ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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April 7, 2022

*VIA ELECTRONIC FILING*

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

**RE: Docket No. 21-035-09**
**PacifiCorp's 2021 Integrated Resource Plan Update**
*PacifiCorp's Reply Comments*

In accordance with the Scheduling Order and Notice of Technical Conference issued by the Public Service Commission of Utah ("Commission") on September 20, 2021 in the above referenced matter, PacifiCorp submits its Reply Comments regarding its 2021 Integrated Resource Plan ("2021 IRP").

Informal inquiries regarding this filing may be directed to Jana Saba, Utah Regulatory Affairs Manager, at (801) 220-2823.

Sincerely,

Joelle Steward
Senior Vice President, Regulation and Customer/Community Solutions

Enclosures

cc: Service List

## CERTIFICATE OF SERVICE

Docket No. 21-035-09

I hereby certify that on April 7, 2022, a true and correct copy of the foregoing was served by electronic mail to the following:

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**BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH**

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| **IN THE MATTER OF PACIFICORP'S 2021 INTEGRATED RESOURCE PLAN (IRP)** | DOCKET NO. 21-035-09 |

**PACIFICORP'S REPLY COMMENTS**

In accordance with the Utah Public Service Commission's ("Commission") Scheduling Order, PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company"), by and through its counsel, provides these Reply Comments to the comments received by the Commission from the Division of Public Utilities ("DPU"), the Office of Consumer Services ("OCS"), Utah Association of Energy Users ("UAE"), Salt Lake City Corporation ("SLC Corp"), Western Resource Advocates ("WRA"), Utah Clean Energy ("UCE"), Southwest Energy Efficiency Project ("SWEEP")/UCE, Sierra Club, Fervo Energy Company ("Fervo"), Interwest Energy Alliance ("IEA"), and the Renewable Energy Coalition ("REC") (collectively "Commenting Parties") on March 4, 2022.

## INTRODUCTION AND SUMMARY

PacifiCorp's 2021 Integrated Resource Plan ("IRP"), filed on September 1, 2021 ("2021 IRP"), complies with the Commission's 1992 Report and Order on Standards and Guidelines for Integrated Resource Planning in Docket No. 90-2035-01 ("Commission's Report and Order"), and adequately addressed the requirements from the 2019 IRP Report and Order in Docket No. 19-035-02 ("2019 IRP Order"). To be acknowledged, the plan must be deemed reasonable at the time it is presented. As part of its review, the Commission determines whether the IRP adequately adheres to the Commission's Report and Order and takes into consideration the "merit and applicability" of public comments.

The 2021 IRP was developed after substantial stakeholder input. The stakeholder process for the 2021 IRP began in January 2020, with a series of technical workshops focused on energy efficiency modeling assumptions to inform an updated Conservation Potential Assessment ("CPA"). PacifiCorp held a series of four technical workshops in January, February, April, and August of 2020. In addition, PacifiCorp began a series of broader-topic general public-input meetings starting in June 2020, which addressed a range of topics describing PacifiCorp's modeling methodology, inputs and assumptions for the 2021 IRP. Agenda topics included, but were not limited to, resource cost-and-performance assumptions, model function and overview, load forecast, price-policy assumptions, supply-side resource cost and performance assumptions, market price assumptions, and transmission options. PacifiCorp held 18 public-input meetings and five state-specific input meetings. Public-input meeting materials, supporting studies, and stakeholder feedback forms can be found on PacifiCorp's IRP webpage.[1]

[1] *See* https://www.pacificorp.com/energy/integrated-resource-plan.html; See also the 2021 IRP Volume II, Appendix C – Public-Input Process for more detail.

The resulting 2021 IRP and action plan[2] provides a roadmap to ensure PacifiCorp will provide adequate and reliable electricity supply to its customers at a reasonable cost. PacifiCorp's selection of the 2021 IRP preferred portfolio is supported by detailed data analysis using five fundamental steps: (1) development of key inputs and assumptions to inform the modeling and portfolio-development process; (2) development of a wide-range of resource portfolios; (3) targeted reliability analysis of the portfolios to ensure sufficient flexible capacity resources to meet reliability requirements; (4) analysis of the resource portfolios to measure comparative costs, risks, reliability and emission levels that inform selection of a preferred portfolio; and (5) development of the near-term resource action plan required to deliver resources in the preferred portfolio.[3] Each of these steps in the 2021 IRP development process are presented in greater detail in the Company's filing, including the supporting work papers that present the underlying data for each of the portfolios analyzed by PacifiCorp.

In these Reply Comments, PacifiCorp describes how the 2021 IRP and the associated action plan comply with all Commission requirements. The Company considered and implemented the Commission's direction in developing the 2021 IRP and believes it complies with all Commission directives. Therefore, the Commission should acknowledge the Company's 2021 IRP.

## COMMISSION IRP STANDARDS

The IRP is a 20-year long-term resource plan intended to identify the least-cost, least risk portfolio of generation and transmission resources needed to meet the Company's obligation to reliably serve its customers. Under the Commission's Report and Order, "The Commission will

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[2] 2021 IRP, Chapter 1 – Executive Summary, Table 1.2 at 23. The 2021 IRP action plan identifies specific resource actions PacifiCorp will take over the next two-to-four years to deliver resources included in the preferred portfolio.
[3] 2021 IRP, Chapter 1 – Executive Summary at 7-8.

require PacifiCorp to pursue the least cost alternative for the provision of energy services to its present and future ratepayers that is consistent with safe and reliable service, the fiscal requirements of a financially healthy utility, and the long-run public interest."[4] The Commission outlined the following standards and guidelines ("Guidelines") regarding PacifiCorp's IRPs:

(1) Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty;

(2) The Company will submit its IRP biennially;

(3) The IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties;

(4) PacifiCorp's future IRPs will include:

a. A range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements;

b. An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis;

c. An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions;

d. A 20-year planning horizon;

e. An action plan outlining the specific resource decisions intended to implement the IRP in a manner consistent with the Company's strategic business plan;

[4] *In the Matter of Analysis of an Integrated Resource Plan for PACIFICORP*, Docket No. 90-2035-01, Report and Order on Standards and Guidelines, ¶ 1 (June 18, 1992).

f. A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds;

g. An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers;

h. An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan;

i. Considerations permitting flexibility in the planning process;

j. An analysis of tradeoffs;

k. A range, rather than attempts at precise quantification, of estimated external costs which may be intangible;

l. A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives;

(5) PacifiCorp will submit its IRP for public comment, review and acknowledgement;

(6) The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan;

(7) Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions; and

(8) The IRP will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.[5]

The Company has met these Guidelines, and has also complied with the Commission's directives from the 2019 IRP Order. Specifically, Appendix B of the 2021 IRP lists the

[5] *Id.* at 16-34.

requirements included in the 2019 IRP Order and provides a reference to where the requirement was met.[6] Compliance with these Commission requirements is explained in more detail in the Company's response to comments below. The Company respectfully requests that the Commission acknowledge the 2021 IRP.

**SUMMARY OF COMMENTS**

DPU, OCS, UAE, SLC Corp, WRA, UCE, SWEEP/UCE, Sierra Club, Fervo, IEA, and REC each filed comments on the 2021 IRP, some of which overlap in subject matter.

DPU recommends that the Commission acknowledge only the new resources in the two-to-four-year window of the 2021 IRP's action plan.[7] DPU states that the 2021 IRP complies with the Commission's Report and Order, with the exception of Guideline 3, which requires the Company to develop the IRP "in consultation with" stakeholders. DPU criticizes the public-input process and raises concerns that the Company did not allow the model to select new natural gas resources. DPU argues that by choosing not to incorporate new natural gas resources in the Company's modeling and including estimates of nuclear plant costs and risks, the Company did not sufficiently take stakeholder feedback into account. DPU supports the Company's decision to move forward with retiring coal-fired generation.[8] DPU does not object to including the Natrium advanced nuclear demonstration project ("Natrium") in Action Item 2c of the action plan because it does not require significant capital investment. DPU recommends that future IRPs allow the model to select a new natural gas proxy resource and only include Natrium if additional discussion of risk is included. DPU also analyzes the Company's load growth, natural gas, and carbon cost

[6] 2021 IRP, Appendix B – IRP Regulatory Compliance at 40-42.
[7] Comments of the Division of Public Utilities in Response to PacifiCorp's 2021 Integrated Resource Plan at 1 (March 4, 2022) ("DPU Comments").
[8] DPU Comments at 29-31.

forecasts, concluding that the load growth and natural gas price forecasts were reasonable, but that a carbon cost is unlikely to be imposed in the near future.

OCS recommends that the Commission not acknowledge the 2021 IRP, claiming that it does not comply with Guidelines 1, 4.b., 4.b.ii., 4.g., and 4.h.[9] Specifically, OCS argues that by including Natrium and hydrogen-fueled non-emitting peaker resources, the Company did not appropriately account for the risks of these resources and did not appropriately quantify the rate impacts of the preferred portfolio. OCS also criticizes the 2021 IRP for constraining the model from selecting a new natural gas proxy resource. Finally, OCS criticizes the public-input process primarily because the final preferred portfolio was presented only four days before the 2021 IRP was filed.

UAE recommends that the Commission partially decline to acknowledge the portion of the 2021 IRP that relates to Natrium.[10] UAE is not opposed to Natrium but states it has concerns about the amount of information the Company provided in the 2021 IRP. UAE also recommends that the Commission direct the Company in providing additional transmission alternatives during the IRP process.

SLC Corp recommends that the Commission encourage assessment and modeling of emerging clean energy technologies in the IRP process, including long-duration storage, and discourage modeling unlicensed and/or non-commercial resources in the first half of the IRP, and require a disclaimer when the Company does so.[11] SLC Corp also requests a comparison of forecasted versus actual carbon dioxide emissions over the past five years and a disclaimer on any

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[9] Comments of the Office of Consumer Services in Response to PacifiCorp's 2021 Integrated Resource Plan at 1-2 (March 4, 2022) ("OCS Comments").

[10] Comments of Utah Association of Energy Users in Response to PacifiCorp's 2021 Integrated Resource Plan at 4 (March 4, 2022) ("UAE Comments").

[11] Comments of Salt Lake City Corporation in Response to PacifiCorp's 2021 Integrated Resource Plan at 3 (March 4, 2022) ("SLC Corp Comments").

preferred portfolio that does not include a functional limit on the amount of carbon dioxide ("$CO_2$") emitted.

WRA supports the Company excluding new natural gas-fired resources and the natural gas conversion of Jim Bridger units 1 and 2.[12] WRA recommends modeling changes relating to the take or pay assumptions, and it also recommends that the Company describe and illustrate the distinction between renewable energy and null power as it relates to the projected energy mix with preferred portfolio resources in future IRPs. WRA recommends that as part of the public- input process, the Company discuss with stakeholders and receive feedback on system-wide emissions accounting, state-specific allocations, and climate change impacts in resource planning.[13]

UCE supports the Company's decision to not model new gas resources due to trends towards decarbonization, risk of stranded costs, and the increasing price gap between natural gas and alternative resources.[14] UCE recommends the Commission not acknowledge Natrium until further information is available. For future IRPs, UCE also recommends that the Company take into account its preferred resources, consider increased electrification in developing load forecasts, incorporate additional climate change scenarios, and use the coal unit dispatch from the IRP when negotiating new fuel supply agreements and real time dispatch.

