Anticline line will provide substantial system reliability benefits by relieving congestion on the current transmission system in eastern Wyoming, providing critical voltage support to the Wyoming transmission system, and increasing the transfer capability across the Aeolus-to-Bridger/Anticline line with the construction of additional segments of the Energy Gateway project in the future. PTCs from the new wind development support construction of the line, making an otherwise uneconomic investment doubly beneficial by allowing for the full use of the new wind resources and creating downstream reliability benefits.

Staff took the company's comments made at the September 14, 2017 workshop out of context to suggest that the new transmission line serves no reliability purpose. This overlooks

[70] *In the Matter of Pub. Util. Comm'n of Or. Investigation Into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 14-058 at 15 (Feb. 24, 2014) (providing for adjustments to avoided cost pricing to account for the differential contribution to capacity of each resource type).

the fact that the lack of an imminent reliability threat does not equate to no reliability need. As PacifiCorp clearly stated at the September 14, 2017 workshop, the company is currently in compliance with all reliability requirements, but the new transmission line will *increase* reliability and provide other reliability benefits, such as voltage support, that make the overall transmission system more robust. Operating the transmission system in a way that achieves reliability should not be used against PacifiCorp to purportedly "prove" that new transmission is not needed.

In response to feedback from stakeholders, PacifiCorp is performing additional transmission studies to assess the performance of the company's transmission system in Wyoming with the anticipated retirement of the Dave Johnston generating plant. PacifiCorp is evaluating the performance of the Wyoming transmission system assuming the retirement of the Dave Johnston generating plant and addition of the planned wind generation facilities in southeast Wyoming. The analysis assumes deferment of the Aeolus to Bridger/Anticline transmission segment; therefore, study findings will define additional 230 kV transmission facilities that will be necessary to support the proposed wind generation addition. PacifiCorp will provide these technical studies to parties as soon as they are available.

Wind resources also provide a valuable hedge against future price volatility and the risk of future carbon regulation because wind resources have no fuel costs or carbon emissions. PacifiCorp's assessment of the risks associated with the Energy Vision 2020 resources appropriately accounted for the valuable risk mitigation provided by wind resources. Staff specifically objects to the use of wind as a hedge because it is a VER.[71] But in docket UM 1716, Staff determined that solar resources—also a VER—provide "a long-term physical hedge against

[71] Staff Final Comments at 25.

changes in fuel and wholesale market prices[.]"[72] In approving the use of solar as a price hedge, Staff emphasized the resource's limited recurring cost and lack of fuel costs as central to its hedge value.[73] And in PacifiCorp's 2003 IRP, Staff noted that wind resources "do not pose the risks related to fuel price and emissions compliance that fossil-fuel resources do."[74] And again in docket UM 1118, Staff argued for "the value of [wind resources'] long-term price stability (avoiding natural-gas price volatility and the risk of further regulation of CO_2 and other pollutants)."[75] "The fuel cost for wind," Staff commented, "is always zero, and it is pollution-free."[76]

Now, Staff states that "VERs generally and wind especially" make undesirable hedges against uncertainty.[77] Staff does not explain this abrupt change in position concerning the use of VERs as price hedges nor does Staff present any analysis supporting a change in position. Like solar, wind's lack of ongoing fuel costs effectively hedges against price instability. Staff's unsupported shift in positions simply highlights the bias that Staff has against the results of this 2017 IRP.

5. *The Energy Vision 2020 projects have the added benefit of deferring an RPS compliance shortfall.*

The Energy Vision 2020 projects have the added benefit of allowing PacifiCorp to defer its RPS compliance shortfall, which is currently forecasted to occur in 2025.[78] The fact that the Energy Vision 2020 resources provide multiple benefits counts for—rather than against—their

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[72] *Investigation to Determine Resource Value of Solar*, Docket No. UM 1716, Staff's Reply Testimony of Mark Bassett at Staff/600, Bassett/17 (June 7, 2017).
[73] *Id. at* Staff/600, Bassett/17.
[74] Order No. 03-508 at 16.
[75] Order No. 04-091 at 8.
[76] *Id*.
[77] Staff Final Comments at 26.
[78] *In the matter of PacifiCorp, dba Pacific Power, 2017-2021 Renewable Portfolio Standard Implementation Plan, Docket No. UM 1790, Initial Application (Jul. 15, 2016).*

value. The Energy Vision 2020 resources will defer PacifiCorp's RPS compliance shortfall, which provides additional economic support for PacifiCorp's proposal, but those benefits are not the basis for the Energy Vision 2020 resources and are over-and-above the economic benefits included in PacifiCorp's analysis.

Although PacifiCorp's timeline for acquiring RPS-qualifying resources is similar to the timeline of PGE's 2016 IRP seeking acknowledgement of near-term acquisition of wind resources to meet a long-term need for RPS (beginning in 2029), the deficiencies the Commission identified with PGE's analysis are not applicable to PacifiCorp. PGE "primarily justified the size, timing, and expected technological characteristics of its proposed acquisition on the basis of projected long-term RPS compliance savings."[79] Because PGE justified the resources largely based on avoided RPS compliance costs, the Commission faulted PGE for not considering "how renewable resources could contribute most cost-competitively to near-term capacity and energy needs[.]"[80] Unlike PGE's proposal, the Energy Vision 2020 projects fill a capacity and energy need and are independently justified by economic benefits and the ability to provide the least-cost, least-risk electricity for the current capacity and energy needs, while providing an additional RPS compliance benefit.

