PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 11, 2022

VIA ELECTRONIC FILING

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

RE: LC 77— PacifiCorp's Response to Staff's Final Report and Recommendations

PacifiCorp d/b/a Pacific Power encloses for filing its Response to Staff's Final Report and Recommendations in the above-referenced docket.

Informal inquiries may be directed to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 77

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2021 Integrated Resource Plan	PACIFICORP'S RESPONSE TO STAFF'S FINAL REPORT AND RECOMMENDATIONS

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) filed its 2021 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (Commission) on September 1, 2021. Following one round of comments by PacifiCorp and stakeholders, numerous discovery requests, and a Commission workshop, Commission Staff filed a Final Report and Recommendations on February 11, 2022, setting forth its recommendations to the Commission regarding acknowledgment of the 2021 IRP (Report). The Report recommends acknowledgement of PacifiCorp's 2021 IRP Action Plan with the exception of Action Plan Item 2c (Natrium Demonstration Project), Action Plan Items 3a and 3b (Transmission project Gateway Energy South and Energy Gateway West, Segment D.1 (GWS)), and Action Plan Item 3d (Local Reinforcement Projects). The Report also makes requests for information prior to decision and makes requests and recommendations relating to the 2022 All Source Requests for Proposals (2022AS RFP)[1] and the 2023 IRP. The Company is appreciative of Staff and other stakeholders' efforts in the development of the 2021 IRP and in this proceeding and provides its response to the Report below.

[1] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of 2022 All-Source Request for Proposals,* Docket No. UM 2193.

II. CONDITIONS TO ACKNOWLEDGMENT

As referenced above, the Report recommends acknowledgement of certain action items subject to specific conditions. The Company requests that any conditions be imposed by the Commission as conditions rather than revisions to PacifiCorp's 2021 IRP Action Plan. As a multi-jurisdictional utility that develops its IRP on a system-wide basis, any revisions to specific action items at this time may trigger additional regulatory process in other jurisdictions that could result in delay to implementation of the 2021 IRP. For this reason, the Company respectfully requests that the Commission, in its final order, specify that its acknowledgement is contingent upon any conditions ultimately adopted.

III. RESPONSE TO STAFF RECOMMENDATIONS

Since the Report was issued, the Company has responded to seven Commission bench requests and participated in two Commission workshops, on February 24, 2022 and March 8, 2022 (March 8 Workshop), where the Company was able to address some of the concerns raised in the Report.[2] In this context, the Company was able to address the take or pay assumptions relating to Jim Bridger 3 and 4, the Company's planning reserve margin, and its justification for GWS. PacifiCorp also provided a sensitivity removing take-or-pay assumptions described in the Report[3] and the additional information regarding the sensitivity requested by the Commission.

In the Report and further discussed at the March 8 Workshop, Staff expressed concerns that the Company was not sufficiently transparent about the need for GWS or a justification for the cost of transmission upgrades that would be necessary if GWS were not built.

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[2] A Commission workshop was also held on January 13, 2022, prior to the filing of the Report.
[3] Staff Report at 9-13.

The 2021 IRP includes an estimated $1.4 billion in transmission upgrades if GWS is not constructed. This estimate is based on a high-level analysis of the minimum network upgrades that would be required to provide 500 megawatts (MW) of point-to-point transmission service as set forth in an executed transmission service contract with a third-party transmission customer. This estimate is conservative as it does not consider the unavoidable transmission investment that would also be required to provide interconnection service as set forth in 12 executed generator interconnections agreements. GWS itself becomes the unavoidable project required to meet the Company's obligations under all 13 executed contracts. Nonetheless, the Company conservatively assumed that a 230-kilovolt (kV) transmission line along the same path as GWS at an estimated cost of $1.4 billion would be needed to provide the 500 megawatt (MW) of transmission service outlined in the single executed contract.

Also, in the Report, Staff discusses the potential for alternative financing of GWS. In addition, Staff references Order 21-437, which acknowledged the Company's 2020 AS RFP Final Shortlist, where the Commission directed PacifiCorp to present to Commissioners within five months of October 12, 2021, a "discussion of the federal-state relationship around transmission decisions and the obligations that transmission providers have under federal law, and if appropriate, alternate financing of future transmission investments."[4] While the directive in Order 21-437 was not addressed at the March 8 Workshop, the Commission discussed the ratemaking treatment associated with transmission projects. In Section IV below, PacifiCorp provides comments on federal transmission requirements and pricing policies and addresses alternative financing for transmission projects.

[4] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of 2020 All-Source Request for Proposal,* Docket No. UM 2059, Order No. 21-437 at page 15 (Nov. 24,2021).

Finally, as explained in more detail below, the Company agrees with and accepts many of the recommendations provided in the Report. However, the Company strongly disagrees with the recommendation that the Commission should not acknowledge action items relating to Natrium, GWS, and Local Reinforcement Projects.

PacifiCorp responds to the specific recommendations presented by Staff in its Report below.

RECOMMENDATION NO. 1: In the 2023 IRP, PacifiCorp should provide a metric calculated in its capacity expansion model that provides stakeholders with an estimate of the relative value of each coal unit to the system.[5]

RESPONSE TO RECOMMENDATION NO. 1: The Company will consider this recommendation to develop a metric established by PLEXOS modeling as part of its 2023 IRP.

RECOMMENDATION NO. 2: If the data on the relative value of each coal unit is available for 2021 IRP resources, the Company should provide the data in a filing before the acknowledgment decision meeting. If the data is considered confidential, then a ranked table of PacifiCorp's coal units from least to most valuable should be provided in the filing in a non-confidential format.[6]

RESPONSE TO RECOMMENDATION NO. 2: The Company has provided information regarding the relative value of all resources, including coal facilities, in its confidential data disc.[7] The Company has not prepared a public ranking as it would provide

[5] Report at 5.
[6] Report at 5.
[7] Specifically, the Short-Term (ST) Cost Summaries that include each resource. For example, folder "ST Studies", file "ST Cost Summary -P02-MMGR ST Split Run Cost Data LT 5230 ST 19667.xlsx". Tabs "Generator Costs" and "Battery Costs" provide annual results by resource for generators and batteries

information that could potentially influence bid offers in the 2022AS RFP. The information could tell a buyer the relative value of a unit in our system and could be used to reduce a potential offer for a specific unit.

RECOMMENDATION NO. 3: The 2023 IRP data discs should provide graphs of the average fixed and variable costs of operating each coal unit over the planning timeframe. This should include fuel cost and run rate capital, but exclude depreciation expense.[8]

RESPONSE TO RECOMMENDATION NO. 3: The Company will provide this information in the 2023 IRP.

RECOMMENDATION NO. 4: Perform an investigation of the potential to burn green hydrogen at the converted Bridger units and report on its findings in the 2023 IRP, including an explanation of the engineering reasons that a converted boiler would or would not be able to accommodate a percentage of green hydrogen.[9]

RESPONSE TO RECOMMENDATION NO. 4: The Company will investigate the technical and engineering feasibility of converting an existing coal-fired power boiler to hydrogen fuel, including the availability of hydrogen necessary to supply Jim Bridger Units 1 and 2. The Company will provide the results of this research in the 2023 IRP.

(including Natrium nuclear storage capability), respectively. The following columns from tab "Generator Costs" provide information on the value of resources: - Pool Revenue: the value of a generator's hourly output, based on the hourly shadow price at its location (i.e. locational marginal price (LMP)). - Reserves Revenue: the value of reserve provision (the amount the model assigned for a resource to hold) in each hour, based on the hourly marginal reserve cost in its balancing area (BA) (east or west). - Net Revenue: pool revenue plus reserves revenue minus fuel costs (including start-up), emissions costs, Use of System (UoS) Cost (reflecting transmission and distribution (T&D) credits for demand response (DR)) and variable operations and maintenance costs (VOM). On tab "Battery Costs," comparable information is provided: - Net Generation Revenue: the value of a generator's hourly net generation, based on the hourly shadow price at its location (i.e. LMP). The cost of charging, including efficiency losses, is subtracted from the value of discharging. - Reserves Revenue: the value of reserve provision (the amount the model assigned for a resource to hold) in each hour, based on the hourly marginal reserve cost in its BA (east or west). Note: the shadow price for each location in PLEXOS reflects all of the variable cost components discussed in "Net Revenue" above, including fuel, emissions, and VOM, along with the cost of market purchases and sales to the extent transmission is available.

