BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In re: Union Electric Company's 2017 Utility Resource Filing Pursuant to 4 CSR 240 – Chapter 22	)))	Case No. EO-2018-0038

SIERRA CLUB'S REPLY TO AMEREN MISSOURI'S RESPONSE TO ALLEGED DEFICIENCIES

Sierra Club, by and through counsel, hereby submits the following reply to Ameren Missouri's Response to Alleged Deficiencies regarding its 2017 Integrated Resource Plan ("IRP").

- Ameren's Description of Sierra Club Deficiency 1 – "Sierra Club alleges that Ameren Missouri inadequately considers likelihood of increasingly stringent environmental regulations."

Sierra Club Response:

In its response, Ameren restates its assumptions for future environmental regulations and its arguments for why its plants are likely to be in compliance, concluding that "the Company has appropriately assessed what it believes to be the probable future requirements of environmental regulations during the planning horizon as required by 4 CSR 240-22.040(2)(B)."

However, in its IRP, Ameren acknowledges that "[i]f future revisions require additional reductions in the CSAPR SO_2 and/or NO_x allocations, Ameren Missouri would evaluate compliance strategies that could include modified operation of existing generation resources *as well as the installation of additional pollution control equipment at one or more of its facilities depending on the level of required reduction*." (Chapter 5, page 4, emphasis added). The deficiency identified by Sierra Club is that, while Ameren noted this possible regulatory direction, it failed to take the potential costs of this outcome into account in its analysis.

- Ameren's Description of Sierra Club Deficiency 2 – "Sierra Club alleges that Ameren Missouri's treatment of future carbon regulations is deficient because it assumes carbon prices so unreasonably low even in the 'high' case, and with no carbon price before 2025."

Sierra Club Response:

The deficiency identified by Sierra Club was two-pronged. First, that the carbon emissions prices assumed by Ameren were so low that they cannot possibly reflect a realistic policy scenario to address global climate disruption; and second, that Ameren did not actually apply the carbon prices from the sources it identified correctly. The first of these may possibly be described as "a differing opinion" as Ameren does in its response, by the same token the

Commission should not accept "opinions" from Ameren that lack a logical consistency with reasonable future policy scenarios. The second was confirmed after Sierra Club submitted its comments in materials provided by Ameren purportedly to support its carbon emissions price modeling.

Specifically, in response to Sierra Club data request No. 12, Ameren provided a 2016 presentation from HIS showing, on Slide 13, the "Rivalry" carbon price forecast upon which Ameren relied for its carbon price. (While Ameren cites several sources and considerations it says it used in developing its CO_2 price assumptions, ultimately Ameren relied upon the HIS "Rivalry" scenario as shown in Table 6A.7 of its IRP.) However, the HIS presentation is clear that its carbon emissions price is already designed to represent the *full range* of possible future policy options. In other words, it already incorporates a scenario in which there is no price on carbon in the coming decades.

When Ameren applies the HIS "Rivalry" price to its "mid" and "high" carbon cases, but not to its "low" case, it is inherently misusing the price forecast. It would be more appropriate and closer to the intended use to use this as a "mid" case forecast and have higher and lower price trajectories that represent alternative cases, but by only considering "Rivalry" and no carbon alternatives, Ameren biases and compromises its analysis. This does not reflect a difference of opinion – it is an unambiguous misuse of the cited source, and it is and remains a deficiency.

- Ameren's Description of Sierra Club Deficiency 3 – "Sierra Club alleges that Ameren Missouri inadequately considered economic challenges for its coal units; namely low natural gas prices, competition from renewables, low or negative load growth and Ameren Missouri's high capacity position in excess of reliability requirements."

Sierra Club Response:

The basis of this multifaceted allegation is detailed in pages 8 through 19 of Serra Club's comments and need not be reiterated here. Sierra Club noted a wide range of examples of how Ameren underestimated the challenges facing its coal plants in the near future, including those raised in the other deficiencies discussed herein. Sierra Club further found that while Ameren appears to recognize the bleak economic future for the coal fleet around the nation, it seems to believe that its own aging coal units will be magically untouched by the same economic realities. This defies logic to the point of presenting a significant deficiency in Ameren's IRP.

Recent commission decisions in other states have recognized the economic challenges facing coal generation. For example, earlier this month, the State of Washington Utilities and Transportation Commission (WUTC) stated: "We are deeply concerned with the direct costs of continued operation of [Pacific Power's (PacifiCorp)] coal-fueled resources and the magnitude of economic risk of continued investment in those units. Pacific Power's IRP does not explicitly identify or discuss the risks faced by the utility and its ratepayers, including the costs of risks associated with the coal plants' fuel source, projected capital investments, and ongoing operational expenses . . . ."[1] Accordingly, the WUTC ordered PacifiCorp to "undertake a

[1] 2017 Electric IRP Acknowledgement Letter and Attachment, PacifiCorp's 2017 Electric Integrated Resource Plan, Docket UE-160353, May 7, 2018, Attachment at 4, attached hereto as Exhibit A.

complete examination of costs of continued operation and investment into Colstrip Units 3 & 4 and the Jim Bridger plant" [PacifiCorp's remaining coal units providing power to Washington], outlining very specific analyses that the Company must undertake.[2]

Similarly, the Public Utility Commission of Oregon (Oregon PUC) ordered PacifiCorp to conduct 25 system optimizer (SO) runs, one for each coal unit and a base case.[3] Specifically, PacifiCorp agreed to "summarize the results providing a table of the difference in present value of revenue requirement (PVRR) resulting from the early retirement of each unit, an itemized list of coal unit retirement costs assumptions used in each SO run, and a list of coal units that would free up transmission along the path from the proposed Wyoming wind projects if retired."[4]

Ameren's failure to adequately and thoroughly consider economic challenges to its coal units is a significant deficiency, and the Missouri Public Service Commission should order Ameren to conduct a full range of analyses and to provide a thorough accounting of costs and risks, similar to the ones ordered by the WUTC and Oregon PUC.

- Ameren's Description of Sierra Club Deficiency 4 – "Sierra Club alleges that Ameren Missouri inadequately considers renewables since other than RES only portfolio, there is no wind addition after 700MW and Ameren Missouri is unwilling to add solar, and is relying on 2013 information for solar costs."

Sierra Club Response:

Ameren Missouri indeed notes in its 2017 IRP filing that "the potential exists to add even more wind generation in the coming years as a result of improving technology and economics, as well as renewable energy initiatives with large customers." and that, "Ameren Missouri will continue to explore renewable investments beyond the IRP that are in the long-term best interest of customers…"

The deficiency identified by Sierra Club is that, while acknowledged, these highly likely scenarios (because they are consistent with current trends, as detailed by Sierra Club) are not included in the IRP modeling provided by the Company. Thus, Ameren understates the likely contributions from renewables, and biases its plan in favor of continued investment in existing, fossil-fired resources that are likely to be uneconomic during the planning period.

- Ameren's Description of Sierra Club Deficiency 5 – "Sierra Club alleges that the IRP is deficient because Ameren Missouri has not mentioned the findings of the Eastern District of Missouri and has not evaluated remedy costs."

Ameren responds that "[i]t would be inappropriate for Ameren Missouri to comment on this active case in its IRP." Sierra Club strongly disagrees. Judge Sippel's ruling in this case represents a significant, known risk to Ameren's coal fleet, particularly the Rush Island plant,

---

[2] *Id*. at Attachment pp. 4-6.
[3] In the Matter of PacifiCorps, dba Pacific Power, 2017 Integrated Resource Plan, Order, April 27, 2018, pp. 11-13, attached hereto as Exhibit B.
[4] *Id*.

that cannot be ignored merely because the final outcome regarding remedy is not known with certainty. To do so introduces a significant bias in Ameren's analysis in favor of its threatened coal plants. Put simply, a federal judge has found that Ameren violated the law. Litigation continues merely to determine how Ameren must remedy its violations. An IRP, properly conducted, would have looked at a number of scenarios for compliance with long-standing litigation. Ameren did not choose to conduct this analysis, which is a significant deficiency in its IRP.

- Ameren's Description of Sierra Club Deficiency 6 – "According to Sierra Club, 'Ameren has consistently excluded the broader public from participating in the IRP process and requires participants to sign draconian confidentiality agreements.' Sierra Club asks the Commission to improve public involvement in utilities' long range planning including considering the implementation of one or more public hearings."

Sierra Club Response:

Sierra Club refers the Commission to its original comments on page 3 of its February 28, 2018 filing. Because the fundamental objective of the resource planning process is to serve the public interest, Sierra Club urges the Commission to consider improving opportunities for public involvement in utilities' long range planning, including considering the implementation of one or more public hearings where members of the public can have more meaningful input into energy decisions, similar to rate cases.

Conclusion

Sierra Club respectfully requests that the Company agree to prepare, or the Commission order the Company to prepare, a revised triennial IRP filing that corrects the deficiencies discussed above and in more detail in Sierra Club's February 28, 2018 comments of Dr. Hausman; and that the Commission order the Company to conduct one or more public hearings to provide the opportunity for public input required by 4 CSR 240-22.080(5).

Respectfully submitted,

/s/ Henry B. Robertson
Henry B. Robertson (Mo. Bar No. 29502)
Great Rivers Environmental Law Center
319 N. Fourth Street, Suite 800
St. Louis, Missouri 63102
Tel. (314) 231-4181
Fax (314) 231-4184
hrobertson@greatriverslaw.org

Attorney for Sierra Club

CERTIFICATE OF SERVICE

I hereby certify that a true and correct PDF version of the foregoing was filed on EFIS and electronically mailed to all counsel of record on this 30th day of May, 2018.

/s/Henry B. Robertson
Henry B. Robertson

Exhibit A
Service date: May 7, 2018

STATE OF WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION
1300 S. Evergreen Park Dr. S.W., P.O. Box 47250 ● Olympia, Washington 98504-7250
(360) 664-1160 ● www.utc.wa.gov

May 07, 2018

Etta Lockey
Vice President, Regulation
Pacific Power and Light Company
825 Northeast Multnomah, Suite 2000
Portland, Oregon 97232

Re: PacifiCorp's 2017 Electric Integrated Resource Plan
Docket UE-160353

Dear Ms. Lockey:

The Washington Utilities and Transportation Commission (Commission) has reviewed the 2017 Electric Integrated Resource Plan (IRP) filed by Pacific Power and Light Company (Pacific Power or Company) on April 4, 2017, and finds that it meets the requirements of Revised Code of Washington (RCW) 19.280.030 and Washington Administrative Code (WAC) 480-100-238.[1]

By acknowledging compliance with statute and rule, the Commission does not signal pre-approval for ratemaking purposes of any course of action identified in the IRP. The Commission will review the prudence of the Company's actions at the time of any future request to recover costs of resources in customer rates. The Commission will reach a prudence determination after giving due weight to the information, analyses, and strategies contained in the Company's IRP along with other relevant evidence.