The Commission determined PGE's analysis lacked a "showing of how the proposed resource action aligns with current capacity needs, how PGE can mitigate short-term rate impacts, and how long-term optionality can be maintained[.]"[81] PacifiCorp's analysis addresses each of these issues in detail. PacifiCorp demonstrated that near-term rate impacts associated with the Energy Vision 2020 resources will be minimal and that the new resources will displace

[79] Order No. 17-386 at 15.
[80] *Id*.
[81] *Id.* at 15-16.

uncommitted FOTs. PacifiCorp's Energy Vision 2020 resources do not foreclose future optionality. On the contrary, the new wind resources and repowering will displace only a fraction of the uncommitted FOTs in the preferred portfolio, leaving substantial head room to account for "future utility load [that is] smaller than expected, and maintain optionality in future resource selection to take advantage of new market opportunities and technological advances."[82] Staff's comments point out that to replace all of the FOTs in the preferred portfolio, PacifiCorp "would need to procure nearly 11,000 MW of wind."[83] This demonstrates that even after the Energy Vision 2020 projects are completed, PacifiCorp will retain sufficient future flexibility to respond to changing demands and marketplace opportunities.

C. Staff's Recommended "Guidance" for the Commission's Subsequent Prudence Review Is Not Warranted and Constitutes Inappropriate Prejudgment of Prudence

PacifiCorp is intrigued by Staff's proposal to provide "guidance" to future Commissions engaged in prudence analysis, particularly since Staff's proposed approach would seem to turn the IRP into a pre-approval-type process. PacifiCorp would be open to further discussions with Staff and stakeholders if there is a desire to place additional conditions in future IRP acknowledgment processes or to provide "guidance" to future Commissions when undertaking a prudence review. This change in the IRP review and acknowledgment process would be more properly analyzed by stakeholders in either workshops or a generic policy docket. But there is no need to answer this policy question in this IRP proceeding because PacifiCorp's 2017 IRP is properly analyzed within the existing IRP framework without wholesale changes regarding the IRP and the Commission's subsequent prudence analysis.

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[82] *See id.* at 14.
[83] Staff Final Comments at 26.

While PacifiCorp is open to further discussions with Staff and parties on this topic, the Commission has so far declined to import acknowledgment assumptions into subsequent ratemaking proceedings, and has carefully reinforced the divide between IRPs and ratemaking.

1. PacifiCorp's 2017 IRP does not require pre-approval.

Staff proposes two novel conditions should the Commission acknowledge the Energy Vision 2020 proposals: (1) setting a construction cost cap; and (2) prohibiting recovery beyond modeled assumptions, thereby allocating all performance risk or performance upside to company shareholders.[84] PacifiCorp believes its resource cost and performance assumptions are reasonable because they are based on robust data and analytics. Despite the company's confidence in its analysis Staff provided no rational basis for the Commission to depart so radically from well-established ratemaking practices by imposing the proposed conditions.

Staff reasons that this unorthodox treatment is appropriate because the resources "are acquired by virtue of an economic opportunity" and thus "are inherently not needed[.]"[85] Not only is Staff's underlying assumption incorrect—the resources are needed—Staff's proposed "guidance" mechanisms transform the IRP into a pre-approval process. Staff's recommendations constitute prospective ratemaking—by fixing the scope of PacifiCorp's possible future recovery, Staff's conditions function as an early prudence review, concluding that any costs outside the assumptions of the IRP are automatically imprudent and, by inference costs inside the IRP assumptions are automatically prudent.

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[84] *Id.* at 29.
[85] *Id.* at 28.

The Commission has repeatedly affirmed its "long-standing view that decisions made in IRP proceedings do not constitute ratemaking."[86] "Decisions whether to allow a utility to recover from its customers the costs associated with new resources *may only be made in a rate case proceeding*."[87] Fixing the ratemaking treatment during the IRP would thus contravene consistent and longstanding Commission precedent.

Staff acknowledges the Commission precedent, while simultaneously suggesting a radical departure from that precedent. Staff recognizes that "it is not possible to impose specific ratemaking treatment as a condition of acknowledgment" in an IRP proceeding.[88] But then Staff recommends that the Commission speculate on its future ratemaking treatment of the proposed resources as a condition of acknowledgment—importing precisely the analysis that the Commission describes as inappropriate to an IRP proceeding.[89] The reason for the distinction between the IRP and ratemaking rests on the relative completeness of the available information; information might arise during or after the IRP process to justify or preclude certain courses of action. Pre-judging a proposal, even in a supposedly non-binding capacity, would merely transport the ratemaking function to the IRP process under a different name.

Staff's proposal for preapproval would be a significant departure from the Commission's long-established and well-understood prudence standard. A utility investment is prudent if the decision was reasonable based on what was known, or should have been known, when the decision was made.[90] Staff's proposal would establish the prudence of the resource decision

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[86] *In the Matter of PacifiCorp, dba Pacific Power, 2013 Integrated Resource Plan*, Docket No. LC 57, Order No. 14-252 at 1 (Jul. 8, 2014) (emphasis added); *see also* Order No. 07-002 at 25 ("[T]he nature of an IRP proceeding is fundamentally different than that of a contested rate case proceeding.").
[87] *Id.*
[88] Staff Final Comment at 28.
[89] *Id.* (suggesting that the Commission "provide guidance about how it intends to evaluate PacifiCorp's resource acquisition decisions").
[90] Order No. 10-051 at 6.

based on what was known when the 2017 IRP was developed, not what will be known when the company decides to move forward with the Energy Vision 2020 resources. Such a radical departure from Commission precedent is unnecessary in the context of the 2017 IRP.

Even if the Commission adopts Staff's pre-approval paradigm, Staff's specific "guidance" suggestions are unreasonable. The Commission has consistently rejected the use of planning assumptions for subsequent ratemaking, particularly for wind resources:

> Although the estimated capacity factor at the time of project approval is dispositive for purposes of prudency review, it is not dispositive for purposes of forecasting resource availability for ratemaking purposes. The most recent reliable data should be used to set rates for the test period, recognizing that such data necessarily will be uncertain, particularly at start-up.[91]

The Commission affirmed this treatment in PacifiCorp's 2016 Transition Adjustment Mechanism.[92] The Commission has also rejected proposals to limit cost recovery to estimates used for benchmark resources submitted in an RFP.[93] Rate-setting should rely on up-to-date information and analysis and not, as Staff suggests here, forecasts that may be years old by the time the company requests ratemaking treatment.