[8] Report at 5.

[9] Report at 8.

RECOMMENDATION NO. 5: If technically feasible, PacifiCorp should report on the costs and emissions (carbon dioxide (CO_2) and nitrogen oxides (NO_X)) of green hydrogen combustion at the converted Bridger unit.[10]

RESPONSE TO RECOMMENDATION NO. 5: The Company will investigate the costs and emissions associated with green hydrogen combustion at Jim Bridger Units 1 and 2 and provide the results of its research in the 2023 IRP.

RECOMMENDATION NO. 6: The 2023 IRP should more thoroughly investigate the potential to install a new turbine designed to run on 100 percent green hydrogen at the sites of one or more retiring coal plants.[11]

RESPONSE TO RECOMMENDATION NO. 6: The supply-side resource table for the 2023 IRP will include a 100 percent hydrogen-fueled combustion turbine at elevations that are consistent with the elevations of existing coal-fueled generating facilities.

RECOMMENDATION NO. 7: PacifiCorp should file the results of its coal sensitivity at least seven (7) days before the February 24, 2022 Commissioner Workshop in LC 77, and be prepared for a discussion of Take or Pay modeling at Jim Bridger 3 and 4.[12]

RESPONSE TO RECOMMENDATION NO. 7: The Company intended to share the requested sensitivity with stakeholders on February 21, 2022. However, the bench requests received on Friday, February 17, required the Company to expand the sensitivity being worked on for Staff. The Company informed Staff that it would provide a response to bench request 1 that included Staff's sensitivity and the information requested in the bench request on the date the bench request was due, February 23, 2022. The response to bench

[10] Report at 8.
[11] Report at 8.
[12] Report at 10.

request 1 was comprehensive of the request Staff made and the additional information the Commission requested. However, the Company needed additional time to prepare the response to bench request 1 and requested an extension to file by March 4, 2022. The response to bench request 1, which included the requested sensitivity, was filed on March 3, 2022.

RECOMMENDATION NO. 8: The 2023 IRP should consider endogenous retirement of Jim Bridger 3 and 4 at least once every two years.[13]

RESPONSE TO RECOMMENDATION NO. 8: The Company selects years for endogenous retirement based on several factors, notably including years just prior to a requirement for a major investment. This is an important consideration because it does not make sense to make a major investment in a resource and then retire it immediately after. The options for retirements will be discussed in advance of modeling as part of the public input process as was done in the 2021 IRP. Options for Jim Bridger 3 and 4 retirements average about 1 option per 3 years of the 20-year horizon. The 2023 IRP and future IRPs are anticipated to continue assessing coal unit retirements endogenously in its two-year IRP cycle. For these reasons, the Company does not support modeling retirement options on an arbitrary basis, as the two-year recommendation seems to imply. However, the Company continues to be interested in discussing retirement options that may be informative as part of the 2023 IRP public-input process.

RECOMMENDATION NO. 9: In the 2023 IRP, PacifiCorp should carefully review the capital and O&M cost forecasts for Jim Bridger 3 and 4 and provide workpapers

[13] Report at 13.

comparing historical costs at these units to the IRP cost forecast, including the categories of Variable O&M, Fixed O&M, and run-rate capital.[14]

RESPONSE TO RECOMMENDATION NO. 9: Forecasted cost assumptions such as fuel costs and operational parameters are updated for each IRP cycle interacting with contracts, mining conditions, regional haze requirements, state legislation and other factors. Model dispatch of a coal unit changes as a consequence of this update, but also as a consequence of load changes, the incorporation of previously selected demand-side resources, system retirements, market pricing, competing technology costs, and several other factors. While an historical review of coal unit costs may be informative, it is the updated forecast that is relevant to the IRP, and not a comparison against historical data formed under a different set of past conditions. For these reasons, the Company disagrees that the IRP is the appropriate forum for providing the requested data. The Company values continued discussion in an appropriate context and scope for reviewing historical data.

RECOMMENDATION NO. 10: In the 2023 IRP, variable operating and maintenance (O&M) costs should be modeled accurately as variable with generation, and not approximated as part of fixed O&M costs as they have been in the 2021 IRP.[15]

RESPONSE TO RECOMMENDATION NO. 10: The Company agrees to model variable O&M costs with generation in the 2023 IRP within the limits of available data and resources available to prepare cost estimates.

[14] Report at 13.
[15] Report at 13.

RECOMMENDATION NO. 11: PacifiCorp should perform a sensitivity before the acknowledgement decision meeting in this IRP on March 22, 2022, where the Huntington minimum take agreement ends in 2023. [16]

RESPONSE TO RECOMMENDATION NO. 11: The Company objects to this recommendation because the Huntington minimum take agreement does not end in 2023, but rather runs until December 31, 2029. The Company has not experienced circumstances that would warrant a reason to exit the agreement before that time because there is no evidence that the plant is consistently unable to economically accept delivery of the minimum volumes required by the contract. Moreover, even if the plant were to require alternate dispatch to reach the minimum take level, there is no evidence that any alternate dispatch is caused by environmental regulations. Because there is no reasonable basis to terminate the coal supply agreement, a sensitivity removing the minimum take provision from the model would not provide any useful information.

RECOMMENDATION NO. 12: Staff recommends acknowledging the preferred portfolio and Action Plan only to the extent that they are consistent with the no-Natrium scenario. [17]

RESPONSE TO RECOMMENDATION NO. 12: The Company disagrees that the Commission should only acknowledge the Action Plan to the extent it is consistent with the no-Natrium scenario. The preferred portfolio and the no-Natrium variant are the same through the end of 2025, which covers the action plan window. The only difference between the two portfolios through the end of 2027 are incremental additions of solar collocated with storage generation resources. Because solar collocated with storage generation has a

[16] Report at 14.
[17] Report at 18.

substantially shorter lead time than nuclear, the Company will be able to adjust its strategy as it moves forward with analysis in the 2022AS RFP and 2023 IRP. Therefore, there is no need for the Commission to exclude the Natrium project when acknowledging the Action Plan.

RECOMMENDATION NO. 13: Staff recommends a Commission workshop at least one month in advance of the 2022AS RFP Final Shortlist for stakeholders, PacifiCorp, and Commissioners to discuss potential benefits of acquiring additional near-term supply or demand side capacity, including in the 2022AS RFP, to help reduce future resource allocation risk for Oregon. [18]

RESPONSE TO RECOMMENDATION NO. 13: The Commission should not implement this requirement as part of its consideration of the 2021 IRP, but rather should consider it within docket UM 2193, the 2022AS RFP, where it can be scheduled in coordination with other procedural requirements such as sensitivity analyses.

RECOMMENDATION NO. 14: Regarding the Natrium plant, PacifiCorp should not pursue an alternative acquisition method but may include the plant as a part of a competitive RFP where it can compete against other resources providing similar types of services.[19]

RESPONSE TO RECOMMENDATION NO. 14: PacifiCorp objects to this recommendation. The Company has been engaged with a specific developer, TerraPower, with U.S. Department of Energy (DOE) grant funding that understands and is committed to ensuring the project must provide value to PacifiCorp's customers. TerraPower will be responsible for securing the private investment and managing the project. The project should

[18] Report at 18.
[19] Report at 19.

not be required to, nor be precluded from, participating in an RFP. Because of the special nature of the value proposition associated with the Natrium project, which is different from cost-based or bid-based resource options, terms and conditions between PacifiCorp and TerraPower need to be identified before any determination on RFP participation should be made. The Company should not be prohibited through an acknowledgement order in this IRP from seeking a waiver if it finds good cause to request a waiver under the Commission's competitive bidding rules. Further, the operating attributes for this resource, specifically the energy storage and inherent safety features associated with sodium, are attractive and needed in a world that is transitioning to more non-carbon and renewable resources.

The Commission should not constrain the Natrium acquisition at this preliminary stage. The Commission should evaluate any alternative acquisition request by the Company based on the information available if and when such a request is made.