SWEEP/UCE claims that the Company refused to provide the analysis requested and recommends that the Commission create a new docket or alternatively require the following items be included in the 2023 IRP: (1) Low, medium, and high cases for technically achievable potential in the CPA; (2) An analysis that compares measure-level levelized cost and supply assumptions

[12] Comments of Western Resource Advocates in Response to PacifiCorp's 2021 Integrated Resource Plan at 5 (March 4, 2022) ("WRA Comments").
[13] WRA Comments at 31-32.
[14] Comments of Utah Clean Energy in Response to PacifiCorp's 2021 Integrated Resource Plan at 8 (March 4, 2022) ("UCE Comments").

from the 2015, 2017, 2019, and 2021 CPAs with historical measure-level cost and program achievements in Utah; and (3) If program performance differs from targets modeled in the IRP, increase Demand Side Management ("DSM") targets and spending.[15]

Sierra Club claims that the Company did not meet the requirement of demonstrating that its plan and actions with the 2021 IRP are in the public interest and urges the Commission to require action by the Company in reducing emissions in accordance with Utah policy and transitioning to a clean energy fleet.[16]

Fervo claims that the Company used "outdated information on the cost and resource potential of geothermal energy development in Utah."[17] Accordingly, Fervo recommends that the Company more accurately model geothermal energy in future planning scenarios. It does not make a recommendation about whether the Commission should acknowledge the 2021 IRP.

IEA recommends that the Commission acknowledge the 2021 IRP and associated action plan with the following conditions required by the Company: improve the analysis of capacity contributions and essential grid services provided by new renewable energy resources and energy storage, continue to focus on transmission expansion, and establish a pattern of procurements that align with the cluster study process.[18] IEA notes several resource planning issues that provide context for but do not directly relate to the Company's 2021 IRP but which could be considered in the 2023 IRP through the stakeholder feedback form or public-input meeting process.

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[15] Comments of Southwest Energy Efficiency Project and Utah Clean Energy in Response to PacifiCorp's 2021 Integrated Resource Plan at 16 (March 4, 2022) ("SWEEP/UCE Comments").

[16] Comments of Sierra Club in Response to PacifiCorp's 2021 Integrated Resource Plan at 1, 4 (March 4, 2022) ("Sierra Club Comments").

[17] Comments of Fervo Energy Company in Response to PacifiCorp's 2021 Integrated Resource Plan at 1 (March 4, 2022) ("Fervo Comments").

[18] Comments of Interwest Energy Alliance in Response to PacifiCorp's 2021 Integrated Resource Plan at 2, 25 (March 4, 2022) ("IEA Comments"). Concerns with the procurement process are not relevant to the IRP and were addressed in the comments responding to the Company's 2022AS RFP, Docket No. 21-035-12, filed on March 31, 2022.

REC recommends that the Commission direct the Company to (1) assume that qualifying facility ("QF") contracts will be renewed or that new contracts will be executed, (2) complete a sensitivity analysis, and (3) provide a reasonable estimate of the capacity value for renewing QFs.[19] As a result of this criticism, it requests that the Commission not acknowledge the Company's 2021 IRP assumptions.

## REPLY TO PARTIES' COMMENTS

Because many of the comments overlap, the Company will respond to many comments by subject matter, noting the position of commenting parties as appropriate. The Company will first respond to comments that the 2021 IRP does not comply with certain Commission Guidelines and the recommendation by several parties that all or part of the 2021 IRP should not be acknowledged. The Company then addresses criticisms of Natrium and explains why it was appropriate to include this project in the 2021 preferred portfolio. The Company also addresses why it chose to constrain the model from selecting new natural gas resources. Next, the Company addresses concerns with various modeling assumptions raised by the parties. The Company also explains how it demonstrated the ratepayer impacts of the preferred portfolio, addresses transmission planning concerns raised by UAE and IEA, and explains the role of state policy in developing the IRP. Finally, the Company addresses the way the 2021 IRP considers climate change and a number of comments raised by the Sierra Club. The Company's response demonstrates that the 2021 IRP relies on considered, reasonable assumptions, and the Commission should acknowledge it.

### A. 2021 IRP – Filing and Stakeholder Process

The Company provided substantial opportunities for stakeholder participation in the development of the 2021 IRP. In their opening comments, DPU and OCS express concern that the

[19] Comments of Renewable Energy Coalition in Response to PacifiCorp's 2021 Integrated Resource Plan at 10 (March 4, 2022) ("REC Comments").

Company did not provide enough time for stakeholder feedback and criticize the meeting schedule and short lead time for meeting materials. OCS asserts that the Company did not provide enough time for stakeholder feedback because the final preferred portfolio was not presented to stakeholders until the August 27, 2021 public-input meeting. DPU claims that the alleged deficiencies in the process rose to the level of noncompliance with IRP Guideline 3, which requires the Company to "provide ample opportunity for public input and information exchange." DPU also argues that the Company should be required to provide a draft IRP in advance of its next IRP filing.

PacifiCorp conducted a robust stakeholder feedback process to develop its 2021 IRP. Beginning in January 2020, PacifiCorp held a series of technical workshops focused on energy efficiency modeling assumptions. PacifiCorp then held a series of three technical workshops in January, February, and April of 2020. PacifiCorp began a series of broader-topic general public-input meetings starting in June 2020, which addressed a range of topics describing PacifiCorp's modeling methodology, inputs and assumptions for the 2021 IRP. Agenda topics included, but were not limited to, resource cost-and-performance assumptions, model function and overview, load forecast, price-policy assumptions, supply-side resource cost and performance assumptions, market price assumptions, and transmission options. PacifiCorp has held 18 public-input meetings in addition to five state-specific input meetings. All public-input meeting materials, supporting studies, and stakeholder feedback forms can be found on PacifiCorp's IRP webpage.[20]

For its 2021 IRP, PacifiCorp implemented a new advanced optimization modeling system called PLEXOS. Despite a methodical and dedicated approach to the implementation and testing of PLEXOS, the Company experienced issues with the software and ability to produce modeling

[20] *See* www.pacificorp.com/es/irp.html; See also the 2021 IRP Volume II, Appendix C – Public-Input Process for more detail.

outcomes in January 2021 that involved fixes or software patches from the vendor. Given the need to resolve these implementation issues and the timeline of the then on-going 2020 All-Source Request for Proposals ("2020AS RFP"),[21] PacifiCorp provided notice that it extended the anticipated filing date of for the 2021 IRP from April 1, 2021, to no later than September 1, 2021.[22]

The Company presented an indicative preferred portfolio at a public-input meeting held on June 24-25, 2021, which described the best performing portfolio in advance of the variant cases and sensitivities that were still being developed. This allowed parties two full months before the final 2021 IRP to ask questions and provide feedback. The indicative portfolio was broadly consistent with the eventual preferred portfolio. The Company cannot finalize its preferred portfolio until all analysis has been completed, which is why the final preferred portfolio was presented days before it was filed. The stakeholder feedback process used to develop the 2021 IRP met the IRP Guideline requiring "public comment, review and acknowledgment." However, the Company appreciates the feedback from OCS and DPU regarding the stakeholder process and will continue to look for ways to improve the IRP stakeholder process and certainty around the public-input meeting schedule and deliverables.

A draft IRP is not necessary to the IRP development process, and the current feedback process is superior to a draft IRP. DPU asserts that the 2021 IRP arguably did not meet Guidelines 5 and 6 because PacifiCorp did not submit a draft IRP and recommends the Commission require a draft to be filed on February 1, 2023, in advance of the next IRP. As an initial matter, Guidelines 5 and 6 do not specifically require a full draft IRP in advance of the finalized report. Guideline 5 requires only that PacifiCorp "submit its IRP for public comment, review and acknowledgement,"

[21] *Application of Rocky Mountain Power for Approval of Solicitation Process for 2020 All Source Request for Proposals,* Docket No. 20-035-05, Order Approving 2020 All Source RFP (July 17, 2020).
[22] Docket No. 21-035-09, Rocky Mountain Power's Request for Extension (February 12, 2021).

which it did when it submitted its IRP on September 1, 2021. Guideline 6 requires that stakeholders "have the opportunity to make formal comment to the Commission on the adequacy of the Plan," which is the process in which parties are currently engaged. Nothing in the Guidelines requires a draft, especially given that the goals of a draft are already accomplished through the robust stakeholder feedback process as part of the IRP's development.

The Company provided the information that would be included in a draft IRP in its public-input meetings. For example, in addition to discussing its portfolio modeling approach, PacifiCorp also discussed the sensitivities that it planned to run at its December 3, 2020, public-input meeting, providing stakeholders ample opportunity to comment. The last public-input meeting held on August 27, 2021, continued portfolio results discussions that had been ongoing since the June 24-25, 2021, public-input meeting, including the preferred portfolio and draft action plan items. The top performing P02-MM portfolio had been discussed at the July 2021 and early August 2021 public-input meetings along with an indicative portfolio that was discussed at the June public-input meeting. PacifiCorp appreciates the value that the 18 months of extensive stakeholder involvement provided in the 2021 IRP development cycle, including over 90 feedback forms and hundreds of questions and comments to which the Company responded. PacifiCorp looks forward to continuing this ongoing dialog within its 2023 IRP development cycle. The Company also hosted a workshop on October 1, 2021, after the IRP was filed for additional feedback and discussion.

DPU argues that this process is not sufficient to constitute a draft IRP; however the Company believes that this process is qualitatively superior and less disruptive compared to the establishment of a draft document submission. Ongoing and interactive communications with a wide public audience allows the most flexibility throughout the IRP development cycle and does not require a full stop while drafting requirements are accelerated for drafting, formatting, and review at all levels. The draft-as-document requirement in a four-week timeframe effectively doubles the time required for internal drafting, validation, formatting and review at all levels, as the same exercise must be repeated for the draft and for the final filing. Also, four weeks is not sufficient time for all parties to review and comment meaningfully on a new and comprehensive document while leaving the additional time required for the IRP to assess and integrate additional recommendations for the final filing a short time later. It is far more likely that feedback occurring as part of the ongoing conversation and development cycle, without the distraction of a repeated document creation process, will result in more meaningful input that can be incorporated in the IRP.

DPU claims that under the current process its opportunity to provide feedback is not sufficiently "robust" and that there has been an "erosion of opportunities for meaningful consultation and direction by non-Company parties," which justifies a draft requirement. As explained above, the Company held numerous meetings and provided responses to dozens of stakeholder feedback forms. Occasionally rescheduled meetings and late meeting materials driven by necessity do not justify imposing an onerous draft requirement when the existing process has not been shown to be deficient. Therefore, the Company respectfully requests that the Commission deny DPU's request for a draft IRP going forward.