Staff's guidance assumes that the Energy Vision 2020 proposals involve acquisition of specific resources that will be owned by PacifiCorp.[94] But the IRP looks at only generic

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[91] *In the Matter of PacifiCorp 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 at 21 (Nov. 14, 2008); *see also* Order No. 07-002 at 25 (rejecting use of IRP assumptions for prudence review).

[92] *In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 6-7 (Dec. 11, 2015).

[93] *In the Matter of PacifiCorp, dba Pacific Power, Request for Approval of Draft 2009R Request for Proposals for New Renewable Resources*, Docket No. UM 1429, Order No. 09-492, Appendix A at 5-6 (Dec. 14, 2009). When the Commission approved the final shortlist for PacifiCorp's 2009R RFP, the Independent Evaluation (IE) recommended that at the time of ratemaking the Commission should hold PacifiCorp to the cost estimates resulting from the RFP. Staff recommended against this approach because the "ratemaking treatment for the prudently incurred costs of the PacifiCorp benchmark resource is a proper subject of a future ratemaking proceeding." The Commission did not adopt the IE's recommendation.

[94] Staff Final Comments a 23 (assuming that resource actions necessarily involve PacifiCorp investment, rather than third-party development).

resources; the actual resource is selected through an RFP process. The Commission explained this distinction in Order No. 04-375, wherein PGE sought acknowledgement of a decision to build a specific natural gas plant.[95] Other participants objected, noting that the IRP does not consider specific resources.[96] The Commission agreed with the objectors, declining to acknowledge construction of the specific plant, but acknowledging instead the *generic* gas resource.[97] This distinction is key. It is not a foregone conclusion that any specific resource will be owned by PacifiCorp. Only after the RFP process, and only after a fresh economic analysis is then performed, can the prudence of a particular project be fairly and fully judged.

2. Acknowledgment of the 2017 IRP does not alter the Commission's role in making prudence determinations.

The 2017 IRP represents a traditional IRP that identifies a set of resources to serve a traditionally-identified resource need. The 2017 IRP does not, as Staff implies, create a slippery slope precedent for utilities to rely on to inflate ratebase on the backs of customers. Staff claims that if the Energy Vision 2020 projects are acknowledged without Staff's proposed limitations, "utilities would see a reward in finding new resource investments in future IRPs that add capital to rate base but really aren't needed to provide service."[98] Staff's argument relies on a series of misplaced assumptions and unreasonably discounts the Commission's ability to review the prudence of utility resource decisions.

Staff's concern relies on the assumption that PacifiCorp's investment is risk-free, with a "guaranteed" rate of return.[99] But Staff's characterization is inaccurate. Not only is there no surety that PacifiCorp will be the entity responsible for any capital investment, but any

[95] *In the Matter of Portland Gen. Elec. Co. OAR 860-038-0080, Resource Policies*, Docket No. LC 33, Order No. 04-375 at 9 (Jul. 20, 2004).
[96] *Id.* at 6.
[97] *Id.* at 9.
[98] Staff Final Comments at 23.
[99] *Id*.

investment must later be justified as prudent before it is allowed in rates—leaving investments exposed to possible denial of any recovery, let alone return on investment. Commission approval in ratemaking is merely an *opportunity* to receive a rate of return, on top of the need to recover the investment itself; utilities are by no means guaranteed to receive a specific return on those investments.[100] PacifiCorp has regularly earned less than its authorized rate of return—demonstrating that guaranteed, risk-free return is far from the sure thing that Staff describes.[101]

Staff argues that "[t]he monopolistic utility model under the regulatory compact" encourages utilities to add to rate base even when additional resources are not needed.[102] Staff supports this conclusion by citing the Averch-Johnson thesis, which theorizes that traditional rate-base and rate-of-return regulation biases a regulated firm, as compared to an unregulated one, toward more capital-intensive modes of production.[103] Staff's reliance on the Averch-Johnson thesis is misplaced, however, because there is considerable debate about whether the Averch-Johnson effect is real and, even if it is real, whether such an effect would be undesirable.[104] And even were the effect both real and undesirable, Staff's concern again

[100] *Application of Portland Gen. Elec. Co. for an Investigation into Least Cost Plan Plant Retirement*, Docket No. DR 10 *et al.*, Order No. 08-487 at 7 (Sept. 30, 2008) ("The rate of return established in rates represents the utility's *opportunity* to earn a profit, but utilities are not guaranteed a fair rate of return.") (emphasis in original) (citing *See, e.g.*, *Pub. Serv. Comm'n of Mont. v. Great Northern Utils. Co.*, 289 US 130, 135, 53 S Ct 546, 548, 77 L Ed 1080 (1933) (The Fourteenth Amendment does not "assure to public utilities the right under all circumstances to have a return upon the value of its property * * *."); *Market St. Ry. Co. v. Railroad Comm'n*, 324 US 548, 567, 65 S Ct 770, 89 L Ed 1171 (1945) ("The due process clause has been applied to prevent governmental destruction of existing economic values. It has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces.").).
[101] *See* Staff Final Comments at 23.
[102] *Id.*.
[103] James C. Bonbright et al., *Principles of Public Utility Rates* 356 (2d ed. 1988).
[104] Charles F. Phillips, Jr., *The Regulation of Public Utilities* 892-93 (1993); *see also* Bonbright at 362 ("[T]o the extent [the Averch-Johnson effect] exists, it could well be a more important influence for good than for poor performance[.]") (quoting Alfred E. Kahn, *Applications of Economics to Utility Rate Structures*, 101 Public Utilities Fortnightly 59 (Jan. 19, 1978)); *id*. ("To repeat: we find a paucity of data documenting the Averch-Johnson effects and instead find largely educated speculation."). A recent meta-analysis of scholarship concerning the Averch-Johnson effect concluded that it amounts to "an intellectual curiosity," and suggested that further efforts to discern an Averch-Johnson effect on regulated utilities be "abandoned in favour of more productive enterprises." Stephen

assumes that PacifiCorp will own the wind resources; this is not necessarily true. The RFP process will determine what party is responsible for project development, project type, and the concomitant capital investment.