Because an IRP cannot pinpoint precisely the future actions that will minimize a utility's costs and risks, we expect that the Company will regularly update the assumptions that underlie the analysis within the IRP and adjust its investment strategies accordingly.

Overall, the Commission is pleased with the thorough presentation of the Company's analyses in the 2017 IRP, and encourages the Company to continue its transparent and

[1] On May 1, 2018, Pacific Power filed an update to its 2017 Integrated Resource Plan. This Acknowledgment Letter and attachment do not reflect the Company's updated filing.

inclusive work with its advisory group on resource planning for the 2019 IRP. In the attached document the Commission provides specific comments regarding this IRP, and expectations for the 2019 IRP. While a majority of the Commission, Chair Danner and Commissioner Rendahl, support all of the specific comments and expectations expressed in the attached document, Commissioner Balasbas, as outlined at the end of the attached document, does not agree with all of the comments and expectations in Section III. i., pertaining to Emissions Price Modeling and Cost Abatement Supply Curve.

As a reminder, Pacific Power should file its next IRP on or before March 31, 2019.

Sincerely,

MARK. L. JOHNSON
Executive Director and Secretary

Attachment

Attachment

Pacific Power & Light Company 2017 Integrated Resource Plan
Docket UE-160353

I. Introduction

RCW 19.280.030 and WAC 480-100-238 direct investor-owned energy companies (IOUs) to develop an integrated resource plan (IRP) every two years. The IRP, or plan must identify "the mix of energy supply resources and conservation that will meet current and future needs at the lowest reasonable cost to the utilities and its ratepayers."[1] The IRP touches every aspect of a company's operations and provides essential public participation opportunities for stakeholders to assist in the development of an effective plan. In preparing an IRP, utilities are required to consider changes and trends in energy markets, resource costs, cost of risks associated with greenhouse gas emissions, state and federal regulatory requirements, and other shifts in the policy and market landscape.[2] The statute and the Commission's rule require that IOUs conduct a comprehensive analysis of the costs, benefits, and risks of various approaches to meeting future resource needs using commercially available information. The intent is for each regulated utility to develop a strategic approach that fits its unique situation, while minimizing risks and costs for the company and its ratepayers.

The Washington Utilities and Transportation Commission (Commission) recognizes and appreciates the efforts of Pacific Power and Light Company's (Pacific Power or Company) to navigate a carbon regulatory environment that has proven hard to predict. The shifting status of the Clean Power Plan (CPP) made this planning cycle challenging. The Commission also appreciates the Company's thoughtful consideration of its many options with regard to Regional Haze compliance. Though we have concerns regarding the stepwise nature of the IRP modeling process, and do not agree with some of the assumptions that Pacific Power has incorporated into its models, we hope that the Company will continue to develop and refine its models as states develop their implementation plans and the Company's compliance obligations become clearer.

The Commission determines that Pacific Power's 2017 IRP complies with the statute and rules governing IRPs, but recommends the Company address several areas for improvement in developing its next IRP. In the following sections, we provide comments on the 2017 IRP and identify specific areas for improvement for the 2019 IRP.

[1] WAC 480-100-238(2)(a); see also RCW 19.280.020(9).
[2] RCW 19.280.020(11); WAC 480-100-238(2)(b).

II. Summary of 2017 Electric Integrated Resource Plan

Pacific Power projects its Washington service territory to experience negative load growth of -0.03 percent annually between 2017 and 2026,[3] but peak load is projected to grow in the western side of its system at 0.05 percent in the summer and 0.09 percent in the winter over the 20-year planning horizon.[4] As a single system, Pacific Power's projections of the rate of growth in total energy demand and peak demand are lower relative to the 2015 IRP and the 2015 IRP update, which the Company primarily attributes to reduced industrial loads and continued gains in conservation.[5]

The biggest change from the 2015 to 2017 IRP is the Company's decision to pursue significant wind resources in the near term. Pacific Power contends that, because repowered and new wind resources qualify for a production tax credit, acquiring these resources will lower the cost and risk of the total portfolio. In addition, the Company reviewed its approach to complying with Regional Haze requirements, accelerating the retirement dates for some of its coal-fired generation assets. The 2017 Plan also significantly increases the Company's use of front office transactions and demand response. Table 1 compares the preferred portfolio identified in the 2017 IRP with the 2015 IRP portfolio.

[3] Pacific Power 2017 IRP, Vol. 2, p. 16, Table A.10. Load growth calculations net of demand side management.
[4] Pacific Power 2017 IRP, Vol. 1, p. 91 and 92. Figures calculated by Commission staff based on data in Tables 5.14 and 5.15. load growth calculations net of demand side management.
[5] Pacific Power 2017 IRP, Vol.1 , p. 3.

Table 1. Pacific Power's preferred portfolios: differences between the 2015 IRP and 2017 IRP [6]

	2015 IRP Portfolio Changes	2017 IRP Portfolio Changes
Generation : Supply-side resources		
2017		
2018	Reitre Naughton 3 (280 MW); add 337 MW gas repower	
2019		Retire Naughton 3 (280 MW)
2020		
2021		Retire Cholla 4 (387 MW); add 1100 MW wind
2022		
2023		
2024		
2025	Convert Cholla 4 from coal to gas	
2026		Retire Craig 1 (82 MW)
2027		
2028	Retire Dave Johnson units 1-4 (762 MW); add 423 MW CCCT	Retire Dave Johnson units 1-4 (762 MW)
2029		Retire Jim Bridger 1 (354); add SCCT (200 MW); add 97 MW solar
2030	Retire Huntington 2 (450 MW), and Naughton 1, 2 (357 MW), and gas repower (337 MW); add 1159 MW CCCT	Retire Naughton 1, 2 (156, 201 MW); add 436 MW CCCT
2031	Retire Hayden 1, 2 (78 MW)	Retire Hayden 1, 2 (45, 33 MW); add 85 MW wind, 117 MW solar
2032		Add 237 MW solar
2033	Retire Hunter 2 (269 MW) and Gatsby 1-6 (358 MW); add 635 MW CCCT	Retire Gadsby 1-6 (358 MW); add 477 MW CCCT, 200 MW SCCT, 226 MW solar
2034	Add 635 MW CCCT	Add 49 MW solar
2035		Retire Craig 2 (82 MW); add 291 MW solar
2036		Add 774 MW wind
Total generation for 20-year cycle:	Coal: (3,163 MW) Natural gas: 3,239 MW Wind: 0 MW Solar: 7 MW	Coal: (3,099 MW) Natural gas: 913 MW Wind: 1,959 MW Solar: 1,040 MW
Demand Side : DSM 1 - Demand response; DSM 2 - Energy efficiency/Conservation		
first 10 years	20.5 MW DSM 1; 1,429 MW DSM 2	0 MW DSM 1; 1,229 MW DSM 2
second 10 years	21.2 MW DSM 1; 1,250 MW DSM 2	365.3 MW DSM 1; 848 MW DSM 2
Total DSM:	41.7 MW DSM 1; 2,679 MW DSM 2	365.3 MW DSM 1; 2,077 MW DSM 2
Front Office Transactions : Spot market purchases packaged into energy and capacity resources		
first 10 years	Annual average of 843 MW	Annual average of 1,128 MW
second 10 years	Annual average of 1,123 MW	Annual average of 2,004 MW
Total FOT:	Annual average of 983 MW	Annual average of 1,556 MW

III. Comments and Modeling Improvements

Commission staff and other stakeholders have communicated to the Commission that the Company did not share the timing and nature of the Wyoming wind and transmission project decisions with the advisory group in a timely manner. The Company did not offer any details on the projects, which

[6] Data from 2015 IRP, Vol. 1, p. 196 and 2017 IRP, Vol.1 , p. 244. Figures do not sum perfectly due to the exclusion of years 2015 and 2016, and the inclusion of small resources in generation summaries.

entailed a substantial reorientation of the IRP's focus, until months after the internal decision to pursue the projects was made, late in the IRP process and without vetting by the advisory group. We are disappointed to see that Pacific Power's commitments to transparency and inclusiveness with the advisory group were not met, and encourage the Company to refocus on conducting its resource planning activities in that spirit.

Generally, the Commission is pleased with the thorough presentation of the Company's analyses in the 2017 IRP. As with the 2015 IRP, we appreciate the Company's inclusion of extensive data disks with the filing.

The Commission also appreciates the Company's new conservation potential assessment, as well as the description of how lowered projections for energy costs influence the amount of cost-effective conservation. We note that the 2017 IRP shows that projected energy growth in its west balancing authority (BA) is more than offset by energy efficiency through 2024, and commend the Company for its continued commitment to conservation as a cost- and risk-reducing resource.

a. Colstrip and Jim Bridger

Two of Pacific Power's remaining coal-fuel generation facilities remain in Washington's Western Control Area allocation. Jim Bridger is a 2,121 MW plant in Wyoming completed in 1979. Pacific Power also owns 10 percent of each of Colstrip Units 3 & 4, which were built in the mid-1980s.

As part of its 2015 IRP, Pacific Power performed an in-depth analysis of the economics of a select group of its coal generation facilities.[7] Since that time, changing demand and market forces have fundamentally altered the dispatch and economics of Jim Bridger and Colstrip.[8] Furthermore, by 2030 Pacific Power will no longer be able to dispatch Colstrip and its other coal generating plants to serve Oregon load or charge Oregon ratepayers for its expenses for these plants, even though Oregon is one of its largest customer bases.[9] As such, continued investment in the plant's operation must be continuously reviewed.

We are deeply concerned with the direct costs of continued operation of its coal-fueled resources and the magnitude of economic risk of continued investment in those units. Pacific Power's IRP does not explicitly identify or discuss the risks faced by the utility and its ratepayers, including the costs of risks associated with the coal plants' fuel source, projected capital investments, and ongoing operational expenses, or cost shifts to Washington customers when the Company must remove coal generation expense from Oregon rates.

As part of its 2019 IRP, Pacific Power must undertake a complete examination of costs of continued operation and investment into Colstrip Units 3 & 4 and the Jim Bridger plant. For Jim Bridger, in addition to the applicable questions asked concerning Colstrip below, the examination should include:

[7] Docket UE-140546.
[8] For example, the demand for energy and capacity has slowed, and market prices for energy have declined due to a drop in natural gas prices and a buildout of renewable resources in the Western Interconnection.
[9] Oregon Clean Electricity & Clean Transition Law, https://www.pacificpower.net/env/oregon-clean-energy/oregon-law-details.html.