## B. Natrium Should Be Acknowledged as Part of the Preferred Portfolio

DPU, OCS, UAE, SLC Corp, UCE, and Sierra Club each raise concerns about the risks associated with Natrium. DPU does not object to Natrium being modeled in sensitivity scenarios, but argues it should not be included in the preferred portfolio[23] as required by Guideline 4.c.[24]

[23] DPU Comments at 6.
[24] UAE Comments at 2.

OCS disagrees that the Company's analysis of Natrium satisfies the Guidelines 1, 4.b., 4.b.ii., and 4.h., arguing it is premature to model such a plant for selection until the technology and costs are established and proven.[25] Similarly, SLC Corp asserts that preferred portfolio should not rely on unlicensed or non-commercial technologies.[26] Finally, UCE and Sierra Club take the position that there are too many uncertain variables associated with the project and the Company failed to evaluate the risks such as regulatory, permitting, financial, operational, environmental and technical risks.[27]

The Company appropriately selected Natrium as part of its preferred portfolio based on identified project specifications and a significant funding source. TerraPower's Natrium demonstration project is a 500 megawatt ("MW") advanced nuclear resource expected to come online in 2028. This non-emitting thermal resource is a molten sodium-cooled nuclear reactor paired with a molten salt thermal energy sodium tank.[28] The reactor and storage generate power through a single turbine.[29] Operating characteristics include: 345 MWs of baseload energy production at a 92 percent capacity factor; maximum output of 500 MWs and minimum output of 100 MWs; a ramp rate of approximately 40 MWs per minute from minimum to maximum; molten salt storage supports maximum output of 500 MWs for a 5.5-hour duration;[30] and maximum storage efficiency of 99 percent.[31] The Natrium plant is specifically designed to integrate into the 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.

[25] OCS Comments at 7.
[26] SLC Corp Comments at 3.
[27] UCE Comments at 6; Sierra Club Comments at 42.
[28] 2021 IRP, Chapter 7 – Resource Options at 204.
[29] *Id.*
[30] Maximum output then drops to 345 MWs until output is reduced and more heat can be stored.
[31] 2021 IRP, Chapter 7 – Resource Options at 204.

That energy can be used during times of peak demand when the wind isn't blowing, or the sun isn't shining.

The Company modeled reasonably anticipated costs based on currently available information and took the further step of ensuring that the Natrium demonstration project is indeed cost-effective as modeled by conducting a variant study, P02e, which excludes Natrium from the preferred portfolio.[32] The results demonstrated $158 million of risk-adjusted customer benefits and a 9.5 million ton reduction in $CO_2$ emissions through 2040 from the inclusion of Natrium in the preferred portfolio. The Company will continue to evaluate the project with a clear focus on customer protection and realizing customer benefits. The Company's decision to include Natrium in the preferred portfolio was based on its unique attributes and the opportunities that the project offers, including substantial grants from the U.S. Department of Energy ("DOE") and development by TerraPower, an advanced nuclear development company founded by Bill Gates. TerraPower will be responsible for all risks associated with the development of the project including project costs, licensing, construction and technology risk. As the Natrium project presents a unique project anticipated to provide customer benefits and its pursuit is the Company's anticipated path forward, it would have been imprudent to not include it in the preferred portfolio where it could be comparably evaluated with other resources and indeed, competing portfolios.

With respect to potential risks associated with Natrium raised by OCS and Sierra Club, while Natrium is included as a resource in the preferred portfolio, TerraPower is the developer of the project and is responsible for all development risks. PacifiCorp has not signed any contractual agreements with TerraPower regarding Natrium and PacifiCorp will only move forward with the Natrium demonstration project if it brings value to customers. The Company and TerraPower are

[32] 2021 IRP, Chapter 8 – Modeling and Portfolio Evaluation Approach at 250.

discussing potential commercial agreement structures which will provide adequate protections to PacifiCorp and its customers. The agreement is expected to contain numerous conditions, including PacifiCorp obtaining required state regulatory approvals and/or waivers, project offramps and performance related metrics which must be met for PacifiCorp to move forward with acquisition of the Natrium project. Further, Natrium will be required to meet Nuclear Regulatory Commission requirements and will be responsible for obtaining all required project permits and licenses, which will ensure that it continues to be the best option for PacifiCorp customers. TerraPower has many years of nuclear experience that will help in both construction and commissioning.

Concerns about the risks associated with permitting requirements, technological development, and fuel development are mitigated because alternatives to Natrium require much shorter lead-times than nuclear projects, and there will be ample opportunities to meet demands in 2028 and beyond, prior to a firm commitment from Natrium. The Company also notes that while there are excellent reasons to continue evaluating the promise of Natrium in the near-term, the potential realization of the project does not fall within the action plan window. The Company's decision to include Natrium was based in part on the unique opportunities that the project offers, including substantial grants from the DOE and development by TerraPower. Based on these unique attributes, the Company anticipated customer benefits from including the project in the preferred portfolio. Given that the project will not be acquired if it cannot demonstrate benefits to PacifiCorp's customers, the Company will continue to evaluate this project in future IRPs.

### C. New Natural Gas Generation Is Risky Given Current and Projected Environmental Regulation

WRA, UCE, and IEA agree that the Company appropriately excluded a new natural gas proxy resource from its modeling, noting the "unfavorable economics,"[33] "practical concerns,"[34] and climate change.[35] DPU and OCS both argue that the Company did not comply with the Guidelines when it chose to constrain the model from selecting a new natural gas proxy resource. OCS claims the Company provided insufficient justification for its decision.[36] DPU expresses concern that the decision was communicated late in the IRP development process, the decision was made in response to other state policies, stranded cost and permitting risks were not identified with sufficient detail, and it was inappropriate to substitute a non-emitting proxy resource for natural gas.[37] DPU "requests that new natural gas generation be modeled as an available resource in the next IRP, and if not, a robust quantitative analysis should be performed showing why natural gas is not part of a least-cost, least-risk planning process."[38]

The Company did not exclude natural gas generation from the 2021 IRP modeling. Rather, it allowed the model to select the conversion of coal-fired generation units to natural gas, and conversion of Jim Bridger Units 1 and 2 was selected for the preferred portfolio. Given the current and projected regulatory environment concerning fossil fuel generation and concerns over stranded costs, the Company determined that it would not be feasible to construct new natural gas generation and constrained the model from selecting it as a proxy resource. Contrary to DPU's argument, this decision was not driven by Washington's Clean Energy Transformation Act ("CETA").[39] As

[33] UCE Comments at 8.
[34] IEA Comments at 13-14; WRA Comments at 9.
[35] WRA Comments at 9.
[36] OCS Comments at 7-8.
[37] DPU Comments at 31-41; SLC Corp. Comments at 1-2.
[38] DPU Comments at 41.
[39] Washington Clean Energy Transformation Act, SB 5116 (effective May 7, 2019).

discussed at the 2021 IRP public-input meeting held on July 30, 2021, and when considering the potential for future greenhouse gas ("GHG") policies, PacifiCorp noted that new natural gas resources would not be depreciated until 2070, assuming depreciable lives ranging between 30 to 40 years. This length of time presents a considerable stranded cost risk considering the potential for future regulation constraining fossil fuel generation. Further, it is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in parts of PacifiCorp's service territory. Finally, PacifiCorp has observed that there is very limited development activity for new natural gas facilities. This was most recently evident in the Company's 2020AS RFP, which did not result in a single bid for new natural gas resources. In reply to the assertion that the 2020 AS RFP did not seek new gas resources, by its very nature the all-source RFP did not prohibit gas bids. Regardless of resources modeled in the IRP, PacifiCorp encourages developers to submit competitive bids into the Company's all source RFPs. This is stated in the RFP document as well as in formal Q&A responses. Nonetheless, PacifiCorp produced a sensitivity in the 2021 IRP that allowed new natural gas proxy resources for transparency, and with the understanding that the inclusion of new natural gas could not be considered the least-risk resource.[40] This sensitivity did not select a new natural gas resource until 2033, which is significantly beyond the Action Plan window. It also shows an increase of 6 million tons of $CO_2$ emissions over the study period. While the model demonstrated a benefit to customers, the benefit was insufficient to justify the substantial risks relating to new natural gas generation.

DPU and OCS's argument that they were insufficiently involved in this modeling decision is belied by the fact that the Company performed a sensitivity with a natural gas proxy resource at

[40] 2021 IRP, Chapter 9 – Modeling and Portfolio Selection Results at 317; and supplemental filing "Sensitivity – Modeling Results" at 5.

the request of stakeholders.[41] The Company did not incorporate this sensitivity into its preferred portfolio for the reasons stated above, and instead included a non-emitting hydrogen-fueled peaking resource. While the DPU accurately states that this technology has not yet matured, it is reasonable to assume it will likely be operational by the time the model has identified a resource need in 2030 and beyond.

## D. The Company Made Appropriate Modeling Assumptions

Several commenting parties criticize the Company for selecting modeling inputs that are different from their preferred inputs. SLC Corp, UCE, and Sierra Club comment on the Company's consideration of battery storage. OCS comments on the Company's consideration of pumped hydroelectric storage. DPU criticizes the Company's use of a cost of carbon. REC comments on the Company's modeling of QF contracts. UCE/SWEEP requests modeling adjustments relating to DSM. UCE criticizes the Company's load growth assumptions relating to electrification. The Company must make many choices when it determines what assumptions to include in its model. In each of these instances, the Company made a reasonable choice considering all information known at the time of the 2021 IRP. During the development of each subsequent IRP, the Company will take into account any new information that bears on these modeling assumptions.

### i. The Company prudently considered battery storage resources in the IRP

SLC Corp, UCE, and Sierra Club each weigh-in on the way battery storage was considered in the 2021 IRP. SLC Corp and UCE criticize the Company for not considering a wider variety of battery technologies in the 2021 IRP, including long-duration battery storage, aggregated distributed energy resources, and different flow battery technologies.[42] Sierra Club urges the Commission to require the Company to revise its long-term resource cost assumptions relating to

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[41] 2021 IRP Vol I, p. 252.
[42] UCE Comments at 10-11; SLC Corp Comments at 2.

batteries, incorrectly claiming that the 2021 IRP does not accurately reflect current costs or the results of the Company's 2020AS RFP.[43]

As early as October 2020, the 2020AS RFP initial shortlist was developed from bids received in the RFP process. The final shortlist RFP was completed July 2021. The Supply Side Table ("SST") in the 2021 IRP was finalized March 2021. During this time, the RFP bid costs for 2023 to 2024 were compared to the SST in the same years. That comparison found that the wind and solar capital investment costs were reasonably aligned but the standalone Li storage in the SST was higher cost than the RFP. In light of this, battery costs were assumed to de-escalate faster between 2021 and 2024 to be more in line with the RFP. Thus, the 2021 IRP took into account the 2020AS RFP and current cost information.

The 2021 IRP provides analysis of battery storage project experience and prudently considers and includes battery storage resources. As with all proxy resources in the IRP, modeled resources are representative and are not actual projects, thus the term "proxy". The model includes adequate representation of classes of resource and not every specific example that could be named. Given the proxy nature of the IRP as a long-term planning tool, the kind specificity being requested amounts to precision without accuracy.