RECOMMENDATION NO. 15: In Reply Comments, PacifiCorp should provide responses to Staff's thoughts on incorporating flexible hydrogen load onto PacifiCorp's system.[20]

RESPONSE TO RECOMMENDATION NO. 15: PacifiCorp's modeling can readily identify the marginal cost of serving additional energy demand at a particular location. For large volumes, this can significantly change system operations, emissions, and costs. The cost impact would not be driven by the type of generation, hydrogen production, and instead would be driven by the characteristics of an interruptible load including price-sensitivity, notice, and duration requirements. Tariff structures and resource cost allocation

[20] Report at 19.

would be relevant to the modeling of any significant new load and are generally beyond the scope of the IRP.

RECOMMENDATION NO. 16: Before the PacifiCorp IRP meeting to discuss supply side resources in early 2022, Staff will convene a brief Oregon stakeholder conference to discuss ways to model hydrogen resources in the 2023 IRP and potential tariffs to encourage hydrogen load generation timed and located in ways that benefit the system.[21]

RESPONSE TO RECOMMENDATION NO. 16: The Company is open to participating in discussions related to modeling hydrogen resources should a conference be scheduled and/or considering feedback within its IRP stakeholder feedback form and public-input meeting process.

RECOMMENDATION NO. 17: PacifiCorp should conduct a stakeholder feedback process to determine what source the Offshore Wind cost data in the 2023 IRP will be based on, with consideration for public data such as the 2021 DOE Offshore Wind Market Report.[22]

RESPONSE TO RECOMMENDATION NO. 17: The Company plans to incorporate data for offshore wind proxy resources as part of the public-input process and development of its 2023 IRP.

RECOMMENDATION NO. 18: PacifiCorp should conduct an analysis akin to the sensitivity Staff proposed in Opening Comments that considers the development of Offshore Wind in comparison to resources associated with the 2022AS RFP Final Shortlist and publish the analysis with the 2022AS RFP Final Short List.[23]

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[21] Report at 19.
[22] Report at 20.
[23] Report at 20.

RESPONSE TO RECOMMENDATION NO. 18: The Commission should not implement this requirement as part of its consideration of the 2021 IRP, but rather should consider it within docket UM 2193, the 2022AS RFP, where it can be requested in coordination with other procedural requirements for sensitivity analyses. For purposes of performing any sensitivities in the 2022AS RFP to meet resource needs that come online by 2026, it is not anticipated that offshore wind can be permitted and constructed in that timeframe. Should that not be the case, that project could bid into the 2022AS RFP and be considered in that process. The 2023 IRP focus will be the response to recommendation number 17 and developing informed proxy assumptions.

RECOMMENDATION NO. 19: After a conversation with Staff and stakeholders, PacifiCorp should engage with PacifiCorp Transmission prior to the 2023 IRP to request a power flow study of the addition of Offshore Wind near Brookings, Oregon to inform what upgrades or enhancements might be needed to interconnect 500 MW to 1,000 MW at this location. [24]

RESPONSE TO RECOMMENDATION NO. 19: PacifiCorp Transmission conducts this type of analysis during its annual cluster study but does not evaluate hypothetical projects as part of its cluster study. PacifiCorp Transmission is engaged however, as part of the 2023 IRP development process to identify transmission cost estimates to reasonably inform consideration and evaluation of potential offshore wind proxy resource opportunities. Additional transmission studies will be performed with NW utilities to inform potential region wide transmission system upgrades.

[24] Report at 20-21.

RECOMMENDATION NO. 20: Regarding these Oregon qualifying facilities (QF) projects, re-run the IRP model using the solar or solar + storage proxy costs and CF values for these QFs, including identified interconnection costs, to see how these QF resources compete in the model, if they are selected, and their impact on this IRP's other resource selections.[25]

RESPONSE TO RECOMMENDATION NO. 20: The Company believes it would not be efficient to model QF project benefits to customers in the context of an IRP docket because the Company is required to purchase the electricity under terms and conditions that have either already been determined or will be determined through the Commission's determination of the appropriate avoided cost pricing for QF projects. The Company will file to update the avoided cost calculation in accordance with Commission rules and established Commission methodologies. The projects noted in the Staff Report are also free to bid into the Company's 2022AS RFP.

RECOMMENDATION NO. 21: Much like offshore wind, Staff requests that an analysis considering the development of these projects in comparison to resources associated with the Final Shortlist be published with the Final Shortlist in the 2022AS RFP.[26]

RESPONSE TO RECOMMENDATION NO. 21: Please see the Company's response to Recommendation No. 20. The Commission should not implement this requirement as part of its consideration of the 2021 IRP, but rather should consider it within docket UM 2193, the 2022AS RFP, where it can be scheduled in coordination with other procedural requirements such as sensitivity analyses.

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[25] Report at 22.
[26] Report at 22.

RECOMMENDATION NO. 22: Depending on the outcome of docket UM 2032[27] and based on the benefits of the seven Oregon QF cluster study projects, provide a report on the impact of ratepayers covering some or all of the Network Upgrade costs and negotiating terms with these projects so they can be brought online before 2026 to serve customer demand identified in the IRP.[28]

RESPONSE TO RECOMMENDATION NO. 22: The Company believes this recommendation should be addressed in docket UM 2032

RECOMMENDATION NO. 23: For the 2023 IRP, PacifiCorp should take steps necessary to provide complete and accurate information in the IRP document that reflects actual IRP modeling assumptions.[29]

RESPONSE TO RECOMMENDATION NO. 23: The Company is committed to providing accurate information and will take steps to include changes to relevant inputs that evolve during the IRP development process.

RECOMMENDATION NO. 24: In the 2023 IRP, PacifiCorp's storage costs should be in line with the most recent National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) report and most recent RFP Final Shortlist before publishing the Supply Side Table.[30]

RESPONSE TO RECOMMENDATION NO. 24: The Company will evaluate various renewable resource cost estimates, including the NREL ATB report, when conducting its renewable resource study for the 2023 IRP. If costs in the renewable resource

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[27] *In the Matter of Public Utility Commission of Oregon, Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities,* Docket No. UM 2032.
[28] Report at 22.
[29] Report at 23.
[30] Report at 23.

study differ significantly from other publicly available cost estimates, the Company will provide an explanation for the discrepancy. The Company also considers aggregated information from RFP bids as it becomes available without revealing information specific to any one bid to maintain the confidentiality of bids and without revealing information that might give bidders a competitive advantage in the RFP process, as another data point to inform proxy resource cost assumptions.

RECOMMENDATION NO. 25: The 2023 IRP executive summary should include a map of resources added in the preferred portfolio by year and location. [31]

RESPONSE TO RECOMMENDATION NO. 25: The Company will provide this information in the 2023 IRP.

RECOMMENDATION NO. 26: In future IRPs or during future RFP processes, potential RFP bidders should be given access to a 12x24 Loss of Load Probability matrix for one out of every five years in the IRP planning timeframe. [32]

RESPONSE TO RECOMMENDATION NO. 26: This information is publicly available in docket UM 2011.[33] The Company will provide comparable information in the 2023 IRP.

RECOMMENDATION NO. 27: In the 2023 IRP, PacifiCorp should clearly explain the reliability limitations of the LT capacity expansion model, and how the IRP team selected the reliability resources to add to the ST model. [34]

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[31] Report at 24.
[32] Report at 24.
[33] *In the Matter of the Public Utility Commission of Oregon, General Capacity Investigation,* Docket No. UM 2011.
[34] Report at 25.

RESPONSE TO RECOMMENDATION NO. 27: The Company agrees to provide the requested information in the 2023 IRP. The Company notes that the 2021 IRP included a description of the reliability process, which was also covered in detail over two public-input meetings during the 2021 IRP[35] all of which speak to the limitations of the LT model, the LT model's role in the PLEXOS suite of optimization tools, and the appropriate use of the MT and ST models to ensure reliable portfolios. The Company is interested in discussing with Staff how to enhance the information provided.

RECOMMENDATION NO. 28: The 2023 IRP workpapers should include a report of the timing and duration of reliability events from the ST run that necessitated the addition of reliability resources in each portfolio. [36]

RESPONSE TO RECOMMENDATION NO. 28: The Company agrees to provide the requested information in the 2023 IRP.