1. What are the market alternatives to continued operation of the Rosebud mine?
2. How do the risks of continued operation of the Rosebud mine compare to purchasing coal in the market?
3. Using the price of coal from the Rosebud mine, how does the economic dispatch of Jim Bridger compare to market prices for electricity in the Western Interconnection?
4. Could the Jim Bridger plant obtain sufficient fuel to dispatch during the utility's winter peak without the coal supply from the Rosebud mine?

Regarding Colstrip Units 3 & 4, the Commission expects Pacific Power to answer the following questions in its 2019 IRP:

1. Regarding fuel source cost and risk:
    a. How dependent is Colstrip on a single-source mine for its fuel?
    b. How well understood is the supply of coal from the Colstrip mine?
        i. What are the financial risks of the type of mining used to extract the existing coal?
        ii. As the need for fuel for Colstrip declines, how does the cost per unit of coal from the Colstrip mine increase?
        iii. What are the counter-party risk of mine operation?
        iv. What risks to coal supply and coal cost does the Joint Colstrip ownership agreement impose? How will Pacific Power manage them?
    c. How does the fuel supply risk from Colstrip compare to that of natural gas?
2. Does Pacific Power have an assessment of the cost related to the counter-party risk of Riverstone ceasing operation of its share of Colstrip Units 3?[10] If not, why not?
3. Does Pacific Power have an assessment of the cost of the counter-party risk of Riverstone being financially unable or otherwise failing to pay its share of decommissioning and remediation costs for Units 3?
4. What are the economics of the high-cost scenario under a "low gas" scenario forecast?
5. How are the economics of the Colstrip Units 3 & 4 affected if natural gas prices continue to remain relatively flat?
6. What are Pacific Power's best estimates of remediation and decommissioning costs associated with Colstrip Units 3 & 4?
7. Has the Company quantified capacity replacement costs for Colstrip Units 3 or 4 that it could use as a basis of seeking replacement capacity as an alternative to any large capital investments it faces at Colstrip?
8. What is the risk of the failure of a large cost component of Colstrip Units 3 or 4 (such as: the heat exchangers, steam turbine or drive shafts) over Pacific Power's expected 20-year life of the plant?

The economic viability of Jim Bridger and Colstrip Units 3 & 4 are dependent on the outcome of numerous future events. To properly capture the expected cost over the 20-year horizon of the Plan, the probability of each event needs to be assessed and the cost weighted by its probability of occurrence. This comprehensive approach produces a probability distribution for the set of possible total cost outcomes of the operation of a plant over the planning horizon. The Commission recognizes that the approach taken to achieve this analysis may vary; however, regardless of the approach used,

[10] Riverstone purchased the assets of Talon Energy.

each utility's resource plan must comprehensively assess all categories of cost and risk, particularly for complex resources like its coal-fueled plants that are included in the Plan.

In its next IRP, Pacific Power should assess all categories of operational costs for Jim Bridger and Colstrip Units 3 & 4 and explicitly identify the range of possible costs in each category over the expected life of the plants. Pacific Power should also identify whether the costs are known or if they are open-ended. If costs are not known and measurable, the risk that such unknowns add to the utility portfolio should be identified by modeling a range of possible costs or other suitable means. As appropriate, the probability needs to be assessed and the cost weighted by its probability of occurrence. The Company's 2019 Plan should clearly and transparently identify cost data and discuss in detail the relationship between the range of these input assumptions, portfolio modeling logic, and the output of the modeling, as well as how the Company used such analysis to choose its expected case.

b. Balancing Area (BA) Analysis

In acknowledging Pacific Power's 2013 IRP, the Commission requested that the Company model its east and west BAs separately in the 2015 IRP.[11] We expressed a concern that the Company's system-level approach to modeling failed to account for the differences in load growth and resource base between the two areas and may be resulting in portfolios that do not optimally meet the individual needs of each BA. In acknowledging the 2015 IRP, we did not accept the S-10 sensitivity as a satisfactory response to our request, and requested another study be done which more transparently optimized the portfolio for the Western Control Area (WCA), and which either correlated with the power flow details provided in other proceedings, or explained any differences.[12]

Pacific Power responded to the Commission's request by including the East/West Split Sensitivity as a part of its analysis.[13] We appreciate the Company's responsiveness and incremental improvements to this modeling process in the 2017 IRP. The sensitivity provided some useful information and presents a more accurate cost comparison on WCA terms. However, a number of questions remain. We are particularly interested in gaining a better understanding of how and why the model is making the resource decisions that it makes in the WCA sensitivity, as some of the outcomes seem counterintuitive. We encourage the Company to continue working with Staff to ensure that the model is accurately portraying the benefits of system integration and that Staff understands the model's operations.

The Company presents the cost impacts of the preferred portfolio on a system basis. The 2017 IRP fits with the pattern of previous IRPs in projecting that the WCA's load growth and peak demand growth after conservation are flat or very close to flat, while the Eastern Control Area (ECA) of Pacific Power's system is projected to continue experiencing robust growth. But the purpose of the Commission's request is not to see how much the WCA portfolio would cost if the ECA were not present; it is a means of quantifying the benefits of system integration to each individual BA.

[11] Docket UE-120416, Pacific Power & Light Company 2013 IRP Acknowledgment Letter Attachment (Nov. 25, 2013) at p. 5-6.
[12] Docket UE-140546, Pacific Power & Light Company 2015 IRP Acknowledgment Letter Attachment (Nov. 13, 2015) at p. 5-6.
[13] 2017 IRP, Vol. 1, p. 258-9.

Accordingly, we again ask that a WCA stand-alone analysis be completed that shows the cost impacts at the BA level. This request implies a stand-alone analysis of the ECA, and a robust description of the modeling interaction between the two discrete systems, i.e. discrete within this modeling exercise.

As we have stated in prior acknowledgement letters, the Commission does not necessarily disagree with the Company's system-wide approach to resource planning, and recognizes that such an approach may offer integration benefits that reduce costs for all of the Company's customers. But we cannot accept such a significant assumption on its face; the system-wide plan must be accompanied by a counterfactual analysis that provides a check by identifying the costs of a BA approach. We therefore request that in addition to addressing the concerns mentioned above, the Company incorporate the BA analysis in all future IRPs.

c. Wind Repowering, New Wind and Energy Gateway West

Public Process: Like many other stakeholders participating in Pacific Power's IRP public process, Commission staff were surprised by the Company's proposal to pursue new wind resources and repower much of its wind generation facilities, which was presented at the final General Public Meeting on March 2017. We are concerned about the lack of timely communication of this change in direction. The Company's decision to make investments to qualify for the safe harbor provisions of the wind production tax credits (PTC) was made in December 2016, but stakeholders remained uninformed of the Company's decision and subsequent shift in the IRP's direction until the final General Public Meeting. There has been no clear explanation for why the Company decided to withhold this information during the January 2017 meeting. We request that the Company provide this in this current IRP docket. While the Commission understands the time-sensitive nature of the Company's decision to act on an expiring opportunity, the lack of communication on this issue is troubling – especially given the Company's expectation that all participants sign and abide by its non-disclosure agreement.

Repowered Wind: While the Company's analysis of the repowered wind proposal forecasts that the decision would be beneficial within the IRP's 20-year planning horizon, much of the justification for the repowering plan is the stream of benefits created by "resetting the clock" on the useful lives of the Company's wind resources. The Commission has concerns about forecasting streams of benefits beyond the IRP's planning horizon. We note that decisions made based on projections into such a remote future are inherently tenuous, especially when those decisions derive benefit primarily by attempting to beat projected power prices.

New ECA Wind and Associated Transmission: The Company's selected portfolio includes very large investments in new wind resources in the Eastern Control Area (ECA). The portfolio was selected based on modeled savings relative to other alternatives, but these savings represent about 0.6 percent of the portfolio's total present value revenue requirement (PVRR). These margins are not substantial enough to be the sole justification for multi-billion dollar investments, and projected over 20 years they seem unacceptably risky. This is particularly true when the acquisitions are being made solely for economic reasons based on the Company's assumptions.

We appreciate the Company's voluntary, informational filing of applicable RFP documentation to this docket. This should make any potential review of these acquisitions easier for the Commission, Staff and the Company.

d. Energy Storage

In its acknowledgment of the Company's 2015 IRP, the Commission identified a number of benefits of energy storage not contemplated in the main analysis of the 2015 IRP, and encouraged Pacific Power to expand the scope of its energy storage study in the 2017 IRP. We requested that the 2017 study quantify the ancillary benefits of energy storage and identify specific opportunities for energy storage projects on Pacific Power's system, both at the transmission and distribution levels. While we appreciate the Company's recognition "that there are stacked benefits from storage systems,"[14] it appears that the modeling tools used in the 2017 IRP were still not capable of identifying and assigning value to those benefits, nor to easily and more directly compare energy storage with more traditional resources. The Company instead performed some sensitivities around batteries and compressed air storage using its traditional tools, and mentioned that evaluation of energy storage projects is done on a case-by-case basis.

We recognize that the Commission issued its policy statement on energy storage several months after Pacific Power filed its 2017 IRP, and that the Company had limited guidance for the treatment of energy storage in that planning cycle. However, now that the Commission has issue its policy statement, we expect that the Company will include its principles when developing the 2019 IRP.

e. Demand Response

We commend the Company for identifying in the 2015 IRP an irrigation load control pilot in the west BA as an action item, and are pleased to see that the program is operating in Oregon.[15] We also appreciate that demand response has been represented in this IRP analysis as a resource that is directly competitive with other resources, both to meet peak load and to comply with carbon regulations.

While we recognize that the selected portfolio is optimized to be least-cost and least-risk, we are nonetheless concerned about the mismatch between the Company's preferred portfolio and the Northwest Power and Conservation Council's (Council) conclusion in its Seventh Northwest Power Plan. The Company's portfolio would add no DSM Class 1 resources to its western BA until 2028, but the Council contends that significant demand response resources are needed in the region by 2021 to meet additional winter peaking capacity.[16] Our concern is exacerbated by Pacific Power's reliance on market purchases to meet peak load, as the risk of any regional peak demand shortages falls most heavily on utilities that are reliant on the market.

f. Resource Adequacy Analysis

In its 2013 IRP acknowledgment letter, the Commission asked for an analysis of the risks inherent in the Company's substantial reliance on market resources. The resulting evaluation in the 2015 IRP did

[14] 2017 IRP, Vol. 1, p. 255.
[15] 2017 IRP Vol. 1, p. 271.
[16] Northwest Power and Conservation Council, Seventh Northwest Power Plan, at 1-6.

not capture these risks. In the 2015 acknowledgment letter, we again asked the Company to include a market reliance risk assessment in the 2017 IRP as a condition to granting the Company's RFP waiver request in Docket UE-151694.