There is nothing in the IRP that prevents a flow battery or a longer duration battery from being bid into an all source RFP. However, basic economics and utility must be recognized, and were discussed in the development of the supply-side resource table. As an example, longer duration batteries are considerably more expensive than the reasonably aligned 4-hour duration modeled in the IRP. The longer duration battery would require energy to fill it. This means that better economics are achieved through selecting more solar with storage assuming a 4-hour

[43] Sierra Club Comments at 55-57.

duration, rather than burdening the system with a higher cost 8-hour battery that brings limited incremental benefits. The Company further notes that its 2021 IRP modeling is a step change improvement in battery modeling due to the adoption of PLEXOS, which allows for the endogenous optimization of battery operations. The Company will continue to evaluate and include battery technology in its future IRPs as appropriate.

**ii. Pumped Hydroelectric Storage Is Included in the 2021 IRP Based on Economics as Compared to Other Proxy Resources.**

OCS criticizes the IRP because it does not mention PacifiCorp's pursuit of at least 11 pumped storage projects for which PacifiCorp recently filed for permits at the Federal Energy Regulatory Commission ("FERC") in October 2021.[44]

The PLEXOS model selected the pumped storage project in 2040, which is the last year of the 2021 IRP planning horizon. The PLEXOS model could have chosen an earlier date as the pumped storage projects were available for selection starting 2027 to 2029 but did not due to economics relative to other available proxy resources. Pumped storage will be evaluated and considered should bids be submitted in the 2022AS RFP. As with other resource types, PacifiCorp will continue to review and update its cost and performance assumptions for the 2023 IRP, including pumped storage resources.

As noted in OCS's comments, PacifiCorp filed applications with FERC for preliminary permits for 11 pumped storage projects on October 13, 2021. According to FERC's website:

> *A preliminary permit, issued for up to four years, does not authorize construction; rather, it maintains priority of application for license (i.e., guaranteed first-to-file status) while the permittee studies the site and prepares to apply for a license.* [45]

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[44] OCS Comments at 7.
[45] https://www.ferc.gov/industries-data/hydropower/general-information/licensing/preliminary-permits (emphasis added).

As utilities and other developers compete to address potential demand for resources including pumped storage hydroelectric projects, preliminary permits are sought from FERC to obtain commercially advantageous "first-to-file status," thereby securing the opportunity to perform feasibility studies for a proposed project site without competition for the site during the permit term. Identifying such potential pumped storage projects in the IRP ahead of filing applications for preliminary permits with FERC would have jeopardized PacifiCorp's ability to obtain first-to-file status for pumped storage projects that may serve PacifiCorp's customers as its generation portfolio transitions to increasing levels of intermittent renewable resources. This is due, in part, because pumped storage projects are unique in that they are limited to specific locations dictated by favorable topography (e.g., available elevation between an upper and lower reservoir), suitable geotechnical conditions, available water supplies, and transmission interconnection locations.

Feasibility studies conducted during a preliminary permit term, should they be granted, may indicate that a proposed pumped storage project is not feasible due to technical, financial, environmental, water supply, or other constraints, in which case PacifiCorp would not pursue the proposed project. PacifiCorp will continue to explore the feasibility of the 11 identified pumped storage projects and other potential sites in the future. PacifiCorp anticipates that these pumped storage alternatives will be evaluated through subsequent IRP planning processes if and when PacifiCorp determines that any of these projects are feasible and after a more informed assessment of the costs, performance, and capacity of the projects is established.

**iii. The Cost of Carbon Is Appropriately Included in the Company's Forecast**

DPU criticizes the Company's selection of a scenario that includes a cost of carbon emissions, claiming that such a cost is "unlikely" and included based on the policies of other states.[46] The carbon price used in the 2021 IRP is a proxy for future GHG drivers which are clearly trending toward the reduction of $CO_2$ emissions. This trend has been accelerating over the past several IRPs, driven by regulatory requirements, market trends, tax incentives, public and political pressures and other factors. The Company expects this trend to continue. In this environment, the proxy $CO_2$ price represents the risk of continued carbon emissions. This same reasoning, with greater specificity and recent evidence from the energy resource market, also supports the exclusion of new natural gas fired resources from these portfolios, as discussed further below. Because the Company analyzed two price-policy scenarios with no carbon price across multiple 2021 IRP portfolios there is no need for the Commission to require the Company to exclude carbon cost from any of its future modeling.

**iv. DSM Resources Were Accurately Modeled**

UCE/SWEEP submitted comments supporting the inclusion of DSM resources in the 2021 IRP and criticizing certain modeling inputs relating to its CPA. The CPA is a system-wide study to identify the potential of demand-side management resources and their related costs over the IRP planning horizon and is updated every two to three years. The Company receives and incorporates feedback relating to the CPA through the IRP development process. In 2021, the Company held five workshops specific to the CPA and continues to encourage stakeholder feedback during the development of the study. As UCE/SWEEP noted in their comments, the Company met with them individually to discuss their requested analysis.[47]

UCE/SWEEP claims that the Company's CPA forecasted a 1% savings per year, while citing historical program achievement data to suggest a higher savings is possible. However, increased market adoption of high efficacy technologies resulting from prior program activities

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[46] DPU Comments at 54.
[47] UCE/SWEEP Comments at page 11.

and the prevalence of codes and standards have resulted in diminished energy efficiency opportunities in the future for certain end-uses. This is particularly true for lighting and motors, which have undergone increases in baseline efficacy because of federal standards and increased market adoption of efficient technologies. It is not reasonable, therefore, to assume that energy efficiency opportunities and potential savings should be tied to history or remain constant from one year to the next.

UCE/SWEEP further claims that the Company did not conduct two requested analyses relating to the CPA modeling: a low, medium, and high case to assess the robustness of the modeling to an increased amount of Class 2 DSM, and a comparison of the 2015, 2017, and 2019 CPA results with historical measure-level cost and program achievements. UCE/SWEEP believes the model would have selected additional Class 2 DSM resources had its modeling inputs been performed and accepted, and recommends the Commission direct the Company to perform its requested modeling in its 2023 IRP.

PacifiCorp considered UCE/SWEEP's requested analyses as part of the 2021 CPA development process. In lieu of a low, medium, high case in the CPA, the Company chose to prioritize sensitivity analyses in the IRP with adjustments to the revised measure bundling methodology introduced in response to stakeholder feedback, and sensitivities to selections under varying load forecast scenarios. Additionally, the Company has already committed to performing sensitivity analysis with respect to CPA inputs in the 2023 CPA workplan.[48] The Company also performed a comparison of historical program achievements to inform future adoption of high potential energy efficiency measures and provided a comparative analysis between the 2021 study

[48] 2023 Draft Potential Study Work Plan Task 4 at Page 2-11. Available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/PacifiCorp_2023_Potential_Study_Work_Plan_Draft.pdf

and the previous study in the 2021 CPA report.[49] The Company believes the model selected an appropriate number of Class 2 DSM resources in light of the analysis performed.

PacifiCorp appreciates the feedback regarding the modeling assumptions and the recommendations will be taken into consideration in future planning processes. Additionally, in its 2023 IRP development process, PacifiCorp plans to include workshops specifically to inform its CPA and welcomes further stakeholder feedback to inform the 2023 CPA and IRP.

**v. The 2021 IRP Makes Reasonable Assumptions Concerning QFs**

REC suggests that the Commission should not acknowledge PacifiCorp's 2021 IRP assumptions because it claims the 2021 IRP assumed that no QF contracts are renewed. REC also states that PacifiCorp did not produce a sensitivity analysis or provide an adequate explanation of the impact of renewing QF contracts on its load resource balance, or if it did it is not clearly articulated.

PacifiCorp's modeling of QFs in its preferred portfolio assumes that QFs will not renew their contracts at the conclusion of the existing QF contract term, similar to how they were modeled in PacifiCorp's 2017 and 2019 IRP. In its comments, REC recommends that the Commission direct PacifiCorp to assume a reasonable amount of QFs renew their power purchase agreements ("PPAs").[50]

The IRP is prepared on a two-year cycle and includes all QF PPAs that have been executed, even if the projects are not yet on-line if the projects are expected to reach commercial operation within the IRP planning period (based on information from the QF developer), including those that renew an existing contract or negotiate a new contract. PacifiCorp cannot require a QF to renew

[49] PacifiCorp DSM Potential Report, Volume I at 53, available at https://www.pacificorp.com/energy/integrated-resource-plan/support.html.
[50] REC Opening Comments at 6-8.

or execute a new agreement, and so relying on such projects is problematic from a planning and reliability perspective. Trying to develop an assumption around potential additional QF capacity based on historical trends related to renewal could lead to unreasonable or misleading results.

For example, during the period 2013 to 2019, PacifiCorp executed new or renewed PPAs ranging between a low of 84 MWs in 2019 and a high of 209 MWs in 2014. These are the projects that are either currently operational or under construction. However, during this same time period PacifiCorp terminated over 400 MWs of new QF PPAs because the facilities were never built. A forecast based on historical trends could erroneously overestimate the number of QF PPAs in the IRP. Further, historical trends are almost certainly not a reasonable predictor of future QF development activities, which are influenced by a broad range of complex factors. Instead, the Company continues to assert that using the best available data based on actual contracts is the most appropriate incorporation of QF capacity when developing an IRP, especially where new capacity resources represented by proxy resources can be QFs.

Assumptions about the extensions of QFs also have implications under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). PURPA is designed to compensate QFs based on the avoided costs of the resources that a utility would otherwise acquire. This compensation determination is made at the time that a QF contract is signed; the resource a QF is allowing a utility to avoid changes over time. As a result, if all QF contracts were assumed extended in the preferred portfolio it would not be possible to discern the replacement resources.

REC suggests that PacifiCorp complete a sensitivity analysis requiring the Company to continue paying QFs the capacity payment at the beginning of their renewed PPA (*i.e.*, eliminate the sufficiency period at the beginning of a new or renewed QF contract).[51] While IRP models

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[51] REC Opening Comments at 9.

may be a tool to help determine the appropriate capacity value of QF contracts, the IRP process is not the appropriate venue for exploring the compensation and contracting practices of QFs.

**vi. The Company Appropriately Modeled Geothermal Resources**

Fervo claims that the Company used "outdated information on the cost and resource potential of geothermal energy development in Utah."[52] Accordingly, Fervo recommends that the Company more accurately model geothermal energy in future planning scenarios.

