BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 77

In the Matter of PACIFICORP, dba PACIFIC POWER, 2021 Integrated Resource Plan.	Staff Opening Comments

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PacifiCorp's 2021 Integrated Resource Plan (IRP) presents the Company's long-term plan to meet customer load with new generation, load reduction, and transmission resources. The preferred portfolio is selected using a model capable of minimizing costs while considering constraints such as reliability, policy requirements, and transmission limits. The modeling process not only considers what generation resources to build to meet load, but also what transmission investments and economic coal retirements may help to reduce costs for customers. A model's results, however, can only be as good as the inputs and assumptions the model is given. Staff's review of the 2021 IRP largely focuses on the inputs and assumptions used in modeling the 2021 IRP portfolios, sensitivities, and variants.

PacifiCorp's public input process leading up to the 2021 IRP consisted of about 20 meetings over 22 months. PacifiCorp presented information regarding modeling inputs and assumptions, including the results of studies that inform those inputs. These meetings provide a space for stakeholders and interested parties to learn about the resource planning process and provide feedback. The process was useful for helping participants understand PacifiCorp's resource planning at a high level, including load forecasting, energy market transactions, and the study of economic coal retirements. Staff provided several recommendations and rounds of feedback for the Company during the process, and the feedback seemed to be heard and considered by the Company. In some instances, the Company included Staff and stakeholder recommendations in the 2021 IRP.

The public input process, however, is limited in its ability to allow parties a close look at the detailed planning assumptions that go into the IRP. No draft IRP was filed, per OAR 860-027-0400 (2) and guideline 2(c).[1,2] The filing of the 2021 IRP with the Commission marked the first opportunity for stakeholders to read the IRP and to delve into any planning assumptions that were too complex for the public input meetings or that contained confidential information.

Staff's Initial Comments on the 2021 IRP discuss the details of the IRP and to seek to determine where PacifiCorp's planning process is succeeding at providing customers with the best balance between cost and risk, as well as places where the IRP is likely not providing the best portfolio for customers.

[1] OAR 860-027-0400(2).
[2] Order No. 07-002.

Section 1: 2021 IRP Modeling

1.1 Portfolio Selection, Development, and Evaluation

1.1.1 The Plexos Model

Staff appreciates PacifiCorp's continuing work to improve its IRP modeling and find optimal portfolios to reduce cost and risk for customers. PacifiCorp's implementation of the Plexos model appears to have significantly improved the planning process, making it more efficient and more capable of identifying least cost resource combinations. The 2021 IRP represents an improvement over the 2017 and 2019 IRPs, since it considers endogenous (within model) selection of economic coal unit retirements and improved endogenous selection of transmission investments. There is still room for improvement in endogenous selection. For example, in the 2021 IRP endogenous coal unit retirements have only been considered once every few years, instead of in every year.[3]

1.1.2 Generation Resource Modeling

The 2021 IRP is generally thorough in its consideration of generation resources. A variety of potential new resources are considered, and a variety of coal retirement dates are considered for the value they can provide to the system. System constraints like generator ramp rates and minimum take requirements are included in the modeling. The correlation between renewable generation and load, as well as the correlation between wind generation and solar generation, has been updated in the 2021 IRP to reflect recent experience.[4] Staff has identified a few areas where the modeling of energy and capacity resources needs to be improved immediately, as well as some additional items for future consideration or improvement.

Coal Economics

The 2019 IRP introduced an economic study of coal retirement dates that showed benefit from retiring certain coal resources early and replacing them with lower cost energy resources like wind, solar, and storage.[5] Coal retirement dates are proving to be an important consideration when planning to reduce cost and risk on PacifiCorp's system, and it will continue to be crucial to evaluate these generators fully to ensure they are not creating unnecessary costs for customers.

After reviewing the modeling inputs and assumptions used to represent coal units in the 2021 IRP, Staff finds that:

[3] PacifiCorp's December 3, 2020, Public Input Meeting Presentation.
[4] PacifiCorp's January 29, 2021, Public Input Meeting presentation. Page 13.
[5] PacifiCorp 2019 Integrated Resource Plan. Appendix R.

- Coal prices modeled in the IRP appear to be largely consistent with recent historical coal prices, although there is some variation that Staff is continuing to evaluate.
- The near-term coal generation forecast is largely consistent with recent historical actuals at PacifiCorp's coal units, with the exception of Naughton 1 and 2, which **[Begin Confidential]** [redacted] **[End Confidential].**[6] Later in these comments, Staff recommends a portfolio analysis to investigate this and other potential issues.
- Minimum take requirements in existing coal contracts appear to be reflected accurately in the modeling of IRP coal resources, with one exception discussed later in these comments.

Items of ongoing review regarding the coal fleet include:

- A review of any economic coal cycling in the preferred portfolio.
- Whether coal plant O&M costs have been updated to reflect the effects of changing operations at the units to provide more flexible ramping.
- Whether variable O&M costs have been modeled appropriately as variable with unit dispatch, or have been inappropriately modeled as part of fixed costs.
- Whether coal plants dispatch mostly during high or low market price hours, and the extent to which their optimal dispatch in the IRP reflects actual operations.
- The extent to which the IRP may be contributing to the uneconomic dispatch of PacifiCorp's coal plants by setting expected generation at the units at unrealistically high levels.

Jim Bridger 1 and 2 Gas Conversion

The preferred portfolio converts Jim Bridger 1 and 2 to natural gas in 2023. The Jim Bridger (JB) gas conversion appears to be a reasonable way to retain system capacity while providing customers with the benefits of relatively low gas costs. The IRP notes that the initial capital cost of a gas conversion at these units is approximately $25/kW, whereas initial capital costs of solar plus storage would be $2,890/kW.[7] Although solar plus storage would have lower variable operating costs across its lifespan, PacifiCorp's sensitivity without Bridger 1 and 2 gas conversion shows that the gas conversion saves about $470 million in the risk-adjusted medium gas price, medium carbon price (MM) scenario. In the Plexos modeling, the converted JB units **[Begin Confidential]** [redacted] **[End Confidential]** [8]

[6] Appendix A. Confidential IRP Details. Page 1.
[7] PacifiCorp 2021 IRP. Page 270.
[8] Appendix A. Page 3.

<u>Staff Request/Recommendation 1</u>
Given that the gas conversion at Jim Bridger 1 and 2 created substantial cost reduction, Staff requests that PacifiCorp explain in its reply comments why gas conversion at Jim Bridger 3 and 4 was not considered.

Jim Bridger 3 and 4 Modeling

Staff has concerns about the modeling of Jim Bridger 3 and 4 in the 2021 IRP. These coal units appear to be modeled as **[Begin Confidential]** [redacted] **[End Confidential].**[9] This assumption seems unreasonable and inaccurate.

Keeping Bridger units 3 and 4 online throughout the planning timeframe using inaccurate modeling assumptions reduces the ability to plan for a system that creates the best balance of cost and risk for customers. Further, the **[Begin Confidential]** [redacted] **[End Confidential]**[10] prevents the Company from planning for the potential lower cost, non-emitting resources that could take the place of this high-cost plant. Staff is concerned that the inaccurate modeling of Jim Bridger is effectively operating as a coal subsidy at the expense of ratepayers.

PacifiCorp's variant that looks at Jim Bridger 3 and 4 retirement by 2030 is not sufficient to assess whether these units are valuable to the system, because it does not allow other coal retirements to be optimized along with Bridger. It appears to simply require retirement of Bridger by 2030 while keeping other coal retirements fixed. This means that the model is missing opportunities to potentially rearrange coal unit retirements to find a more optimal outcome.

Staff's assessment is that the **[Begin Confidential]** [redacted] **[End Confidential]** appears to be the main reason for Bridger 3 and 4 remaining online through 2037. If PacifiCorp has an argument as to why keeping the plant online that long is a good decision for customers or is essential for the Company to maintain its opportunity to earn a reasonable return, Staff would like PacifiCorp to share that argument in reply comments.

Finally, this IRP may be a good opportunity for a conversation around securitization of coal assets at Bridger. If coal assets are retired early, then securitization might provide the opportunity to reduce customer rate impacts while providing the Company assurance of receiving the return of its investment in a resource.

However, for securitization to occur at some utilities, authorization from state legislatures has been required. There appear to be laws allowing securitization already in three of the six states in which PacifiCorp serves.[11] Staff would like to discuss with PacifiCorp in this IRP docket any

[9] Appendix A. Page 2.
[10] Appendix A. Page 3.
[11] Utility Dive. [Securitization fever: Renewables advocates seize Wall Street's innovative way to end coal.]()

steps the Company has taken to pursue the possibility of securitization for its Oregon, Utah, and Wyoming customers.

Staff Request/Recommendation 2

Staff requests PacifiCorp address the following in its Reply Comments:

- **Why the Company believes that a [Begin Confidential]** [redacted] **[End Confidential] is reasonable at Jim Bridger 3 and 4.**
- **Whether PacifiCorp has an argument as to why keeping the plant online through 2037 is a good decision for customers or is essential for the Company to maintain its opportunity to earn a reasonable return.**
- **Whether early retirement of Jim Bridger 3 and 4 combined with securitization could provide savings to customers while helping transition away from coal.**
- **Any steps the Company has taken to pursue the possibility of securitization for its Oregon, Utah, and Wyoming customers.**

Huntington

Staff is concerned that the 2035/2036 retirement dates for Huntington units 1 and 2 may not have been selected optimally due to limitations in the granularity of modeling for economic coal retirements. Huntington units 1 and 2 were given the options to retire in 2023/2024, 2027/2028, 2031/2032, and 2035/2036. In the preferred portfolio, both units continue operating through 2036, **[Begin Confidential]** [redacted] **[End Confidential].** [12]

However, Staff suggests that retirement at Huntington 1 and 2 should have been considered in by the end of 2029/2030 instead of 2031/2032.[13] Staff includes this recommendation in the coal sensitivity recommendation provided later in these comments.

Coal Unit EIM participation

The Plexos model dispatches coal units economically based on operating costs and constraints, including ramp rate, minimum generation level, and existing minimum take coal agreements. However, EIM-participating coal units may not be dispatched economically in actual operations if EIM bid prices are not decided based on economics. If the Company's operations at its coal units do not reflect the economic dispatch in the preferred portfolio, then the actual benefits to customers of the preferred portfolio may not be realized.

Staff is reviewing PacifiCorp's bidding in the EIM to identify whether coal units are being bid correctly for economic dispatch. PacifiCorp has shared that coal units are sometimes 'self-scheduled' or 'self-committed' into the EIM at their minimum generation levels.[14] Staff is

[12] Appendix A. Page 4.
[13] Appendix A. Page 4.
[14] Staff Data Request 025.

looking into this practice, as well as the Company's calculation of coal bids for various levels of generation. Staff will consider whether these practices are consistent with the operation of the coal fleet in a manner that provides the best value to customers. Staff's concern is that if EIM bids are too low, the coal units will be dispatched too often and compensated too little, resulting in unnecessarily high emissions, overall ratepayer costs, and distorted market signals for proper investments.

Environmental Remediation and Coal Communities

Securitization of early-retiring coal plants can be helpful to ratepayers and communities. Because these costs can be paid back over a long period of time, the rate impacts of accelerated depreciation due to early retirement can be mitigated. Also, communities can be supported through securitization by including funding for a thorough environmental remediation that protects the health of these communities while protecting ratepayers from future environmental liabilities if remediation is not done correctly.

Proper, thorough shutdown and environmental remediation at coal plant locations can help with the economic transition for coal communities by providing jobs during the transition period, as well as mitigating potential health and environmental impacts to communities. For example, a 2019 case study on the shutdown of the Colstrip coal plant found that the current environmental remediation plan would have left coal ash in contact with groundwater in the long-term. An alternative, more robust plan would include excavating coal ash, dewatering it, and repairing the groundwater. This plan is expected to create twice as many jobs as the– jobs for which priority could be given to the local workforce.[15] Staff is interested in discussing options to support communities around retiring coal plants and protect Oregon ratepayers by ensuring thorough environmental remediation of these sites.

Staff Request/Recommendation 3

Staff would like PacifiCorp to report in its reply comments on what its environmental remediation requirements will be at the Colstrip, Dave Johnston, and Jim Bridger coal plants, and whether there are options to engage in more or less thorough environmental remediation plans and the risks that may be associated with those options.

Coal Unit Exit Orders

Staff notes that the 2020 Multi-State Protocol provides that Oregon Exit Orders should be issued with four years advance notice to other states.[17] For Jim Bridger, the recommended Exit Dates are 2023 for Jim Bridger 1 and 2025 for Jim Bridger 2-4. In PacifiCorp's recent rate case, the Commission declined to issue Exit Orders for the Jim Bridger units 2-4, noting that the units were expected to retire later than 2025, and that 2025 exit dates were not supported by evidence in the rate case.[18]

[15] Northern Plains Resource Council. Doing it Right II, Job Creation Through Colstrip Cleanup. April 2019.

For Jim Bridger unit 1 and 2, PacifiCorp's plan has shifted from one of early retirement to a plan of gas conversion. The 2020 Multi-State Protocol does not address or contemplate the function of Exit Orders when the unit is being converted to a different fuel source, such as natural gas. As such, the Commission may want to clarify its intent in the IRP as to whether the previously issued Exit Order at Jim Bridger unit 1 should be considered to apply in the event that the unit is converted to natural gas. Staff would recommend keeping the converted gas units in Oregon's portfolio, since the economics of the gas conversion seem favorable for reasons described in Staff's comments above.

Staff is continuing to investigate the economics of Jim Bridger 3 and 4, and finds there is reason to believe that the continued operation of the plants through 2037 is not economic, and that earlier retirement would likely be selected if the units were modeled accurately. It seems reasonable to issue Exit Orders for 2025 at these units now, even though they run through 2037 in the preferred portfolio. Although Staff supports a 2025 Exit Order, Staff does not have specific evidence that a 2025 retirement date is more optimal than another date before 2030. When Oregon exits a coal unit and the associated costs and benefits of that unit are removed from Oregon rates, Oregon will need to pick up another resource's costs and benefits to replace it. The 2025 date may help smooth any rate impacts to customers by evenly distributing the Exit Orders and their rate impacts throughout the years before 2030.