We find that the Company's 2017 market reliance risk assessment is substantively similar to its 2015 assessment, and vulnerable to the same criticisms. The assessment essentially reviews two studies – a power supply assessment from the Western Electricity Coordinating Council (WECC), and the Council's Pacific Northwest Power Supply Adequacy Assessment for 2021. While the Company presents these studies as market risk assessments, the Company does not perform any assessment of the risks inherent in relying on the market. The WECC's assessment concludes that available power supply will be adequate to meet demand on a WECC-wide basis for many years; the Council's assessment concludes that regional power supply will be adequate until 2020. The Company's assessment does not synthesize these reports' conclusions, and lacks explanation for how or why power supply sufficiency on a WECC level protects Pacific Power customers from shortages at the regional level.

The assessment also lacks any quantitative analysis of the risk identified by the Council and acknowledged by the Company. The Council's power supply assessments have consistently identified the early 2020s as the timeframe for a shift in the regional market. Given Pacific Power's long-term reliance on Mid-Columbia market purchases, it is imperative that the Company understand the risks it faces as many regional plant retirements draw nearer. We again request that the Company provide a market reliance risk assessment in the 2019 IRP, and expect that this analysis will result in a quantified representation of risk that can be folded into the IRP analytical framework.

g. Transmission

On pages 59 and 61 of the 2017 IRP, Pacific Power requests that the Commission acknowledge its planned investment in two transmission capacity projects: Wallula to McNary, and Aeolus to Bridger/Anticline. The Commission recognizes that other states in which the Company operates require a Certificate of Public Convenience and Necessity for transmission resources. Washington has no such requirement, nor does the Commission regulate the siting of intrastate transmission lines. This function is performed by the Washington State Energy Facility Site Evaluation Council.[17]

We therefore do not to respond at this time to the Company's request for acknowledgment of its plan to build these projects. We will evaluate the prudency of these and any similar projects based on the need to serve core customers within the context of a general rate case when the Company seeks recovery of its investments. We note that the Aeolus to Bridger/Anticline project is on the eastern side of the Jim Bridger generating facility, so we presume that the line will not be used and useful to the WCA when it is completed.

h. Portfolio Scenario Cost Comparison

Pacific Power summarizes its key assumptions and portfolio results for each portfolio in Appendix M of its IRP.[18] The Quick Reference Guides are useful for giving the Commission,

[17] *See* RCW 80.50.060, RCW 80.50.020.
[18] 2017 IRP, Vol. 2, p. 263.

stakeholders, and policymakers a quick comparative overview of the costs and risks of each portfolio in the Company's IRP. We ask that in future IRPs, Pacific Power more prominently display these tables in its IRP.

i. Emissions Price Modeling and Cost Abatement Supply Curve

State statute and Commission rule require an electric utility's preferred portfolio to represent the lowest reasonable cost, which includes "public policies regarding resource preference adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide."[19] That is, the Company must consider both known regulatory costs and the risk of future costs.

Since the 2015 IRP, there have been significant changes to greenhouse gas emissions regulations, including increases to the renewable portfolio standards in California and Oregon, possible repeal and replacement of the Clean Power Plan (CPP), the implementation of Washington's Clean Air Rule, and more recently, ambiguity with the rule's legality. Despite the uncertainty surrounding the Clean Air Rule and the CPP, there continues to be considerable legislative and regulatory risk associated with greenhouse gas emissions. In the last two years at the Washington State legislature, more than a dozen bills were introduced that would impose a cost on greenhouse gas emissions, or place limits on emissions.[20] Voters rejected a carbon tax at the ballot in 2016,[21] but another initiative has been filed, which may appear on the ballot in November 2018.[22] Additionally, Washington State and the federal government are being sued to require regulation of the impacts of fossil fuels.[23]

These uncertainties in carbon policy exemplify the shifting regulatory terrain challenging the Company's planning efforts. In this environment, it is imperative that utility planners recognize the risks and uncertainties associated with greenhouse gas emissions and identify a reasonable, cost-effective approach to addressing them.

Pacific Power handled this by modeling two iterations of a hypothetical CPP as a proxy for potential future carbon regulation. In the 2015 IRP acknowledgment letter, the Commission asked that the Company model a sensitivity for both a carbon trading system and carbon tax system in its 2017 IRP, and consult with Commission Staff regarding the appropriate assumptions and inputs. While we are disappointed to see that these analyses were not done, the Company instead highlighted its CPP

[19] RCW 19.280.020(11); WAC 480-100-238(2)(b).

[20] *See*, e.g. HB 1144, HB 1155, HB 1646, HB 2230, HB 2839, SHB 2995, SB 5127, SB 5385, SB 5509, SB 5930, SB 6096, SB 6203, SB 6335, and SB 6629.

[21] Washington Carbon Emission Tax and Sales Tax Reduction, Initiative 732.

[22] Seattle Times, "New Washington initiative would put fee on carbon emissions", March 2, 2018. https://www.seattletimes.com/seattle-news/environment/new-washington-initiative-would-put-fee-on-carbon-emissions/

[23] Associated Press, "Activists Sue Washington State for Tougher Climate Policy", February 16, 2018. https://www.usnews.com/news/best-states/washington/articles/2018-02-16/activists-sue-washington-state-for-tougher-climate-policym, and Bloomberg, "Teenagers Defeat Trump's Move to Kill Climate Change Lawsuit", March 7, 2018. https://www.bloomberg.com/news/articles/2018-03-07/youths-defeat-trump-s-move-to-kill-climate-change-lawsuit.

modeling study and an alternative CO2 price sensitivity.[24] We understand Pacific Power's contention that a trading system has essentially the same impact as a tax system on the Company's costs; however we do not find that the Company's analyses incorporated the cost of risk of future greenhouse gas regulation.

As we note at the beginning of this document, RCW 19.280.030(f) requires utilities to prepare a long term plan that identifies the near term and future needs at the lowest reasonable cost and risk to the utility and its ratepayers. To determine lowest reasonable cost, the utility must consider "the risks imposed on the utility and its ratepayers, public policies regarding resource preference adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide."[25] By modeling only existing state and provincial regulation in its preferred portfolio, the Company's price of carbon does not consider the complete risk of additional regulation and, as such, risks not meeting statutory requirements. In future IRPs, Pacific Power should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its preferred portfolio. This cost estimate should come from a comprehensive, peer-reviewed estimate of the monetary cost of climate change damages, produced by a reputable organization. We suggest using the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a three percent discount rate. Pacific Power should also continue to model other higher and lower cost estimates to understand how the resource portfolio changes based on these costs.[26]

The Company should also develop a supply curve of emissions abatement. We envision this as a tool that considers all mechanisms for reducing emissions including energy efficiency, emissions controls, plant conversions, and their costs. We asked the Company to develop a carbon abatement cost curve for inclusion in the 2017 IRP, but the Company did not to do so. We again ask the Company to include this cost curve in its 2019 IRP. This analysis should identify all programs and technologies reasonably available in Pacific Power's service area, then use the best available information to estimate the amount of emissions reductions each option might achieve, and at what cost. This tool would increase transparency on the issue, and would allow the Company, the Commission, and stakeholders to engage in meaningful and informed conversations regarding the costs and benefits of reducing Pacific Power's emissions. It would also guide policymakers in their efforts to reduce emissions in a least-cost manner. We encourage the Company to work with Staff and other stakeholders who can provide further detail and assist in scoping this request.

IV. Conclusion

The Commission acknowledges that Pacific Power's 2017 Integrated Resource Plan complies with RCW 19.280.030 and WAC 480-100-238, on the condition that the recommendations made concerning the 2017 IRP are addressed in its submission of the 2019 Integrated Resource Plan. The Commission expects Pacific Power to follow the recommendations outlined in this letter as it develops future IRPs.

---

[24] Pacific Power 2017 IRP, Vol. 2, p. 36.
[25] RCW 19.280.020(11).
[26] For example, for complying with Executive Order 14-04, the Washington State Energy Office recommends state agencies use the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a two and one-half percent discount rate.

V. Separate Statement of Commissioner Balasbas on Part III i.

I agree with my colleagues that in future IRPs, Pacific Power should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its preferred portfolio. However, for the reasons outlined below, I respectfully disagree with my colleague's expectation that Pacific Power use in its preferred portfolio the social cost of carbon as the proxy for future greenhouse gas regulation.

The 2018 legislature considered, but did not take final action on, House Bill No. 2839 and Senate Bill No. 6424. These bills, among other provisions, amended Commission statutes to require use of a "greenhouse gas planning adder" when evaluating integrated resource plans as well as intermediate-term and long-term resource options selected by electrical and gas companies under Commission jurisdiction.[27] The greenhouse gas planning adder can also be referred to as the social cost of carbon. The legislature's mere consideration of this provision indicates there is not clear authorization in current statute for the Commission to require use of the social cost of carbon in IRPs.

The expectation for Pacific Power to use the social cost of carbon in its preferred portfolio is a clear statement that the 2018 legislation was irrelevant. I strongly disagree and would instead defer to the legislature's judgment of the Commission's statutory authority.

When commenting on IRPs, it is appropriate for the Commission to request scenarios using specific assumptions. However, I do not believe the Commission should mandate use of specific assumptions in the ***utility's*** preferred portfolio. My preference would have been to ask Pacific Power to model a separate scenario in its 2019 IRP that uses the social cost of carbon. Then Pacific Power can decide whether that model outcome should be used in its preferred portfolio (i.e. the lowest reasonable cost portfolio).

Finally, I disagree with my colleagues mandating the use of the social cost of carbon to represent the "lowest reasonable cost" portfolio. As the Federal Energy Regulatory Commission recently stated in an order, "Without complete information, an analysis using the Social Cost of Carbon calculations would necessarily be based on multiple assumptions, producing misleading results."[28] While IRPs are by necessity assumption driven, I am concerned that requiring use of a speculative tool to choose a preferred portfolio could lead to higher than necessary rates for utility customers.

---

[27] ESHB 2839, Section 3.

[28] FERC Docket Nos. CP14-554-002, CP15-16-003, CP15-17-002 Order on Remand Reinstating Certificate and Abandonment Authorization, ¶ 41 (Issued March 14, 2018).