RECOMMENDATION NO. 29: PacifiCorp should re-run its IRP model using updated cost assumptions for pumped hydro storage, either as a part of a requested sensitivity to the 2021 IRP, or in the 2023 IRP. [37]

RESPONSE TO RECOMMENDATION NO. 29: The 2021 IRP contained current cost assumptions for pumped hydrogen storage projects, and PacifiCorp is not aware of material changes to the cost of such projects. The Company will update costs as it develops its 2023 IRP.

[35] 2021 IRP, Chapter 8 – Modeling and Portfolio Evaluation Approach, and especially pages 219-223; June 25, 2021 public input meeting; July 30, 2021 public input meeting.
[36] Report at 25.
[37] Report at 28.

RECOMMENDATION NO. 30: PacifiCorp should discuss and compare the transmission and operational constraints faced by Swan Lake relative to the proposed Crooked Creek in its final IRP comments. [38]

RESPONSE TO RECOMMENDATION NO. 30: The Company is unable to perform the requested analysis. Transmission studies have been performed for Swan Lake but have not been performed for Crooked Creek or any other pumped storage developments the Company is evaluating in southern Oregon, including Crooked Creek. This is because Swan Lake has entered into an interconnection agreement, but Crooked Creek has not yet reached that stage of the development process.

RECOMMENDATION NO. 31: As part of the 2023 IRP public workshop series, the Company should review the pumped hydro project proposals PacifiCorp is considering and detail the potential benefits of pumped hydro in an era of decarbonization, including the reliability benefits of adding more than one project to its portfolio and the benefits of adding mass/inertia from large rotating generators to an increasingly inverter-based portfolio of resources. [39]

RESPONSE TO RECOMMENDATION NO. 31: The Company agrees to this recommendation to provide a more robust discussion of pumped hydro storage and its potential benefits as part of the 2023 IRP.

RECOMMENDATION NO. 32: In the 2023 IRP, PacifiCorp should describe how it delineates between reliability-related transmission system improvements and those which

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[38] Report at 28.
[39] Report at 28.

are deemed resource-related. Further, transmission system improvements should be clearly specified as reliability or resource related. [40]

RESPONSE TO RECOMMENDATION NO. 32: The Company would note that in the context of its IRP modeling there is no meaningful distinction between transmission system improvements that are "reliability-related" and those that are "resource-related." As shown in Table 1.1 of PacifiCorp's 2021 IRP, all of the transmission projects included in the 2021 IRP preferred portfolio included incremental interconnection capacity and resource additions. The model cannot add resources if there is not available interconnection capacity, and likewise, where there are transmission system improvement opportunities available that are not required but which would improve system reliability, the model can select resources that further enhance reliability in conjunction with such upgrades, resulting in more cost-effective outcomes.

From a transmission provider perspective, it is similarly difficult to cleanly delineate between "reliability-related" and "resource-related" transmission projects. Many projects are driven by multiple factors, e.g., a transmission line that facilitates the Company's compliance with mandatory reliability standards and the interconnection of additional resources, such as GWS and Gateway West, D.1. In addition, "resource-related" projects, at their core, are also driven by reliability, as discussed in more detail in Section IV.

RECOMMENDATION NO. 33: In Reply Comments, PacifiCorp should provide additional clarity on the data submitted to Western Resource Adequacy Program (WRAP) Program Operator in the 2021 IRP. [41]

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[40] Report at 29.
[41] Report at 32.

RESPONSE TO RECOMMENDATION NO. 33: As part of the WRAP capacity determination process, the Company expects to provide historical hourly generation for existing facilities, expected hourly generation for facilities that were not online or have been repowered since the historical period, and details on the performance characteristics of its dispatchable resources, including duration limits for energy limited resources. The information that the Company has provided to the WRAP has also been provided to Commission Staff in the Oregon Resource Adequacy docket UM 2143.[42]

RECOMMENDATION NO. 34: In the 2023 IRP, PacifiCorp should be required to clearly show how its IRP Planning Reserve Margin is consistent with any planning reserve margin (PRM) assigned to the Company in the WRAP process. Any deviation from the WRAP PRM should be thoroughly explained and justified. [43]

RESPONSE TO RECOMMENDATION NO. 34: The Company disagrees with this recommendation because the WRAP PRM and the IRP PRM cannot be expected to be the same. This is because they are the result of different models and used for different purposes. Specifically, the WRAP PRM is designed to determine near-term resource adequacy for the following winter or following summer, while the IRP PRM looks across the entire 20-year planning horizon and considers changes to the Company's resource portfolio over that time. The IRP portfolio-development process ensures that the Company's resource portfolio plus a limited reliance on market purchases (FOTs) is sufficient to reliably serve its load obligations. Significant changes in the amount of wind, solar, and storage resources among other proxy resources in the Company's portfolio will likely take place over the IRP

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[42] UM 2143 *In the Matter of Public Utility Commission of Oregon, Investigation into Resource Adequacy, Docket No. UM 2143,* PacifiCorp's Confidential Informational Filings (January 25, 2022 and March 3, 2022).
[43] Report at 32.

planning horizon. Even if the WRAP PRM were the same as the IRP PRM today, the two values would diverge relatively quickly as the Company's resource portfolio changes. PacifiCorp does not have a method to forecast WRAP capacity values into the future, and whether the WRAP PRM is higher or lower than the IRP today is not indicative of future conditions. The aggregate portfolio of the WRAP participants will continuously evolve, and techniques for calculating capacity values are also expected to evolve with changes in circumstances.

RECOMMENDATION NO. 35: Staff recommends a Commission workshop to discuss potential ways to increase efficiency and demand response to decrease resource allocation risk for Oregon customers, including but not limited to consideration of a new or updated risk-reduction credit to efficiency. [44]

RESPONSE TO RECOMMENDATION NO. 35: The Company does not oppose this recommendation. There are multiple parties and a number of active processes related to energy efficiency and demand response planning and acquisition. To ensure successful facilitation of this effort, it would be helpful to outline the interactions of these proceedings and how they can work together to achieve outcomes. For energy efficiency for example, much of the near-term acquisition is driven by the Energy Trust of Oregon processes. If the Commission accepts this recommendation, the Company requests additional information to better understand the expectation and desired outcome of any workshop.

RECOMMENDATION NO. 36: Before the next IRP, PacifiCorp should hire a consulting firm to help PacifiCorp staff design a Peak-Time Rebate program for Oregon. In their work, the consultant should benchmark best practices from the most impactful programs

[44] Report at 33.

by other utilities and suggest Class 3 demand-side management (DSM) designs capable of working with PacifiCorp's existing AMI, billing, and customer communication systems. The Company should present the consultant's findings to an IRP stakeholder workshop prior to filing the next IRP. [45]

RESPONSE TO RECOMMENDATION NO. 36: The Company does not agree with this recommendation at this time because it could be more effectively implemented after the Company transitions to its new billing system, which is projected to take place in 2024. Engaging a consultant and preparing a study for a peak time rebate that would use the Company's pre-existing legacy billing system would be premature and duplicative at this time, because the Company is actively in the process of replacing its billing system. While AMI is a necessary precedent before deploying a peak time rebate program, an advanced billing system capable of accurately billing customers on peak time rebate is also necessary. Fortunately, the new billing system the Company is planning to deploy could, with modest changes, process a peak time rebate program. It would be far more efficient to study a potential peak time rebate program nearer to the 2024 implementation date for the new billing system. The Company will however, study the potential impacts of a peak time rebate program in its Conservation Potential Study for the 2023 IRP.

RECOMMENDATION NO. 37: Acknowledge all action items except the element of item 2c to "finalize commercial agreements" for Natrium, items 3a and 3b because they have been discussed at length in previous dockets, and 3d because it is vague and insufficient supporting data has been provided. [46]

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[45] Report at 35.
[46] Report at 36.

RESPONSE TO RECOMMENDATION NO. 37: The Company appreciates the recommendation to acknowledge the majority of its action items but disagrees with the recommended exceptions.