Nuclear

The Natrium Nuclear plant is modeled in the 2021 IRP as being located at the site of the retiring Naughton coal plant and brought into service in 2028. The Natrium plant appears to be an interesting potential resource that could provide low-carbon power, while contributing to a transition away from emitting resources with minimal impacts to coal communities. However, the costs of the plant as modeled are highly uncertain at this time, and PacifiCorp has provided little evidence that they will be representative of the actual demonstration project. PacifiCorp's estimate that Natrium will reduce system PVRR by $158 million should be considered highly speculative. The risks of nuclear are also unique and likely are not fully reflected in the IRP models.

Staff has looked into the differences in system buildout between the preferred portfolio and the 'No nuclear' sensitivity. The portfolio without Natrium constructs 348 MW of solar plus storage at **[Begin Confidential]** [redacted] **[End Confidential** in 2026 and 240 MW of solar plus storage in 2030 at the same location. There are no changes in major transmission investments between the two portfolios.

Staff's understanding is that the 'No nuclear' sensitivity model run did not allow for endogenous selection of coal retirements. Instead, it used the coal retirement dates that had been optimized for a portfolio with Natrium nuclear included in 2028. This further decreases

Staff's confidence in PacifiCorp's statement in the IRP that the inclusion of the Natrium plant reduces system costs by $158 million.[16]

Further, given the history of long delays in construction timelines for nuclear projects, Staff would like the Company to clarify how their Integrated Resource Plan accounts for the portfolio risk, especially around reliability and costs, should the Natrium plant take longer to build rather than the proposed five years. [17,18] What will the capacity shortfall be for the PacifiCorp system in 2028 – 2033, should the plant be delayed by five years? How will the Company manage the shortfall?

Staff is aware that the Natrium demonstration plant may have substantial outside funding, may be delivered to the Company as a turnkey project, and may be offered to PacifiCorp at "market rate" for energy and capacity.[19] If the Natrium project will indeed be delivered to PacifiCorp as a turnkey project at market rates, Staff's concern about this project can be reduced. However, these agreements appear to be informal at present, and Staff views the 'No nuclear' portfolio to be equally as important for consideration as the preferred portfolio in this IRP.

Staff Request/Recommendation 4

Staff requests that PacifiCorp provide more detail in Reply Comments about any plans or agreements the Company is currently considering to reduce risk and cost for customers at the Natrium demonstration project, including any agreements that energy and capacity from the project will be provided to PacifiCorp at market rates.

At this time, Staff is interested in learning more about the Natrium nuclear resource and under what terms it could be a part of a portfolio that best balances costs and risks for PacifiCorp customers. Staff may have trouble recommending acknowledgement of Natrium in the 2021 IRP because of the lack of detail provided in the IRP and the uncertainty around whether the costs and risks modeled are accurate. As more details come to light about the resource and the terms under which PacifiCorp may acquire it, Staff will be better able to evaluate the cost and risk of the resource.

Additionally, Staff is concerned about the modeling of the proxy nuclear resource. Since there is no indication that the proxy nuclear resource in the IRP will have access to the same advantages as the initial Natrium demonstration plant, modeling future nuclear plants with the same costs as the Natrium project would be problematic.

Risks Unique to Nuclear

The very limited domestic availability of enriched nuclear fuel introduces fuel procurement risk that is not a factor for coal or gas generators.[20] PacifiCorp has explained that it expects the

[16] PacifiCorp 2021 IRP. Page 280.

[17] NuclearVsWWS (stanford.edu).

[18] https://www.statista.com/statistics/712841/median-construction-time-for-reactors-since-1981/.

[19] Ernst, Steve. TerraPower Selects Site for Demo Reactor; Rocky Mountain Power Going Nuclear. Clearing Up. November 19, 2021.

[20] Pollack, Nicole. Fueling Change in Wyoming: Can a Coal State Go Nuclear? Casper Tribune. November 14, 2021.

'initial' fuel at the Natrium plant to be domestically sourced sodium bonded metallic uranium fuel encased lead. PacifiCorp's reply references the existence of two test facilities that are said to use the fuel in the United States.[21] However, of the two facilities mentioned, the Hanford facility has been deactivated since 2009. It is currently in a state of 'long-term, low-cost surveillance and maintenance' and is scheduled for decommissioning.[22] The other facility mentioned, the Experimental Breeder Reactor II in Idaho, was decommissioned in 1994.[23] It is unclear whether there is a facility currently producing this fuel in the United States.

Finally, Staff would like to highlight that nuclear is a resource that introduces risk by its nature as a radioactive fuel that requires safe fuel procurement, safe operations, and long-term storage, while potentially being an attractive target for anyone seeking nuclear weapons material.

Staff Request/Recommendation 5

Staff requests PacifiCorp report in Reply Comments on what the Company is currently doing to learn the skills required to safely procure fuel, safely run a nuclear plant, and securely store spent nuclear fuel, all at a reasonable cost.

Resource Procurement Rules

Per Order No. 18-324, Staff would like to understand if/how the Naughton transmission resources will be made available to all bidders in an eventual RFP.[24] Staff would note that long lead-time resources, such as pumped hydro, have had to compete in RFPs against renewables and storage resources. Will the Natrium resource compete with other resources in an RFP?

Staff Request/Recommendation 6

Staff requests PacifiCorp report in this IRP docket on whether it expects the Natrium nuclear facility to compete against other resources in an eventual RFP, and if not, why not.

Hydrogen

The 2021 IRP includes non-emitting hydrogen peakers as a proxy resource available after 2030.[25] Staff is supportive of the consideration of this emerging technology for selection in the preferred portfolio. Additionally, Staff recommends consideration of other potential scenarios for hydrogen that could be modeled in future IRPs or potentially as a part of the 2021 IRP review process.

First, there is potential that third-party hydrogen electrolysis may at some point become a significant and possibly dynamic load on the system. Staff is interested in a discussion of

[21] PacifiCorp's Response to CUB Information Request 04.
[22] https://www.hanford.gov/page.cfm/400areafftf.
[23] https://www.ne.anl.gov/About/reactors/frt.shtml.
[24] Order No. 18-324. Page 10. See also 860-089-0300 (2) - (3).
[25] PacifiCorp 2021 Integrated Resource Plan. Page 168.

whether the creation of tariffs for hydrogen could allow the Company to charge electric rates based on the unique cost and value of the flexible hydrogen load. Additionally, could a tariff for hydrogen be able to attract flexible hydrogen load to the most cost-effective locations on the Company's system if it were based on a study of locational marginal cost?

Finally, it may prove beneficial to include potential hydrogen loads in resource planning and procurement decisions. Staff is interested in a conversation around whether optimization modeling could be used to determine the most cost-effective locations for hydrogen electrolysis load.

In summary, Staff would like to engage PacifiCorp in a conversation about preparing to incorporate flexible hydrogen electrolysis load in a way that encourages it to be located in places, and nudged toward times, that reduce system costs.

Staff Request/Recommendation 7
Staff requests that PacifiCorp and stakeholders provide any responses to Staff's thoughts on incorporating flexible hydrogen load onto PacifiCorp's system in their Reply Comments.

Offshore Wind

PacifiCorp's 2021 IRP includes a section on the potential for floating Offshore Wind (OSW) resource on the west coast near Southern Oregon.[26] Recent studies have found that OSW may provide a significant amount of winter-peaking, high-capacity factor renewable energy to customers, without the need for major transmission upgrades. Because energy typically flows from the interior of coastal states to the coast, adding OSW on the west coast could reverse these flows, allowing for the addition of new energy resources without the need for new transmission.[27] It is estimated that up to 2.6 GW of OSW could be built on the west coast without the need for major transmission upgrades.[28] Certain grid strengthening improvements would likely be advisable due to the "weak" coastal transmission system that currently has limited redundancy and stabilizing support systems.[29]

Staff is hoping to learn more about the value of OSW to PacifiCorp's system, especially through providing access to renewable energy without the need for major new transmission investments, and potentially through avoiding the need for new transmission upgrades to transfer energy from the eastern balancing area to the western balancing area.

[26] PacifiCorp's 2021 Integrated Resource Plan. Page 195.
[27] PNNL. Exploring the Grid Value Potential of Offshore Wind Energy in Oregon. May 2020. Page 45.
[28] PNNL. Exploring the Grid Value Potential of Offshore Wind Energy in Oregon. May 2020. Page 44.
[29] PNNL. Exploring the Grid Value Potential of Offshore Wind Energy in Oregon. May 2020. Page 38.

Given that floating OSW is an emerging technology, Staff hopes that PacifiCorp will gain access to the best available cost and operational parameter estimates and use them to consider the value of OSW in its IRP modeling moving forward.

Additionally, Staff finds it important to perform a study of the potential value of OSW before the Final Shortlist (FSL) acknowledgement decision in the 2022 AS RFP, specifically around whether the option to install 1 GW of OSW in 2028 or 2030 could significantly change the economics of constructing the B2H line and FSL generation resources in 2026.

Staff notes that the future cost estimates of floating OSW, while subject to uncertainty, are publicly available from national laboratories and based on actual deployments, unlike the Natrium project.[30] There are about 105 MW of floating OSW projects currently in service.[31] Staff requests that PacifiCorp's study use the best available estimates of OSW costs in 2028/2030. Additionally, Staff hopes that there is time for PacifiCorp Transmission to provide an estimate of any transmission upgrades needed to interconnect either 500 MW or 1 GW of floating OSW.

Interpretation of any study would need to be cautious. The purpose of the study would be to test whether addition of OSW to PacifiCorp's system could provide savings of a magnitude that could justify the consideration of a delay in procuring the Final Shortlist. Staff understands any analysis would be provisional, and the potential savings would need to be quite substantial in order to show that a change in plans could be justified. However, such an analysis could lead to valuable, actionable insight on near-term procurement, and will be less speculative than a nuclear technology that has never been permitted, built, or tested in the field.

Staff finds it especially important to consider the value of an optimized portfolio that allows for endogenous selection of the B2H line. Given that the B2H line is providing mostly east-to-west transmission capacity between PacifiCorp's Balancing Areas (BA), the addition of OSW may significantly change the economics of the B2H line, while reducing the high variable operating costs and greenhouse gas emissions associated with generation from the eastern BA.[32]

Staff Request/Recommendation 8

Staff requests that PacifiCorp respond in Reply Comments regarding any obstacles or issues the Company sees around providing the Commission with an Offshore Wind study in the 2022 RFP at the time that it presents the Final Shortlist. The study should:

- **Require at least 500 MW of OSW to be added to the portfolio, with the model given the option between 2028 or 2030;**
- **Allow the addition of an additional 500 MW, for a total of up to 1 GW of OSW to be added to the portfolio in 2028 or 2030;**

[30] National Renewable Energy Laboratory. Oregon Offshore Wind Site Feasibility and Cost Study. Pages 59-61.
[31] https://en.wikipedia.org/wiki/Floating_wind_turbine.
[32] PacifiCorp's 2021 IRP. Page 89.

- **Utilize the best available cost estimates for OSW, including all costs necessary to transport electricity to shore;**
- **Include necessary interconnection costs and transmission upgrades, if they could be made available by PacifiCorp Transmission by the FSL presentation date;**
- **Allow for endogenous selection of the B2H transmission line;**
- **Allow for endogenous selection of the 2028 Natrium Nuclear plant; and**
- **Allow for endogenous selection of RFP bids and proxy resources.**

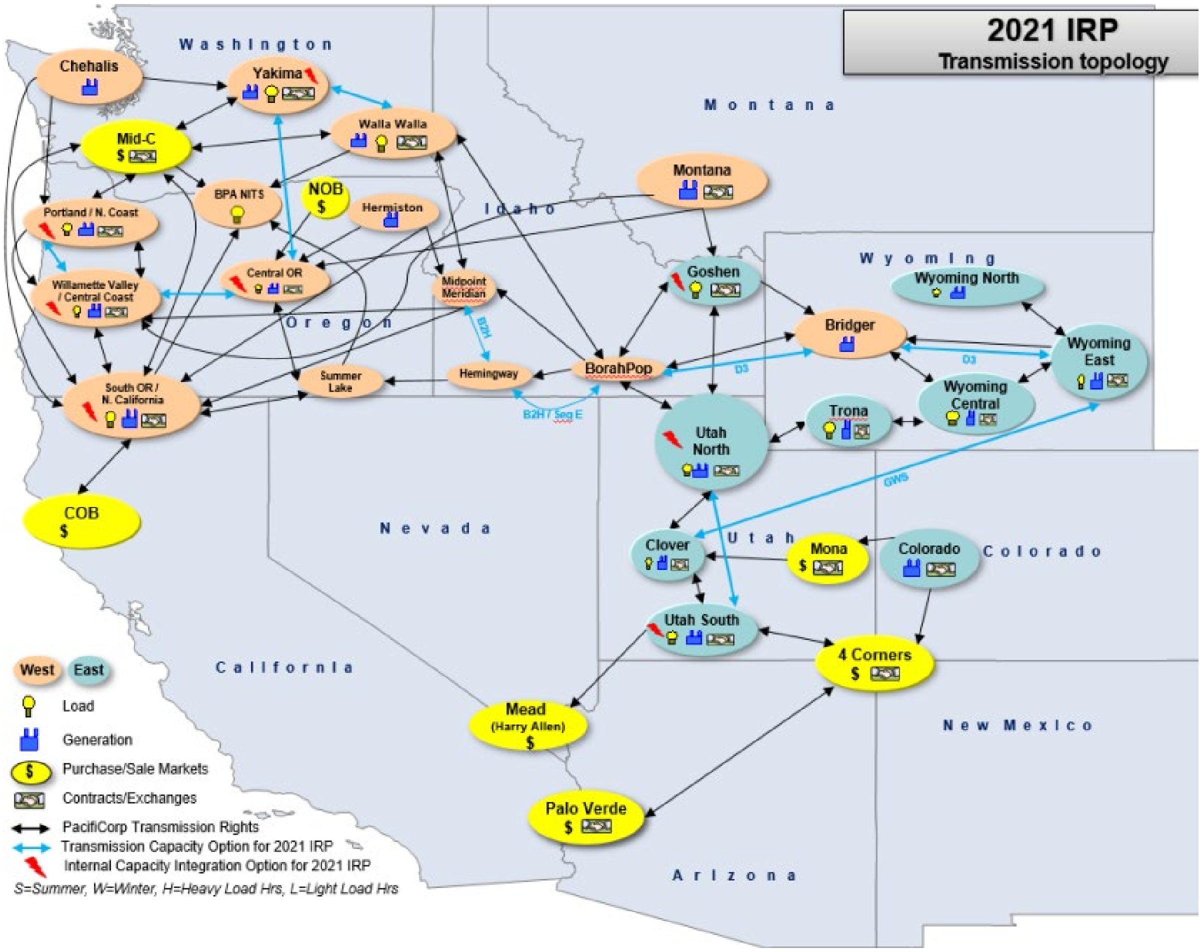
1.1.3 Transmission

Overview of Transmission in the IRP

The current IRP continues to incorporate endogenous transmission modeling, meaning that the model has the capability to select optimal transmission options instead of PacifiCorp creating transmission portfolios or imposing transmission scenarios in the model. The IRP's transmission modeling is not an exact replica of PacifiCorp's transmission system— using current technology, this would be onerous and likely impossible from a practical standpoint. Thus, the Company creates a "transmission topology" in Plexos that is designed to represent transmission availability based on PacifiCorp transmission rights. Plexos models aggregated transmission paths and does not generally consider individual lines, with the exception being transmission paths that are in themselves single lines connecting two areas, such as Gateway South. [33] Below is a picture of PacifiCorp's transmission topology from Chapter 8 of the IRP. Blue lines represent transmission capacity options for the model to choose, and black lines represent existing capacity. The selectable transmission options, as Staff understands it, primarily include projects that improve line ratings between two transmission areas or "bubbles."[34]

[33] PacifiCorp's Response to Staff Information Request 37.