It is not clear how Staff's dire predictions of unchecked economic development would occur while still satisfying the Commission's prudence standard.[105] The IRP is tasked to identify the least-cost, least-risk portfolio for customers. The Energy Vision 2020 projects provide the least-cost, least risk option. The only scenario in which Staff's fears could materialize—excessive capital investment at excessive ratepayer risk—requires the Commission to radically change its prudence review standard to ignore the reasonableness of the utility decision-making based on what the utility knew or should have known at the time of the acquisition decision.[106]

The assumptions underlying Staff's reallocation of risk are mistaken, and fail to justify transferring all possible risks onto PacifiCorp's shareholders as a condition of acknowledgment of Energy Vision 2020's generic resource portfolio.

IV. REPLY TO STAFF'S FINAL COMMENTS

A. Energy Efficiency/Class 2 Demand Side Management

Staff believes PacifiCorp Action Plan Item 4a for energy efficiency should be acknowledged, subject to modifications because Staff believes PacifiCorp needs to address two issues: (1) Staff's belief that there is an ongoing tendency to underrepresent energy efficiency as a resource; and (2) Staff's statement that the reduction of total system energy efficiency between the 2015 IRP and the 2017 IRP could be perceived as unfair to Oregon customers when

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M. Law, *Assessing the Averch-Johnson-Wellisz Effect for Regulated Utilities*, 6 INT'L J. OF ECON. & FIN. 41, 42, 52 (2014).

[105] Staff Final Comments at 18, 24.

[106] Order No. 10-051 at 6.

comparing savings between Oregon and Utah.[107] Staff further finds PacifiCorp's explanation regarding the disparity between the level of energy efficiency savings across states to be "somewhat insufficient."[108] PacifiCorp appreciates Staff's thorough review of demand-side management (DSM) resources in the 2017 IRP, and provides clarification and comments to address Staff's concerns.

1. Staff's concerns regarding underrepresentation of Class 2 DSM in forecasts.

Staff states that Class 2 DSM is underrepresented in PacifiCorp's 2017 IRP because: (1) the Energy Trust of Oregon has consistently acquired more savings than identified in PacifiCorp's IRPs; and (2) avoided costs used to determine energy efficiency potential may be undervaluing it as a resource.

In response to Staff's first concern, PacifiCorp agrees that there would be value in better aligning the Energy Trust of Oregon (ETO) acquisition levels with PacifiCorp's IRP targets. The ETO has already begun work to better align its inputs to utilities' IRPs with expected acquisition levels and PacifiCorp is hopeful that this process will help address Staff's concerns of misaligned planned and acquired savings levels for the 2019 IRP. On September 22, 2017, PacifiCorp participated in a workshop hosted by the ETO to discuss potential improvements with utilities and interested stakeholders. PacifiCorp plans to stay actively engaged in this process, providing information necessary to ensure that considerations for PacifiCorp's future IRPs are accurately captured in the ETO's processes.

PacifiCorp highlights two additional factors that may be contributing to misalignment of Oregon Class 2 DSM IRP targets and actual acquisition by the ETO. First, PacifiCorp uses the IRP model to develop avoided costs for Class 2 DSM consistent with the resource selections in

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[107] Staff Final Comments at 31.
[108] *Id*.

the preferred portfolio. PacifiCorp provides these values to the ETO, who uses them to assess the cost-effectiveness of energy efficiency measures and programs. However, the ETO does not use these avoided costs directly to assess the value of these resources to PacifiCorp's system. Rather, it blends these values with avoided cost values provided by PGE to develop a single set of avoided costs for assessing the cost-effectiveness of electric energy efficiency measures. This blending process may be inflating the value of energy efficiency that the ETO delivers on behalf of PacifiCorp's customers and leading to higher levels of acquisition than deemed cost-effective in PacifiCorp's IRP. PacifiCorp looks forward to exploring this issue in more depth through the investigation the Commission recently opened into avoided costs for energy efficiency analysis.

Second, PacifiCorp's IRP target is based on acquiring all cost-effective energy efficiency, but the Commission has an exception process that allows the ETO to incentivize energy efficiency measures that are not cost-effective. While there may be policy reasons for allowing these exceptions, this action will tend to lead to the ETO acquiring savings above what is deemed cost-effective in PacifiCorp's IRP.

Regarding avoided costs, Staff noted that it struggles to reconcile the requirement from Senate Bill (SB) 1547 to "[p]lan for and pursue all available energy efficiency resources that are cost effective, reliable and feasible…" with PacifiCorp's statement that the cost of other resource alternatives affects the level of energy efficiency selected by the IRP model, noting that "[t]his would seem to imply that the selection of EE by System Optimizer in PacifiCorp's preferred portfolio is relative to the costs of other resources, rather than being based on all cost-effective EE."[109] Contrary to Staff's assertion, the cost-effectiveness of energy efficiency resources and the cost of alternative resources are inherently intertwined.

[109] *Id.* at 33.

As defined in statute "'Cost-effective' means that an energy conservation measure that provides or saves a specific amount of energy during its life cycle results in the lowest present value of delivered energy costs of any available alternative."[110] This means that an energy conservation measure is deemed cost-effective if it provides energy savings at a cost lower than available energy delivery alternatives. This comparison of costs of energy efficiency resources to the costs of available alternatives is precisely the analysis that is performed in PacifiCorp's IRP model, which is why the cost of resource alternatives inherently affects the cost-effectiveness of energy efficiency resources. The amount of energy efficiency resources included in the preferred portfolio *is* all energy efficiency that is cost-effective for PacifiCorp's system.

