BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 67

In the Matter of	)	
	)	
	)	COMMENTS BY THE OREGON
PACIFICORP	)	DEPARTMENT OF ENERGY ON
2017 Integrated Resource Plan	)	STAFF'S RECOMMENDATIONS
____	)	

Organization of ODOE's comments:

I. Introduction
II. Energy Vision 2020: Wind repowering, new wind, new transmission
III. Need for a comprehensive coal transition plan
IV. Decarbonization in the IRP process: planning and analysis framework
V. DR potential and planning
VI. Market transactions
VII. Conclusion

I. Introduction

The Oregon Department of Energy (ODOE or department) appreciates the opportunity to submit these comments in response to the Oregon Public Utility Commission staff's (staff) final comments on Pacific Power's (PAC or company) 2017 Integrated Resource Plan (IRP) submitted on October 6, 2017, and to PAC's reply comments submitted on July 28, 2017. The department's reply comments are framed by the state's overarching energy and climate change goals and the impact that energy resource decisions made pursuant to this IRP could have on achieving those goals.

These comments focus on the proposed acquisition of significant new renewable energy resources and supporting infrastructure and programs. The department respectfully points out that the risks, alternatives, and frames through which to view these new resource additions have not been fully examined by the company. A coal transition plan, common understanding of effects of the new resource additions on decarbonization of the electricity resource mix, and planning for other capacity resources are important components in order for the current IRP to be comprehensive.

II. Energy Vision 2020

In its opening comments, the department generally supports acquisition of renewable energy resources earlier rather than later in the 20-year planning timeframe.[1] Stakeholder meetings conducted by the company in 2016-2017 and the content of the IRP as submitted April 4, 2017,

[1] ODOE Opening Comments, pp. 4-5

led ODOE to the understanding that early renewables meant lower carbon emissions. Specifically, ODOE expected that deployment of Energy Vision 2020 would result in

1. a near-term reduction in carbon emissions as renewable resources displace fossil resources in the early years of the plan, and
2. lower carbon emissions overall for the company from accelerated coal retirements.

Information presented by the company at the September 14, 2017, Special Public Meeting and the staff analysis as represented in staff's final comments[2] make ODOE strongly question these two assumptions. The company states that more renewables will result in reduced market purchases, and staff analysis concludes that no accelerated coal retirements are assured. As a result, ODOE's continued support for acquisition of early renewables is qualified in these comments as support with recommendations: develop tools and processes to quantify the decarbonization of the company's resource mix and to protect customers from financial risks.

The department expressed concerns in its opening comments on risks related to the development timeframe and costs of the three elements of Energy Vision 2020: wind repowering, new wind, and transmission expansion. The information presented by the company was not sufficient to fully address our concerns about risk, particularly the tight development timeframe and hard commercial operation date (COD) deadline to fully capture the federal production tax credit (PTC).

Staff's analysis encompasses the elements of risk described by ODOE, and identifies several more elements[3]. Staff's final comments come down firmly against Energy Vision 2020 being acknowledged in the 2017 IRP, or in any upcoming IRP, as staff asserts there is no energy or capacity need demonstrated by the company. The economics of acquiring these new resources may be good, which could result in customer benefits, but without demonstration of need the risks must be examined with extreme care[4]. ODOE agrees that Energy Vision 2020 carries significant risks and supports strategies to mitigate those risks for customers.

The department supports staff's recommendation that, should the Commission decide to acknowledge the wind repowering, new wind, and/or transmission expansion, a cost containment mechanism is warranted to protect customers from cost overruns, financial implications of delay of commercial operation, or lower than expected revenue from the projects[5].

The Commission may decide not to acknowledge some or all of the components of Energy Vision 2020. With accelerated renewables targets in other states in the west, delaying acquisition of renewables may put the company at a disadvantage in 10 years. The department has not seen a discussion of a different category of risk to ratepayers: risk that the highest quality renewable energy resources with easy access to available transmission capacity will be built out and the

[2] Staff Final comments, p. 14
[3] Staff Final comments, pp. 21-22
[4] Staff Final comments, p. 19
[5] Staff Final comments, pp. 28-29

power purchased by other entities at attractive prices. If the company is in a position where it must acquire more renewable energy in a short time frame to achieve “just in time” RPS compliance, and only lower quality renewable resources, or only projects with high transmission costs, are available, the overall cost of RPS compliance may be higher. ODOE recommends that this risk be analyzed in the next IRP cycle, including potential risks and benefits of the company adopting a “glide path” approach to renewable resource acquisition as compared to a step-function acquisition plan.