[34] PacifiCorp Response to Staff IR 48.



Staff notes that the Walla Walla to Borah/Populus path is scheduled for 2026 in the preferred portfolio, and appears to be a part of the B2H project, but is not coded in blue in the map above.

PacifiCorp's IRP topology includes new incremental transmission options tied to resource selections, existing transmission rights tied to the use of post-retirement brownfield sites, certain costs associated with the transmission options, and transmission options that interact with multiple or complex elements of the IRP transmission topology.[35] Based on PacifiCorp's reply to Staff DRs, it is still unclear whether all of the transmission investments in the 2021 IRP Action Plan are included and considered in the Plexos model, especially for interconnection upgrades that do not increase transmission capacity between two IRP bubbles.[36]

Staff Request/Recommendation 9

Staff requests that PacifiCorp respond in Reply Comments:

Whether the Walla Walla to Borah/Populus path is a selectable option in Plexos. If it is not a selectable option, PacifiCorp should justify its inclusion in the preferred portfolio. If it is

[35] See page 19 of PacifiCorp's 2021 IRP.

[36] See PacifiCorp response to Staff IR 36, 46, and 48.

selectable, then the Company should explain why it is not colored in blue in the IRP topology map.

Whether and how the costs of each transmission and interconnection upgrade in the 2021 IRP Action Plan are considered in the Plexos modeling.

Boardman to Hemingway

One of Staff's most prominent concerns in the 2019 IRP was the inability for System Optimizer to model Boardman to Hemingway (B2H) endogenously. Multiple stakeholders also generally expressed concerns with PacifiCorp's transmission modeling, in particular the Company's prioritization of Gateway South and lack of endogenous selection of B2H.[37] Modeling both of these projects endogenously would allow the opportunity to see how these projects compete with each other. Staff had previously expressed that it was important to see whether Gateway South could be postponed in favor of a cheaper project like B2H. At the December 3, 2020, Public Input meeting for the PacifiCorp IRP, the Company had indicated to stakeholders that B2H would be modeled endogenously alongside Gateway South in the 2021 IRP. Staff greatly appreciated that PacifiCorp was poised to include this significant modeling improvement and was looking forward to a comprehensive analysis of how these two projects compare to each other.

Staff was surprised to learn that the preferred portfolio in the 2021 IRP did not allow B2H to be selected endogenously. As discovery confirms, B2H and Gateway South (and the associated D.1 project) have been hard-coded into the model, rather than economically selected in Plexos.[38]

Though the Company includes a sensitivity removing Gateway South (but including B2H), and another sensitivity removing B2H (but including Gateway South), Staff is unaware of a portfolio in which these two projects are able to compete with each other. It is disappointing that the Company strayed from its initial intent to model these two projects endogenously in the preferred portfolio, and Staff remains highly interested in an analysis that allows the two projects to compete. In Staff's Opening and Final Comments on the 2019 IRP, Staff argued that Gateway South is an inferior project compared to B2H with respect to regional value, cost, and bi-directionality. It is frustrating to see that PacifiCorp has the ability to show whether B2H might delay the need for Gateway South, but has declined to provide this study in the IRP.

PacifiCorp's Transparency Failures

In Staff's IRP Comments in the 2019 IRP, Staff expressed frustration with the fact that PacifiCorp's transmission costs for items in the Action Plan were not transparently highlighted throughout the IRP. Staff had to request the total costs of projects, received it confidentially,

[37] See CUB and AWEC Comments in the 2019 IRP.
[38] See PacifiCorp response to Sierra Club IR 1.14 and PacifiCorp response to Staff IR 48.

and found that some of the information was still unclear to Staff when it was received.[39] Ultimately PacifiCorp provided these costs in its Final Comments, but these should have been transparently highlighted in the IRP filing itself. In addition, whereas PacifiCorp provided a rough estimate of costs for transmission options in the 2019 IRP, in the 2021 IRP, PacifiCorp has not provided even basic estimates of transmission costs.[40]

Additionally, the Company did not delineate certain Action Items in its Action Plan. In particular, Action Item 3d states, "Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids."[41] These projects were never outlined in the IRP, so Staff had to ask PacifiCorp what specifically it was requesting acknowledgment of, and how much it would cost.[11] As explained above, local transmission projects are not part of the Plexos transmission topology, and it is unclear whether Plexos modeling has shown that these upgrades are reasonable. The IRP does not give a clear picture of how the transmission options modeled in Plexos relate to the Action Items, nor does it provide any reliability justification for those projects. The Company did provide total costs and names for the projects when requested, but itemized costs were not provided, and the justifications for these projects remain unclear.[42]

The precedent set in other IRPs, such as NW Natural's and Cascade Natural Gas' ("Cascade") most recent IRPs is to delineate need and justification clearly.[43] For example, NW Natural provided a 35-page data response to Staff justifying the need for specific distribution projects. Cascade similarly removed distribution Action Items from its Action Plan and agreed to do additional analysis justifying need.[13] Cascade similarly removed distribution Action Items from its Action Plan and agreed to do additional analysis justifying need.[44]

To Staff's knowledge, the projects in Action Item 3d and their associated costs are not specifically delineated anywhere in the IRP. Staff requested project details and associated costs in discovery and they are represented in the confidential table below:

[39] See Staff's comments in the 2019 IRP.
[40] PacifiCorp 2021 IRP, page 27.
[41] PacifiCorp 2021 IRP, page 27.
[42] See PacifiCorp response to Staff DR 53 and Confidential Attachment.
[43] LC 71 and LC 76
[44] See Staff Report in LC 76.

[Begin Confidential]

[redacted]

[End Confidential]

Because the Action Item 3d projects are not associated with the "Planned Transmission System Improvements" listed on pages 100-103 of the IRP and it is unclear whether they are directly modeled in Plexos, Staff does not have a clear picture of need at this time.[45]

To understand the need for projects outlined in the IRP, particularly the smaller projects in the "Planned Transmission System Improvements" section on pages 100-103, Staff requested load studies that would justify buildout of the local projects. The Company has yet to produce any. Staff also asked for load studies on the Transmission Projects Included in the 2021 IRP Preferred Portfolio listed in Table 9.16, but the Company indicated that because those were proxy resources, there were no associated load studies.[46]

It is unacceptable that the Company has failed to provide a clear outline of these projects, their costs, or the extent to which they are justified by Plexos modeling.

[45] See PacifiCorp response to Staff IR 53.

[46] See PacifiCorp response to Staff IR 48. The projects associated with Gateway South did include some interconnection studies.

Staff Request/Recommendation 10 & 11

Staff requests PacifiCorp respond in Reply Comments regarding whether each of the Local Reinforcements from Action Item 3d and the "Planned Transmission System Improvements" on pages 100-103, including their respective costs, are modeled and considered in selection decisions made by Plexos.

PacifiCorp should provide a clear outline of Action Plan transmission investment costs by project in its Reply Comments, and a justification for the Local Reinforcement Projects in Action Item 3d.

Energy Gateway South

In Docket No. UM 2059, the cost of Gateway South is estimated to be roughly $1.9 billion. However, this number is never explicitly stated in the IRP, and when Staff asked about the total cost of the project, PacifiCorp's estimate was **[Begin Confidential]** [redacted] **[End Confidential]**, which includes a 20 percent discount expected to be paid by OATT transmission customers. Staff assumes that this cost estimate includes the $1.4 billion cost offset that PacifiCorp says is triggered by a 500 MW Transmission Service Request (TSR) across Gateway South. [47] It is unclear whether PacifiCorp has included the cost of Segment D.1, Windstar to Aeolus, as part of the cost of Gateway South in the IRP. Staff could not identify Segment D.1, or reference to it, as one of the transmission projects modeled individually in Plexos and assumes it is being included as part of Gateway South.[48] Staff notes that Segment D.1 was never an Action Item in PacifiCorp's 2019 IRP, nor is it an Action Item in the 2021 IRP.

Staff Request/Recommendation 12 & 13

In its response comments, PacifiCorp should explain how Segment D.1 and its costs are considered by the Plexos model in the 2021 IRP, and whether they are included as part of the cost of Gateway South.

The Company should also provide an explicit delineation of build costs of each of the transmission projects in the Action Plan, with and without any offsets, and narrative of why those offsets were included.

Staff continues to have doubts about the justification for the $1.4 billion 230 kV line that PacifiCorp claims is required by the TSR to accommodate 500 MW of firm Point-to-Point (PTP) transmission service. Staff reviewed the TSR System Impact Study (SIS), where Gateway South was assumed to already be in service when the study was complete. The study does not mention how PacifiCorp derived the need for a 230 kV upgrade and associated cost as it is not recommended nor mentioned in the SIS. The SIS study concluded that:

[47] See PacifiCorp IRP, page 278 and PacifiCorp's presentation in UM 2059 on August 5, 2021.
[48] See PacifiCorp IR to Staff Request 36.

> The requested transmission service can be accommodated provided that the following upgrades/improvements are completed:
>
> - Aeolus to Clover 500 kV line (Energy Gateway South) and the ancillary network improvements as identified in Section 4.0;
>
> All of the network improvements required to grant service are planned, rather than triggered by the requested service, and therefore no additional study is required.[49]

It is unclear whether additional studies justifying the 230 kV line, and its cost, were ever completed by PacifiCorp**.**

__Staff Request/Recommendation 14__

If a study justifying the 230 kV line said to be needed to connect Eastern Wyoming to Clover exists, PacifiCorp should produce it as part of its Response Comments or explain how the cost and engineering necessity was derived and explain when it was derived.

Further, Staff identified a concerning detail in PacifiCorp's TSR queue. On April 22, 2021, two full years after it requested the 500 MW PTP request on PacifiCorp's system, the original transmission customer made a redirect request for 390 MW of firm PTP to another point of delivery (POD). PacifiCorp indicated that many upgrades would be required to deliver such a service, though it is unknown whether this transmission customer will continue to pursue this service. This particular study indicates that the service will also be using Gateway South, but it is of concern to Staff that the same customer PacifiCorp is relying on to justify a $1.4 billion offset, and subsequent economics of the Gateway South, has submitted a TSR to redirect 390 MW of the approved 500 MW long-term firm request to go to a different POD.[50]

In the 2019 IRP, it appeared that PacifiCorp was leveraging the urgency of expiring production tax credits to justify Gateway South as least-cost, least-risk solution. The fact that the Company did not reveal a $1.4 billion offset until August 5, 2021, public meeting is concerning from Staff's perspective as it represents a lack of transparency into major assumptions made to justify the Gateway South transmission line.

PacifiCorp has made it abundantly clear, as per its interpretation of the OATT, that there are certain projects it has an "obligation" to build. The Company is relying on this 500 MW TSR to effectively impose a "discount" on the Gateway South project, but as noted above, there is uncertainty as to the seriousness of the transmission service requestor. Staff continues to have questions about whether applying a cost offset to the Gateway South line is reasonable. Staff looks forward to further conversation on this topic with stakeholders, PacifiCorp, and Commissioners.

[49] See PacifiCorp Transmission Service Request System Impact Study Report, Q2594.

[50] See TSR Q2936. http://www.oatioasis.com/PPW/PPWdocs/TSRQ2936SIS.pdf.

Substantially Complete Action Items are Inappropriate for an Action Plan

It is unclear whether PacifiCorp's requested Action Items are substantially complete or will be substantially complete by the time the Commission makes a decision on acknowledgement in this IRP. In the future, the Company should not use the Action Plan as an update to previous Action Items, or request acknowledgment for projects that are substantially complete.[51]

1.1.4 Load Forecast Methodology

Load forecasting is an elemental component of PAC's load and resource balance. Staff reviewed the Company's load forecasting methodology, as well as the Covid-19, electric vehicle (EV), and climate change modeling adjustments. Overall Staff is comfortable with the Company's load forecasting methodology, but it has some concerns with the adjustments. What follows is the overview of the load forecasting methodology and Staff's concerns about the adjustments.

Summary of PacifiCorp's Load Forecasting Methodology and Results

Oregon Load Forecast

PAC is forecasting growing energy and peak capacity needs in Oregon, due primarily to continued, if slowed, population and economic growth. While Oregon's population growth rate declined slightly from the 2018 forecast to the 2019 forecast, Oregon's population continues to grow. The employment forecast also dampened slightly but remains positive.[52] The Company uses these growth trends in conjunction with past load data and forecasts of use-per-customer to determine forecasted peak load (MW) and sales (MWh).

Residential Sales Forecast

Residential sales (MWh) are forecast using a use-per-customer forecast multiplied by the forecasted number of customers. The Company uses a statistically adjusted end-use (SAE) model to forecast sales per customer for the residential class. ITRON, a third party that provides SAE software and services, provides data that accounts for past and future appliance efficiency standards, along with the life cycles for each appliance.

Non-Residential Sales Forecast

Commercial, irrigation and street lighting, and industrial monthly sales are forecast directly from historical sales volumes, and not as a product of use per customer and number of customers. The major economic drivers of commercial forecasts are non-manufacturing employment and non-farm employment, along with weather-related variables. The forecasts for large industrial customers rely on information provided by the customers to the Company through a regional business manager.

[51] Order No. 14-252.
[52] PacifiCorp's 2021 Integrated Resource Plan. Appendix A. Page 6.