Fervo encourages the Company to use general estimates of the cost of geothermal energy to develop its IRP, including Lazard's levelized cost of energy estimates. However, the Company believes it is more reasonable to use its historical experience of costs to operate the Blundell Geothermal Plant, which is located on the Roosevelt Hot Springs, a known geothermal resource area near Milford, Utah. The Blundell Plant has high operating costs compared to the Company's other generation resources, and the Company's study indicates that further geothermal development is likely to diminish the resource. The Company's cost estimates are not significantly higher than the costs of recent Power Purchase Agreements cited by Fervo for resources outside of the Company's service territory as far away as Hawaii.[53]

PacifiCorp is pleased to see the commitment of the Utah Governor's Office of Energy Development and DOE to further study geothermal potential through the Utah FORGE project. According to Dr. Laura Nelson, Utah has the potential for about 2,200 MW potential for geothermal generation, which could be a considerable contribution to PacifiCorp's generation capacity; however it is unclear how economically viable the potential geothermal generation will be. PacifiCorp's last two request for proposals for generation resources have been open to all

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[52] Comments of Fervo Energy Company in Response to PacifiCorp's 2021 Integrated Resource Plan at 1 (March 4, 2022).
[53] Id. at 3-5.

sources. Regardless of resources modeled in the IRP, PacifiCorp encourages developers to submit competitive bids into one of the Company's all source RFPs. If developers are not ready to meet the requirements of the RFPs but can provide detailed and competitive cost estimates for the resource, the Company would consider such estimates when developing future IRPs.

### vii. The Company Has Considered Electrification and Climate Change Load Growth in Its Load Growth Projections

The Company uses reasonable inputs to forecast future load growth. DPU noted that the Company's "forecasting team does an excellent job creating forecasts in a changing environment."[54]

UCE criticizes the Company's modeling of load growth and requests changes going forward. The Company will consider incorporating additional electrification impacts as part of future IRPs. This will include climate change impacts to load from air conditioner saturation.

The Company will continue to evaluate load impacts of building electrification in all PacifiCorp states and will incorporate this as part of future IRPs. Additionally, the Company will consider incorporating an additional transportation electrification scenario as part of future IRPs. Finally, the Company will continue to monitor and develop methods and utility best practices to evaluate electrification scenarios in future IRPs. Regarding climate change, the Company will continue to assess climate change best practices within its 2023 IRP development cycle and evaluate the appropriateness of incorporating climate change as part of the base load forecast.

## E. The IRP Process Appropriately Accounts for Transmission Planning

UAE urges a more robust discussion of long-term transmission planning activities as part of the IRP process.[55] UAE specifically seeks the ability to provide input to the transmission

[54] DPU Comments at 47-48.
[55] UAE Comments at 5-10.

configuration. IEA also makes several recommendations relating to transmission planning, including requiring the Commission to participate and report on regional transmission planning processes, identify, analyze, and report on reliability benefits of new transmission lines, and provide information about opportunities arising from the Infrastructure Investment and Jobs Act.[56] As UAE notes, the Company provides information about transmission planning projects in Chapter 4 of the IRP.

These suggestions may be incorporated into the development of future IRPs but should not be the basis of any additional Commission IRP requirements. The scope and cost of transmission upgrades modeled in PLEXOS were based on planning estimates. The actual MWs of capacity available, scope and costs associated with particular upgrades vary depending upon the interconnection queue, the transmission service queue, the specific location of any given project and the type of equipment proposed for any given project. Costs of all transmission and interconnection upgrades are evaluated by the PLEXOS model and weighed against all other options before being selected. The model is provided annual build costs, the economic life of the project and the discount rate. All potential future projects are given the same consideration by the model based on the above referenced inputs. PacifiCorp has several opportunities for stakeholders to participate in the transmission planning process. PacifiCorp must comply with FERC order 1000 and the company's attachment K in its OATT. Quarterly meetings, posted on OASIS at this location OATI OASIS are held and are open to stakeholders. PacifiCorp also hosts monthly Network Transmission customer meetings that are also posted on OASIS. In addition to PacifiCorp led transmission meetings, NorthernGrid also hosts regional transmission planning meetings which can found at www.northerngrid.net under the "EVENTS" tab.

[56] IEA Comments at 4-5, 15-23.

## F. The 2021 IRP Estimates Rate Impacts of the Preferred Portfolio

OCS claims the Company failed to include a customer rate impact analysis.[57] But the 2021 IRP specifically includes an indicator of customer rate pressure over time among the initial portfolios discussed relative to the 2021 IRP preferred portfolio.[58] In addition, Volume II, Appendix J, Stochastic Simulation Results show incremental customer rate impacts over a 10-year and 20-year planning period. Specifically, Table J.5 shows the 10-year incremental rate impact and rank among the initial portfolios and Table J.6 shows the rate impacts across 20-years, also shown in Figures J.1 and J.2, respectively. The estimated rate impacts apply equitably across all classes of ratepayers, which is the most reasonable and useful assumption in the absence of a rate-making process or instrument. The Company is willing and interested in pursuing alternative approaches, provided that suggested portfolios can meet all system requirements.

When considering the rate impacts of a preferred portfolio, it is important to note that the IRP is a plan, informed by proxy resources among other considerations, where exact costs cannot be known until specific resources are known. A number of factors can drive rate impact, notably including actual project costs once known. Estimates of rate impacts are merely estimates, and the actual rate impacts should be evaluated in the context of a specific project. The Company sufficiently complied with the Guideline requiring an evaluation of rate impacts.

## G. The 2021 IRP Does Not Present Unacceptable Risks to Utah Customers Based on Other States' Law and Policies

DPU raises concerns that state law and policies in other jurisdictions, which the Company has recognized impact its long-term resource planning, may leave Utah customers burdened with a "disproportionate share of costs for resource selections that are planned primarily to meet other

[57] OCS Comments at 2-3.

[58] 2021 IRP, Chapter 9 – Modeling and Portfolio Selection Results, Figure 9.30 at 292.

states' energy policies."[59] Specifically, as to Washington's laws and policies, DPU cites to CETA,[60] which requires all electricity sold in the state to be greenhouse neutral by 2030, the Clean Energy Action Plan ("CEAP"),[61] which provides a Washington-specific look at what resources may be added or retired in Washington's allocation of electricity over the next 10 years, the Clean Energy Implementation Plan ("CEIP"),[62] which includes a four-year action plan to move toward meeting CETA's milestones, and the Energy Independence Act ("EIA"),[63] which establishes renewable portfolio standard targets that increase over time, as mandates that raise risks for Utah customers.[64] Regarding Oregon's laws and policies, DPU cites recently passed House Bill 2021 ("HB 2021"), which requires electricity providers to reduce GHG emissions by 80 below baseline levels by 2030 and increase reductions by 10 percent every five years until 100 percent carbon-free electricity is achieved in 2040. In addition, DPU notes that the Company has stated its 2023 IRP will include a Clean Energy Plan, showing a pathway to clean energy standards, in response to proposed new IRP guidelines from the Oregon Public Utility Commission implementing Executive Order No. 20-04.

As DPU notes, the Company recognizes the challenges it faces in meeting "the legal requirements as a public utility in each state in a risk-adjusted, least-cost manner, while striving to mitigate cost impacts in other states."[65] However, because the Company is obligated to comply with the laws and regulations of each state where it operates, and because each state will be responsible for the costs of complying with its laws and regulations, cost and benefit allocations for specific resources is being addressed in the Multi-State Protocol discussions for a new inter-

[59] DPU Comments at 56.
[60] Washington Clean Energy Transformation Act, SB 5116 (effective May 7, 2019).
[61] DPU Comments at 56-58.
[62] *Id.* at 58-59.
[63] *Id.* at 59.
[64] *Id.* at 56-60.
[65] *Id.* at 64.

jurisdictional cost allocation methodology. Accordingly, a requirement regarding cost allocations in the IRP process would not be appropriate.

## H. The 2021 IRP Appropriately Accounted for Climate Change Impacts

In their opening comments, UCE, WRA, and Sierra Club comment on the impacts of climate change as considered in the 2021 IRP. UCE asserts that the Company is required to account for the costs and risks of climate change on PacifiCorp's operations, and it urges the Commission to require the Company to work with stakeholders in the 2023 IRP process to include a more diverse range of climate change scenarios. Similarly, WRA recommends that the Company work with stakeholders in the future to receive and apply feedback on ways the Company can account for climate change impacts in the resource planning. Sierra Club and UCE also criticize the important role the Company's coal fleet plays in its resource mix.

In Chapter 5 – Reliability and Resiliency, the Company addressed the need to plan for load changes as a result of climate change. The Company prepared a climate change scenario in the 2021 IRP to assess the ways in which climate change may impact planning assumptions. The Company would note that PacifiCorp used downscaled GCM models from the United States Bureau of Reclamation Hydroclimate Projections annual temperature range projections to calculate the daily average temperatures and peak producing temperatures. These temperatures are then converted into Heating Degree Days ("HDD") and Cooling Degree days ("CDD") at various temperature break points to include in the Company's Models, similar to the HDD and CDD impacts used in the 2021 Northwest Power Plan.

Regarding UCE's and WRA's requests for the Company to work with stakeholders in the future, the Company welcomes additional input from stakeholders regarding incremental improvements to climate change scenarios in future IRPs. The Company agrees that climate change modeling at the local utility level is an evolving process with no standardized method. The Company will continue to monitor and develop methods and utility best practices to improve its modeling of climate change as part of future IRPs.

As to the comments of UCE that PacifiCorp's coal fleet is a substantial contributor to climate change, and the Sierra Club's criticism that PacifiCorp continues to describe its coal fleet as playing "a pivotal role," the Company reiterates that the 2021 IRP preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate the addition of over 3,000 MWs of new renewable resources and 697 MWs of battery storage capacity by the end of 2024, with nearly 9,300 MWs of new renewable resources over the 20-year planning period through 2038.

Concerning the pivotal role of coal operations, the above criticisms fail to acknowledge that the role coal plays in the preferred portfolio changes over time as a consequence of increasing renewables penetration. Over time, remaining coal unit dispatch declines but remains available to support renewables additions, thus reducing emissions and providing a cost-effective means to maintain reliability.

## I. Emissions Accounting and Allocation Are Outside the Scope of the IRP Process

WRA expresses concern that not all of the Company's renewable resources should count as renewable because the Company sells some of its renewable energy credits ("RECs") on the market.[66] It urges the Commission to consider requiring emissions reporting and accounting due to policies in PacifiCorp states, and potential changes to the allocation protocol, so that climate impacts can be appropriately evaluated.[67] PacifiCorp follows established rules and regulations for environmental reporting and accounts for REC sales and for renewable power purchase

[66] WRA Comments at 27-29.
[67] WRA Comments at 30-31.

agreements without RECs when making renewable claims. The data provided in the 2021 IRP notes where the data does not account for REC retention, which provides full transparency.[68] Additional requirements for emissions reporting and accounting beyond what is required for resource planning purposes is beyond the scope of the IRP development process.