2. There appears to be confusion regarding energy efficiency as a resource type.

Staff believes that the Company's reply comments present a false equivalency between Energy Vision 2020 projects and energy efficiency, stating that "[t]he need for EE is immediate as both an energy resource and as an instrument for regulatory compliance."[111] While Staff is correct that under SB 1547 PacifiCorp has an obligation to plan for and pursue all available energy efficiency resources that are cost effective, reliable and feasible, Staff is incorrect that the need for energy efficiency as an energy resource is immediate.

The IRP establishes the amount of energy efficiency that is cost-effective for PacifiCorp's system, but does not investigate the resource need without energy efficiency. This analysis is performed through a separate study,[112] which also establishes the avoided costs of

[110] ORS 469.631(4).
[111] Staff Final Comments at 36.
[112] PacifiCorp's 2017 Class 2 Demand-Side Management Decrement Study is available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/2017/PacifiCorp_Class2_DSM_Decrement_Study.pdf.

energy efficiency, which are used to assess the cost-effectiveness of measures and programs. This analysis is performed by removing all new energy efficiency resources selected in the preferred portfolio, creating a resource gap to fill, and forcing the model to fill this gap with non-energy efficiency resources. The increased cost of filling this gap is the value of energy efficiency to PacifiCorp's system.

In *PacifiCorp's 2017 Class 2 Demand-Side Management Decrement Study*, when not allowed to select energy efficiency resources, the model selected the following resources that were not included in the 2017 IRP preferred portfolio:

- 150 MW of additional wind in 2021;
- 416 MW combined cycle combustion turbine in 2028
- Two 200 MW Frames in 2028
- 477 MW combined cycle combustion turbine in 2029 and 2033

As shown above the first non-renewable resource deferred by energy efficiency in the 2017 IRP is in 2028. This analysis demonstrates that the IRP model is not selecting energy efficiency to satisfy an immediate resource need, as suggested by Staff, but rather as an economic proposition based on long-term resource needs.

3. *Staff's recommendations regarding energy efficiency/Class 2 DSM.*

Staff recommends that PacifiCorp hire an independent consultant to conduct an analysis to identify and compare the ongoing differences between the ETO's and PacifiCorp's near- to long-term energy efficiency forecasts with ETO actual achieved savings.[113] Staff also

[113] Staff Final Comments at 36.

recommends that PacifiCorp hire an independent consultant to identify and compare potential, technical, and achievable energy efficiency savings across states.[114]

As discussed above, the ETO, in collaboration with Staff, utilities, and stakeholders is working to improve alignment between inputs to utility IRPs and actual acquisition levels. It is likely this process will address the concerns raised by Staff and engagement of an independent consultant at this time may be redundant. PacifiCorp recommends that the Commission revisit the use of an independent consultant when reviewing the 2019 IRP because discussions with ETO are anticipated to continue in 2018.

The second analysis recommended by Staff seems duplicative to work PacifiCorp already performs. As Staff notes "[i]t would appear most of the states will contribute levels of EE savings close to their percent of total sales in the 2017 IRP."[115] Every two years, PacifiCorp hires an independent consultant to perform a multi-state analysis of available DSM potential and create a report including a detailed discussion of inputs, methodology, and results, a comparison of measures analyzed to the ETO's analysis, and a discussion of similarities and differences of ramp rates and deployment curves between the consultant's study and the ETO's inputs to the IRP. This work that PacifiCorp already performs to support the IRP should already be sufficient to address Staff's concerns about DSM acquisition levels across states, and PacifiCorp will work with Staff to ensure that information necessary for Staff's review is available.

B. Load Forecasting and Load and Resource Balance

Staff expresses concerns that PacifiCorp's forecasts "might be inaccurate because the relationship between load and economic variables has not been constant over time."[116] Staff

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[114] *Id.* at 37.
[115] *Id. at* 35.
[116] *Id.* at 37.

identified issues when rerunning PacifiCorp's residential number of customers model with only exogenous variables.[117] Staff recommends that PacifiCorp investigate if it can transform its data before inputting it into statistical software. [118]

Consistent with information provided in a discovery response to Staff, although the relationship between employment and electricity usage has been less responsive since the recession, PacifiCorp believes that the historical relationship between the data is a reasonable predictor of the future relationship and that electric usage will become more responsive to employment beyond 2017. In some instances, such as in Wyoming, PacifiCorp applied post-model adjustments to correct the forecast until the relationship between employment and electric usage stabilizes. PacifiCorp continues to monitor and evaluate the stability of the relationship between the economic driver and class level loads, and intends to provide an analysis of driver to load relationships in a future IRP.

Staff also noted that additional forecast drivers in PacifiCorp's street light forecast could help more accurately model energy savings due to customers switching to light-emitting diodes (LEDs).[119] PacifiCorp currently accounts for the impact of LED lighting adoption for street lighting within its retail level forecast. These efficiency gains, however, have not been specifically allocated to the street lighting class and have been apportioned to energy sales for other classes within the forecast. PacifiCorp acknowledges that efficiency gains for street lighting should be reflected within the street lighting class and has recently taken steps to correct this in future forecasts. This methodological update would have no net effect on the overall

[117] *Id.*
[118] *Id.*
[119] *Id.* at 37-38.

retail level forecast because efficiency gains attributable to street lighting is currently being reflected in energy sales within other classes.

C. Modeling and Portfolio and Results

Staff states that the model and portfolio evaluation "appears to be robust and of a level of complexity well suited for the IRP process" but staff still has "lingering concerns" regarding PacifiCorp's use of Monte Carlo analysis.[120] PacifiCorp is open to further discussions with Staff to address t these concerns and discuss its model and portfolio evaluation.

Staff recommends that PacifiCorp "investigate a more diverse renewable portfolio in future IRPs and IRP updates."[121] As seen in the Supply-Side Resource Table of the 2017 IRP, PacifiCorp considered several diverse renewable resources for portfolio selection.