ORDER NO. 18 138

ENTERED APR 27 2018

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 67

In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Integrated Resource Plan.	ORDER

DISPOSITION: 2017 IRP ACKNOWLEDGED WITH CONDITIONS AND MODIFICATIONS

This order memorializes our decision, made and effective at the December 11, 2017 Special Public Meeting, regarding the 2017 Integrated Resource Plan (IRP) filed by PacifiCorp, dba Pacific Power. We acknowledge all action items in PacifiCorp's action plan and adopt many modifications and conditions informed by recommendations from PacifiCorp, Staff and other intervenors. In particular, we condition and limit our acknowledgement of PacifiCorp's Energy Vision 2020 projects in order to respond to the unusual timing circumstances caused by expiration of federal Production Tax Credits (PTCs) while recognizing that material uncertainties and issues remain unresolved. Appendix A to this order lists the acknowledged action items and modifications. For a full background on PacifiCorp's 2017 IRP and the intervenors' comments,[1] see the Staff Report.[2]

I. INTRODUCTION

Our review of PacifiCorp's 2017 IRP involved a complex and dynamic conversation about our IRP acknowledgment standards, the proper timing of resource procurement, a reasonable balance of customer risk and benefits, and short deadlines to maximize the value of the PTC. We appreciate the robust engagement of Staff, intervenors, and interested members of the public, which gave us a broad context for considering PacifiCorp's IRP.

---

[1] In this proceeding, 11 intervenors submitted written comments: Commission Staff, Oregon Citizens' Utility Board (CUB), Northwest Energy Coalition (NWEC), Oregon Department of Energy (ODOE), Industrial Customers of Northwest Utilities (ICNU), Renewable Energy Coalition (REC), Renewable Northwest, Sierra Club, the Northwest and Intermountain Power Producers Coalition (NIPPC), National Grid USA, and Robert Proctor.

[2] Staff Report for the December 5, 2017 Special Public Meeting (Nov 21, 2017).

As our public meeting discussions revealed, each Commissioner had different reasons underlying the decisions reached at our December 11, 2017 Special Public Meeting. We also note that we did not reach consensus on all issues. Commissioner Bloom writes separately to address his vote against acknowledging three action items. Chair Hardie and Commissioner Decker also write separately to provide additional reasoning underlying their decisions to acknowledge those three action items with conditions and limitations.

We emphasize that this order does not address all arguments and recommendations raised by the intervenors during this IRP process. Many of our adopted conditions limited and narrowed the scope of our decisions. This order is intended to document those decisions and provide an explanation of key points.

II. IRP PROCESS

We require regulated energy utilities to prepare and file IRPs within two years of acknowledgment of the utility's last plan.[3] The IRP is a road map for providing reliable and least cost and least risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing, and planning for, uncertainties. The primary outcome of the process is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. After selecting a best cost/risk portfolio, the utility develops a proposed "Action Plan" of resource activities to undertake over the next two to four years to implement the plan.

Our IRP guidelines provide procedural and substantive requirements for utilities to meet in developing their IRPs.[4] Consistent with our guidelines, a utility's IRP must include the following key components:

- Identification of capacity and energy needs to bridge the gap between expected loads and resources
- Identification and estimated costs of all supply-side and demand-side resource options
- Construction of a representative set of resource portfolios
- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties
- Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers

---

[3] OAR 860-027-0400(3).

[4] *See In the Matter of Investigation into Integrated Resource Planning,* Docket No. UM 1056, Order No. 07-002 (Jan 8, 2007) and Order No. 07-047 (Feb 9, 2007) (adopting 13 IRP Guidelines); *In the Matter of Investigation into the Treatment of CO_2 Risk in the Integrated Resource Planning Process*, Docket No. UM 1302, Order No. 08-339 (Jun 30, 2008) (refining Guideline 8 addressing environmental costs).

- Creation of an Action Plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies

In our guidelines, we instruct utilities to use at least a 20-year planning horizon for analyzing resource choices and to account for end effects. To evaluate the cost implications of various portfolios, we direct utilities to use net present value of revenue requirement (NPVRR) as the key cost metric.

In reviewing an IRP, we examine the resource activities in the Action Plan and determine whether to acknowledge them based on the reasonableness of those actions, given the information available at the time. Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. The question of whether a specific investment made by a utility in its planning process was prudent will be fairly examined in the subsequent rate proceeding. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our subsequent examination of whether the utility's resource investment is prudent and should be recovered from customers.

III. PacifiCorp's 2017 IRP

A. Projected Resource Needs

In producing its IRP, PacifiCorp quantifies its resource need over a 20 year planning horizon. PacifiCorp states that, in the near-term, it has less contracted or owned generation resources than needed to meet customer load, as evidenced by the presence of front office transactions (FOTs) throughout the planning horizon.[5] Rather than identifying a specific capacity or energy resource need, PacifiCorp presents a portfolio of incremental acquisition to meet its load projection, including a 13 percent target planning reserve margin, RPS requirements of three states, and planned coal retirements. PacifiCorp's three-prong near-term action plan uses incremental acquisition of: (1) new and repowered wind resources, (2) new demand-side management (DSM), and (3) wholesale power market purchases/FOTs.

B. Preferred Portfolio Development and Overview

PacifiCorp's 2017 IRP modeling and evaluation approach consists of three screening stages used to select a preferred portfolio, including Regional Haze screening, eligible portfolio screening, and final screening. PacifiCorp used System Optimizer (SO) to produce 43 SO portfolios across a range of different planning assumptions. For each SO portfolio, Planning and Risk (PaR) studies are developed for three natural gas price scenarios (low, base, and high) and two carbon dioxide (CO_2) emissions limit assumptions. These cost and risk metrics are used to compare portfolio alternatives.

---

[5] FOTs are proxy planning resources that represent short-term firm market purchases to meet customer load.

PacifiCorp developed 24 sensitivity cases that highlight the impact of specific planning assumptions. The result of the final screening stage is the preferred portfolio.

PacifiCorp's preferred portfolio includes a resource procurement plan called "Energy Vision 2020"— with the addition by 2020 of 905 megawatts (MW) of repowered wind resources, 1,100 MW of new wind resources, and a new 140-mile 500 kilovolt (kV) transmission line in Wyoming to access the new wind resources and relieve congestion for existing capacity. The preferred portfolio also assumes retirement of 667 MW of coal-fired generation by the end of 2020. In the longer time frame, PacifiCorp plans for 1,040 MW of additional solar resources to come online from 2028 to 2036, new natural gas resources added in 2029 and 2030, and additional coal retirements of approximately 2,074 MW by 2036.

1. New Wind Resources and Transmission

PacifiCorp identifies Energy Vision 2020 as the least-cost, least-risk option to meet near-term need within the two- to four-year period that otherwise would be filled by uncommitted FOTs, and to meet a long-term energy and capacity need. PacifiCorp states that the timing of its proposed near-term acquisition is intended to capture the maximum value of the PTC,[6] which is available for resources that satisfy safe harbor requirements and comply with the assumed construction period. PacifiCorp states that its Energy Vision 2020 plan also reduces risks related to market reliance and future compliance with renewable portfolio standards (RPS).

2. Repowered Wind

PacifiCorp's IRP analysis supports repowering 905 MW of existing wind resources by the end of 2020. PacifiCorp explains the scope of the repowering project involves the installation of new rotors with longer blades and new nacelles with higher-capacity generators, which will increase energy output without changing the footprint, towers, foundations or energy collector systems of the wind facilities.

3. Renewable Portfolio Standards

PacifiCorp uses Renewable Energy Certificates (RECs) to meet the annual requirements of Oregon's RPS. RECs, issued per megawatt-hour of qualifying generation produced, may be either bundled with energy or unbundled, where the REC and energy are exchanged separately.[7] PacifiCorp's current RPS obligation is 15 percent of annual retail

[6] 26 USC § 45 (establishing a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year).
[7] Use of unbundled RECs is limited to 20 percent of the RPS requirement; this limit does not apply to RECs issued for generation in Oregon by a PURPA qualifying facility. ORS 469A.145.

sales; this increases to 20 percent in 2020, with further increases every five years to arrive at a 50 percent obligation in 2040.

PacifiCorp's proposed Oregon RPS compliance strategy through 2036 includes the addition of the Energy Vision 2020 repowered wind, new wind resources, and transmission in the 2017 IRP preferred portfolio, as well as annual purchases of unbundled RECs, beginning at under 160,000 RECs in 2018.

4. Demand-Side Management

PacifiCorp states that, over the first 10 years of the planning horizon, accumulated acquisition of incremental energy efficiency resources meets 88 percent of forecasted load growth from 2017 through 2026 (up from 86 percent in the 2015 IRP). PacifiCorp states that decreased selection of energy efficiency resources relative to the 2015 IRP is driven by reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives. PacifiCorp states that, in addition to continued investment in energy efficiency programs, the preferred portfolio identifies an increasing role for direct load control programs with total capacity reaching 365 MW by 2036, the end of the planning period.

5. Wholesale Power Market Purchases

PacifiCorp explains that market conditions for firm wholesale power purchases, or FOTs, remain favorable, but that reduced loads and continued investment in energy efficiency programs reduce the need for wholesale power purchases relative to the 2015 IRP Update through 2027. Over this period, PacifiCorp estimates that average annual wholesale power purchases are on par with wholesale power purchases projected in the 2015 IRP.

6. Coal Resources

PacifiCorp's 2017 IRP preferred portfolio does not include any incremental selective catalytic reduction (SCR) equipment throughout the planning horizon. PacifiCorp states that the 2017 IRP studies a range of Regional Haze compliance scenarios, reflecting potential bookend alternatives that consider early retirement outcomes as a means to avoid installation of expensive SCR equipment. PacifiCorp states that individual unit retirements presented in the IRP are reasonable for planning purposes, but the unit-specific outcomes will ultimately be determined by on-going rulemaking, results of litigation, and future negotiations with partner plant owners, regulatory agencies, and other vested stakeholders. By the end of the planning horizon in 2036, PacifiCorp assumes 3,650 MW of existing coal capacity will be retired.

7. *Natural Gas Resources*

PacifiCorp explains the first natural gas resource, a 200 MW frame simple cycle combustion turbine (SCCT), is added to the portfolio in 2029, one year later than the first natural gas resource in the 2015 IRP. The first combined cycle combustion turbine (CCCT), 436 MW, is added to the system in 2030, two years later than the first CCCT in the 2015 IRP.