### J. Sierra Club Inaccurately Characterizes the Utah Community Renewable Energy Program

Sierra Club argues that the 2021 IRP did not "properly detail or provide adequate assumptions" about the Company's compliance with the Community Renewable Energy Act ("CREA").[69] Under CREA, communities can receive "100% of the annual electric energy supply for participating customers from a renewable energy resource by 2030."[70] CREA explains how communities will pay for their renewable energy supply to the extent the cost of renewable energy exceeds the cost of the Company's existing portfolio. To accomplish the goal of allowing communities to select renewable resources while leaving other customers indifferent, the definition of "renewable electric energy supply" is defined as the "incremental renewable energy resources."[71] This means that communities will not have to bear additional costs for renewable energy that is already part of the Company's generation portfolio. It does not mean, as suggested by Sierra Club, that the Company must acquire new renewable generation to serve the entire load of the participating community. Indeed, such resource acquisition would be cost prohibitive and would likely result in dramatically reduced participation in the program. Sierra Club is simply incorrect when it argues that the Company "undercounted the demand for renewable resources" based on its interpretation of CREA.

[68] 2021 IRP at Chapter 9 – Modeling and Portfolio Selection Results at 304, fn 11.
[69] CREA is codified in Utah Code Ann. §§ 54-17-901 – 909.
[70] Utah Code Ann. § 54-17-903(2)(a)
[71] Utah Code Ann. § 54-17-902(13).

## K. The Company Made Appropriate Methodological Choices About Reliability in the 2021 IRP

Sierra Club criticizes the Company's "methodological choices" for reliability and resource adequacy. Specifically, it points to concerns with the Company's assumed capacity contribution of solar plus storage resources, the application of an hourly 13 percent reserve margin at the load area level, and the Company's post-modeling reliability adjustments.[72]

### i. Capacity value of solar with storage

Sierra Club expresses concerns regarding reliability modeling, specifically the inconsistencies between PacifiCorp's capacity contribution study and the 2021 IRP preferred portfolio with respect to the capacity value of solar with storage. As a result, Sierra Club recommends that the Commission direct PacifiCorp to provide more detail on the capacity value of solar with storage assumed in each year of its model and justify the decline in capacity value after 2030 in this IRP and all future IRPs, and its assumptions for capacity contribution in the resource selection process, including any assumed decline in capacity value over time.[73]

#### a. Capacity Contribution

PacifiCorp discussed capacity contribution in Volume II, Appendix K of the 2021 IRP and highlighted the fact that a resource's capacity value (or contribution to ensuring reliable system operation) is dependent on both its characteristics and the composition of the overall portfolio. PacifiCorp's portfolio composition changes dramatically over time, as a result of retirements and expiring contracts. PacifiCorp's portfolio also changes dramatically over time as a result of resource additions identified in the 2021 IRP preferred portfolio, and with the resource additions specific to each of the other portfolios. As shown in Figure 1.1 in PacifiCorp's 2021 IRP, solar

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[72] Sierra Club Comments at 12-20.
[73] *Id.* at 12-14.

capacity increases significantly above an already high level in 2030 and beyond. As solar capacity increases, each incremental addition has a lower capacity contribution than the prior increment, as any remaining shortfalls will be less and less likely to occur during hours when the sun is shining. To help temper this effect, PacifiCorp's 2021 IRP assumed all proxy solar resources were combined with four-hour storage equal to the solar nameplate capacity, as storage can allow solar output to be spread across additional hours. However, storage is also subject to diminishing capacity value, as the shortest duration events are eliminated and periods in which surplus energy is available to allow storage to recharge shrink.

PacifiCorp discussed the details of its reporting of the load and resource capacity balance in Chapter 6 of its 2021 IRP, and noted in that discussion that the load and resource results would not match the marginal or "last-in" capacity contribution estimates provided in Appendix K. The load and resource balances reported in Chapter 9, Tables 9.18 and 9.19 also reflect a portfolio capacity contribution (the cumulative contribution for each resource type) in the same manner as that described in Chapter 6 rather than marginal capacity contribution values as identified in Appendix K.

Regarding the annual changes in solar capacity contribution in the load and resource results, PacifiCorp notes that the timing of solar output and peak load changes from year to year, as the solar output reflects a static hourly profile (8,760 hours), while the peak load day rotates with the calendar (so the peak load day never falls on a weekend). While the alignment from year to year varies as a result, the average alignment between renewable output and load setup reflects the actual alignments observed in recent history, as discussed in Appendix K.[74]

b. Results of study for solar with storage

[74] 2021 IRP Volume II at 221-223.

PacifiCorp's capacity contribution analysis was based on a 2030 portfolio composition. After 2030, PacifiCorp's 2021 IRP preferred portfolio contains an additional 820 MWs of solar with storage in 2031 and 1,100 MWs in 2033. These subsequent incremental solar with storage resource additions amount to roughly 20 percent of PacifiCorp's annual peak load on top of the Company's existing resources, 2020AS RFP selections, and proxy resource additions through 2030, so significant changes are anticipated relative to the 2030 values shown in Appendix K. While the preferred portfolio also includes significant solar resource additions in 2037, this coincides with the expiration of a significant quantity of QF solar contracts, resulting in a relatively small net change in solar resources. Furthermore, the Company's load and resource balance for the preferred portfolio includes front office transactions in the winter starting in 2038. Because solar output is relatively low in the winter, solar combined with storage does not provide sufficient total energy to both serve load during the day and enable charging for even higher loads in the evening and the following morning.

PacifiCorp identified that further additions of solar with storage resources were inadequate to address reliability issues in the 2038 timeframe as part of its reliability assessment.

c. Assumptions for capacity contributions

With respect to Sierra Club's recommendation that the Commission require PacifiCorp to provide much more detail on its assumptions for capacity contribution in the resource selection process, PacifiCorp did not assume any inherent decline in the capacity contribution of any resources over time. PacifiCorp's reliability analysis indicated that, once solar with storage reached a relatively high penetration level, incremental solar with storage no longer provided sufficient incremental capability during the remaining shortfall periods, which became increasingly prevalent in the winter. Given limitations on the available interconnection capacity, it was not feasible to further increase additions of solar with storage to compensate. As a result, it was necessary to add resources with higher capacity contributions during the winter, relative to their interconnection capacity.

**ii. Reserve Margin**

Sierra Club claims that the Company's application of an hourly reserve margin to individual load areas is overly conservative and does not account for the benefits of geographic diversity. Sierra Club makes a number of recommendations regarding the setting of a reserve margin requesting that PacifiCorp be directed to (1) provide a detailed justification for why 13 percent is an appropriate level for its hourly reserve margin, rather than a number closer to its current operating reserve requirements; and (2) apply its assumed reserve margin requirement at the system level rather than the load area.[75]

a. Application of the reserve margin

By applying an hourly planning reserve margin to individual load areas, PLEXOS is adding proxy resources into these locations on an east and west control area basis. The location of these added proxy resources creates geographic diversity to the system but also considers imports from adjacent areas. Applying a reserve margin requirement at the system level creates flexibility but may not ensure load growth is being met due to transmission limitations or resource retirements. The PLEXOS LT model considers the proxy resource locations and associated transmission selection in determining the lowest PVRR cost.

The 13 percent planning reserve margin by load area is a floor in the PacifiCorp's portfolio development process using PLEXOS LT model and not a ceiling. Proxy resources can be added

[75] *Id.* at 15-18.

that exceed the 13 percent planning reserve margin that allows proxy resources that are larger in megawatt size. The 2019 IRP also used a 13 percent planning reserve margin.

b. Selection of a 13 percent reserve margin

PacifiCorp's 2021 IRP discusses planning reserve margins in Chapter 5: Reliability and Resiliency. As discussed in Chapter 5, both the 2010 Energy Gateway Western Electricity Coordinating Council ("WECC") and the Northwest Power Pool ("NWPP") consider planning reserve margins of 15 percent. The planning reserve margin used by WECC, NWPP, and PacifiCorp includes more than just the spinning and non-spinning contingency reserve requirement and it is incorrect to assume that this could be sufficient to ensure system reliability. The contingency reserves can only be employed following certain generation and transmission outages or derates, and only in the 60 minutes immediately after the event. After 60 minutes have expired, additional replacement resources must be brought online so that contingency reserves can be restored and ready to respond to additional contingency events.

As discussed in Chapter 5, stochastic analysis is a key aspect of determining reliability risks and identifying an appropriate planning reserve margin. In PacifiCorp's reliability analysis load, hydro conditions, and thermal availability all vary stochastically. PacifiCorp's planning reserve margin is intended to cover not only spinning and non-spinning reserve requirements, but also higher than expected load, lower than expected hydro availability, and lower than expected thermal availability. If load is high in a dry hydro year when multiple thermal resources are experiencing forced outages, more resources will be necessary to ensure reliability. To the extent renewable resource shortfalls are correlated with high load or dry hydro conditions, a larger planning reserve requirement might be necessary. Increasing volatility as a result of climate change may also increase planning reserve requirements. PacifiCorp intends to further evaluate these relationships in its 2023 IRP.

**iii. <u>Transparency of the portfolio development process</u>**

Sierra Club claims that the Company's portfolio development process included a non-transparent pre-modeling reliability adjustment that lacked adequate support. To aid in transparency, Sierra Club recommends that PacifiCorp be directed to provide (1) a characterization of the reliability risks these adjustments are attempting to address; (2) an evaluation of the ability of all resources under consideration to address these reliability needs; and (3) data on the specific resource adjustments that were made to each portfolio as part of the reliability adjustment.[76] However, the Commission does not need to direct the Company to provide this information because it was adequately described in the IRP and can be discussed further in the development of the 2023 IRP. Moreover, there is no basis for Sierra Club's argument that the Company is using this adjustment to "put its thumb on the scale" to guide the IRP to its desired outcome.

Early in the IRP process, the Company identified shortcomings in portfolio selection, in terms of both economics and reliability and the Company discussed this topic in Chapter 8 of its 2021 IRP. The PLEXOS model reports the value or revenue for every resource based on its hourly generation profile and locational marginal price. Using that data, the Company identified that the resource value estimates coming from the LT model diverged for some resource types from the values identified by the more granular ST model. PacifiCorp calculated the difference in resource value between the two models and fed that difference back into the LT model as an adjustment to fixed costs for use in portfolio selection. Resources that provided more value in the ST model than the LT model were assigned credits, resources that provided less value in the ST model than the

[76] *Id.* at 20.

LT model were assigned costs. While this improved portfolio selections, it did not result in fully reliable portfolios, as the Company continued to see unserved load and unmet reserve requirements in some hours in ST model results. The Company presented LT Portfolio 3112 at the June 25, 2021, IRP public-input meeting.[77] This "indicative portfolio" was the initial production portfolio vetted for reliability in the 2021 IRP.

In this indicative portfolio, the duration of reliability risk ranged anywhere from 1-15 hours. The largest shortages tended to occur in summer shoulder and evening/night hours when solar radiance was falling off. Due to the duration and timing of the shortages, short duration and solar/wind resources were not sufficient to cover all hours of shortfall. To address the identified shortfalls, PacifiCorp increased the capacity requirements in the PLEXOS model, forcing it to add additional resources. Depending on the timing and year of the reliability needs, resources eligible for consideration for the reliability additions included:

1. Solar with storage
2. Standalone battery
3. Non-emitting peaker
4. Nuclear

As part of this process, the Company identified that system interconnection constraints were limiting the ability of solar combined with 50 percent storage capability to address reliability needs. In response, the storage component of proxy solar with storage resources in the portfolio was increased from 50 percent of the PV resource capacity to 100 percent of the PV resource capacity. The storage duration was held at four hours, so the effective storage capability was doubled.