Action plan item 2c: This action item relates to the Natrium project. With increased reliance on wind and solar, nuclear energy is one of the only large-scale, carbon-free electricity sources that can provide power 24/7. TerraPower's Natrium plant is specifically designed to integrate into a system with high levels of variable renewables. Additionally, the plant's molten salt storage system can store large amounts of energy, far surpassing the capacity of typical battery storage facilities. That energy can be used during times of peak demand when the wind is not blowing, or the sun isn't shining.

PacifiCorp recognizes that acknowledgement of an IRP action item is not an approval or a prudence review. While this is new technology, PacifiCorp has been engaged with a specific developer with DOE grant funding that understands and is committed to ensuring the project must provide value to our customers. TerraPower, as the developer of the Natirum plant, will be responsible for securing the private investment and managing the project. Once the plant is built and operational, PacifiCorp will seek regulatory approvals to acquire the demonstration project and operate the plant as part of its energy generation fleet. Further, the operating attributes for this resource, specifically the energy storage and inherent safety features associated with sodium, are attractive and needed in a world that is transitioning to more non-carbon and renewable resources.

PacifiCorp and Terra Power understand that PacifiCorp will only move forward if the Natrium demonstration project brings value to our customers. For these reasons, the

Company requests that the Commission acknowledge the Natrium project as a reasonable inclusion in the Company's Action Plan.

<u>Action plan items 3a and 3b:</u> These action items relate to the Company's Energy Gateway South Segment F and Energy Gateway West, Segment D.1. The economic analysis for GWS/D.1 in the 2021 IRP is extensive, including four initial portfolios each assessed with five price-policy scenarios and two variant studies also analyzed under five price-policy scenarios.

In the expected case, when adjusted for risk, the benefits of the portfolio that includes GWS/D.1 increases from $128 million to $260 million. Put another way, foregoing these projects is expected to cost customers $260 million more over the next 20 years. The risk-adjusted results indicate that these transmission projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages. While there are risks associated with pursing the GWS/D.1, any 20-year forecast is inherently uncertain. But when faced with a near-term need for additional generation to reliably serve customers, it makes little sense to forego the resources that are expected to be lowest cost in pursuit of a higher cost and higher risk path.

Moreover, the 2021 IRP economic analysis is conservative for several reasons. First, the $260 million in net benefits does not include the value of renewable energy credits generated by the associated wind resources. Second, the $260 million in net benefits are based off the first 16 years of operation for GWS and D.1 and associated wind resources. But the benefits will continue to accrue over the 60-year life of the projects and 30-year life of the associated wind resources. Even if the net customer benefits do not accrue until 2040, the resource portfolio that includes that transmission projects is still better than a portfolio without GWS/D.1, which has no net benefits and only net costs. Third, the $260 million in net benefits conservatively assumes the need to construct only a 230-kV line to satisfy its federal obligation to provide transmission service in accordance with a 500 MW point to point agreement. This is conservative because it ignores 12 executed interconnection agreements. The Company would have to build the equivalent of GWS/D.1 to satisfy its obligations under those agreements, in which case the customer net benefits from the portfolio with the transmission projects increases to $742 million.

Parties have been critical of the assumption that we would have to build other facilities to meet our federal obligation and that the costs of those other facilities would be included in the Company's FERC-jurisdictional transmission rates paid by all transmission customers, including retail customers. However, under long-standing FERC policy, we can neither avoid our obligation to provide transmission and interconnection service nor assign the costs of upgrades required to provide that service to only the customers requesting the service.

While not factored into the 2021 IRP analysis, GWS/D.1 is consistent with the objectives of HB 2021, an assessment which will feature in the 2023 IRP. Acknowledgement is also consistent with the Commission's acknowledgement of the 2020AS RFP Final Short List, which is fully supported by the 2021 IRP and affirms the need for GWS/D.1 to fulfill on identified RFP resources.

The Company submits that choosing not to acknowledge because GWS/D.1 are discussed elsewhere will surely raise confusion, as GWS/D.1 is a key feature of the preferred portfolio and 2021 IRP as a whole. When there is a need that must be met, the least cost path to meeting the need should be pursued, which is GWS/D.1 and the renewable resources enabled by this plan.

Further discussion of these action items is addressed in detail in Section IV. Federal Transmission Requirements and Ratemaking, below.

<u>Action plan item 3d:</u> States that the Company will "[i]initiate local reinforcement projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids." As discussed in response 32 above, PacifiCorp included in Table 1.1 of PacifiCorp's 2021 IRP all of the transmission projects where incremental interconnection capacity and resource additions were available to be selected by the model. The local reinforcement projects included in Table 1.1 identified opportunities where there are transmission system improvements available on PacifiCorp's system which are not required but which would ultimately improve reliability. The model selected resources in conjunction with these local reinforcements and would not have selected the additional resources if not for the interconnection capacity made available by the local reinforcement projects. Insomuch as the reinforcement projects will be required for the selection of resources in the 2022AS RFP and insomuch as the 2022AS RFP is an action item of the IRP, and insomuch as the local reinforcements may have permitting and construction timeliness which would impact a proposed resource cluster study, PacifiCorp recommends the Commission acknowledge item 3d. Allowing the local reinforcements to proceed will enable the selection of certain resources and lead to the most cost-effective option for improving system reliability associated with these specific reinforcements.

RECOMMENDATION NO. 38: PacifiCorp address ownership diversity and risks in its derivation of future RFP shortlists. [47]

RESPONSE TO RECOMMENDATION NO. 38: The Commission should not implement this requirement as part of its consideration of the 2021 IRP, but rather should consider it within docket UM 2193, the 2022AS RFP, where it can be scheduled in coordination with other procedural requirements such as sensitivity analyses.

The Company's proposed 2022AS RFP provides ample opportunity for both Power Purchase Agreement and Build Transfer Agreement transactions to be bid and considered without bias. The Company has established a specific process for benchmark resources to be considered, as explained in the Company's reply comments in docket UM 2193.[48] Additionally, the three independent evaluators required by Utah, Oregon, and Washington, will also oversee the fairness and transparency of the evaluation process.

RECOMMENDATION NO. 39: In the public input process prior to its 2023 IRP, PAC should engage with stakeholders in the public input process to propose a method for modeling some level of assumed QF renewals in its next IRP and then apply said modeling in its 2023 IRP. [49]

RESPONSE TO RECOMMENDATION NO. 39: The Company does not believe the IRP is the appropriate forum to determine modifications to QF compensation. Such changes should be considered in a proceeding relating to avoided costs. Please see the Company's response to Recommendation No. 20.

[47] Report at 38.
[48] UM 2193, PacifiCorp's Reply Comments at 8-11 (March 4, 2022)
[49] Report at 40.

RECOMMENDATION NO. 40: Before the 2023 IRP, include climate-change risk and adaptation as a topic of a public-input meeting to share and discuss approaches to modeling climate risk in the IRP including: proposed changes to how weather and extreme events are considered; proposed changes for the consideration of climate-related risks on supply side resources, transmission, and loads; and a discussion on how the Company proposes to include climate change impacts as part of the status quo. [50]

RESPONSE TO RECOMMENDATION NO. 40: The Company agrees that climate-change risk is an appropriate topic of discussion to include in the 2023 IRP and anticipates discussing these issues during the public-input process. Specifically, PacifiCorp will continue to coordinate with the Northwest Power and Conservation Council on climate change modeling and how to incorporate best practices into PacifiCorp's 2023 IRP, assess climate-related risks regarding temperature sensitive loads, and continue to evaluate electric vehicle and building electrification adoption impacts to load. PacifiCorp will also evaluate the appropriate methods of including an increase to load due to climate migration to PacifiCorp's Oregon service territory. PacifiCorp will include climate-change risk and adaptation as a topic of a public-input meeting to share and discuss approaches to capturing climate risk in the 2023 IRP and beyond.

RECOMMENDATION NO. 41: The Commission should direct PacifiCorp to file its Biannual Environmental, Transmission, and DSM Update once annually instead of biannually. Alternately, Staff would support a filing of this report one year after the filing of each IRP. [51]

[50] Report at 43.
[51] Report at 44.

RESPONSE TO RECOMMENDATION NO. 41: The Company agrees with this recommendation.