C. Proposed Action Plan

PacifiCorp's action plan identifies steps to be taken in the next two to four years to acquire the resources in its preferred portfolio. PacifiCorp proposes supply-side actions of implementing the wind repowering project, issuing a RFP for new wind resources, and acquiring front office transactions. PacifiCorp proposes demand-side management actions through acquisitions of incremental energy efficiency. PacifiCorp proposes transmission actions of pursuing a portion of the Energy Gateway segment D.2 (Aeolus to Bridger/Anticline) and completing the Wallula to McNary transmission segment.

IV. DISCUSSION

We focus our discussion on PacifiCorp's proposed action items. For each proposal, we summarize PacifiCorp's proposal, very briefly note some intervenors' comments, and explain our resolution.

A. Energy Vision 2020

Three action items comprise Energy Vision 2020, covering wind repowering, new wind resources, and the Aeolus to Bridger/Anticline transmission line. Specifically, Action Item 1a describes PacifiCorp's plan to repower existing wind resources. PacifiCorp asserts the wind repowering project will 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 date. To achieve the full PTC benefits, PacifiCorp must complete the wind repowering project by the end of 2020.

Action Items 1c and 2a describe PacifiCorp's plan for new wind resources and a new transmission line. Action Item 1c describes the company's 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 Action Item 2a, which describes 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). PacifiCorp states the transmission resource is necessary to relieve existing congestion and will enable interconnection of the proposed wind resources into PacifiCorp's transmission system. PacifiCorp asserts that 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.

1. Comments

Staff recommends we not acknowledge these action items, or alternatively incorporate strong ratepayer protections against several different risks, including capacity factor shortfall, PTC decrease, commercial operation date delay, changes in official forward price curve for energy, and construction cost overruns. Staff's recommendations are grounded in its view that there is no resource need to which the Energy Vision 2020 projects respond. CUB and ICNU largely share this view and agree with Staff that the benefits are too small compared to the risks.[8] They propose either modeled revenues being used for net power cost proceedings, or an alternative form of ratemaking that would allow rate recovery with a showing of net benefits. ODOE generally supports early renewable acquisition as consistent with the state's decarbonization goals, but asks PacifiCorp to quantify the carbon reductions. NWEC recommends acknowledgement of the new wind and repowering projects and a broader transmission assessment prior to acknowledging new transmission. Renewable Northwest supports acknowledgment of these items.

PacifiCorp responds that Energy Vision 2020 is a continuation of its renewable trajectory. The company states that the Energy Vision 2020 projects leverage PTCs to provide least-cost, committed resources to serve customer load. PacifiCorp states that these resources will otherwise be procured at some later date without the PTC savings. PacifiCorp argues that the IRP is not narrowly focused on a short-term capacity need, but rather represents a long-term plan that balances short-term opportunities with long-term risks.

2. Resolution

We acknowledge Energy Vision 2020 Action Items 1a, 1b, and 2a, subject to the following conditions and limitations that we adapted from proposals by Staff and PacifiCorp:

---

[8] CUB supports acknowledgment of repowering because the benefits were larger and the action could be viewed in context of a company's continuing obligation to optimize efficiency and performance of its existing resource fleet.

- Given the uncertainty at this time regarding the outcome of the 2017R RFP, the result of any RFP for the engineering, design, and construction of the Aeolus to Bridger/Anticline transmission projects, and the outcome of recent tax reform efforts on the federal level, PacifiCorp must:

  - Provide an updated economic analysis with the request for acknowledgement of the final shortlist from the 2017R RFP;

  - Update its analysis of the Energy Vision 2020 projects as part of its 2017 IRP Update, including any changes resulting from the 2017R RFP or changes to critical assumptions, such as availability of tax credits, corporate tax rate, then-current cost-and-performance data for repowered wind resources, cost-and-performance data from the 2017R RFP final shortlist, and cost assumptions for the transmission projects; and

  - Provide quarterly updates to the Commission and Staff as development of the projects chosen in the 2017R RFP and the transmission projects proceed (through the date the projects go into service).

- The risk of proceeding with the Energy Vision 2020 projects remains with PacifiCorp unless and until the Commission completes a prudence review and approves cost recovery of these resources in rates. Recovery may be conditioned or limited to ensure customer benefits remain at least as favorable as IRP planning assumptions.

  - For uncertainties that will be resolved by the time of the projects' commercial operation date (pre-COD risks), we acknowledge the projects only insofar as customers do not bear the risk of construction cost overruns, delays or other factors that impact PTC value, or project costs and expected capacity factors that are less favorable than the assumptions presented in the IRP.

  - For uncertainties that may persist beyond project commercial operation date (post-COD risks), such as project performance, tax policy changes, and resource value relative to market, we will carefully scrutinize the net benefits during future shortlist acknowledgement, IRP Update filing, and rate recovery proceedings. We intend to ensure that customer risk exposure is mitigated appropriately, and recovery may be structured to hold PacifiCorp to the cost and benefit projections in its analysis.

- PacifiCorp must provide the Dave Johnston early retirement transmission analysis to the Commission and parties in this proceeding once the third-party review and validation has been finalized.

In making this decision on PacifiCorp's Energy Vision 2020 action items, we share Staff's and the intervenors' struggles with the abrupt presentation of PacifiCorp's plan and rigidity of its procurement proposal. PacifiCorp's procurement plans presented in pre-IRP planning meetings changed dramatically to what the company proposed in its filed IRP and supplemental analysis. This left many stakeholders unable to support the 2017 IRP, as they had little chance for input and for comparing the proposal with alternatives.

Intervenors presented us with vigorously opposing viewpoints not only as to whether the projected customer economic benefits of PacifiCorp's Energy Vision 2020 projects outweigh the risks of changing cost assumptions and future conditions, but also as to whether our IRP policy limits acknowledgment to resources that are needed during the action plan window to avoid system reliability impacts to customers that market purchases are unable to address. Essentially, PacifiCorp determined there was customer benefit to displacing FOTs with long-term resource investment while stakeholders saw the level of past FOT activity to be a reasonable level of FOTs going forward, thus making the EV 2020 investments unnecessary. We were unable to reach a full consensus on this complex issue through public meeting deliberations. Going forward, we expect the planning process to be transparent and to provide a robust forum for all stakeholders and the Commission to address system resource needs and evaluate all available resource options to meet system needs in the least cost and least risk manner.

Nonetheless, we recognize that expiring tax incentives represent a time-limited opportunity that could significantly benefit customers. Consequently, we have narrowed our acknowledgement in an unusual manner. Since the company must act soon to capture the full value of the expiring tax incentives, we have explicitly limited our acknowledgement in order to make clear that we intend to protect customers going forward, while still giving the company the flexibility to try to capture the significant economic benefits that the company's planning assumptions show PTC-enabled resources would deliver to customers.

Limiting our acknowledgment to PacifiCorp's planning assumptions is an unusual step that responds to the unusual difficulties of this planning cycle. Although we do not definitively resolve questions surrounding need, it should be apparent that when a utility does not need to take action within the action plan window to address regulatory compliance or reliability needs in the near-term, we will pay significantly more attention to near-term cost impacts and longer-term cost risks.[9]

We reaffirm our commitment to the fundamentals of our IRP precedent, identifying a preferred portfolio that is a least-cost, least-risk portfolio of resources to meet customer capacity and energy needs. We have adopted the above conditions and limitations in response to the timing exigencies associated with PTC availability.

The adopted conditions and limitations also highlight and make explicit the fundamental principle that, regardless of acknowledgment, any resource investment decisions ultimately rest firmly with the company.[10] PacifiCorp has explained that in the next few months it will have third-party validation of performance assumptions, and more clarity on regulatory and commercial uncertainties. We recognize the off-ramps in PacifiCorp's action plan, and acknowledge only the plan as presented, recognizing that any number of variables may change. Changes in material assumptions, as always, require a utility to re-evaluate and course correct from the plan presented.[11]

B. Additional Transmission Action

PacifiCorp requests acknowledgement of an action item to complete construction of the Wallula to McNary transmission line. Staff recommends acknowledgement of this action item.

We acknowledge this action item, but noted the concerns previously raised in our review of PacifiCorp's 2015 IRP.[12]

C. Energy Efficiency/Class 2 DSM

PacifiCorp's Action Item 4a requests acknowledgement of cost-effective Class 2 DSM (energy efficiency resources) as shown in its action plan.

---

[9] *In the Matter of Portland General Electric Co., 2016 Integrated Resource Plan*, Docket No. LC 66, Order No. 17-386 (Oct 9, 2017).

[10] *See 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 6 (Apr 20, 1989) (explaining, "The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission * * *.").

[11] *See e.g.,* PacifiCorp's Response to Independent Evaluator's Comments on PacifiCorp's Termination of the 2012 RFP Process at 9, Docket No. UM 1208 (May 21, 2009) ("The Company's ultimate obligation is to find the best solution for its customers with the lowest risk-adjusted cost. It is not the purpose of the RFP to displace management's prudent judgment in seeking the lowest cost solutions for customers or to justify a decision to acquire a resource costing over double historical costs just because it is the best result of an RFP.").

[12] *In the Matter of PacifiCorp, dba Pacific Power, 2015 Integrated Resource Plan,* Order No. 16-071 at 9-10 (Feb 29, 2016).

1. Comments

Staff believes energy efficiency is underrepresented as a resource because the Energy Trust of Oregon (ETO) historically acquires more savings than identified in the IRP. NWEC recommends not acknowledging Action Item 4a until PacifiCorp improves its methodology for Class 2 DSM that identifies all cost effective conservation throughout its system. NWEC maintains that PacifiCorp must improve their conservation potential studies and produce more accurate and effective forecasting of energy efficiency.

PacifiCorp responds that ETO uses a blended utility value to assess the cost effectiveness of energy efficiency measures, and this blended value may inflate the value of energy efficiency and lead to higher levels of acquisition than what is modeled in the IRP. However, PacifiCorp agreed to modifications to Action Item 4a, described below.

2. Resolution

We acknowledge PacifiCorp's energy efficiency action item with the addition of the modification agreed to by PacifiCorp and Staff. PacifiCorp agrees to hire an independent consultant to conduct an analysis by the next IRP that identifies and compares the differences between ETO and PacifiCorp's energy efficiency forecasts with ETO's actual achieved savings in Oregon and PacifiCorp's achievements in other states. Early in the 2019 IRP process, PacifiCorp will hold a DSM technical workshop to review and receive input regarding how the company models energy efficiency potential in the IRP.

D. Wholesale Power Market Purchases (FOTs)

Several intervenors discussed issues with FOTs, including whether displacing FOTs could constitute a resource need, whether PacifiCorp underestimated seasonal price impacts and overestimated availability, and the proper energy, capacity, and hedging value for FOTs.