[77] See https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/PacifiCorps_2021_IRP_PIM_June_25_2021.pdf Slides 18-32 of the presentation discuss the indicative portfolio. Slides 39-41 in the PIM deck describe the reliability assessment process, while slide 42 presents details on the reliability requirements.

A number of resource additions were required over the 2021 IRP study horizon to address reliability needs, and by 2038, interconnection constraints and the declining capacity contribution from further additions of solar with storage meant that it was no longer sufficient to meet reliability requirements, which were increasing in the winter. As a result, the addition of nuclear and non-emitting peaking resources became the most cost-effective options to address reliability needs. The Company did not make any further changes to modeled costs as part of the reliability adjustment, beyond that already incorporated as part of the granularity adjustment. Because the granularity adjustment represents the difference in value between the LT model and the ST model, it does not impact dispatch in the ST model and is not reported as part of the ST model results.

After the reliability assessment was completed, a portfolio optimized under the MM price-policy scenario, the Company incorporated portfolio refinements to adjust to portfolios under other price-policy conditions. The relative value of available resource options varies by price-policy conditions, but the reliability of the portfolio does not, as resources will be dispatched to ensure reliability regardless of their economics. For each price-policy scenario and at each location with potential proxy resource options, the most economic resource option was selected, while attempting to maintain the overall level of reliability resources through time. The most economic resource option was calculated based on the net cost per kW-year, calculated by subtracting a resource's reported revenue in the ST model from its fixed and variable costs. Where shortfalls were able to be covered by solar with storage, that resource was generally the most cost-effective. In instances where that was not the case and longer duration energy was needed, non-emitting peaking and nuclear resources were typically selected, depending upon the need and cost per kW-year of each option. For each price-policy scenario, this optimized LT portfolio for P02-MM was run through the ST model. Any residual shortfalls were evaluated and the most economic resources available were selected to resolve shortfalls.

After the reliability adjustments described above, the Company also re-optimized energy efficiency and demand response selections to ensure all cost-effective demand-side resources were included, based on the net cost per kw-year metric. Because demand-side measures do not require interconnection capacity, they do not compete with utility-scale resources for limited interconnection capacity. The changes to energy efficiency and demand response were generally minor and would not have materially impacted the reliability assessment.

As should be clear based on the preceding discussion, the reliability assessment is a direct result of modeling outcomes at every stage, appropriately uses the tools available in PLEXOS, is not "ad-hoc," and was conducted with integrity. PacifiCorp remains committed to the continuous improvement of transparency and clarity.

## L. The 2021 IRP Includes a Unit-by-unit Analysis of Coal-Fired Generating Units

Sierra Club incorrectly asserts that PacifiCorp failed to perform a unit-by-unit coal analysis as it has done in the 2019 IRP.[78] There was no requirement to produce such an analysis, but more importantly, the analysis performed in the 2021 IRP is substantially improved over the earlier approach. As discussed at the July 30, 2020, and December 3, 2020, public-input meetings, instead of producing a narrow set of about 80 unit-by-unit coal studies examining a single unit in a single year for each, the 2021 IRP endogenously considered an estimated 260,000 retirement and coal alternatives before selecting the best initial capacity expansion plan. This was achieved in PLEXOS allowing for multiple options per coal unit to compete within the same optimization analysis. While the company did not endogenously model every possible coal and transmission

[78] Sierra Club Comments at 21.

option, such as every possible retirement year, due to data availability and performance constraints, this still represents a sea-change, expanding analytical options considered by more than 2300 percent. In response to stakeholder feedback, the Company also conducted several variant analyses which examined specific retirement changes in the 2021 IRP. Each of these variants confirmed the selection of the preferred portfolio. The company looks forward to building on its experience with PLEXOS to improve this further, with an aim to incorporating additional years and options where it is possible and likely to lead to valuable insights.

### M. The 2021 IRP appropriately models the minimum take or take or pay provisions of the Company's coal supply agreements

Sierra Club also recommends that the Commission direct the Company to conduct an additional model run in this IRP cycle that does not include any minimum take or "take or pay" provisions.[79] To support its recommendation, Sierra Club relies on assertions regarding the influence these provisions have on the decision of when to retire a plant; the appropriateness of the Company's assumptions, and the environmental clause in the Huntington coal supply agreement.[80] WRA similarly argues that the Company should remove minimum take assumptions, speculating that the Company is including such assumptions for self-serving reasons.[81]

However, the Company's take or pay assumptions are reasonable and well-supported. The Company's coal fuel inputs for the 2021 IRP incorporate existing contracts through the end of their terms as well as expected costs for any additional volumes or future periods not covered by existing contracts. The suggested removal of take-or-pay assumes there will be no contractual obligations of any kind for future fueling beyond current contracts. This assumes adequate and reliable coal supply would be available on demand, and that this fuel supply could be achieved

[79] Sierra Club Comments at 25-31.
[80] *Id.* at 30-31.
[81] WRA Comments at 13-21.

without significant additional expense. This is an unrealistic scenario as coal suppliers require some assurance that the supplier can cover the costs to produce the coal and maintain an adequate workforce, which is typically done through minimum take-or-pay provisions in a contract.

Coal supply strategy is multi-faceted, especially at the Company's larger plants, so specific details of future coal procurement are beyond the scope of the IRP. The inputs are intended to be representative of the expected operations and restrictions that would likely exist in the future but there is flexibility in how coal supply could be procured over time, and this would be expected to evolve over time.

In the 2021 IRP, the key plants where this is an issue are Huntington and Jim Bridger, both of which included take or pay assumptions that extended beyond the next five years. However, Sierra Club is incorrect that this is treated as a purely sunk cost. The Company's 2021 IRP results reflected the assumption that when a plant is retired it no longer incurs any take or pay costs from that point forward. The primary effect of take or pay obligations in the 2021 IRP is to constrain future coal-fired operations. Without this constraint, future coal-fired operation would have more flexibility, which would manifest as lower costs across a range of conditions. This flexibility would have little impact in early-retirement scenarios, as they already reflect zero coal-related costs in those future periods. As a result, the Company anticipates that model runs removing future take or pay commitments would provide greater benefits to the preferred portfolio than to early-retirement scenarios. The benefits to the preferred portfolio would be particularly high under scenarios with high GHG costs, as economic coal-fired dispatch would be expected to be low under those conditions.

Finally, with respect to the environmental regulation provision of the Huntington coal supply agreement, conditions do not exist at this time to invoke this clause.

PacifiCorp is interested in continued discussion of modeling strategies for coal supply and the potential for sensitivities.

## N. Modeling of the dispatch of coal resources should be based on incremental costs in future IRPs

Sierra Club continues to argue that in future IRPs, the dispatch of coal resources should be modeled based on average fuel costs over a period of one year or more.[82]

The Company's IRP modeling is intended to reasonably represent the constraints and operating parameters faced by each resource. The Company's 2021 IRP results reasonably reflect the total fuel supply costs for each of its coal units. While some of these coal resources are dispatched based on take or pay contracts, with an incremental cost that is lower than the average, this structure is consistent with many of the Company's existing obligations and comparable structures are likely in future coal supply procurement. While each coal supply procurement is likely to extend only a few years into the future, the capital requirements and balance of fixed and variable costs associated with coal production make the take or pay contract design preferable to coal suppliers each time a new contract is under consideration. The Company would note that total coal costs are reflected in the Company's reported results, so each portfolio incorporates what is effectively an average fuel cost in that regard. By allowing for dispatch based on incremental costs, the Company's results automatically capture changes in average fuel costs as a function of coal demand.

Finally, with respect to the Company's California 2021 Energy Cost Adjustment Clause ("ECAC"), rebuttal testimony in the 2021 ECAC proceeding was filed on May 7, 2021,

[82] Sierra Club Comments at 32-33.

approximately three months before the 2021 IRP.[83] The response "The Company's IRP uses a 20-year planning horizon and considers the average coal fuel cost in its dispatch commitment" is based on the 2019 IRP and not related to the 2021 IRP.

### O. The P02h Variant Should Not Replace the Preferred Portfolio

Sierra Club claims that the P02h variant, which retires Jim Bridger units 1 and 2 before 2030, is lower in cost than the 2021 IRP preferred portfolio despite some "questionable assumptions that needlessly inflate cost."[84] Sierra Club asserts that the P02h variant is lower cost than CETA,[85] and could be CETA-compliant already, making it the lowest cost portfolio.[86] Sierra Club recommends that the Commission direct PacifiCorp to evaluate the P02h variant portfolio for Washington's CETA compliance and assess whether it should be considered as a potential replacement for the preferred portfolio.[87]

Sierra Club's claims make incorrect assumptions regarding the P02h variant. As a P02-MM variant case that is not least-cost, it is inappropriate to include CETA compliance costs, particularly as the early retirements that are the specific subject of the study are not Washington-allocated and occur outside of the action plan window, in a timeframe that will be restudied on an ongoing basis as long-term resource plans evolve. The system-wide optimization in the P02 variants is based on the optimal portfolio for all states, whereas costs inherent to CETA's increased requirements and constraints are to be borne by Washington customers as provided by the incremental cost of CETA calculation.

[83] *In the Matter of the Application of PacifiCorp (U 901 E) for Approval of its 2021 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue*, CA Application 20-08-002, Decision 21-11-001 (Nov. 4, 2021).
[84] Sierra Club Comments at 33-34.
[85] Washington Clean Energy Transformation Act, SB 5116 (effective May 7, 2019).
[86] Sierra Club Comments at 33-34.
[87] *Id*.

Regardless of the relative cost of a P02h case adjusted for CETA compliance, adopting P02h as the preferred portfolio would inherently and needlessly increase costs to other states, as the P02h's present value revenue requirement differential ("PVRR(d)") clearly demonstrates when compared to P02-MM.

The correct comparison for P02h is therefore not the preferred portfolio (which includes the reconfigured Washington Situs resource and other costs that will only impact Washington customers), but rather P02-MM as presented in the 2021 IRP Chapter 9 in Table 9.14.[88] The result of P02h study was that retiring Jim Bridger units 3 and 4 early was $95 million more expensive ($60 million more expensive adjusted for risk) under medium gas and medium $CO_2$ ("MM").

The Company further notes that the preferred portfolio's costs relative to P02-MM are impacted by approximately $65 million of increased energy efficiency investment for Washington, a CETA-driven cost that would be similarly incurred in P02h regardless of other resource selections made for CETA compliance. Other resource additions are allocated based on each state's load and resource balance and Washington receives a significantly smaller portion of the total. As a result, the total quantity of renewable resources in each portfolio is not a good gauge of CETA compliance.

Furthermore, with respect to the addition of a nuclear resource in 2030, Sierra Club fails to recognize that Jim Bridger units 3 and 4 are dispatchable resources and available in all hours. Removing two dispatchable resources, per the study request, accelerated the need for additional long duration resources that could run around the clock. The best fit was nuclear located at the Jim Bridger site. The Jim Bridger nuclear addition was accelerated from 2038 when Jim Bridger units

[88] 2021 IRP Volume I at 289.