Staff also recommends that PacifiCorp rerun its model with the assumption that the EPA's regional haze litigation would be successful.[122] PacifiCorp already provided this scenario with the reference case scenario in the 2017 IRP analysis process. PacifiCorp based its assumptions for each unit in the reference case on known court decisions that impacted a unit's compliance litigation, any settlement decisions available to inform PacifiCorp's 2017 IRP, and regional haze compliance requirements, reflecting SCR installations, should litigation be unsuccessful from the PacifiCorp's perspective.

1. Stochastic Parameters

Staff stated that it appreciates PacifiCorp's detailed explanation of how distributions were chosen and how seasonal and regional correlations were developed, but, in IRP updates,

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[120] *Id.* at 39.
[121] *Id.*
[122] *Id.*

encourages PacifiCorp to clearly explain the reason for sometimes low correlation in the short-term forecast.[123]

PacifiCorp includes a detailed description of its stochastic parameters and their development in Volume II, Appendix H of the 2017 IRP. While PacifiCorp discusses its short-term correlation estimation process and calculation, the presented results do not include descriptions of the reason for sometimes low correlation commented on by Staff. PacifiCorp is open to including explanation for sometimes low correlation in the short-term forecast as relevant for future IRPs.

2. Planning Reserve Margin Study

Staff stated that it is "generally satisfied" with the PRM study procedures and the 13 percent PRM "with some caveats."[124] Staff said that it "appreciates the inclusion of DSM in the present IRP, but other combinations of resources should be considered in IRP updates."[125] In addition to including DSM in the 2017 IRP PRM study, PacifiCorp also included renewable resources, however, they were not selected by the model to meet the PRM. PacifiCorp is open to discussing Staff's interests in future PRM studies.

3. Flexible Reserve Study

Staff said that it appreciates PacifiCorp's responsiveness to inquiries regarding the flexible reserve study and notes that while there may be some concerns around the "robustness of the resource set analyzed," the modeling strategy appears to be reasonable.[126] Staff recommends

[123] *Id.* at 40.
[124] *Id.* at 41.
[125] *Id.*
[126] *Id.* at 42.

that PacifiCorp model natural gas and storage for meeting the flexible reserve study needs in the IRP update.[127]

PacifiCorp is currently evaluating a variety of use cases for energy storage systems as part of its Energy Storage Potential Evaluation in docket UM 1857. PacifiCorp anticipates that the results of that analysis will identify credits to be applied to various flexible resources to capture value streams not already accounted for in the existing IRP models, which will incorporate capacity requirements, as well as some energy arbitrage and operating reserve benefits. The current assumptions for energy storage systems in the IRP models do not incorporate sub-hourly benefits that could be realized through the EIM, nor do they account for all transmission and distribution-related benefits, including deferral of upgrades or reduced congestion. Resource potential limits that incorporate these additional value streams, potentially organized in bundles similar to those used for demand-side management, are also expected to be an output of docket UM 1857. To the extent the value streams identified in the storage potential evaluation are also applicable to other flexible resource types (such as natural gas, as referenced in Staff's comments), PacifiCorp agrees that it would be appropriate to include consistent assumptions for all resource types. PacifiCorp intends to include the best information available on all resources for its 2017 IRP Update, but notes that the results of the Energy Storage Potential Evaluation may be limited or preliminary when the IRP Update is prepared. As a result, further refinement of the assumptions for flexible resources modeled in the IRP is expected in the 2019 IRP and beyond.

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[127] *Id*.

Staff notes that the flexible reserve study results "indicate that the need for wind resources to meet FRS needs are considerably lower than what is being proposed elsewhere in the IRP."[128]

Staff's precise concern is unclear to PacifiCorp. PacifiCorp's 2017 IRP does not assume that wind resources can help meet flexible reserve needs, and does not add wind resources to meet those needs. Wind resource additions in the IRP are based on their contribution to the least-cost, least-risk portfolio of the available resource options. While the FRS results show that flexible reserve needs increase with the incremental wind resource additions, as a modeling simplification the 2017 IRP uses the fixed integration charge value from the FRS to approximate the associated costs, rather than adjusting or modifying the modeled reserve needs.

D. Distribution System Planning

Staff clarified that it "does not mean to imply" that PacifiCorp "is not currently planning for distribution system investments in a way that will prudently transition its system towards a more modern grid that is capable of meeting changing expectations for energy services," but this is difficult to assess.[129] Staff plans to further explore how some form of integrated planning between IRP and DSP would be useful.[130] PacifiCorp welcomes further discussions with Staff to address Staff's concerns and to help Staff better assess PacifiCorp's distribution system planning.

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[128] *Id.*
[129] *Id.* at 43.
[130] *Id.*

E. Smart Grid Report

Staff requested additional information regarding "any interrelation (or lack thereof) between AMI and planning and resource applications."[131] Staff also inquired as to whether PacifiCorp intends to use AMI data in its integrated resource planning.[132]

PacifiCorp is and will continue to evaluate AMI data and associated analytics as an opportunity to leverage additional AMI value in Oregon. For example, AMI data could improve confidence in load estimations and forecasts, provide greater load prediction in response to temperature changes, increase accuracy of load profiles, provide detailed load profile information to aid rate design for customer classes, and enable distributed energy resources and other non-wires alternatives (e.g. targeted efficiency, demand response, and home area networks). PacifiCorp believes it is premature to provide additional detail regarding the use of AMI data in its planning and resource applications until the breadth of the data analytics and its value can be adequately explored.

V. CONCLUSION

PacifiCorp's 2017 IRP complies with the Commission's existing IRP framework and guidelines. The 2017 IRP is supported by robust portfolio modeling and prudent planning assumptions that lead to selection of a least-cost, least-risk preferred portfolio and 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. PacifiCorp requests that the Commission acknowledge the 2017 IRP and the 2017 IRP action plan.