To help address these issues in future IRPs, we adopted Staff's three modifications to the FOT action item. First, PacifiCorp is to report back in its 2017 IRP Update as to current and forecasted FOTs through the planning window and any changes in assumptions since the 2017 IRP. Second, in the 2019 IRP, PacifiCorp is to repeat its studies to support reliance on market purchases. Finally, in the 2019 IRP, PacifiCorp is to specifically address the cost and risk tradeoffs between any generating resource and the market. This additional analyses should be helpful and relevant to how we approach this question in the future.

E. Miscellaneous Items

Staff, Sierra Club, CUB, and ODOE request the company perform additional analysis on the economics of coal unit retirements. PacifiCorp agrees to perform 25 system optimizer (SO) runs, one for each coal unit and a base case. PacifiCorp agrees to summarize the results providing a table of the difference in present value of revenue requirement (PVRR) resulting from the early retirement of each unit, an itemized list of coal unit retirement costs assumptions used in each SO run, and a list of coal units that would free up transmission along the path from the proposed Wyoming wind projects if retired. PacifiCorp is to provide this information by June 30, 2018. If there is a dispute about modeling in the meantime, PacifiCorp, Staff and intervenors should first attempt to resolve it informally, but if that fails, Staff may report back to us at a public meeting before the 2019 IRP is filed. A Commissioner workshop will be scheduled to review this analysis once it is complete.

In addition, Renewable Energy Coalition asserts that the company should be required to actually study the capacity benefits that qualifying facilities (QFs) provide, as directed in docket UM 1610.[13] PacifiCorp responds that it has complied with the order by not assuming QFs will renew. We acknowledge that non-renewal may not be the best planning assumption when many (or most) QFs do, in fact, renew, but question the value of additional studies of the capacity of renewing QFs. We direct Staff to work with intervenors and bring this issue to a public meeting so that we can make a decision regarding whether a new study of existing QF capacity would be useful and how existing QF contract renewals should be modeled in the IRP.

V. ORDER

IT IS ORDERED that:

1. The Integrated Resource Plan filed by PacifiCorp is acknowledged as described with the terms of this order and the attached Appendix A.

2. PacifiCorp is directed to provide updated economic analysis with its request for acknowledgment of the final shortlist from the 2017R RFP.

3. PacifiCorp is directed to update its analysis of the Energy Vision 2020 projects as part of its 2017 IRP Update.

4. PacifiCorp is directed to provide quarterly updates to the Commission and Staff as development of the projects chosen in the 2017R RFP and the transmission projects proceed (through the date the projects go into service).

[13] *In re Investigation into Qualifying Facility Contracting and Pricing,* Docket No. UM 1610, Order No. 16-174 at 19 (May 13, 2016) ("We agree with Staff and the Joint QFs that a certain amount of capacity may not be valued if utilities assume in their IRPs that existing QFs nearing contract expiration will automatically renew. We direct each utility to work with parties to address this issue in its next IRP.").

5. PacifiCorp is directed to provide Dave Johnston early retirement transmission analysis to the Commission and parties in this proceeding.

6. PacifiCorp is directed to perform the system optimizer runs for each coal unit and a base case and provide the results to the parties in LC 67 by June 30, 2018, and Staff to update the Commission prior to June of any delays or difficulties.

Made, entered, and effective APR 27 2018.

By the Commission. Chair Hardie is concurring in part with a separate statement below.
Commissioner Bloom is dissenting in part with a separate statement below.
Commissioner Decker is concurring in part with a separate statement below.

Chair Hardie, *concurring in part*:

Given the unique facts and the time-limited opportunities presented here, I agree with Commissioner Decker that acknowledging PacifiCorp's EV 2020 action items with conditions to protect customers is both within our authority and consistent with the public interest. I write separately to clarify a few points regarding my view of our "need" standard. I also address my decision to acknowledge PacifiCorp's EV 2020 investments.

A. The Concept of Need Is a Meaningful Part of Our IRP Analysis

In my view, the concept of utility need continues to be a meaningful part of our IRP analysis, though it was subject to a fair amount of criticism in these proceedings. Our current regulatory system contemplates that ratepayers and utilities share certain risks of a utility's long-term investment so the utility can continue to provide safe, reliable electric service and to attract the capital to do so.[14] An identified need (whether that is a system need or a regulatory compliance need) can provide a reasoned basis for regulators to acknowledge a long term investment, even if that investment presents risks. In fact, a projected need provides good reason for regulators to actively encourage certain resource investments and expenditures of capital.[15]

[14] For example, in the 1980s, state and federal energy policy encouraged utility investment in new nuclear plants, believing those plants to be the least-cost, least-risk response to projected energy shortages. By providing some assurance of rate recovery for prudently incurred costs, our system made the construction of such projects possible despite their high cost and long construction times.
[15] Consistent with this theme, our IRP process has minimized discussion of rate impacts of proposed near-term investments. If an investment is unavoidable in the near term, the near-term rate impacts may be unavoidable to some extent, too.

A hypothetical pure "economic opportunity," by contrast, involves investments that, in theory, could be shifted to later years without impacting reliability or regulatory compliance. An "economic opportunity" could raise the question of whether *current* ratepayers should be forced to pay for resources that will not be needed for a decade. A large early investment could provide benefits over the long-term, but might have considerable near-term rate impacts or long-term risks which we might feel compelled to mitigate as part of our regulatory oversight. And, as we discussed in PGE's most recent IRP docket, the modeling required by our current IRP process cannot always comfortably take into account the risks associated with longer-term investments in an industry that is rapidly changing.

If an investment opportunity is a clear winner by all measures, I agree there may be good reason to acknowledge that investment well ahead of need.[16] But Commission-mandated utility resource planning is a precursor to a Commission ratemaking determination and ordinarily informs a later prudence finding.[17] The closer in time the need for a utility investment is, the more certain the Commission can be that the proposed investment is not excessive and that the cost projections behind it are sound. In short, I believe the concept of need has provided a check to keep our IRP acknowledgement and later ratemaking treatment reasonably aligned, and has helped to ensure that ratepayers are not required to fund excessive capital investment.

I recognize that our approach to the concept of need and the appropriate time horizon for investments is something we will continue to grapple with. Society is increasingly asking utilities and our regulatory system to do more than they have in the past. We may need to find new ways of thinking about how to properly evaluate investments that fall more on the economic opportunity side of the spectrum than on the side of nearer-term need, particularly when other benefits can be attributed to the investments. Until then, however, I believe we should be reluctant to discard historical ratepayer safeguards that are implicitly part of our current IRP review process without adequate replacement.

B. EV 2020's Ratepayer Benefits and Evaluating Long-Term Risk

On the whole, PacifiCorp's modeling shows that the EV 2020 projects have net ratepayer benefits. As we have stated in the past, however, a modeling result alone is not enough to demonstrate that an investment is least-cost and least-risk. We must also apply "subjective judgment when reviewing [a utility's IRP] modeling and risk analysis

---

[16] Appropriate timing also depends on the resource at issue: energy storage can be deployed in months, while transmission lines can require decades of planning—the appropriate time horizon for planning, first steps, and investment are relative.

[17] As the Commission noted when it adopted least-cost planning, consistency of resource investments with least-cost planning principles is a factor the Commission will consider in judging prudence. Order 89-507 at 7. "Rates are relevant to the planning process." *Id.* at 10.

results."[18] The modeling results must be backed up with a thoughtful evaluation of the relative risks and benefits of modeled results while keeping in mind the ends our regulation is intended to accomplish. The facts in this case are challenging.

First, there is reasonable disagreement about whether PacifiCorp's EV 2020 investments respond to a system "need." PacifiCorp explains that in the near-term, FOTs are partially displaced; and, in the long-term, the proposed EV 2020 resources defer the need for other, higher-cost resources.[19] FOTs have proven to be flexible, reliable, and affordable market options to serve PacifiCorp's load. While technically uncommitted, FOTs have also been viewed as filling a resource need, and the company has been considered resource sufficient while relying on them. Thus, it is not surprising that there was some confusion over how to view the company's current resource position and the proposal to invest in long-term resources. Given this ambiguity, it is not clear that the time horizon for the company's generation and transmission needs would itself cause us to encourage significant long-term investments.

Second, although PacifiCorp's modeling reasonably demonstrates net customer benefits, several important risk elements stand out. Capital investments carry certain risks, but just as importantly, assumptions about market conditions, policy and tax incentives, regulatory issues, technology costs, and a host of other factors could all be meaningfully different well before the investments are strictly needed. This challenge is exacerbated when certain economic benefits ascribed to the investments are nearly a decade away.[20] As Staff notes, even minor changes to modeling assumptions could mean the costs of the new investments outweigh their potential financial benefits. Overall, it is not evident that the ratepayer benefits of the EV 2020 investments are so clear—or that the costs and risks so low—that they justify acknowledgement and the shifting of investment risk that follows.

C Reasons to Consider Acknowledgement with Conditions

Despite these concerns above, I ultimately believe there is good cause to acknowledge the investments with the conditions imposed during our deliberations.[21] PacifiCorp is

---

[18] Order No. 10-066 at 14.

[19] PacifiCorp's Response to Staff's Public Meeting Memo at 7. Over the longer term, PacifiCorp explains that it has a 395 MW energy and capacity need beginning in 2028. *Id.* at 4.

[20] *See, e.g.,* Richard J. Pierce, Jr., *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity*, 132 U. Pa. L. Rev. 497 a 509 (1984) (*Pierce*) (observing that the difficulty of forecasting customer demand, fuel prices, availability of power from other sources, construction costs, and costs of capital over the construction timeframe for a major plant—let alone its operational life—is nearly impossible, and that "[e]ven forecasts of only a few of these factors made by well-qualified specialists and covering much shorter time periods have often proven extremely unreliable.").

[21] As we noted in the majority opinion, the risk of proceeding with the EV 2020 projects remains with PacifiCorp unless and until the Commission completes a prudence review and approves cost recovery of these resources in rates. Recovery may be conditioned or limited to ensure customer benefits remain at least as favorable as IRP planning assumptions.

confident the benefits of the EV 2020 projects will materialize; other parties are less confident, and still others see their promise. An acknowledgement with conditions recognizes the potential benefits of the investments, particularly those related to the expiration of PTCs, while the conditions will help protect ratepayers from some of the more uncertain benefits of the projects.[22]

An acknowledgement with conditions is not particularly satisfying, but I believe it is appropriate here. The EV 2020 projects have a now-or-never fact pattern that makes it difficult from a timing perspective to seek additional analysis; moreover, the uncertainties of analyzing long-term risk discussed above makes it impractical to think that additional information will meaningfully assist our review.