Oregon's Coincident Peak Load Forecast
Table A.2 states that Oregon's 2024 forecasted coincident peak load at generation, pre-DSM is 2,480 MW (growing at a 0.63 percent compound annual rate from 2021 to 2030). This is a three percent decrease as compared to the 2,555 MW in PAC's previous IRP (LC 70).

Potential Load Forecast Issue
A potential issue in the Company's peak load forecasting approach is the use of forecasted base load as an explanatory variable, because this creates a forecast within a forecast. The Company explains, "the forecast base load index uses forecasted class load converted to average MW."[53] Staff is concerned that if the actual forecasted class load exceeds or falls short of its forecast, then the peak load forecast could amplify forecasting error.

Staff Analysis of Load Forecast Adjustments

Covid-19 Adjustments
In this IRP the Company incorporated anticipated COVID-19 impacts on their electricity demand forecasts. These anticipated effects included stay-at-home impacts, long to medium term economic impacts, and potential commodity price impacts. Stay-at-home period impacts are based on observed changes to class level loads over the March through April 2020 timeframe. Longer-term economic impacts are based on IHS Markit economic driver data released March 2020.

The Company describes that COVID-19 impacts adjustments are made outside of the load forecasting models.[54] Staff understands that some factors such as the percentage of workers working from home can be difficult to include as variables in the model. However, the Company making adjustments outside of the load forecast is also problematic. As one possible example, an out-of-model adjustment might double-count anticipated impacts of working from home if any of the explanatory variables in the load forecasting model are also impacted by COVID-19.

Electrification Adjustments
The load forecast includes the expected impacts from transportation electrification based on current and projected electric-vehicle adoption trends. On Appendix A, page 15, PAC states that the EV forecast is "incorporated in the load forecast as a post-model adjustment to the residential and commercial sales forecasts." Staff has a long history of opposing post-model adjustments. Although Portland General Electric in Docket LC 73 and Idaho Power Company in Docket LC 74 both also modeled EV load separately from the energy use forecasts by customer class, Staff highlights the potential for double-counting when EV load is added to existing customer usage loads. One possible source of double-counting is if any of the explanatory variables in the use-per-customer forecast already included increased EV load. To partially alleviate Staff's concern, the Company states, "electric vehicle (EV) load is not included in the

[53] PacifiCorp's Response to Staff Information Request 60.
[54] PacifiCorp's response to Staff Information Request 57.

Statistically Adjusted End-Use (SAE) model variables."[55] Staff will continue to investigate whether it makes more sense for the Company to instead include an EV variable within the use-per-customer load forecast and will make a recommendation in Final Comments if needed.

Staff also notes that PAC is forecasting rapid EV load growth.[56] Because PAC's out of model adjustment makes meaningful changes to PAC's forecasted load, Staff will further investigate PAC's EV forecast.

Weather and Climate Change
In the 2021 IRP, the Company defines 'normal' weather by the 20-year time period from 2000-2019. The 2021 IRP considered the possibility of using the average weather from a shorter time period, such as 5 years, as 'normal' weather for load forecasting purposes. To inform this possibility, Figure A.10 was provided, showing peak weather from 20-, 10-, and 5-year averages.

Reproduction of Figure A.10

Figure A.10 – Comparison of Utah 5, 10, and 20-Year Average Peak Producing Temperatures

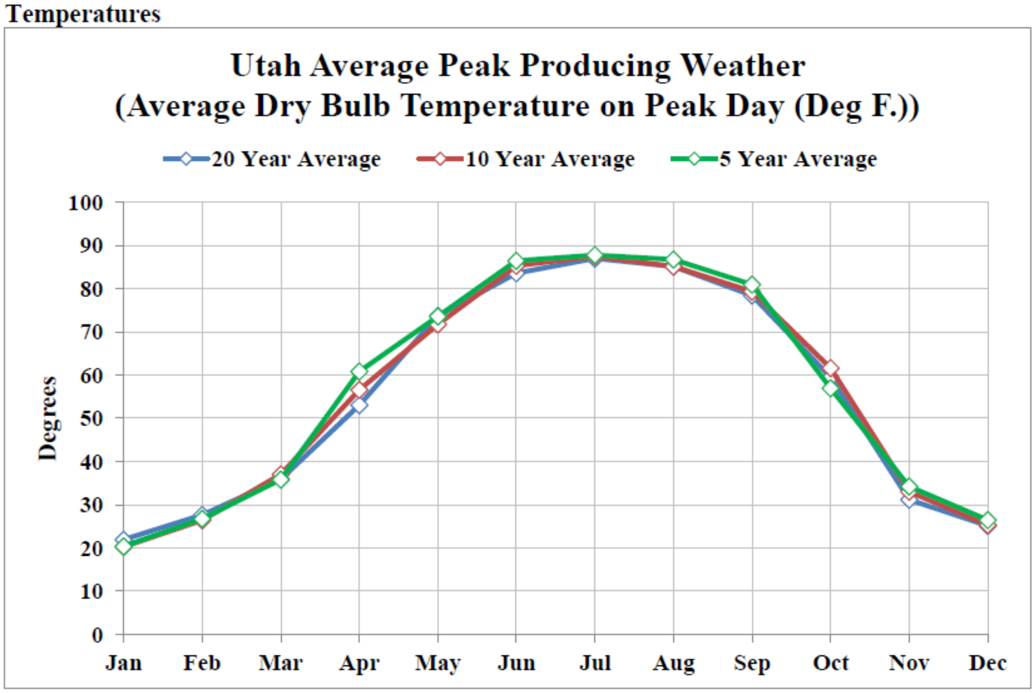


Figure A.10 shows that 5-year average temperatures are slightly higher than 10-year averages, which tend to be slightly higher than 20-year averages. This is indicative of a warming trend. Staff appreciates PacifiCorp consideration of this matter, and accepts that moving to a 5- or 10-year average for the base case load forecast does not seem likely to have a significant impact in this IRP. However, Staff would appreciate continued consideration of whether 5- or 10-year averages will be necessary to inform an accurate load forecast in future IRPs.

[55] PacifiCorp's response to Staff Information Request 62.
[56] PacifiCorp's response to Staff Information Request 63.

The Company also considered alternative scenarios that could impact its load forecast based on changes in the weather extremes. The Company includes a climate change scenario, relying on projected temperature increases over the 1990 average temperatures as determined by the United States Bureau of Reclamation in the West-Wide Climate Risk Assessments: Hydroclimate Projections Study. Table A.15 contains the Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s for selected sites within Company's service territory. These temperatures were used to model the projected temperatures in the climate change scenario for the 2021 IRP.

Reproduction of Table A.15

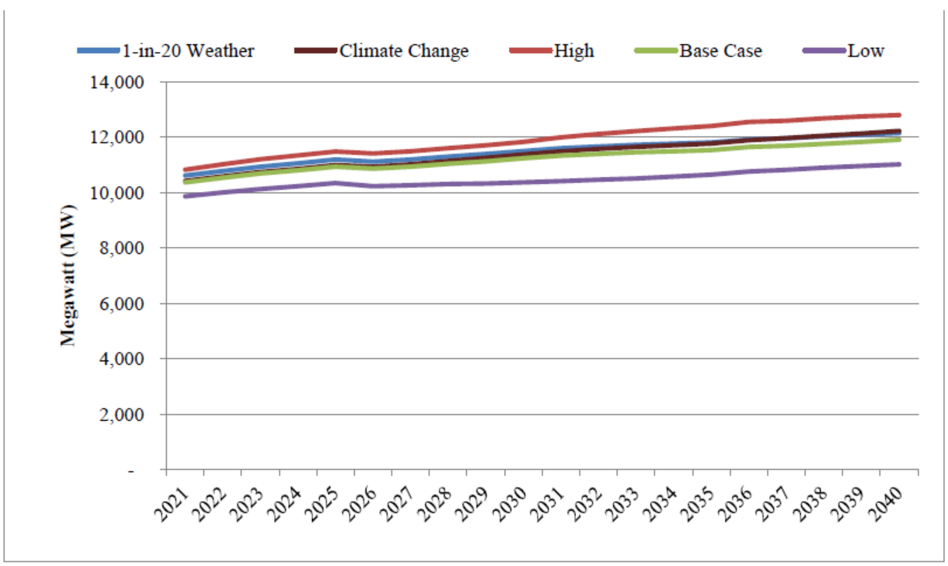
Table A.15 – Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s[4]

Bureau of Reclamation Site	PacifiCorp Jurisdiction Assumption	Projected Range of Temperature Change (°F)	
		2020s	2050s
Klamath River near Klamath	California	1.4 to 2.4	2.6 to 4.4
Snake River Near Heise	Idaho	1.6 to 3.1	3.1 to 5.6
Klamath River near Seiad Valley	Oregon	1.4 to 2.5	2.7 to 4.5
Green River near Greendale	Utah	1.7 to 3.1	3.1 to 5.7
Yakima River at Parker	Washington	1.5 to 2.6	2.7 to 5.0
Green River near Greendale	Wyoming	1.7 to 3.1	3.1 to 5.7

Figure A.11 shows the Company's Load Forecast Scenarios for the 1-in-20 Weather scenario, Climate Change scenario, and the High, Low, and Base Cases, pre-DSM.

Reproduction of Figure A.11

Figure A.11 – Load Forecast Scenarios for 1-in-20 Weather, Climate Change, High, Base Case and Low, pre-DSM



Staff appreciates the climate change scenarios considered in the 2021 IRP and finds the analysis to be somewhat useful for considering how many additional MW of capacity may be needed to reliably serve load under a variety of future climate scenarios. However, the 2021 IRP does not show what resource portfolio would be needed to meet the climate change load forecast using reference planning assumptions. The climate change scenario in the 2021 IRP utilizes the Social Cost of Carbon instead of MM reference case assumptions, and as such it cannot isolate the effects of the climate change load forecast. In future IRPs, it may be informative to include a climate change scenario that uses reference case (MM) IRP assumptions to demonstrate the resource decisions the Company would make if it incorporated climate change forecasts into its reference case planning.

Staff concerns:
In summary, Staff has raised concerns and will further investigate:

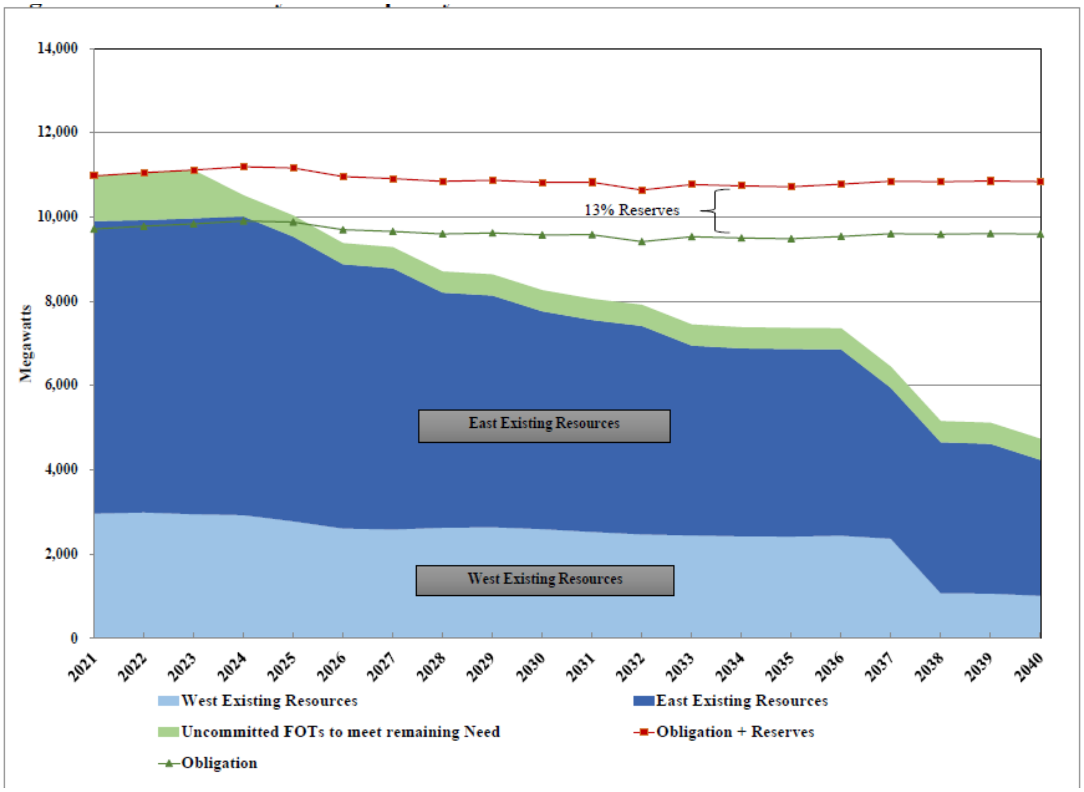
1. Potential alternatives to the Company's COVID-19 impacts modeling,
2. The Company's use of separate forecasts for electric vehicle load, and
3. The potential for a climate change scenario using reference planning assumptions.

1.1.5 Load Resource Balance & Capacity Analysis:

Summary of Load Resource Balance

The load and resource balance study in Chapter 6 shows that, without the addition of new resources, the company predicts a summer peak capacity deficit by 2024 and a winter peak capacity deficit by 2025/2026 (1 MW in 2025).

Figure 6.4 from the 2021 IRP is shown here for reference:



Staff highlights that available front office transactions are forecasted to decrease sharply in 2024, the same year as PAC's first capacity need.

2019 IRP Load Resource Balance Follow-Up

In the 2019 IRP, Staff raised a number of concerns regarding the load resource balance, and in Order No. 20-186, the Commission provided direction to PAC regarding the use of Front Office Transactions (FOT), renewable capacity contribution calculation, and the handling of QF forecasting.

Front Office Transactions:

Compared to the 2019 IRP, the availability of FOTs is assumed to be substantially lower in the 2021 IRP. PacifiCorp provided justification for this assumption in the 2021 IRP Public Input Meeting in October, 2020.[57] Market liquidity appears to be decreasing in recent years, and PacifiCorp's IRP assumes reduced market availability in response to this trend.

Below is a reproduction of PAC table 7.11:

[57] PacifiCorp October, 2020 Public Input Meeting presentation. Pages 36-43.