IV. FEDERAL TRANSMISSION REQUIREMENTS AND RATEMAKING

As noted earlier, in this section of its comments, PacifiCorp addresses federal transmission requirements and pricing policies and provides clarifications regarding ratemaking for transmission projects.

As a threshold matter, following up on the ratemaking discussion at the March 8 Workshop, PacifiCorp first reiterates that it plans to recover the cost of GWS and Gateway West, D.1 (the "Transmission Projects") using the long-standing federal and state cost recovery constructs used for all transmission assets. In particular, on the federal side, the Transmission Projects are considered integrated network transmission assets under PacifiCorp's Open Access Tariff (OATT), so 100 percent of their cost would be included in PacifiCorp's FERC-approved formula rate that has been in place since 2012 and that is charged to wholesale transmission customers. On the state side, 100 percent of the cost of the Transmission Projects will also be included in the retail revenue requirement in every state, but Oregon retail rates would reflect the offsetting impacts of: (1) a revenue credit reflecting third-party, wholesale use of PacifiCorp's system paid at the FERC formula rate (which typically accounts for roughly 20 percent of system usage); and (2) the state's system allocation of the cost of the Transmission Projects established as part of the MSP process.

As a second point of clarification, PacifiCorp views its obligation to construct transmission upgrades that facilitate reliable operations as encompassing more than just compliance with mandatory reliability standards issued by the North American Reliability Corporation (NERC) or the Western Electricity Coordinating Council (WECC), as was suggested during the March 8 Workshop. PacifiCorp's obligation to operate its transmission system reliably also stems from its obligation to comply with the requirements of the federal OATT that governs the rates, terms, and conditions of PacifiCorp's reliable provision of transmission and interconnection services—services it must offer to third parties, and that in some instances cannot be reliably offered without constructing upgrades. In the case of the Transmission Projects in particular, PacifiCorp used the federal OATT study process to identify the construction of the Transmission Projects as prerequisites to *reliably* providing over 2,500 MW of transmission and interconnection service requests, and the Transmission Projects were listed in multiple FERC-jurisdictional executed contracts accordingly.[52]

A. OATT Fundamentals

Before addressing the Transmission Project-dependent executed transmission service and interconnection service contracts specifically, PacifiCorp first offers some basic information about its OATT process and requirements, some of which is in response to areas of potential confusion identified during the March 8 Workshop discussion.

In 1996, FERC issued a landmark order (Order No. 888) establishing its open access transmission policies. In short, FERC required that transmission providers offer third parties "open access" to their transmission systems. To implement this requirement, FERC created a pro forma OATT with standardized rates, terms, conditions, processes, and contracts to govern the provision of transmission services. In 2003, FERC issued another series of landmark "open access" orders (Order Nos. 2003 and later 2006) specifically focused on the standardization of the rates, terms, conditions, processes, and contracts under which a

[52] Although not the focus of these comments, the Transmission Projects also facilitate PacifiCorp's compliance with federal, mandatory reliability standards. For example, they have been included in PacifiCorp's short and long-term reliability plans required by NERC's mandatory TPL-001-4 standard for the last 8 years.

transmission provider offers generator interconnection service. FERC established pro forma interconnection provisions to be included in every transmission provider's OATT on file with FERC. All transmission providers must model their OATT after FERC's pro forma OATT and maintain their FERC-approved OATT on file with FERC at all times. Any deviations from the pro forma OATT must be filed with FERC for approval.

The OATT primarily governs two basic services: (1) transmission service; and (2) generator interconnection service. OATT service is requested through a FERC-mandated public website called the Open Access Same-Time Information System (OASIS). After PacifiCorp receives a request for OATT service, it must follow the OATT process to perform a series of increasingly more involved engineering studies that evaluate the cost and timing requirements associated with providing the requested service. PacifiCorp must issue reports summarizing the results of its OATT studies and make those reports publicly available by posting them on OASIS. At the end of the study process, PacifiCorp must tender the requesting party a standardized OATT contract that memorializes the cost and timing requirements identified in the study process.

When PacifiCorp receives a request for OATT service, it must evaluate whether it can *reliably* provide that service on its existing transmission system within the timeframe requested. For example, if the existing transmission system is capable of reliably delivering the requested amount of additional transfer capacity associated with a transmission service request or reliably interconnecting the requested amount of generation associated with a generator interconnection request, the OATT studies evaluating that request are likely to state that the service can be granted within the requested timeframe with minimal or no transmission system upgrade costs. If, on the other hand, the existing transmission system is not capable of reliably delivering or reliably interconnecting additional capacity in the area of the system where the OATT service has been requested, PacifiCorp cannot simply conclude no service can be provided and reject the service request. Rather, the OATT requires PacifiCorp to identify what transmission system upgrades are needed to accommodate the request, as well as the estimated cost and timing associated with constructing those upgrades. Those upgrades then become requirements identified in the OATT customer's OATT contract.

B. OATT Obligation to Construct Transmission System Upgrades

The OATT requires PacifiCorp to construct transmission system upgrades necessary to grant OATT requests for transmission service and OATT requests for generator interconnection service. This obligation to construct is found in the OATT's provisions governing: (1) network transmission service; (2) point-to-point transmission service; and (3) generator interconnection service.

First, the OATT's network transmission service provisions require a transmission provider to "plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System" and "endeavor to construct and place into service sufficient transfer capability" to deliver network customer resources to load.[53]

Second, the OATT's point-to-point transmission service provisions require a transmission provider to "use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service" if the transmission provider cannot

[53] PacifiCorp OATT, Section 28.2 (emphasis added).

accommodate the request because of insufficient capability on its system.[54] PacifiCorp's OATT provides as follows:

> In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4.[55]

Third, sections 36-52 of PacifiCorp's OATT contain comprehensive rules for interconnecting new generators, including the identification and construction of new network upgrades if they are necessary to grant the request. Importantly, the OATT process does not give PacifiCorp any tariff authority to refuse an interconnection request simply because it would require new network upgrades. FERC has clarified that its pro forma interconnection services "provide for the construction of Network Upgrades that would allow the Interconnection Customer to flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner."[56]

C. Construction Obligation and Planned Projects

As a point of clarity in response to the March 8 Workshop discussion regarding utility planned projects, the OATT obligation to construct applies whether or not the transmission upgrade at issue was part of the transmission provider's plan. In other words, it applies to both (1) transmission system upgrades triggered for the first time in response to an OATT request and (2) previously planned transmission projects identified as necessary to grant an OATT request.

[54] PacifiCorp OATT, Section 15.4 (emphasis added).
[55] PacifiCorp OATT, Section 13.5 (emphasis added).
[56] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 104 FERC ¶ 61,103 at P 767 (2003) (emphasis added).

By way of background, FERC required transmission providers to amend their OATTs to address transmission planning obligations and processes. For PacifiCorp, Attachment K of its OATT sets forth inter-regional, regional, and local transmission planning processes that are overseen by FERC, NERC, and WECC. As with all provisions in the OATT, PacifiCorp secured FERC approval of the Attachment K provisions and must file any proposed changes with FERC. The Attachment K planning process is a highly regulated, FERC-approved process that employs regional planning organizations – in PacifiCorp's case, NorthernGrid, which develops a regional plan under rules also approved by FERC. The Transmission Projects have been a component of PacifiCorp's long-term transmission plan since 2007. NorthernGrid has an enrolled party and states committee providing the opportunity for stakeholders to provide input into the regional transmission planning process. The Transmission Projects have also been included in regional transmission plans prepared by Norther Tier Transmission Group for many years. The 2020-2021 NorthernGrid Regional Transmission Plan also confirmed that the Transmission Projects were selected as part of the most efficient solution for the region. The Transmission Projects are also included in the WECC Anchor Data Set and base cases. Each utility in the West uses those base cases to perform planning and interconnection studies assuming these projects will be in service by 2024. The Company has also included the Transmission Projects in its annual TP-001-4 assessment as part of its short- and long-term plans to dependably meet NERC and WECC reliability requirements for eight years.