III. Comprehensive Coal Transition Plan

Stakeholders such as Northwest Energy Coalition expressed doubt that the proposed new wind in Wyoming necessitates building a major new 500-kV transmission line. NWEC questioned the company’s assumptions on coal plant retirements, and assumptions on available transmission capacity in future years[6] given that the retirement of coal plants in the company’s system is speculative in this IRP (as in the 2015 IRP). A major driver in the company’s analysis of retirement of coal plants is the outcome of pending legal action related to EPA Regional Haze program compliance. As the department expressed in interim comments, a more comprehensive coal plan retirement analysis is needed[7].

Staff suggests additional coal fleet analysis be performed by the company and reported by March 30, 2018. The analysis is comprised of four discrete actions[8]. The department supports the analytical approach and the four actions as described by staff.

1. Perform 25 System Optimizer (SO) runs – one for each coal unit and a ‘base case.’
2. Provide the results of the SO runs to parties in LC 67 by March 30, 2018.
    a) Also provide an itemized list of coal unit retirement cost assumptions used in each SO run by the same date.
3. Provide a list of coal units that would free up transmission along the path from the proposed Wyoming wind project if retired, also by March 30, 2018.
4. Summarize the results in PacifiCorp’s final comments, providing a table of the difference in PVRR resulting from the early retirement of each unit.

The analysis will help stakeholders and the Commission understand potential pathways to decarbonization of PacifiCorp’s resource mix and identify temporal opportunities to tap into available transmission capacity.

The department recommends adding a fifth action to the analysis. For each of the 25 SO runs, the department requests that the company quantify the system-wide carbon emissions. Given the importance of decarbonization of the electric sector to meeting state climate goals, not identifying emissions in the coal transition analysis would be a missed opportunity. The risks of delaying significant decarbonization need to be identified, and this analysis is a first and important step.

[6] NWEC Opening comments, p. 2
[7] ODOE Interim comments, p. 6
[8] Staff Final comments, p. 31

IV. Consideration of Decarbonization in the IRP

Current decision-making at the Commission for the preferred portfolio in the company's IRP is guided by the overall objective of least-cost, least-risk planning. ODOE's preference for early renewables, as an instrument for an Oregon utility to assist in meeting the climate goals of the state, is not squarely in this planning structure. It is ODOE's firm belief that in order to do an effective least-cost, least-risk plan, carbon pricing and the direct costs of carbon must be taken into account.

Staff describes the need for comprehensive utility planning for decarbonization, and staff proposes a process and analytical framework that could be used to incorporate decarbonization as a consideration in future IRPs[9]. ODOE strongly supports the inclusion of this key state goal for energy and climate in the IRP process.

The Oregon PUC is not alone among state regulators in recognizing the need for a clear framework for decision-making regarding reduction of GHG emissions in the electricity sector. Below are examples of two states engaging with utilities in long-term planning to reduce carbon emissions.

<u>California</u>

In 2015, the California Assembly directed the California PUC to undertake an integrated resource planning effort, starting in 2017, to ensure that utilities and other load-serving entities:

> (A) Meet the greenhouse gas emissions reduction targets established by the State Air Resources Board, in coordination with the commission and the Energy Commission, for the electricity sector and each load-serving entity that reflect the electricity sector's percentage in achieving the economy-wide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.[10]

To meet this requirement, California PUC is considering a multi-prong approach to including GHG emission reductions in IRPs. The CPUC proposes to develop a Reference System Plan[11], structured around three primary questions:

1. What resources are needed to reduce GHG emissions in the electric sector?
2. What is the optimal portfolio of resources under different, alternative futures?
3. What investments, or actions, if any, should be taken in the short term (1-3 years)?

Oregon PUC could use these guideposts in developing analysis for decarbonization. The investigations needed to answer these questions align well with the analysis proposed by Staff.

---

[9] Staff Final comments, pp. 26-28

[10] Section 454.52 of the California Public Utilities Code, as added by Senate Bill 350 (2015) "Clean Energy and Pollution Reduction Act of 2015."

[11] CPUC "Proposed Reference System Plan", September 18, 2017; accessed on October 17, 2017 at http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentA.CPUC_IRP_Proposed_Ref_System_Plan_2017_09_18.pdf

California PUC staff outlines in considerable detail four recommendations that the California Commission could adopt to advance utility planning to meet GHG reduction targets.