Table 7.11 - Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type Available over Study Period	Megawatt Limit and Availability (MW)	
	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	350	350
Heavy Load Hour ("6X16")	150	0
California Oregon Border (COB)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	0	250
Nevada Oregon Border (NOB) Heavy Load Hour ("6X16")	0	100
Mona Heavy Load Hour ("6X16")	0	300

This assumption is significant because it reduces the quantity of market purchases the Company will rely on for capacity before planning to acquire a new resource. As an initial test of the reasonableness of PAC's assumption, Staff compared PacifiCorp's assumed market availability to the values produced by PGE's third-party IRP study consultant E3. In 2018, E3 found that in some scenarios there was "no [summer] market surplus capacity" beginning in the near term.[58] This finding appears to support PacifiCorp's assumption of decreasing market purchase availability. Staff will continue to look into the issue of decreased available front office transactions, keeping in mind the activities of the NWPP RA program.

In the 2019 IRP, Order 20-186 directed Staff to work with PAC and the Independent Evaluator (IE) in their All Source RFP (UM 2059) to "come to an understanding of PacifiCorp's capacity needs, the economics of its energy position, and the advantages and disadvantages of greater reliance on FOTs" to inform how the Commission considers the size of PacifiCorp's procurement.[59]

In the 2020 RFP, Staff and the IE considered PacifiCorp's energy position and capacity needs. Given that the concurrent 2021 IRP Public Input Process was showing credible evidence for doubting the availability of the 1,475 MW of market capacity assumed in the 2019 IRP, Staff did not challenge the Company's plans to acquire capacity in the RFP. Instead, Staff's analysis focused on ensuring that the RFP was not over-procuring energy resources based on a market price forecast that increased substantially over time.

<u>Capacity Contribution of Renewables:</u>

Order 20-186 directed PAC to "provide a workshop or presentation on how it calculates the capacity contribution of renewables (including solar and wind co-located with battery storage)

[58] E3, "Long-Term Assessment of Load-Resource Balance in the Pacific Northwest," Prepared for PGE 2019 IRP, Docket No. LC 73, slide 41, October 31, 2018, available at: https://assets.ctfassets.net/416ywc1laqmd/6B9ovB3AoDkzSAiGWzbXLF/32a85b77420b5d95aa4f6a15ab8f037c/e3-market-capacity-study-rt-18-5-2018-10-28.pdf.

[59] Order No. 20-186. Pages 12-13.

for its 2019 and 2021 IRPs." The Company's Appendix B stated that this workshop took place on January 29, 2021. However, Staff would like to clarify that the January 29 meeting contained only brief mentions of capacity contribution. A more substantive conversation on capacity contribution of renewables was provided in the July 30-31, 2020, Public Input Meeting. This meeting met the expectations that Staff had for this workshop by providing valuable information on the ways the Plexos model is able to select renewable resources based on their operational characteristics and their contributions to reliability, instead of relying on a simplified 'capacity contribution' modeling input.[60]

Although Plexos does not rely on a capacity contribution estimate to determine optimal portfolios, capacity contribution continues to be important to understanding the Company's Load Resource Balance and is an informative metric that helps increase understanding of the Plexos model's resource decisions for stakeholders in the IRP and potential RFP bidders. The Company provided Appendix K to the 2021 IRP filing, which describes the Company's use of NREL's CF Method for its capacity contribution calculation. Appendix K includes reports of the capacity contribution for wind, solar, and solar plus storage, but it does not include wind with co-located storage. However, there does not appear to be a substantial amount of wind plus storage selected in the 2021 IRP preferred portfolio. In the future, to the extent that any wind plus storage resources are selected in the preferred portfolio, Staff would expect to see capacity contributions for wind plus storage published in Appendix K.

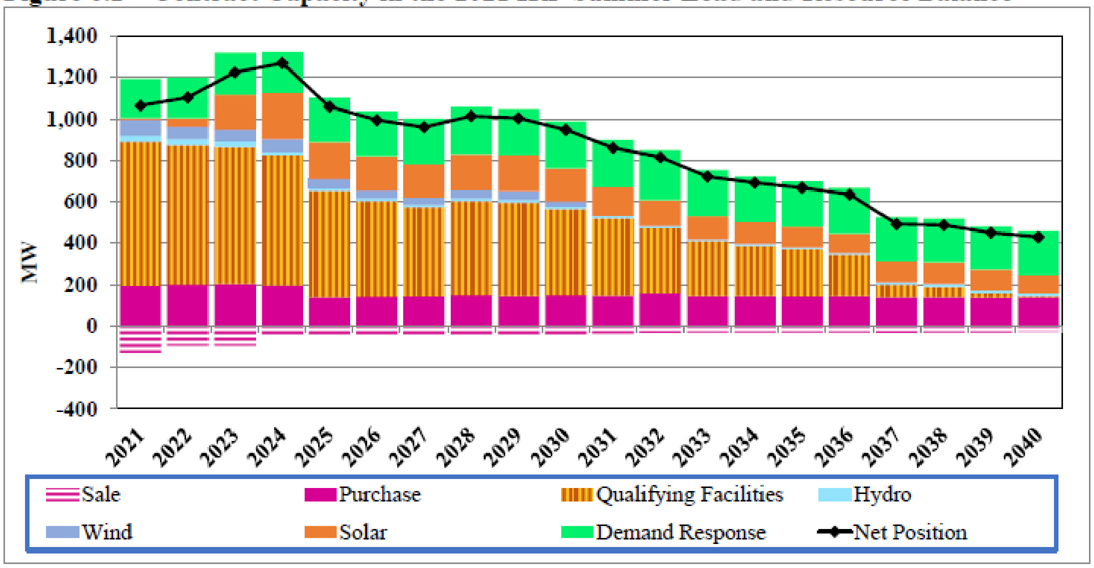
QF Forecasting / Contract Renewals:
In the 2019 IRP, Staff recommended that PacifiCorp use a QF renewal rate in the IRP that reflects the historical QF renewal rate on PacifiCorp's system.[61] PacifiCorp responded that because the Company cannot rely on QF renewals, QF renewals should not be assumed in long term planning, and argued that assuming QF renewals in the Action Plan might not include the right amount of capacity acquisition.[62] Order No. 20-186 directed PacifiCorp to "produce a sensitivity or other explanation of the impact of renewing QFs on its load resource balance" and to include this in its 2021 IRP.[63]

Unfortunately, it is not clear to Staff how the Company has "explained the impact of renewing QFs on its load resource balance" in the 2021 IRP. It appears that the QF contract renewal assumptions are unchanged from the 2019 IRP and no study has been done to show the potential effects that QF renewals might have on capacity. While the IRP states that the impact of QF renewal assumptions is explained in Chapter 6, Staff is unable to locate any analysis of QF renewal assumptions in that chapter.[64]

[60] PacifiCorp's July 30-31 Public Input Meeting Presentation.
[61] Docket No. LC 70. Staff Report. Pages 27-30.
[62] PacifiCorp's Final Comments. Docket No. LC 70. Pages 43-44.
[63] Order No. 20-186. Page 13.
[64] PacifiCorp 2021 Integrated Resource Plan. Appendix B. Page 36.

Below is a reproduction of PAC Figure 6.2 which shows QF contract capacity falling with contract expirations:

Figure 6.2 – Contract Capacity in the 2021 IRP Summer Load and Resource Balance



This topic has also been discussed in the Idaho Power 2019 IRP (LC 74), and the Commission directed Idaho Power to include a reasonable forecast of QF renewals in a sensitivity in its next IRP, and to report on how use of that QF renewal assumption would impact the preferred portfolio. The Order said that "some reasonable assumptions must be made" even though there is considerable uncertainty.[65]

Staff Request/Recommendation 15
Staff recommends that PacifiCorp also begin to include a non-zero rate of QF renewals in its long-term forecast, or as a sensitivity. To address near-term reliability concerns, a zero-renewal rate could be used in the near-term Action Plan timeframe, while a reasonable renewal rate could be assumed thereafter.

1.1.6 Resource Adequacy (RA)

Staff is encouraged to see consideration of risks, reliability, and RA in Chapters 5 and 8 of the IRP. Staff finds that some of the risk considerations in Chapter 5 could be more beneficial if applied to the IRP modeling. For example, Staff is not clear whether the Plexos modeling includes stochastic risk assessment before the final stage of the modeling, where high risk scenarios are identified and used to calculate risk-adjusted nPVRR.

Staff is looking further into the consideration of risk in the Plexos portfolio modeling. Further study of risk, including climate risk, and resource adequacy can be built on the foundation of the 2021 IRP. For example, extreme weather events could be reflected in market liquidity

[65] Order No. 21-184. Page 19.

modeling assumptions as well as market prices. Wildfires could reduce solar generation, high temperatures could reduce gas-fired generation, and drought could reduce hydro generation simultaneously. Staff hopes that the excellent information provided in Chapter 5 can begin to be considered in a risk assessment analysis moving forward in future IRPs or Clean Energy Plans.

1.1.7 DSM, Conservation, and Demand Response

Demand Response

Staff is pleased to see a significant increase in DR resource acquisition in the 2021 IRP action plan relative to the 2019 IRP. In compliance with Order No. 20-186 in LC 70, PacifiCorp conducted an RFP for new DR resources in Q1 2021. The RFP resulted in numerous cost-effective bids for turnkey delivery of new DR programs. Three of the new DR programs will be available to Oregon customers beginning in 2022. Staff commends PacifiCorp for engaging stakeholders in the development of a successful RFP and for including equity metrics in the bid scoring criteria. Staff believes that continuing such stakeholder engagement throughout program delivery, particularly in the early years, will help the Company maximize the effectiveness and equity of the programs. Therefore, Staff makes the following recommendations related to PacifiCorp's DR acquisition in Oregon:

1. Conduct annual third-party evaluations of the Oregon DR programs after each of the first two years of delivery.
2. Convene at least one stakeholder workshop annually from 2022 through 2025 to share and receive input on:
    1. DR program outreach and delivery activities;
    2. DR program performance and evaluation results;
    3. PacifiCorp's plans to acquire additional DR to meet the DR capacity goals in the IRP; and
    4. PacifiCorp's plans to acquire and integrate DR resources to meet system needs identified in the Company's distribution system planning.
3. Expand the Company's Utah residential battery DR program to Oregon customers.
4. Present to Staff any changes to the DR cost-effectiveness methodology that PacifiCorp recommends.

Efficiency Demand Side Management (DSM)

Measure bundles

The Company creates bins or "bundles" of demand-side resource measures to simplify resource comparisons. As there are hundreds of energy efficiency saving measures, comparing each measure would be computationally restrictive. Measures have typically been bundled based on levelized cost of energy provided.

As memorialized in Order No 20-186, when acknowledging the Company's 2019 IRP, the Commission adopted Staff's recommendation to direct the Company to work with stakeholders to select two to four bundling strategies to choose the method that will identify the highest level of cost-effective energy efficiency for the system and for each state. The Commission also directed the Company to file progress and results prior to the next IRP.[66] Staff made this recommendation because energy efficiency saving measure bundles were not optimized for capacity contributions while being compared to other resources based on capacity contributions. This resulted in under-valuing measures that had higher capacity contributions, which led to under-selecting these measures compared to other resources. Staff also expressed concerns about selections in Oregon specifically compared to the system.

Prior to the 2021 IRP, the Company presented conceptually different approaches to bundling and discussed the challenges related to comparing energy efficiency with other resources. At the Company's October 22, 2020, Public Input Meeting, the Company provided a thoughtful presentation on different factors to consider when bundling resources, considering levelized cost, energy value, capacity contribution, net cost of capacity, and winter capacity. At the end of the presentation, the Company indicated it will study two - four bundle strategies and return with results.[67] The Company revisited this topic at the January 29, 2021 Public Input Meeting, providing different comparisons between variables for an example set of measures and then presented a bundling strategy that separated measures based on net annual costs and net winter costs. This new bundling approach identified a set of measures that provided a similar energy value but at 31 percent less cost.[68]

Based on the findings in the January 29, 2021, presentation, Staff believes that the new approach is a significant improvement on the prior bundling strategy. Staff is satisfied with the result of this analysis in terms of system selections. While the Company only presented the results of one alternate bundling strategy rather than two - four as initially requested, the outcome of the alternate presented are promising. Staff is also interested in understanding how this new methodology affects resource selection at the state level.

Energy Efficiency Resource Selection

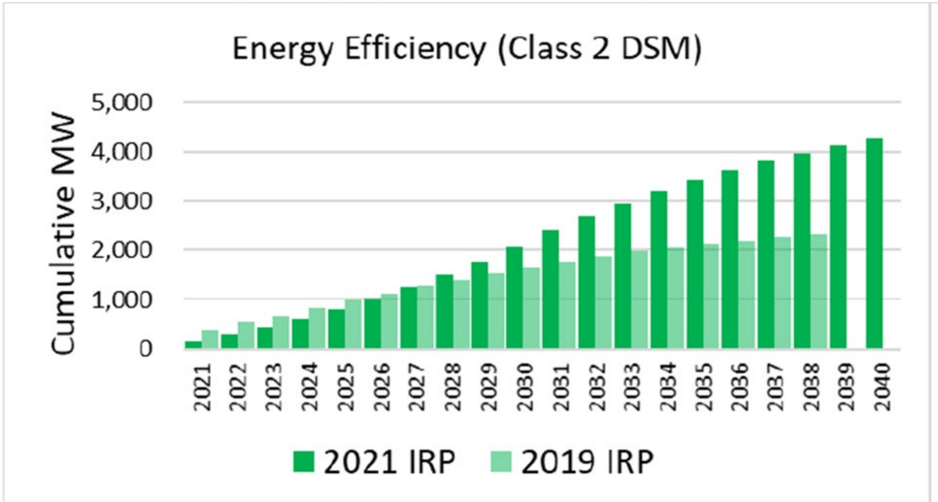
The Company's preferred portfolio includes 4,290 MW of energy efficiency over the planning period, which is significantly more energy efficiency than the previous IRP, particularly in the later years.

[66] Order No. 20-186 p. 23.

[67] PacifiCorp Integrated Resource Plan 2021 IRP Public Input Meeting, October 22, 2020, p. 35 found at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorp_2021_IRP_PIM_October_22_2020.pdf.

[68] PacifiCorp Integrated Resource Plan 2021 IRP Public Input Meeting, January 29, 2021, p. 26 found at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorp%202021%20IRP_PIM_January%2029%202021.pdf.