[131] *Id.*
[132] *Id.*

Respectfully submitted this 30th of October, 2017

Etta Lockey
Vice President, Regulation
PacifiCorp d/b/a Pacific Power

Attachment A

Figure 1. Comparison of the 2017 IRP and Updated Load Forecast Assumption

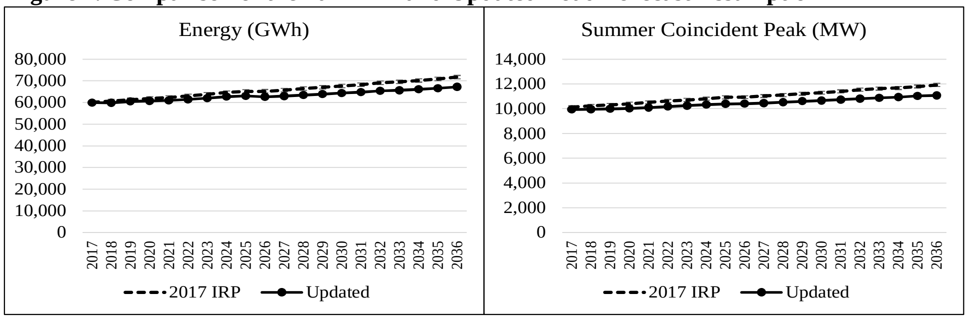

Figure 2. Comparison of the April 2017 and September 2017 OFPC Henry Hub Natural-Gas Price Forecasts

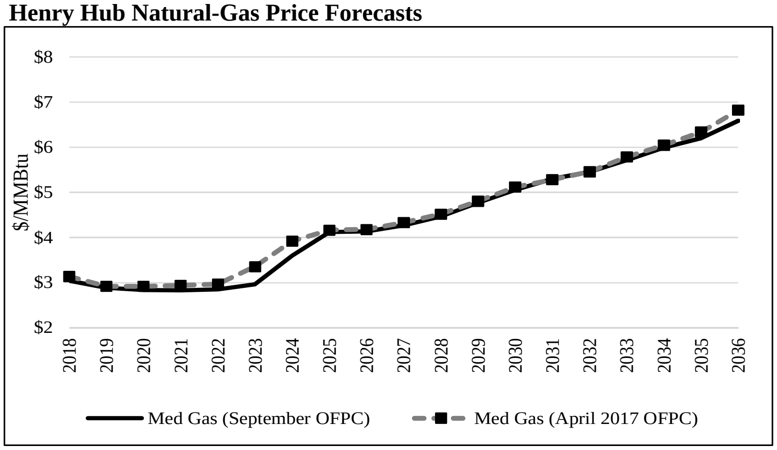

Figure 3. NYMEX Henry Hub Natural Gas Futures Open Interest as of September 11, 2017

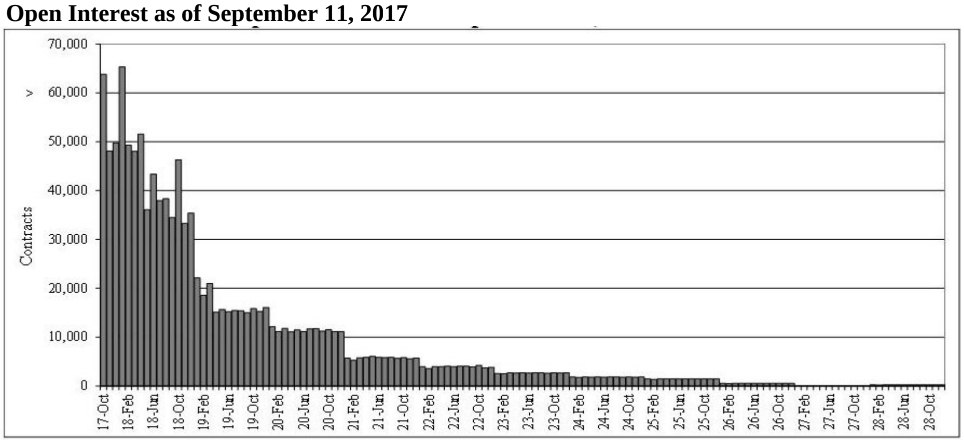

Figure 4. Comparison of the Updated Change in Incremental Wind Energy Output Due to Wind Repowering

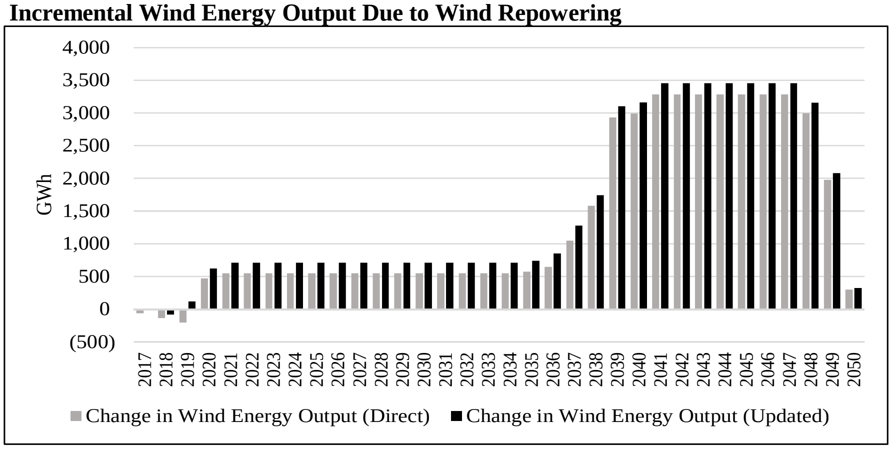

Figure 5. Updated Total-System Annual Revenue Requirement With Wind Repowering ($ million)