PacifiCorp's FERC-approved Attachment K makes clear that once a planned transmission project is required to be in-service in order for PacifiCorp to grant an OATT request for point-to-point transmission service or generator interconnection service, PacifiCorp is obligated to construct the planned facilities: "Transmission Provider shall use Point-to-Point Transmission Service usage forecasts and Demand Resources forecasts to determine system usage trends, and such forecasts do not obligate the Transmission Provider to construct facilities until formal requests for either Point-to-Point Transmission Service or Generator Interconnection Service requests are received pursuant to Parts II and IV of the Tariff."[57] And if PacifiCorp's ability to provide requested OATT service is contingent upon a component of PacifiCorp's long-term transmission plan being in-service, the OATT studies and OATT contracts make that clear. That is, if PacifiCorp cannot reliably provide requested OATT service until a component of PacifiCorp's long-term transmission plan is in place, that upgrade is listed in the OATT study and OATT agreement as a "Contingent Facility." FERC recently formalized this definition with respect to generator interconnection service, and approved the following definition for inclusion in PacifiCorp's OATT:

> Contingent Facilities shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for Re-Studies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.[58]

D. The Transmission Projects are Requirements in FERC-Jurisdictional Executed Contracts

PacifiCorp followed the required federal processes described above, which led to the identification of the construction of the Transmission Projects as a prerequisite to reliably providing OATT service in response to over 2,500 MW of transmission and interconnection requests. PacifiCorp has executed 13 transmission service and generator interconnection service contracts that list either one or both of the Transmission Projects as Contingent

[57] PacifiCorp OATT, Attachment K (emphasis added).
[58] PacifiCorp OATT at section 36.

Facilities accordingly. This means that PacifiCorp cannot provide the contracted services to 13 contractual counterparties without constructing the Transmission Projects.

1. Transmission Service Contract

First, with respect to the transmission service contract, PacifiCorp received an OATT request to provide 500 MW of point-to-point transmission service from Aeolus to Mona starting January 1, 2024. In accordance with the OATT process outlined above, PacifiCorp determined it could not deliver an additional 500 MW of power on its existing transmission system due to *reliability* concerns. More specifically, the OATT states that, "where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4." That was the case here because, under steady-state conditions, increasing transfers between eastern Wyoming (Aeolus) and central Utah (Mona) by 500 MW would result in a voltage collapse of the PacifiCorp east side transmission system for a minor system contingency in Wyoming or northern Utah. Such a voltage collapse would violate NERC and WECC reliability standards, would degrade the reliability of service to other customers, and would negatively impact other utilities in the Western Interconnection.

In light of the fact that PacifiCorp could not provide the requested service on the existing system without degrading reliability, it performed an OATT system impact study to determine what transmission system upgrades would be required to do so. PacifiCorp's

OATT system impact study report, which is publicly posted to OASIS, states that PacifiCorp's planned GWS 500 kV line from the Aeolus substation to the Clover substation near Mona, Utah (GWS) must be in place to grant the requested FERC-jurisdictional point-to-point transmission service. In accordance with the OATT process, GWS was also included as a contingent facility in the pro forma point-to-point contract tendered to and executed by the customer.

Identifying GWS as the "contingent facility" solution to the reliability concern was appropriate because the OATT service request was for 500 MW of point-to-point from Aeolus to Mona – the exact path of the proposed GWS line. In addition, identifying a long-term transmission plan component as a contingent facility to providing requested service is consistent with the OATT's directive that transmission providers make efficient use of the estimated capabilities and estimated timelines associated with the transmission provider's long-term transmission plan. This may not always lead to the identification of a transmission system upgrade that creates the precise amount of transfer or interconnection capability needed to grant the requested service. That is the case here where GWS creates more transfer capability than is needed to grant the point-to-point request. However, it is generally far more efficient to identify planned projects when possible because those projects have gone through extensive local, regional and inter-regional planning coordination spanning multiple years. Additionally, significant permitting efforts and other regulatory processes can take years to get final approvals. Therefore, projects that are already well advanced in this process are more likely to be successful.

In this case, the planned GWS project is not significantly greater than the transmission system upgrades that would be needed to grant just this isolated request based on an evaluation PacifiCorp performed in response to stakeholders in the Company's integrated resource plan proceeding before the Utah Public Service Commission. Specifically, stakeholders asked PacifiCorp to provide information about how its preferred portfolio and system costs might be impacted if GWS is assumed to be removed from the preferred portfolio. In response, PacifiCorp explained that, even if GWS is not constructed, it is unrealistic to assume that PacifiCorp transmission would not be obligated to construct any transmission system upgrades out of eastern Wyoming to accommodate FERC-jurisdictional requests for OATT interconnection service and transmission service. PacifiCorp continued that, even conservatively ignoring what transmission system upgrades would be required to grant all of the requests it has received for FERC-jurisdictional interconnection and transmission service and focusing *only* on the 500 MW point-to-point transmission service request, PacifiCorp estimated it would need to construct, at a minimum, a 230-kV transmission line at a cost in excess of $1 billion.

Staff has asked for a copy of the formal study evaluating this 230-kV line alternative. PacifiCorp did not do a formal study, as this was a hypothetical scenario that assumed away all generator interconnection requests and focused on the minimum network upgrades that would be required to meet just a single, 500 MW point-to-point request within the transmission customer's timeframe. PacifiCorp performed a very high-level, conservative analysis designed to demonstrate that, even with only the 500 MW point to point request, PacifiCorp would be required to make a significant transmission investment. That analysis first involved an evaluation of whether there was any available transfer capability over the path the customer requested. Once it was determined that there was no available transfer capability and significant transmission upgrades across Aeolus

West, Bridger West and Path C would be required to reliably accommodate the requested transmission service on the existing paths, PacifiCorp concluded that a 230-kV transmission line creating roughly 550 MW (as opposed to 1,700 MW) of transfer capability along the same path as GWS would allow PacifiCorp to reliably provide service to the single, 500 MW transmission service request within the customer-requested timeframe. Importantly, however, the 230-kV line would only allow the interconnection of approximately 1,150 MW of new generation, so constructing only this hypothetical line would not permit PacifiCorp to provide service under all of its executed interconnection contracts. It is also important to note that PacifiCorp did not analyze the system impacts of outages on the estimated interconnection and transfer capability of the hypothetical 230kV line, which, if performed, would likely reduce the line's estimated 1,150 MW of interconnection capability and 550 MW of new transfer capability.

2. *Interconnection Service Contracts*

Second, with respect to interconnection service contracts, PacifiCorp received thousands of MWs of requests for generator interconnection service in eastern Wyoming. In accordance with the OATT process described above, PacifiCorp determined it cannot reliably accommodate any additional generator interconnections in that area of the existing transmission system without improvements in place. As a result, PacifiCorp has performed and posted to OASIS many system impact studies identifying either one or both of the components of the Transmission Projects (GWS and Gateway West Segment D.1) as contingent facilities necessary to grant requested interconnection service. The table below identifies these results at a high level:

Q#	MW	One or Both Transmission Projects Required
Q409	320	Gateway South
Q713	350	Gateway South, Gateway West Segment D.1
Q719	280	Gateway South, Gateway West Segment D.1
Q783	30	Gateway South, Gateway West Segment D.1
Q784	80	Gateway South, Gateway West Segment D.1
Q785	100	Gateway South, Gateway West Segment D.1
Q789	74.9	Gateway South, Gateway West Segment D.1
Q801	80	Gateway South, Gateway West Segment D.1
Q802	50	Gateway South, Gateway West Segment D.1
Q807	75.9	Gateway South, Gateway West Segment D.1
Q835	190	Gateway South, Gateway West Segment D.1
Q836	400	Gateway South, Gateway West Segment D.1

Like with the transmission service request described above, PacifiCorp concluded that the requested generator interconnections could not be provided on the existing transmission system due to reliability concerns. FERC requires transmission providers to identify the transmission system upgrades that need to be constructed in order to allow the interconnection customer to "flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner." Here, interconnecting additional generation in the eastern Wyoming area without construction of the Transmission Projects would result in a voltage collapse of the PacifiCorp east side transmission system for a minor system contingency in Wyoming or northern Utah. Such a voltage collapse would violate NERC and WECC reliability standards, would degrade the reliability of service to other customers and would negatively impact other utilities in the Western Interconnection. As a result, PacifiCorp issued studies and executed 12 interconnection agreements that identify the Transmission Projects as contingent facilities. The counterparties to these executed agreements have, in total, secured contractual rights to all of the interconnection capability of the Transmission Projects.