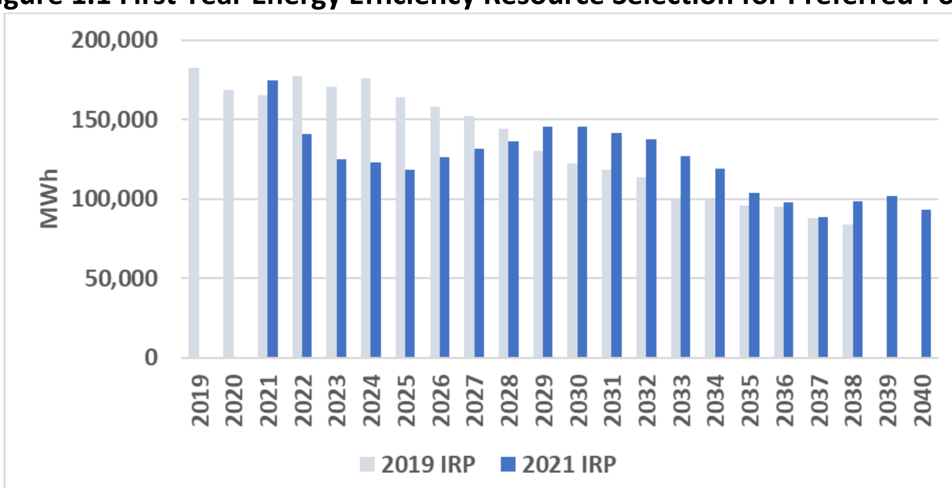
Reproduction of 2021 IRP Figure 9.37:



69

Staff compared the energy efficiency selection between IRPs for Oregon specifically, looking at the energy from the first year selected. Staff found that while the system selection of energy efficiency is higher, the selections for Oregon are lower in the current IRP, particularly in the earlier years.

Figure 1.1 First Year Energy Efficiency Resource Selection for Preferred Portfolio



70,71

Staff is concerned about the reduction in energy efficiency selected for Oregon when compared to the increased system needs. Staff is also concerned about the near-term reduction in selections in the 2022-2028 time period. This reduced investment in energy efficiency is not consistent with how Energy Trust forecasts increasing availability of cost-effective energy

[69] PacifiCorp's 2021 Integrated Resource Plan. Page 297.

[70] PacifiCorp's 2021 Integrated Resource Plan. Appendix D, Page 110.

[71] PacifiCorp's 2019 Integrated Resource Plan. Appendix D, Page 72.

efficiency. Energy Trust expects cost-effective energy efficiency acquisitions to increase in 2022 and 2023.[72] This suggests that the model is not selecting all cost-effective energy efficiency and these selections should be modified to reflect near-term program activities in Oregon.

Additionally, it is also inconsistent with the importance of reducing loads in advance of HB 2021's clean energy goal of reducing carbon emissions by 80 percent by 2030.

In Reply Comments, Staff requests that the Company provide an explanation of how these results will inform energy efficiency acquisition in Oregon. Staff is particularly interested in any modifications the Company intends to make to be consistent with available cost-effective energy efficiency in Oregon.

Finally, Staff will continue to look into the following DSM topics and encourage any comments from the Company or stakeholders:

- Should/has PacifiCorp considered a peak-time rebate program?
- Is the IRP valuing demand response resources for their potential to reduce the amount of reserves needed on the system?
- How will PAC scale DSM? Is the Company prepared to acquire the amounts of DSM forecast in the IRP, especially in states other than Oregon, where PacifiCorp is in charge of acquiring efficiency resources.

1.2 Requested sensitivities

The analysis in PacifiCorp's IRP in many ways is rigorous and helpful, demonstrating outcomes in a variety of potential future scenarios. However, there are a few scenarios that were not included as sensitivities in the 2021 IRP that Staff believes are important for consideration.

Staff notes that these sensitivities could potentially have been requested before the filing of the IRP, and considered in the IRP preferred portfolio selection, if a full draft IRP had been shared in advance of the IRP filing for review and comment. For reference, the IRP Guidelines state that, "The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission."[73]

<u>Staff Request/Recommendation 16</u>
Staff requests PacifiCorp respond in reply comments whether it will commit to provide a full draft IRP for review and comment at least four weeks in advance of its IRP filing in the next IRP cycle.

[72] Staff Report, Presentation of 2022 Draft Budget and 2022-23 Action Plan, November 10, 2021, p.8 found at https://oregonpuc.granicus.com/MetaViewer.php?view_id=2&clip_id=856&meta_id=31180.
[73] Order No. 07-002.

1.2.1 Low Market Price Sensitivity

Market prices forecast in the 2021 IRP are somewhat lower than those from the 2019 IRP, increasing to about $80/MWh over 20 years as compared to $90/MWh in the 2019 IRP. However, Staff finds that there is still a significant risk that market prices will turn out to be lower than forecast, with implications for the cost-effectiveness of the preferred portfolio. Before acknowledgement, Staff would like a study of whether the preferred portfolio would change substantially in composition or cost if market prices turned out to be approximately flat (not increasing or decreasing) in real dollars.

Staff Request/Recommendation 17

Staff recommends that PacifiCorp perform a study before the second Commission workshop scheduled for February 24, 2022, that evaluates two questions regarding a future with low market prices:

- **What resources would be selected in a scenario with reference planning assumptions where market prices were approximately flat throughout the planning timeframe in real dollars (after adjusting for inflation), and**
- **What would happen to the value of the preferred portfolio in a future with flat market prices in real dollars?**

1.2.2 Coal Retirement Sensitivity

Staff appreciates PacifiCorp's responsiveness to concerns about coal economics and extensive work studying coal plant retirements. The 2021 IRP has provided a study that looks at economic retirements of individual coal units and utilizes endogenous selection in Plexos to inform coal retirement dates.

Staff has identified a few areas where the current framework is either using assumptions that are questionable and risk reducing the benefits to customers, or where a more granular look could potentially identify additional benefits through a more optimal retirement schedule. Staff sees benefit in PacifiCorp running an additional sensitivity in this IRP that attempts to more carefully optimize coal unit retirements. Any potential changes in optimal retirement dates will be important for the Company to consider as it continues to make business decisions, including in its 2022 AS RFP, between now and the next IRP Update or IRP.

Staff recommends an additional coal retirement study that:

1. Allows Bridger units 3 and 4 to retire in any year from 2025 through 2030,
2. Does not include a minimum take assumption at Bridger, aside from any existing minimum take provisions in existing contracts with third party coal suppliers.
3. Allows Naughton units 1 and 2 the option to retire in 2023, 2025, or 2026.
4. Allows Huntington 1 and 2 the option to retire in 2029/2030.
5. Also allows for endogenous retirement of all coal units at all other dates studied for endogenous retirement in the 2021 IRP.

Section 2: Moving Forward

2.1 HB 2021 Compatibility

HB 2021 transforms the Oregon electricity landscape by establishing a target of zero GHG emissions by 2040 for the state's two largest utilities. Among its many provisions it creates near-term GHG emission reduction targets in 2030 and 2035 and encourages utilities to meet the targets in a manner that provides direct benefits to communities such as resiliency, health, and economic benefits. The emission targets are in addition to the state's current renewable portfolio standard (RPS).

The PUC's approach to "least-cost / least-risk" planning and utility investments needs to achieve predetermined levels of emission reductions. PacifiCorp's HB 2021 baseline emissions and estimated Greenhouse Gas (GHG) targets are detailed in the table below:

Baseline Average of PAC Oregon Emissions, 2010-2012 *MTCO2e*	**HB 2021 Year & GHG Target, Based on Baseline Average** *MTCO2e*		
	2030 80% Reduction	**2035** 90% Reduction	**2040** 100% Reduction
8,990,103	1,798,021	899,010	0

To ensure the utilities make the investments necessary to meet HB 2021's ambitious targets, utilities must file Clean Energy Plans with future IRPs and report annually on emissions. However, the law does not require IRPs filed prior to January 1, 2022, to include a CEP. Competing considerations arise when trying to evaluate PAC's resource strategy in LC 77, including:

- The investment decisions flowing from this IRP and associated RFP will impact the Company's least-cost / least-risk HB 2021 compliance trajectory.
- The HB 2021 targets are aggressive and will likely require significant investment over a relatively short period of time, raising important cost and risk considerations.
- The analysis in LC 77 does not have to explicitly frame or analyze investments in terms of meeting HB 2021 GHG reduction targets.
- Near-term guidance on key technical and policy questions is required to develop a complete decarbonization strategy and CEP analysis, which is targeted for Q3 2022.[74]

Although PacifiCorp is not yet required to file a Clean Energy Plan, and the OPUC process for specifying and clarifying HB 2021 compliance requirements has not yet been completed, Staff

[74] See the Commission's HB 2021 implementation gantt chart on the 2021 Legislative Activities webpage, available at https://www.oregon.gov/puc/Pages/Legislative-Activities.aspx.

believes it is important to attempt to analyze how well the 2021 IRP strategy positions the Company to decarbonize its retail sales to Oregon customers in a least-cost / least-risk manner in less than 20 years.

The IRP is the main planning document to identify the portfolio of resources with the best combination of the expected costs and associated risks and uncertainties for the utility and its customers.[10] Actions taken by the utility in the next two to four years will be critical to setting PacifiCorp on the best path for compliance with HB 2021.

Beyond the immediate action plan time horizon, IRP Guideline 1(d) states that "[t]he plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies." To this end, Appendix O of the IRP includes a 25-page Clean Energy Action Plan for Washington State. The plan provides a Washington-specific view of how PacifiCorp plans for a clean and equitable energy future that complies with Washington's Clean Energy Transformation Act (CETA). As a result, PacifiCorp has some experience with the type of planning required to meet a state's stringent GHG reduction targets. Staff does not expect that PacifiCorp would have been able to provide a similar level of detail for Oregon given the recent enactment of HB 2021. However, PacifiCorp could have at least provided some preliminary analysis regarding HB 2021 compliance. This analysis could have addressed questions such as how close or far PacifiCorp is from achieving the emissions reduction targets in HB 2021.

As such, Staff finds it difficult to assess the extent to which the IRP is fully consistent with the long-run public interest due to the lack of discussion around HB 2021 compliance.

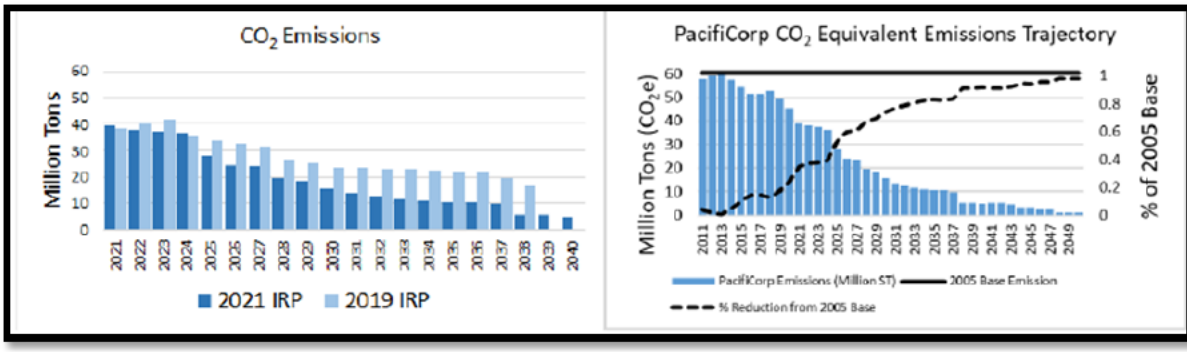
To remedy this, Staff will attempt to conduct the following in this IRP and associated RFP:

- Work with the Company and stakeholders to accurately capture the current and forecasted emissions associated with IRP and RFP.
- Assess if planned investments are least-cost / least-risk in terms of meeting load safely, reliably, and affordably **and** identify remaining gaps or risks in meeting the HB 2021 GHG targets.

2.1.1 Emissions Analysis & Questions

PacifiCorp's recent resource actions are reducing emissions, as shown in the 2021 IRP. [75]

[75] PacifiCorp's 2021 Integrated Resource Plan. Page 16.



However, it was not immediately clear in LC 77 if these reductions would meet the 2030, 2035, and 2040 emission targets of HB 2021. Staff conducted a preliminary assessment the GHG emissions associated with LC 77, focusing on 2030. Staff used two methods to estimate PacifiCorp's forecasted Oregon emissions related to retail sales:

- Oregon's MSP allocated percentage of total PacifiCorp system emissions in 2030 using the current Oregon allocation factor (26.2 percent)
- Oregon-assigned specific resources per the current understanding of MSP

Based on discovery responses, Staff determined that PacifiCorp would be poised to either meet HB 2021's GHG target in 2030 or be close. Here are the results:

Method of Analysis	**Forecasted 2030 GHG Emissions**	**Forecast Meets HB 2021's 2030 Target?**
26.2% OR-allocated Percentage of System Emissions	**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** [76]	No
Approximate, Expected Future MSP Allocation of Resources	1,109,000[77]	Yes

It is expected that Oregon's allocation of emissions will decline more rapidly than PacifiCorp's system emissions profile because of Oregon's exit from coal resources.[78] However, Oregon-allocated emissions are not yet forecast to completely reach HB 2021 goals.

<u>**Staff Request/Recommendation 18**</u>

Staff requests that PacifiCorp provide an explanation in Reply Comments of how the 2021 IRP preferred portfolio better positions Oregon to meet HB 2021 goals. This includes the need for Oregon-allocated emissions to reach HB 2021's targets for 2035 and 2040.

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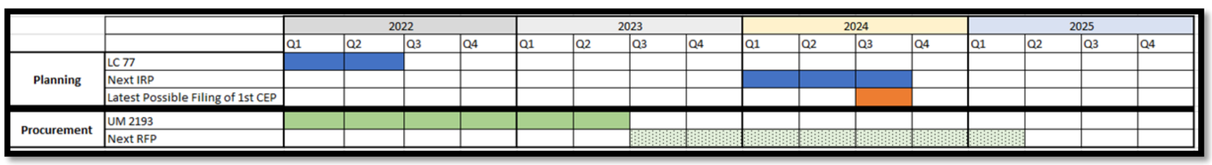
[76] PacifiCorp's Response to Staff Information Request 9.
[77] PacifiCorp's Response to Staff Information Request 15.
[78] Staff DR 010.

2.1.2 Planned Investments & Questions

PAC is planning to procure approximately 2,000 MW of new resources per the IRP Action Plan and documentation in UM 2193. As noted above the preferred portfolio does show emission reductions. What is unclear to Staff is if/how this IRP's action plan and the eventual UM 2193's final short-list (FSL) represents a reasonable least-cost / least-risk step toward meeting the HB 2021 targets. Recent studies have shown that dispatchable, non-emitting, resources – which can be more expensive than solar and wind on an LCOE basis – can sometimes be necessary to reach a 100 percent clean electricity system.