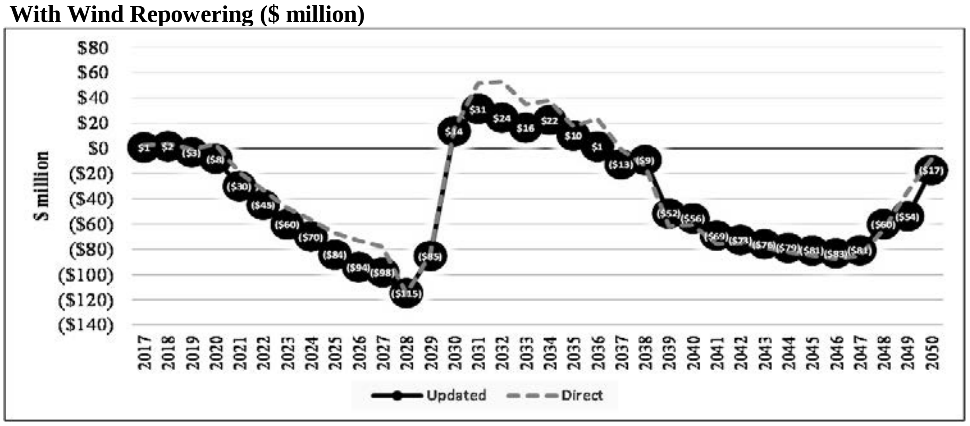

Figure 6. Total-System Annual Revenue Requirement for Leaning Juniper with Wind Repowering ($ million)

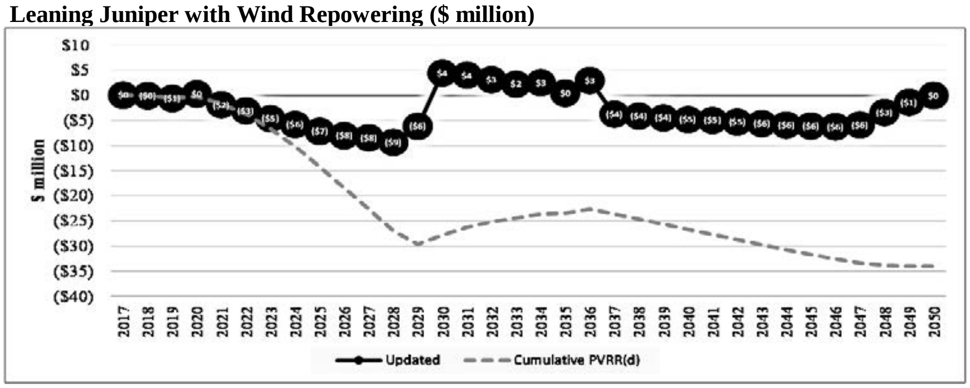

Table 1. Updated SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($110)	($90)	($95)
Low Gas, Medium CO_2	($125)	($108)	($113)
Low Gas, High CO_2	($133)	($114)	($119)
Medium Gas, Zero CO_2	($137)	($116)	($122)
Medium Gas, Medium CO_2	($138)	($115)	($121)
Medium Gas, High CO_2	($157)	($131)	($137)
High Gas, Zero CO_2	($196)	($152)	($160)
High Gas, Medium CO_2	($204)	($167)	($175)
High Gas, High CO_2	($214)	($167)	($176)

Table 2. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($360)
Low Gas, Medium CO_2	($480)
Low Gas, High CO_2	($473)
Medium Gas, Zero CO_2	($483)
Medium Gas, Medium CO_2	($471)
Medium Gas, High CO_2	($534)
High Gas, Zero CO_2	($555)
High Gas, Medium CO_2	($635)
High Gas, High CO_2	($619)

Table 3. Long-Term Benefit Sensitivity

Source of 2037-2050 Benefits	Nominal Levelized Benefit from 2037 –2050 ($/MWh)	Annual Revenue Requirement PVRR(d) (Benefit)/Cost ($ million)
2028-2036 System Modeling	$57.82	($471)
70% of PV Flat OFPC	$45.30	($385)
100% of PV Flat OFPC	$64.71	($522)
130% of PV Flat OFPC	$84.12	($658)
No Value	$0.00	($66)

Table 4. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($17)	($14)	($14)
Glenrock 3	($5)	($3)	($4)
Seven Mile Hill 1	($23)	($20)	($21)
Seven Mile Hill 2	($5)	($5)	($5)
High Plains	($4)	($1)	($1)
McFadden Ridge	($1)	($0.20)	($0.20)
Dunlap Ranch	($14)	($11)	($11)
Rolling Hills	($5)	($3)	($3)
Leaning Juniper	($3)	($3)	($4)
Marengo 1	($28)	($26)	($27)
Marengo 2	($10)	($9)	($10)
Goodnoe Hills	($21)	($21)	($22)
Total	($138)	($117)	($122)

Table 5. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	Annual Revenue Requirement PVRR(d)
Glenrock 1	($50)
Glenrock 3	($15)
Seven Mile Hill 1	($65)
Seven Mile Hill 2	($17)
High Plains	($37)
McFadden Ridge	($11)
Dunlap Ranch	($60)
Rolling Hills	($30)
Leaning Juniper	($34)
Marengo 1	($77)
Marengo 2	($30)
Goodnoe Hills	($50)
Total	($477)

Table 6. Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering ($/MWh)

Wind Facility	Nominal Levelized Net Benefit
Glenrock 1	$43/MWh
Glenrock 3	$39/MWh
Seven Mile Hill 1	$46/MWh
Seven Mile Hill 2	$58/MWh
High Plains	$29/MWh
McFadden Ridge	$28/MWh
Dunlap Ranch	$42/MWh
Rolling Hills	$36/MWh
Leaning Juniper	$27/MWh
Marengo 1	$37/MWh
Marengo 2	$31/MWh
Goodnoe Hills	$47/MWh

Table 7. Tax Policy Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($45)	($138)	$93
PaR Stochastic Mean	($23)	($115)	$93
PaR Risk Adjusted	($24)	($121)	$97

Table 8. LGIA-Limited Equipment Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($152)	($138)	($13)
PaR Stochastic Mean	($127)	($115)	($11)
PaR Risk Adjusted	($132)	($121)	($11)

Table 9. LGIA-Modified Equipment Sensitivity
(Benefit)/Cost of Wind Repowering ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($186)	($138)	($48)
PaR Stochastic Mean	($153)	($115)	($37)
PaR Risk Adjusted	($160)	($121)	($39)