Although our decision to acknowledge with conditions does not dictate any future ratemaking decision, it will help inform any future request for rate recovery. The conditions explicitly affirm that the risks of proceeding with the EV 2020 investments remain with PacifiCorp until this Commission completes a prudence review and approves cost recovery of these resources. During any future rate proceeding, the Commission may condition or limit recovery to ensure customer benefits remain at least as favorable as IRP planning assumptions.[23] PacifiCorp can proceed with these risks in mind.

PUBLIC UTILITY COMMISSION OF OREGON

Lisa D. Hardie
Chair

[22] PacifiCorp argues that we can address the ratepayer risks through our traditional prudence review. A prudence review asks whether a utility action was reasonable given what was known or should have been known at the time the decision was made. As prudence reviews can only consider information known at the time the investment was made, any negative impacts from industry and market changes would likely be borne by ratepayers.

[23] A public utility commission "is not bound to the use of any single formula or combination of formulae in determining rates," as ratemaking inherently involves the making of "pragmatic adjustments" over time. *Federal Power Comm'n. v. Hope Natural Gas Co.,* 320 U.S. 591 at 602 (1944); *see also Verizon Commc'ns., Inc. v. FCC*, 535 U.S. 467, 486-489, 526-527 (2002).

Commissioner Bloom, ***dissenting in part*****:**

Throughout two Commissioner workshops and two public meetings, I raised questions about the need for Energy Vision 2020 projects, about the risks of such large investments, and about the purpose and effect of conditional acknowledgement. Ultimately, I declined to acknowledge the Energy Vision 2020 action items, and I write separately to explain my vote.

Along with many of the parties, I questioned PacifiCorp on the abrupt presentation of Energy Vision 2020 projects. I noted the radical shift from early IRP drafts that proposed no new resources for 10 years. Staff, parties, and my fellow Commissioners raised extensive concerns about whether the company had a "resource need" that Energy Vision would meet, or whether the projects were more accurately characterized as an economic benefit for the company and customers. For such an unusual investment of this size, I expected a consistent, clear showing of a resource need that justifies the expense. New resource acquisition cannot and should not be divorced from need.

My concerns over the resource need are compounded by the risks associated with Energy Vision 2020. I questioned PacifiCorp over changing corporate tax rates and changing PTC benefits, recognizing that changes to either of these would significantly affect the project economics. I opined that Energy Vision is too big, too costly, and too risky for the potentially small benefits.

I considered PacifiCorp's proposed conditions to acknowledgement, including that our acknowledgement could not be used in a future proceeding to support favorable rate-making prudence. I declined to adopt this condition because I question the meaning of such a conditioned-acknowledgment in light of the scope, standards, and precedent of our IRP least-cost and least-risk planning principles.

Because of my questions over whether Energy Vision 2020 is needed, whether project risks outweigh its benefits, and my reluctance to modify our IRP standards with novel conditions, I voted a "soft" no on acknowledging these action items. My vote was soft because I am generally very sympathetic to renewable development, and do not seek to prevent PacifiCorp from going forward with its investment plans without acknowledgement, with a full opportunity to establish prudency of its actions in a future rate proceeding.

PUBLIC UTILITY COMMISSION OF OREGON

Stephen M Bloom /G

Stephen M. Bloom
Commissioner

Commissioner Decker, ***concurring in part*****:**

I agree with my colleagues' comments that resource need plays an important role in our oversight of resource planning. As we recognized recently in Order No. 17-386, "[h]ow utilities characterize need and assess risk and uncertainty within their IRPs and how we integrate that analysis into our review, however, must evolve."[24] I look forward to working with all stakeholders as we examine our resource planning process to meet changes within the utility industry.

Megan W. Decker / G

Megan W. Decker
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

[24] *In the Matter of Portland General Electric Co., 2016 Integrated Resource Plan*, Docket No. LC 66, Order No. 17-386 at 14 (Oct 9, 2017).

Appendix A

Acknowledged Action Items with Modifications and Additions

Action Items 1a, 1b, 2a: (Energy Vision 2020)

- 1a – Wind Repowering - Repower over 900 MW of existing wind resources.
- 1b – New Wind - Issue a Request for Proposals (RFP) for up to 1,270 MW of new wind resources.
- 2a – Aeolus to Bridger/Anticline- Build a 140-mile 500kV transmission line from the Aeolus substation to the Jim Bridger Power Plant.

  Modifications:
    - Given the uncertainty at this time regarding the outcome of the 2017R RFP, the result of any RFP for the engineering, design, and construction of the Aeolus to Bridger/Anticline transmission projects, and the outcome of recent tax reform efforts on the federal level, PacifiCorp must:
        - Provide an updated economic analysis with the request for acknowledgement of the final shortlist from the 2017R RFP;
        - Update its analysis of the Energy Vision 2020 projects as part of its 2017 IRP Update, including any changes resulting from the 2017R RFP or changes to critical assumptions, such as availability of tax credits, corporate tax rate, then-current cost-and-performance data for repowered wind resources, cost-and-performance data from the 2017R RFP final shortlist, and cost assumptions for the transmission projects; and
        - Provide quarterly updates to the Commission and Staff as development of the projects chosen in the 2017R RFP and the transmission projects proceed (through the date the projects go into service).

  - The risk of proceeding with the Energy Vision 2020 projects remains with PacifiCorp unless and until the Commission completes a prudence review and approves cost recovery of these resources in rates. Recovery may be conditioned or limited to ensure customer benefits remain at least as favorable as IRP planning assumptions.
      - For uncertainties that will be resolved by the time of the projects' commercial operation date (pre-COD risks), we acknowledge the projects only insofar as customers do not bear the risk of construction cost overruns, delays or other factors that impact PTC value, or project costs and expected capacity factors that are less favorable than the assumptions presented in the IRP.

- For uncertainties that may persist beyond project commercial operation date (post-COD risks), such as project performance, tax policy changes, and resource value relative to market, we will carefully scrutinize the net benefits during future shortlist acknowledgement, IRP Update filing, and rate recovery proceedings. We intend to ensure that customer risk exposure is mitigated appropriately, and recovery may be structured to hold PacifiCorp to the cost and benefit projections in its analysis.

- PacifiCorp must provide the Dave Johnston early retirement transmission analysis to the Commission and parties in this proceeding once the third-party review and validation has been finalized.

Action Items 1c, 1d: Other Renewable Resource Actions

- 1c - RFP for Renewable Energy Credits (RECs) – Issue an RFP for RECs to meet state RPS compliance requirements as needed.
- 1d - REC Optimization – Evaluate potential opportunities to re-allocate and sell RECs as appropriate for compliance purposes before filing the 2017 IRP Update.

Action Items 2b – 2d: Other Transmission Actions

- 2b - Energy Gateway Permitting – Continue efforts to permit and implement the Energy Gateway transmission plan.
- 2c - Wallula to McNary Construction – Complete the Wallula to McNary project.
- 2d - Planning Studies – Complete planning studies to refine the coal unit retirement assumption inputs that go into transmission assumptions and provide studies in the 2017 IRP Update.

Action Item 3a: Front Office Transactions – Acquire economic short-term firm market purchases for on-peak summer deliveries from 2017 to 2019.

Modifications:

- PacifiCorp is to report back in its 2017 IRP Update as to the current and forecasted use of front office transactions through 2036 and any changes in assumptions impacting front office transaction use from the initial filing of LC 67 in April 2017.
- PacifiCorp should repeat its study of trading hub liquidity and also the market reliance risk analysis of front office transactions prior to the next IRP.
- For the 2019 IRP, if a generating resource is included in the preferred portfolio with an associated action item, then PacifiCorp will report on the cost and risk tradeoffs between the preferred portfolio and alternatives that do not include a generating resource.

Action Item 4a: Class 2 Demand-Side Management – Acquire cost-effective Class 2 DSM (energy efficiency) from 2017-2020 as listed in the action plan.

Modifications:

- PacifiCorp is to hire an independent consultant, in coordination with Staff and the Energy Trust of Oregon, to conduct an analysis by the next IRP that identifies and compares the ongoing differences between ETO's and PacifiCorp's near to long term energy efficiency forecast with ETO's actual achieved savings. The consultant's report should include recommendations to both organizations regarding forecasting improvements that should be considered for the 2019 IRP.
- Early in the public input process for the 2019 IRP, prior to finalizing energy efficiency supply curves, PacifiCorp will hold a DSM technical workshop to review and receive input regarding how the company models energy efficiency potential in the IRP and supporting studies such as the Conservation Potential Assessment.

Action Items 5a – 5h: Coal Resource Actions

- 5a through 5h – Complete economic analysis subject to litigation outcomes, regional haze analysis, natural gas conversion analysis, and review of other actions.

  Modifications:

  - PacifiCorp will perform 25 system optimizer (SO) runs, one for each coal unit and a base case. PacifiCorp will summarize the results providing a table of the difference in PVRR resulting from the early retirement of each unit, an itemized list of coal unit retirement costs assumptions used in each SO run, and a list of coal units that would free up transmission along the path from the proposed Wyoming wind projects if retired. PacifiCorp is to provide this information by June 30, 2018. If there is a dispute about modeling in the meantime, PacifiCorp, Staff and parties should first attempt to resolve it informally, but if that fails, Staff may report back to us at a public meeting before the 2019 IRP is filed. A Commissioner workshop will likely be scheduled to review this analysis once it is complete.

Additional General IRP Action Items:

- Modeling and Portfolio Approach: PacifiCorp will continue to model the assumption that EPA regional haze litigation against the company is successful and that PacifiCorp will be required to comply with the current requirements of the State Implementation Plan (SIP) and Federal Implementation Plan (FIP).
- Stochastic Parameters: In the IRP Update PacifiCorp will explain the reasons for the (sometimes) low correlations in the short-term forecast.

- Flexible Reserve Study: In the IRP Update PacifiCorp will model natural gas and storage for meeting flexible reserve study needs.
- Distribution System Planning: PacifiCorp will work with Staff and parties to advance distributed energy resource forecasting and representation in the IRP, and define a proposal for opening a distribution system planning investigation.
- Smart Grid Report: PacifiCorp will work with Staff and parties to explore the use of AMI data in future IRPs.
- Qualifying Facilities: PacifiCorp, Staff and parties should discuss a potential study of the capacity value of renewing QFs, and Staff shall bring this issue to a public meeting before the 2017 IRP Update.