Additionally, given the Company's recent business practices, Staff believes it is reasonable to assume the Company will launch its next RFP prior to *or* near the conclusion of the current RFP in Docket No. UM 2193. If so, PacifiCorp is poised to effectively launch two RFPs after the passage of HB 2021 but also prior to PAC ever submitting a CEP. The timeline below seeks to illustrate this hypothetical scenario:



Despite the PUC's plan to develop near-term guidance for utilities to develop CEPs in 2023, PAC's historical procurement behavior highlights the potential of continued disconnection between planning and procurement activities. Staff questions how many large-scale procurements can be meaningfully considered without understanding the Company's long-term decarbonization needs. Staff is concerned about the balance PAC is striking between grabbing low hanging fruit and understanding how such large near-term procurements line up with the actions, gaps, and constraints to reach deep decarbonizing that will be explored in a full CEP in 2023 or later. A stakeholder IRP and CEP discussion with PacifiCorp on how to best model and develop an Action Plan to meet HB 2021's GHG targets would happen *after* one and potentially even two, large-scale RFPs have already been issued.

Staff Request/Recommendation 19

In reply comments, Staff would request the Company please:

- **Provide an approximate date (i.e., month and year) for issuing the Company's next IRP, the next RFP, and the first CEP?**
- **Describe the extent to which PacifiCorp's believes the next RFP, or any other resource procurements, should reflect an acknowledged IRP and CEP?**
- **Provide a summary of expected Oregon-allocated emissions, as compared to HB 2021 goals, and explain how any additional emissions reductions will be implemented, especially to get to zero emissions by 2040.**
- **Provide a summary of what additional analysis PacifiCorp could provide regarding HB 2021 compliance prior to an acknowledgement decision on the 2021 IRP.**

2.1.3 Other Things to Resolve in Reply Comments Related to HB 2021

The 2021 IRP considers a carbon price among the variables in portfolio analysis.[79] However, HB 2021 introduces the potential for IRPs to more explicitly account for carbon risk in planning.

Staff Request/Recommendation 20 & 21
In reply comments, we would also like PAC to share their thoughts on how Plexos could be reconfigured by the next IRP to build a portfolio designed to achieve the "least cost / least risk" portfolio that meets HB 2021 emission targets, including going out to 2040. Further, an understanding of how IRP models could also be utilized to explore the GHG emission risks under stochastic scenarios by applying the Societal Cost of CO2 found in Figure 8.4.

Finally, Staff would appreciate PacifiCorp's reply comments discussing the types of Commission guidance, analyses, and/or other procedural efficiencies that the Company foresees as required to facilitate their first CEP and help identify the right investments to hit near- and long- term HB 2021 targets?

2.2 2022 AS RFP

The 2021 IRP includes 1,345 MW of new proxy generation resources with 600 MW of co-located storage resources with COD by December 31, 2026. The 2022 AS RFP action item is for an RFP designed to acquire a similar resource group, as selected by Plexos after input updates and using actual RFP bids. Staff would like to share with stakeholders, Commissioners, and PacifiCorp a few perspectives and considerations on cost, risk, and procedural steps as the Company moves forward with its 2022 RFP.

2.2.1 Risk and Resource Acquisition

Power Purchase Agreements (PPA) Versus Utility Ownership

As a commentary on RFPs in general, and to help inform the 2022 AS RFP, Staff would like to offer comments on the issue of utility ownership versus PPAs. The Commission in Order No. 11-001, stated on page 5 of that order, "We too accept the premise that a bias exists in the utility resource procurement process that favors utility-owned resources over PPAs. This bias is really a logical inference drawn from an understanding of ratemaking practices and the effectiveness of incentives."

However, the Commission also concluded, on the same page 5 of Order No. 11-001, that the Commission is unable to quantify the bias and therefore declined to adopt any mechanism to address the bias.

[79] PacifiCorp's 2021 Integrated Resource Plan. Pages 226-227.

Staff agrees with PacifiCorp with the statements made on page 345 of its IRP including that ownership, and in this case majority ownership, provides greater ability to make life decisions such as to extend or shut-down "pre-maturely" a resource. With respect to controlling costs, depending on how a contract is written, a PPA may define how costs per MWh are determined and thus "control" costs better than resource ownership in that they have no variance from the contract specification. Staff does agree with PacifiCorp that majority ownership in resources provides greater control of costs than does a minority ownership share. Staff also notes that the PacifiCorp text on page 345 of the filing did not include the Commission's finding that bias exists because of regulatory mechanisms such as providing a return on rate base that comes with utility ownership.

The PacifiCorp text on that same page 345 also identifies some of the power purchase benefits such as avoiding uncertainty in closure costs. Also of benefit is that a PPA, as noted above, can cap costs depending on how the PPA is written. A PPA also has the benefit of protection against performance risk in that if the power plant operates at a lower level of output than expected, a per MWh PPA then would have the utility also paying less in relation to output. Performance risk can be left with the outside owner of the resource. Power purchase or fuel commitments, such as minimum takes, though can shift some risks from the owner to the purchaser. Therefore the terms of the PPA are critical. Lastly, Staff agrees with PacifiCorp that power purchase commitments could be viewed like debt by rating agencies.

When PacifiCorp notes the different and contrasting benefits of ownership and power purchase, a reasonable course of action would be to include both power supply options in an action plan. That is, in executing an action plan, the actions would be to own some of the planned resources and to enter into power purchase contracts for other resource needs. This creates a diversity of ownership and a spreading of and benefits risks. Staff will expect additional justification for any resource acquisition plan that does not contain a fair amount of both resource options.

Risk

In the 2020AS RFP, there was discussion of the unique risks of the final shortlist and its reliance on certain assumptions around market prices and PTC value. There was a limited conversation around potential risk sharing between customers and utilities in that docket.

Resources with limited dispatchability and low variable operating costs have a unique market price risk profile for utility customers. These resources are paid for mostly upfront, and there is little room to avoid variable costs throughout the rest of the resource's lifetime. In comparison, a resource with a higher portion of its costs as variable fuel or O&M costs can be managed appropriately for changing market conditions by reducing generation or through early retirement, creating a potential release valve for customers if market conditions do not allow the resource to create continuing value for customers as initially expected.

Sensitivities in the 2020AS RFP showed that the final shortlist resources did not rely on market sales to provide value to customers, and that they remain valuable even if market prices are low. These sensitivities indicated that the final shortlist projects will provide sufficient value to customers in a wide range of market conditions.

Staff has several recommendations on market price risk in resource acquisition moving forward. Market price risk can be managed in part through the use of sensitivities like those in the 2020AS RFP, which show that a resource acquisition is robust to a variety of market price futures. Market price sensitivities that include tests such as sustained low market prices and disallowing market sales provide reasonable assurance that resources are valuable under a variety of market price outcomes. Staff recommends that resources that are shown to be robust in reasonable market price sensitivities should not be subject to further risk sharing considerations.

The 2020AS RFP provides an excellent example of resources that were shown *not* to be robust to a variety of market price futures. Two potential Final Shortlist resources were eliminated from the original final shortlist based on their sharp reduction in value when the ability to make market sales was turned off in the model. These resources were no longer economic if they could not sell energy to the market, which was a sign of significant market price risk to customers. In the 2020AS RFP, PacifiCorp chose not to pursue these resources based on the results of the 'No Sales' sensitivity.

If, after conducting a set of reasonable market price sensitivities, a utility decides to proceed with resources like those from the 2020AS RFP that are shown to have substantial market price risk, the Commission has several options. 1) Choose not to acknowledge that resource in the RFP Final Shortlist, 2) Disallow recovery in a general rate case or AAC, and/or 3) if a resource appears to be reasonable except for its level of market price risk, the Commission may choose to acknowledge and allow the resource while seeking a remedy in power cost proceedings if the value of market sales attributable to the resource diverges significantly from that forecast at the time of resource procurement. The third risk sharing option is a relatively new consideration.

Resources that are not shown to provide value to ratepayers in reasonable market price sensitivities cannot be said to meet customer load in a way that best balances costs and risks. They belong in a separate category of resources that are not strictly required to meet customer load and have speculative value. However, the Commission may decide that the resource is reasonable if the market price risk to customers can be limited and shared with the Company.

A market risk sharing mechanism could be implemented for these higher risk resources by first identifying any such resources through a set of reasonable market price sensitivities. Then, the value of market sales and avoided market purchases attributable to these resources can be identified and documented in a resource procurement proceeding. Finally, in future power cost proceedings, the initially forecast market value for each of these resources can be summed up and compared to the market value collectively forecast from these resources in the year-ahead power cost proceeding. If the difference is greater than a certain percentage, the Company could refund the difference above a fixed percentage to customers. With such protections available, resource acquisition may be reasonable.

Tax Credit Risk

Renewable projects also include some risk associated with the expected value of tax credits. For example, if a wind project cannot meet the capacity factor expected during resource procurement, it may not provide as much value through Production Tax Credits (PTCs) as expected. Or, if a project fails to meet its COD, it may receive a lower value of PTC than expected or may not qualify for the PTC at all. Because the cost of these projects is largely upfront, customers could end up paying the entire cost, even if market conditions and PTC value do not pan out as expected.

Regarding the risk of not receiving the expected value from tax credits for new resources, a similar mechanism could be implemented whereby the tax credit value forecast in the initial resource procurement proceeding could be documented and compared to the value received from the resource in rate recovery proceedings.

Staff would like to continue the conversation about sharing the risk of these projects between utility companies and ratepayers. Staff understands that such a risk sharing mechanism is a new topic of discussion, and welcomes input from stakeholders, PacifiCorp, and Commissioners on the subject in reply comments and Commission workshops.

2.2.2 Scoring and Modeling

PacifiCorp includes a 2022 All-Source Request for Proposals (2022AS RFP) as an action item in its proposed Action Plan.[80] PacifiCorp also included the proposed scoring and modeling methodology for the 2022AS RFP as an Appendix to the IRP.[81] Staff would note that PacifiCorp is also currently pursuing the 2022AS RFP in a concurrent docket – Docket No. UM 2193. PacifiCorp submitted scoring and modeling methodology for the RFP in that docket as well. As a result, Staff is currently faced with the unique situation of PacifiCorp having submitted its scoring and modeling methodology for its 2022AS RFP in both its IRP docket and its RFP docket. This raises questions about in which docket(s) the scoring and modeling methodology should be addressed and to what extent. This has also led Staff to consider whether a change to the competitive bidding rules is needed to address this type of situation in the future.[82]

The competitive bidding rules require that a draft RFP utilize the RFP elements, scoring and any associated modeling described in a Commission-acknowledged IRP, and that the draft reference and adhere to the IRP section that describes the RFP design and scoring.[83] Or, prior to preparing a draft RFP, the utility must develop and file for approval an RFP proposal with scoring and any associated modeling in the IE selection docket.[84] But the rules don't address what happens when the IRP and RFP are filed concurrently.

[80] PacifiCorp's 2021 Integrated Resource Plan. Chapter 1 – Executive Summary. Page 26.
[81] PacifiCorp's 2021 Integrated Resource Plan. Appendix P – Draft Bid Evaluation and Selection Process for 2022 All Source Request for Proposals.
[82] See Staff's Memo dated October 11, 2021 in Docket No. UM 2193. Pages 42-44.
[83] OAR 860-089-0250(2).
[84] OAR 860-089-0250(2)(a).

Staff would also note that the Commission, during the Portland General Electric (PGE) 2019 IRP process, expressed interest in clarifying how it interprets OAR 860-089-0250. The Commission specifically noted its intent to explain what information about scoring and associated modeling is required in an IRP to avoid the extra step of a workshop on scoring and methodology in the IE selection docket.[85] Staff in the current PGE RFP docket (Docket No. UM 2166) has not been able to fully address this given the time constraints in that docket, but Staff has taken note of some of the issues that could potentially need clarification.[86] Staff also noted that given the scope of the issues that came up in that docket, as well as the issue raised by PacifiCorp's concurrent IRP and RFP filing, Staff anticipates that addressing the Commission's interest on the item may benefit from a specific conversation outside of this docket.

Staff working between these dockets have been in close communication regarding the issues that have surfaced as well as how to best address them. Staff plans to propose a strategy for moving the conversation forward in the near future in a forum that includes all electric utilities. The strategy could include either a discussion as part of a RFP rulemaking docket to consider additional updates to the competitive bidding rules, or alternately an informal stakeholder process followed by a Staff recommendation to the Commission at a public meeting.

For the time-being, Staff is planning to review PacifiCorp's 2022AS RFP scoring and modeling methodology in the RFP docket as opposed to the IRP docket.

Section 3: Compliance Items

Appendix B includes tables in which the Company describes how it has complied with OPUC IRP Guidelines and past orders. In this section, Staff identifies those compliance items for which additional comments or questions are warranted. Where the IRP Guidelines or direction included in 20-186 is not referenced below, it is because it appears to Staff that the Company has complied with the Order or that Staff is still evaluating compliance.

3.1 2019 IRP Compliance with Order 20-186

3.1.1 QF Renewals

This issue is also addressed in Section 1.5.5. Order No. 20-186 directed PAC to "produce a sensitivity or other explanation of the impact of renewing QFs on its load resource balance" and to include this in its 2021 IRP. It appears that the QF contract renewal assumptions are unchanged from the 2019 IRP and do not reflect the assumption that QFs will provide some additional capacity. It is also not clear to Staff how the Company has "explained the impact of renewing QFs on its load resource balance." Staff asks that the Company model QF renewals and explain the impact of these renewals on its load resource balance.

[85] Order No. 20-152. Page 27.

[86] See Staff's Memo dated November 19, 2021 in Docket No. UM 2166.

3.1.2 Class 3 DSM Workshop

PacifiCorp agreed to provide a stakeholder workshop on Class 3 DSM (price response and load shifting) during 2021 IRP development. In Order No. 20-186, the Commission asked that the 2021 IRP summarize the timeframes and participation rates of any existing or planned Class 3 DSM pilots or schedules.

Staff finds that the DSM summary in Appendix D of the IRP does not appear to include participation rates or timeframes for existing or planned Class 3 DSM pilots or schedules.

Staff Request/Recommendation 22

Staff requests that PacifiCorp report on its Class 3 DSM pilots or schedules/tariffs with data on participation rates and timeframes for each tariff potential timeframes for each pilot.