1. A GHG Planning Target to use for the electric sector in IRP that is consistent with 40 percent statewide reductions by 2030 and 80 percent by 2050.
2. A Reference System Portfolio – a single portfolio of incremental resources that represents a least-cost, least-risk pathway to achieving the recommended GHG planning target.
3. A GHG Planning Price that represents the marginal cost of GHG abatement associated with the Reference System Portfolio and that will enable the CPUC and load-serving entities to consistently value both demand and supply-side resources.
4. Near-term Commission policy actions to ensure that the results from IRP modeling inform other CPUC proceedings and lead to the development or procurement of adequate resources.

Colorado

Colorado has a requirement that investor-owned utilities include pollution reduction requirements in their long-range planning. The Clean Air Clean Jobs Act (CACJA), signed into Colorado law on April 19, 2010, requires utilities to submit a plan to the PUC showing how they would meet EPA standards for a variety of pollutants. The law requires investor-owned utilities (IOUs) with coal plants to submit a multi-pollutant plan to the PUC to meet the EPA standards for NOx, SO2, particulates, mercury, and CO2. Utilities were not required to adopt a specific plan set by the state, but had to meet with Colorado Department of Public Health and Environment (CDPHE) and PUC approval. Xcel Energy's plan was submitted and approved in 2010.[12]

ODOE recommends that staff review and consider these efforts to incorporate GHG emissions into utility resource planning.

V. Demand Response

In its opening comments, the department expressed that the company is moving in a positive direction by quantifying demand-side management resources as both energy and capacity resources[13]. The department has consistently encouraged the company, in past IRPs and Smart Grid reports, to accelerate deployment of demand response (DR). Staff is recommending that the company aim for more DR than the 77 MW by 2021 as identified in the action plan[14]. ODOE agrees with staff that over a four-year period there is potential for the company to implement more than 77 MW of additional DR resources. The company has experience operating successful DR programs in Utah (e.g., CoolKeeper air conditioning control). The company has also committed to a major system improvement with the implementation of automated metering infrastructure (AMI) in Oregon. DR is one of the key programs that can be enabled by AMI. Staff's recommendation to establish a DR Review Committee and DR Testbed could assist the

---

[12] "Cutting Power Sector Carbon Pollution: State Policies and Programs", US EPA, August 2016. Accessed October 23, 2017 at https://www.epa.gov/sites/production/files/2015-08/documents/existing-state-actions-that-reduce-power-sector-co2-emissions-june-2-2014_0.pdf

[13] ODOE Opening comments, p. 5

[14] Staff Final comments, p. 44

company in identifying near-term opportunities and gaining valuable experience with DR here in its western service territory. Locational benefits of DR are an important attribute to explore. ODOE recommends that the DR Review Committee have at least one member who is also a member of the Demand Response Advisory Committee (DRAC) at the Northwest Power and Conservation Council. The Northwest region is aiming for significant expansion of DR by 2021, and connecting the DR Review Committee with the DRAC at the Council should result in accelerated information gathering and analysis of DR options.

VI. Market Purchases (FOTs)

The department raised concerns in opening comments that the company is underestimating the true amount of FOTs likely to be purchased in the action plan time period (given that the company has exceeded its own planning allowance for FOTs by greater than 25 percent in the past), and the levels of FOTs may represent a hidden risk especially during summer. The company did not provide substantive response on this topic, and Staff's final comments characterize FOTs that are for terms of longer duration (month-ahead and longer) as a *hedge against risk and price.*[15] The department repeats the request that the company perform a more in-depth risk analysis of price escalation for FOTs, preferably with attention to summer and winter FOTs separately, and the request for analysis of energy efficiency and DR as a hedge to any price risks associated with high levels of FOTs.

VII. Conclusion

The department appreciates the opportunity to comment on the 2017 PacifiCorp Integrated Resource Plan. ODOE commends the company for robust engagement of stakeholders and for improving the portfolio development process. Regarding the central issue in this IRP, development of the company's Energy Vision 2020 including wind and transmission resources, the department continues to be generally supportive of the company acquiring new renewable resources earlier rather than later in the planning period. The state's driving interest in early renewables procurement is lowering carbon emissions, therefore the department offers its support accompanied with the recommendation that the company provide clear quantification of the decarbonization result for the company's preferred resource mix. In addition, the department recommends the company implement customer protections against cost and schedule risks of the Energy Vision 2020 plan.

[15] Staff Final comments, p. 25