PacifiCorp performed an analysis to test whether it would have been able to reliably grant the requested generator interconnections with a smaller upgrade if it had not defaulted to PacifiCorp's long-term plan for the upgrade solution, but the answer was no. First, PacifiCorp assumed there was no plan to construct the Transmission Projects. Next, PacifiCorp evaluated what, if any, transmission upgrades would be required to grant the first generator interconnection request that required the Transmission Projects. PacifiCorp continued to add projects and evaluate individual incremental interconnection requirements one at a time until it had added all of the requests currently dependent on the Transmission Projects. The analysis showed that while no single project individually triggered the need for a 500-kV line, because of the cumulative nature of the project-specific studies, the Company would have been required to construct more and more 230-kV and 345-kV transmission lines. In total, the Company could interconnect an estimated 1,441 MW of additional generation resources, which represent 10 interconnection requests, before the next request triggered the need for a 500-kV line to interconnect. To interconnect those 10 projects, however, would cost approximately $1.53 billion dollars, the Company would have achieved only 814 MW of incremental transfer capability, and it would still have remaining interconnection requests in need of upgrade identification. By comparison, the Transmission Projects are estimated to cost $2.04 billion and provide approximately 1,700 MW of transfer capability and 2,030 MW of interconnection capability.

PacifiCorp's identification of the planned Transmission Projects as the upgrade solution to reliably interconnect additional generation in eastern Wyoming thus did not lead to more significant upgrades than would have been otherwise required. The analysis demonstrates that the Company likely would have ended up in largely the same spot (i.e., identifying a 500-kV line) with fewer financial, interconnection, transmission, and operational efficiencies. As a result, it was not only consistent with the OATT to identify components of PacifiCorp's long-term transmission plan as contingent facilities in the interconnection studies, but it was also beneficial. It is also important to remember that this analysis looked at interconnection requests in isolation, without regard to transmission service requests like the 500 MW point-to-point request discussed at length previously. In reality, the OATT requires PacifiCorp to identify the transmission system upgrades necessary to grant *all* of the requests it receives, not just some.

3. Obligation to Comply with Executed Contracts

FERC's recent approval of PacifiCorp's interconnection queue reform proposal reaffirms PacifiCorp's obligation to comply with its executed interconnection contracts. As a reminder, in June 2019, PacifiCorp initiated a six-month stakeholder process to examine potential interconnection processing reforms to address the significant congestion in its interconnection queue, which at the time had 234 requests for over 40,000 MW of interconnection capacity. One of the primary issues discussed throughout the stakeholder process was how to transition from serial-queue processing that cumulatively studies each individual interconnection request and does not test the "commercial readiness" of any generator (i.e., FERC's long-standing, first-come, first-served process) to a first-ready, first-served process that studies requests in groups (called "clusters") on an annual basis and requires large, FERC-jurisdictional generators to demonstrate readiness as a prerequisite to receiving an interconnection study. Readiness may be proven by, for example, providing evidence that the generator has an executed term sheet, executed power-purchase agreement, or has been selected in a competitive solicitation process. One of the most critical elements to this transition discussion was whether any generators should be allowed to keep their serially processed studies or agreements without demonstrating readiness.

Initially, stakeholders strongly supported applying the new readiness testing requirements to all interconnection customers, even those that were already at the end of the study process or that had executed an interconnection agreement. The stakeholders reasoned that allowing parties with executed interconnection contracts to maintain their contractual rights without demonstrating any type of commercial readiness would prevent PacifiCorp from effectively clearing out its congested queue. In response, PacifiCorp initially included this broad application of the transition requirements in its straw proposals issued in September 2019 and November 2019 and planned to make it part of its ultimate proposal filed with FERC. After additional stakeholder discussions, however, it became clear there would be significant opposition to this approach, particularly from counterparties having executed contracts. FERC staff similarly signaled resistance to a proposal that would abrogate executed interconnection agreements.

As a result of this feedback, PacifiCorp's January 31, 2020, filing with FERC reflected a modified transition proposal that: (1) allows generators to retain executed interconnection agreement rights without demonstrating commercial readiness; and (2) allows "late stage" generators, defined as any interconnection customer that reached the facilities study agreement stage or later by April 1, 2020, the option to keep their serially processed studies and proceed to an agreement reflecting those study results as long as, for large generators, they can demonstrate commercial readiness. In addition, given that the vast majority of the projects in PacifiCorp's interconnection queue are large, FERC-jurisdictional generators, PacifiCorp proposed not to require small, FERC-jurisdictional generators or statejurisdictional qualifying facility generators of any size to provide evidence of commercial readiness at this time. PacifiCorp proposed these requirements to be reflected in PacifiCorp's very first cluster study, the "transition cluster," that began in October 2020. PacifiCorp also proposed limitations for requests that were too early in the process by limiting eligibility for the initial October 2020 transition cluster to only those interconnection customers that had a queue position by January 31, 2020.

In its May 12, 2020, order, FERC approved this transition approach, noting in particular with respect to the executed contracts that "PacifiCorp's Transition Process appropriately protects interconnection customers that are in the late stages of interconnection *by not disrupting already signed interconnection agreements* and continuing to process late stage interconnection requests under the currently serial process, provided they meet the commercial readiness criteria."[59] This order did not change PacifiCorp's obligation to provide interconnection service under executed contracts, but rather emphasized the importance of adhering to their terms.

PacifiCorp, in good faith, acted consistently with the federal OATT process and obligations when it identified the Transmission Projects as transmission system upgrades that must be constructed to reliably provide the requested service. PacifiCorp also acted consistently with the federal OATT process when it listed the Transmission Projects as contingent facilities in the executed contracts—contracts that are on file with FERC. If PacifiCorp is put in a position where it cannot construct the Transmission Projects for lack of necessary state regulatory approvals, and it cannot provide the requested OATT service reliably on the existing system, the OATT requirements would prohibit it from simply not

[59] PacifiCorp, 171 FERC ¶ 61,112 at P 144 (2020) (emphasis added).

pursuing transmission system upgrades that are necessary to accommodate FERC-jurisdictional requests for OATT service.

E. Alternative Financing

PacifiCorp offers clarifications regarding the potential for alternative financing for the Transmission Projects in response to the discussion at the March 8, 2022, workshop and statements in the Report[60] regarding use of incremental rates by the Bonneville Power Administration—an entity that is not subject to traditional FERC jurisdiction and is not required to maintain an OATT on file with FERC. In short, Staff is correct that PacifiCorp could not force its 500 MW point-to-point transmission customer to pay an incremental rate because GWS is a component of PacifiCorp's long-term transmission plan.

Likewise, PacifiCorp could not propose to use an incremental rate structure for the 12 executed interconnection contracts because incremental rates are only for transmission service. It is also not possible to directly assign the cost of the Transmission Projects to the counterparties to the interconnection contracts because that type of interconnection cost allocation structure, which is often referred to as "participant funding," is an organized market model, but is not the governing rule in PacifiCorp's OATT.

V. NEXT STEPS

The Commission has a public meeting scheduled for March 22, 2022, and continued on March 29, 2022, to accept final comments and deliberate on PacifiCorp's 2022 IRP. The Company will be prepared to address the items identified above. PacifiCorp will also be prepared to respond to any additional questions that may arise from the Commission, Staff, or other interested stakeholders.

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[60] Final Staff Report at page 31.

VI. CONCLUSION

PacifiCorp's 2021 IRP complies with the Commission's standards and guidelines. The 2021 IRP includes robust portfolio modeling and prudent planning assumptions that led to selection of a least-cost, least-risk preferred portfolio. The 2021 IRP also includes an Action Plan that is consistent with the long-term public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group and has fully responded to all concerns raised by these stakeholders, including Commission Staff. Based on this robust analysis, PacifiCorp respectfully requests that the Commission acknowledge the 2021 IRP and the Action Plan, in accordance with the recommendations set forth in these response comments.

Respectfully submitted this 11th day of March, 2022.

Shelley McCoy

Shelley E. McCoy
Director, Regulation
PacifiCorp d/b/a Pacific Power