3.1.3 Adaptation Plan Scope

In Order No. 20-186, PacifiCorp was directed to include a proposal for the scope of a potential climate adaptation study in the 2021 IRP. Staff anticipated that including this information in the 2021 IRP would allow PacifiCorp to solicit stakeholder feedback on the scope of the plan. In the 2021 IRP, PacifiCorp included information on climate and wildfire risks in Chapter 5 along with its discussion of risks and resource adequacy. Additionally, the IRP included a version of the Company's load forecast adjusted for expected changes in temperature and hydro availability with climate change. In Chapter 8, this load forecast was used in Plexos, along with the application of the Social Cost of Carbon, to create a climate change portfolio.

Staff appreciates the information provided by the Company in Chapter 5 and Chapter 8 of the IRP. In Staff's view, the IRP goes beyond simply providing a scope for a climate adaptation study, and begins to incorporate aspects of climate adaptation planning into the IRP.

Staff is encouraged by the level of detail the Company included to date on climate adaptation, and recommends that the Company's consideration of climate risks and forecasts should build on this foundation in future IRPs. For example, future IRPs can look at climate change scenarios that include modeling of the expected impacts and risks from additional hazards such as the derating of thermal units during peak weather events, impacts to solar and wind under climate change and/or extreme weather events, the risks and costs of increasingly severe and frequent weather events, and the reliability risks of wildfires.

Staff Request/Recommendation 23

Staff requests that PacifiCorp and interested stakeholders respond in this docket regarding what incremental improvements can be made to PacifiCorp's climate adaptation studies. Staff will make a recommendation for next steps on climate adaptation in its Final Comments.

Staff notes that there has been a great deal of work to refine and improve how companies assess climate risk. In particular, the World Business Council on Sustainable Development leveraged the work of the Task Force on Climate-Related Financial Disclosures to provide guidance to utilities on how to assess and disclose climate-related risk.[87] Their report "TCFD Electric Utilities Preparer Forum" suggests that risk reports include a description of the Company's process for identifying, assessing, and managing climate-related risks and how it integrates these risks into its overall risk management. Further, regarding climate risk evaluation and assessment in planning, financial reporting, and other business practices, TCFD specifically suggests the reports from utilities should:

1. Describe the metrics and/or methods that the utility uses to evaluate climate-related financial and operational risks covering investments in and returns from generation;
2. Describe the methods used in considering financial and operational risk mitigation from non-generation activities that make the system more flexible and efficient, (such as investments in smart networks and customer solutions); and
3. Indicate which metrics and/or methods are used to track climate-related transition risks, physical risks, and catastrophic or "tail" risks.

3.1.4 PacifiCorp's Ongoing Regulatory Requirements

In the 2019 IRP, the Commission directed PacifiCorp and Staff to look into PacifiCorp's Oregon compliance items that carry forward into each IRP, and determine which items are no longer relevant or necessary.[88]

Staff and PacifiCorp identified one filing that is currently required from the Company twice each year that could likely be filed less frequently with similar effectiveness. The "Biannual Environmental, Transmission, and DSM Update" is required by Order No. 16-071, and is filed in PacifiCorp's IRP dockets twice a year. This filing could likely be made once annually with similar benefits to stakeholders. Alternately, it could be filed about one year after the filing of an IRP to provide updated data between the filing of the IRP and the filing of the IRP update.

Staff Request/Recommendation 24

Staff requests that stakeholders and PacifiCorp file any responses to this recommendation on streamlining PacifiCorp's regulatory requirements in Reply Comments.

3.2 Compliance with Oregon IRP Guidelines

The Commission's IRP Guidelines cover thirteen aspects of IRP process and content.[89] In Appendix B of the 2021 IRP, PacifiCorp provided a summary of how it addresses each of those Guidelines.[90] Staff reviewed PacifiCorp's summary and notes a few issues regarding compliance with the Guidelines.

[87] https://docs.wbcsd.org/2019/07/WBCSD_TCFD_Electric_Utilities_Preparer_Forum.pdf.
[88] Order No. 20-186. Page 24-25.
[89] See Order No. 07-002 (and Errata Order No. 07-047). PacifiCorp summarized these IRP Guidelines in Volume II, Appendix B. Pages 25-26.
[90] PacifiCorp's 2021 Integrated Resource Plan. Volume II, Appendix B - Table B.3. Pages 49-61.

3.2.1 Public process

A key piece of the preparation of the IRP is public input.[91] Staff appreciates PacifiCorp's efforts to engage the public in the preparation of the IRP but has concerns with the latter end of the process leading up to the filing. PacifiCorp held its final public input meeting three business days before filing its IRP.[92] At this meeting, PacifiCorp presented its preferred portfolio for the first time. This presentation followed multiple cancellations and reschedules of the meeting in less than a month. It also followed stakeholders raising concerns at the August 27, 2021, public input meeting about whether the preferred portfolio would be available to review and whether PacifiCorp would consider pushing back the IRP filing date result given the uncertainty. PacifiCorp declined to push back the filing date. PacifiCorp did however schedule another public input meeting for one month after the filing.[93]

According to Guideline 2(c), "[t]he utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission." The preferred portfolio is a key aspect of the IRP and the public should have the opportunity to review and comment on that information prior to the utility filing its IRP. Presentation of that information at a public input meeting prior to filing may technically meet the Guideline, but not the spirit of it. The public is supposed to be allowed "significant involvement" and have an opportunity to make relevant inquiries of the utility.[94] Provision of this information three business days before filing does not allow for that.

Staff appreciates that PacifiCorp tried to ameliorate the situation by holding another public input meeting post-filing, but Staff does not see that as a release valve for compliance with the Guidelines in the future. Staff asks that PacifiCorp ensures it provides adequate time for public review and input on all components of the draft RFP prior to filing moving forward. Staff is recommending at least four weeks for review of a draft IRP before filing of a final IRP.

3.2.2 "Known" Resource and PAC's Proposed Nuclear Resource

During the November 2, 2021, PAC IRP presentation to the Commission, NWEC raised a question of whether the nuclear resource PAC is considering in the IRP qualifies as a "known" resource under the IRP Guidelines.[95] NWEC noted that the Commission made a relevant statement in the underlying Order for the IRP Guidelines and suggested it should be considered in addressing the question. NWEC said that it would consider the issue further and provide written comments. Staff provides a preliminary analysis of the issue below.

[91] See Order No. 07-002. Guideline 2. Page 8.

[92] The meeting was held on August 27, 2021. See Volume II, Appendix C – Page 88. The IRP was filed on September 1, 2021.

[93] The post-filing public input meeting was held on October 1, 2021.

[94] Order No. 07-002. Guideline 2(a). Page 8.

[95] See November 2, 2021 Special Public Meeting Recording at 2:04:28 – 2:04:48.

Guideline 1(a) of the IRP Guidelines explains that all resources must be evaluated on a consistent and comparable basis. The Guideline includes language that states: "All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response."[96] This language is the basis for the question raised by NWEC.

During the development of the IRP Guidelines, there was discussion of what was meant by "known" resources.[97] One of the utilities recommended that rather than requiring consideration of all "known" resources, the first bullet should be revised to require only consideration "of all commercially or near-commercially viable resources." Staff disagreed noting that it is important to consider resources that are just beginning to be commercialized, as well as others that are expected to become available during the planning horizon. The Commission agreed with Staff and went on to state:

> We do not want utilities to limit their consideration to currently available resources, but rather to include all those that are expected to become available. We prefer the IRP be inclusive of all such resources and allow the parties to debate in the planning process whether it is reasonable to rely on a new technology.[98]

The statement above from the Commission is likely what NWEC was referring to. Staff understands this statement from the Commission as an effort to be more inclusive of resources, rather than limiting. The Commission specifically turned down limiting "known" resources to those that are only commercially available or near-commercially viable. Whether the nuclear resource under consideration is commercially available or near-commercially viable therefore does not weigh on whether PAC can include it for consideration or not. Instead, if the resource is expected to become available during the planning horizon, then it can be considered. There still may be nuances and arguments to be had about what exactly qualifies, but Staff would argue that the intent here is for a broad interpretation that is inclusive of resources, rather than exclusive of resources.

With that said, Staff would point to the second half of the Commission's statement. Although the Commission included a broad interpretation of "known" resources, the Commission also contemplated discussion during the planning process of whether it is reasonable to rely on a particular resource. This is where Staff would direct and focus discussion regarding the nuclear resource PAC is proposing. Staff has questions and concerns about the reasonableness of relying on the new technology as outlined in Section 1.1.2 of these comments.

[96] See November 2, 2021 Special Public Meeting Recording at 2:05:57 – 2:06:36. See also overall related comments on nuclear starting at 2:04:50.
[97] See Order No. 07-002. Page 4.
[98] Order No. 07-002. Page 4.

This concludes Staff's initial comments.

Dated at Salem, Oregon, this 3rd of December, 2021.

/s/ Rose Anderson
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Rose Anderson
Senior Economist
Energy Resources and Planning Division

Appendix A

This appendix provides confidential charts and data to support Staff's Opening Comments.

[Begin Confidential]

[redacted]

[redacted]

[99] PacifiCorp's ST Plexos preferred portfolio workpapers in file "ST Cost Summary -P02-MMGR-CETA ST Split Run Cost Data LT 18609 ST 19709 CONF.xlsx".

[redacted]

[100] PacifiCorp's response to Sierra Club Information Request 1.2.

[redacted]

[101] PacifiCorp's ST Plexos preferred portfolio workpapers in file "ST Cost Summary -P02-MMGR-CETA ST Split Run Cost Data LT 18609 ST 19709 CONF.xlsx".
[102] PacifiCorp's ST Plexos preferred portfolio workpapers in file "ST Cost Summary -P02-MMGR-CETA ST Split Run Cost Data LT 18609 ST 19709 CONF.xlsx".

[redacted]

[End Confidential]

[103] PacifiCorp's ST Plexos preferred portfolio workpapers in file "ST Cost Summary -P02-MMGR-CETA ST Split Run Cost Data LT 18609 ST 19709 CONF.xlsx".
[104] PacifiCorp's ST Plexos preferred portfolio workpapers in file "ST Cost Summary -P02-MMGR-CETA ST Split Run Cost Data LT 18609 ST 19709 CONF.xlsx".

LC 77 – SERVICE LIST

	AWEC
BRENT COLEMAN DAVISON VAN CLEVE, PC	1750 SW HARBOR WAY, SUITE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH DAVISON VAN CLEVE	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com
TYLER C PEPPLE DAVISON VAN CLEVE, PC	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com
NEWSUN ENERGY	
BRITTANY ANDRUS	3317 NE 31ST AVENUE PORTLAND OR 97212 andruspdx@gmail.com
MARIE P BARLOW NEWSUN ENERGY LLC	390 SW COLUMBIA ST STE 120 BEND OR 97702 mbarlow@newsunenergy.net
JACOB (JAKE) STEPHENS NEWSUN ENERGY	3500 S DUPONT HWY DOVER DE 19901 jstephens@newsunenergy.net
NIPPC	
SPENCER GRAY NIPPC	sgray@nippc.org
IRION A SANGER **(C)** SANGER LAW PC	1041 SE 58TH PLACE PORTLAND OR 97215 irion@sanger-law.com
JONI L SLIGER **(C)** SANGER LAW PC	1041 SE 58TH PL PORTLAND OR 97215 joni@sanger-law.com

NW ENERGY COALITION	
FRED HEUTTE NW ENERGY COALITION	PO BOX 40308 PORTLAND OR 97240-0308 fred@nwenergy.org
LAUREN MCCLOY NW ENERGY COALITION	811 1ST AVE SEATTLE WA 98104 lauren@nwenergy.org
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
SUDESHNA PAL **(C)** **(HC)** OREGON CITIZENS UTILITY BOARD	sudeshna@oregoncub.org
PACIFICORP	
PACIFICORP, DBA PACIFIC POWER	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
ETTA LOCKEY C) PACIFIC POWER	825 NE MULTNOMAH ST., STE 2000 PORTLAND OR 97232 etta.lockey@pacificorp.com
CARLA SCARSELLA (C) PACIFIC POWER	825 MULTNOMAH STREET STE 2000 PORTLAND OR 97232 carla.scarsella@pacificorp.com
PGE	
PORTLAND GENERAL ELECTRIC	pge.opuc.filings@pgn.com
ERIN APPERSON PORTLAND GENERAL ELECTRIC	121 SW SALMON STREET, 1WTC1301 PORTLAND OR 97204 erin.apperson@pgn.com
RENEWABLE ENERGY COALITION	

JOHN LOWE RENEWABLE ENERGY COALITION	PO BOX 25576 PORTLAND OR 97298 jravenesanmarcos@yahoo.com
RENEWABLE NORTHWEST	
RENEWABLE NORTHWEST	421 SW 6TH AVE., STE. 975 PORTLAND OR 97204 dockets@renewablenw.org
MAX GREENE **(C)** RENEWABLE NORTHWEST	421 SW 6TH AVE STE 975 PORTLAND OR 97204 max@renewablenw.org
SASHWAT ROY **(C)** RENEWABLE NORTHWEST	sashwat@renewablenw.org
SIERRA CLUB	
ANA BOYD **(C)** **(HC)** SIERRA CLUB	2101 WEBSTER ST STE 1300 OAKLAND CA 94612 ana.boyd@sierraclub.org
ROSE MONAHAN **(C)** **(HC)** SIERRA LCU	2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
GLORIA D SMITH **(C)** **(HC)** SIERRA CLUB LAW PROGRAM	2101 WEBSTER ST STE 1300 OAKLAND CA 94612 gloria.smith@sierraclub.org
STAFF	
ROSE ANDERSON **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308 rose.anderson@puc.oregon.gov
JOHANNA RIEMENSCHNEIDER **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4796 johanna.riemenschneider@doj.state.or.us
STOP B2H	
NORM CIMON	2108 FIRST ST LA GRANDE OR 97850 ncimon@oregontrail.net

JIM KREIDER	60366 MARVIN RD LA GRANDE OR 97850 jkreider@campblackdog.org
SWAN LAKE NORTH HYDRO	
MICHAEL ROONEY RYE DEVELOPMENT	830 ZNE HOLLADAY ST PORTLAND OR 97232 michael@ryedevelopment.com
ERIK STEIMLE SWAN LAKE NORTH HYDRO LLC	220 NW 8TH AVE PORTLAND OR 97209 erik@ryedevelopment.com
CHRIS ZENTZ VAN NESS FELDMAN LLP	cdz@vnf.com

CERTIFICATE OF SERVICE

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I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 3rd day of December, 2021 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (971) 375-5079