3 and 4 were assumed to retire in the P02-MM portfolio, and also removed a non-emitting peaker. The short term ("ST") study was run to verify reliability before finalizing the portfolio.

The assertion that the Company should have re-optimized the portfolio is irrelevant, as the purpose of the long term ("LT"), medium term ("MT"), and ST analyses is to determine the optimal portfolio considering all requirements. At the conclusion of the analysis, which includes the full optimized dispatch of the final portfolio in the ST model, there is nothing left to optimize.

Similarly, Sierra Club's claim that the nuclear resources were not economic selections because they were selected for reasons of reliability is irrelevant because all resource selections are optimized as least-cost to meet system requirements. The nuclear resources in question were determined as the least-cost option to meet system reliability requirements.

### P. The 2021 IRP Appropriately Models Environmental Compliance

The Company has appropriately modeled the minimum take provisions of its coal supply agreements. Sierra Club asserts that the Company did not adequately assess the risk of a scenario in which selective catalytic reduction ("SCR") installations are required for coal units in Utah and Wyoming.[89] Sierra Club recommends that the Commission direct PacifiCorp to model a variant of the preferred portfolio with SCRs installed on all relevant facilities in Utah and Wyoming, which should be compared to early retirement at these facilities before 2030.[90]

PacifiCorp serves Oregon, Washington, and California, each of which has time-certain laws requiring the utility to remove coal generation from the respective states' retail load. SCR system installation scenario for each of the respective coal units in Utah and Wyoming is seen as an extremely high-risk recovery scenario to undertake when SCRs are capital intensive and three out of the six states that PacifiCorp serves have legislation in place to prevent further investment

[89] Sierra Club Comments at 37-40.
[90] *Id.* at 8.

in coal generation. In addition, PacifiCorp evaluated scenarios with SCRs on the Utah and Wyoming units in its 2017 and 2019 IRPs respectively during the analysis phase that showed installation of SCRs would not be economic for customers, and thus was not selected for the preferred portfolios in the respective IRPs. Thus, there was no appetite to consider high risk SCR installation scenarios further in the 2021 IRP.

Furthermore, there are no state or federal SCR requirements for PacifiCorp's Utah coal plants. There are also no SCR requirements at Naughton or Dave Johnston. The SCR requirements at Jim Bridger units 1 and 2 have been removed from state law, and revision processes for the federal requirements were underway during 2020-2021; this is currently subject to litigation. The SCR requirement at Wyodak is stayed and is subject to litigation. PacifiCorp did not model SCR on all of its coal units in Utah and Wyoming because there are no broad SCR requirements on all the coal units in Utah and Wyoming. It is speculative and simply inaccurate to state that "SCR requirements will at some point be required under the Clean Air Act." Regional haze requirements vary by source, by pollutant, and by state.

As such, Sierra Club's recommendation that the Commission direct PacifiCorp to evaluate the P02h variant portfolio for Washington's CETA compliance and assess whether it should be considered as a potential replacement for the preferred portfolio[91] should be rejected.

**Q. The P03 Early Retirement Case Does Not Reflect Deficiencies and Subjective Choices in The Company's Modeling Methodology**

Sierra Club claims that the Company's P03 Early Retirement Case does not set forth an accurate picture of costs as compared to the preferred portfolio in part due to deficiencies and subjective choices in the Company's modeling methodology.[92] Sierra Club asserts that nuclear and

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[91] Sierra Club Comments at 40-41.
[92] Sierra Club Comments at 7.

non-emitting peaker additions are included in the variant and are the main cost drivers between the variants in the base case; however, Sierra Club claims that it is difficult to know what reliability constraints the Company is trying to resolve with these resources as no hourly data for its reliability analysis was provided.[93]

The duration and timing of shortfalls identified by control area in a given year is what led to specific resource selections. Where shortfalls were limited to hours where solar radiance is forecast to be high, solar with storage was the resource selected due to the flexibility to cover shortfalls during the day and up to four more hours during periods with low or no solar generation. In instances where the shortfall durations were short, but in hours when solar resources cannot satisfy reliability, standalone battery was selected. Where shortfalls were of a duration more than four hours, the need for long duration energy led to either nuclear or non-emitting peaker units being selected. Ultimately, the size of the shortfalls and relative system energy value of these options determined which would be selected for reliability. The non-emitting peaker is available in smaller increments but has a very high variable cost. In contrast, each unit of nuclear is large but has a high capacity factor, continuous availability and low variable costs.

## R. The 2021 IRP Appropriately Models the Gas Conversion of Jim Bridger units 1 and 2 and not Jim Bridger units 3 and 4

Sierra Club raises questions about the Company's decision to convert Jim Bridger Units 1 and 2 to natural gas as well as its decision not to model conversion at Jim Bridger Units 3 and 4. Specifically, Sierra Club points to natural gas price risk, insufficient analysis of the future use of Jim Bridger units 1 and 2, and Idaho Power's recent IRP that indicates they will exit Jim Bridger units 3 and 4 early.[94] WRA supports the natural gas conversion as "a cost effective, near-term

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[93] *Id.*
[94] Sierra Club Comments at 46-53.

resource option."[95] IEA discourages gas conversion generally, but it does not oppose the conversion of Jim Bridger units 1 and 2 specifically.[96]

**i. <u>Gas conversion at Jim Bridger units 3 and 4</u>**

There are a number of contributing factors to the Company's decision not to model gas conversion at all four Jim Bridger units and to limit modeling to gas conversion options specifically for Jim Bridger units 1 and 2. Conversion of all four Jim Bridger units to natural gas fueling will likely require a new main natural gas pipeline build or pipeline modification to be able to transport sufficient natural gas to fuel all four units at maximum dependable capacity of respective units combined. In addition, Jim Bridger units 3 and 4 have installed SCR systems on the units. To be able to operate the SCR as a converted natural gas fueled unit, a very preliminary assessment indicates that Jim Bridger units 3 and 4 will need flue gas recirculation ("FGR") systems installed and extensive surface, pressure parts, and fan modifications to achieve steam temperature and air flow to support full load. Unlike Jim Bridger units 1 and 2 that did not require main pipeline build/modifications or have SCRs that would necessitate installation of an FGR retrofit and other modifications, the preliminary identified equipment needs for Jim Bridger units 3 and 4 to convert to natural gas fueling are costly and would likely render such a scenario uneconomic relative to alternatives. Where Jim Bridger units 1 and 2 with no SCRs installed allows for a slimmed-down natural gas conversion, Jim Bridger units 3 and 4 need to balance the operational needs of the SCR in a natural gas conversion scenario, likely making the conversions more capital intensive to operate efficiently at maximum dependable capacity.

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[95] WRA Comments at 9
[96] IEA Comments at 14-15.

**ii. Gas conversion at Jim Bridger units 1 and 2.**

a. Gas conversion fuel price and supply risk

Sierra Club claims that the Company's planned natural gas conversion of Jim Bridger units 1 and 2 by 2024 carries significant fuel costs risks.[97] The DPU also analyzed the Company's natural gas price forecast and found it to be reasonable.[98] The 2021 IRP looked at the risk around natural gas prices in the MT model using stochastics. The Company also looked at several price-policy scenarios for natural gas and GHG costs. The dispatch of Jim Bridger units 1 and 2 when converted to natural gas peaking units is generally very low. For example, the annual capacity factor averages under 5 percent under medium gas / medium $CO_2$ price-policy conditions, so significant changes in gas prices would have a relatively small impact on annual operating costs. The ability to respond to changing conditions adds to the value of this type of resource on the system. The Company's 2021 IRP further increases the amount of renewable resources and storage on the system such that further out in time, solar with storage provides a lesser degree of incremental capacity value. The Jim Bridger units 1 and 2 gas conversions delay the need for alternative long duration dispatchable assets, and because they reuse primarily existing infrastructure, provide that capacity at a significantly lower cost than a new asset.

Sierra Club also argues, without any support, that the Company's decisions concerning natural gas are affected by the Energy Balancing Account, under which the risk of fuel price volatility is borne by customers. This assertion is unfounded and irrelevant, as the gas conversions identified in the preferred portfolio were selected based on least-cost and least-risk for customers. The modeling explicitly includes the assessment of costs and benefits among resources for each distinct portfolio and also incorporates risk metrics to gage portfolio robustness on a comparative

[97] Sierra Club Comments at 52-56.
[98] DPU Comments at 48-52.

basis. This approach is employed to arrive at the best portfolio selection for the Company's customers.

b. Investments to be undertaken for gas conversion

Sierra Club also claims that the 2021 IRP does not provide a description of the plant nor the capital projects that the Company plans to undertake for the Jim Bridger units 1 and 2 gas conversion.[99] The next steps regarding natural gas conversion of Jim Bridger units 1 and 2 are outlined in the Company's 2021 IRP action plan.[100] PacifiCorp provides the following additional detail in these reply comments. PacifiCorp is preparing permit applications for the Wyoming Division of Air Quality to convert Jim Bridger units 1 and 2 to burn natural gas to reduce emissions versus coal fueling accompanied by the installation of SCR equipment. The Company is coordinating plans for the conversion and for air quality compliance with Idaho Power Company. A fixed natural gas transport vendor will need to be selected with price quotes received from the closest natural gas pipelines to the Jim Bridger power plant. Once selected, a natural gas transportation contract will be negotiated, lateral pipeline route selected, permitted and built by the natural gas fuel and pipeline company conditioned upon execution of the natural gas transportation contract. Because Jim Bridger units 1 and 2 are located in Wyoming, PacifiCorp may be required to take actions relating to the fuel conversion if ordered by the Wyoming Public Service Commission. A large generator interconnection agreement will be submitted to PacifiCorp Transmission to formalize the fuel type change, with no change to the generator which remains interconnected to the PacifiCorp Transmission system. PacifiCorp is in the process of developing detailed design plans for natural gas piping from the plant property boundary to the boiler firing equipment, performance guarantees, and construction specifications for the natural gas conversion.

[99] Sierra Club Comments at 52-53.
[100] *See* 2021 IRP Volume 1 at 322.

c. Costs of gas conversion

Sierra Club asserts that the cost of replacing Jim Bridger units 1 and 2 is increased by the Company limiting its IRP capacity resource options to non-emitting peakers and nuclear additions, and thereby favoring gas conversion.[101]

However, solar with storage added in 2024 was the primary resource to replace Jim Bridger units 1 and 2 gas conversion in earlier years. In the 2021 IRP, in Figure 9.12,[102] portfolio P02a-JB 1-2 No GC shows the cumulative and incremental portfolio changes when the gas conversion of Jim Bridger units 1 and 2 is eliminated from the P02-MM portfolio. Without the gas conversion, the model optimizes the next-best selection—an additional 700 MWs of solar co-located with storage is added in 2024. Over 600 MWs of non-emitting peaker resources displace a similar amount of solar co-located with storage over the 2031-2037 timeframe. Taken together, the retirement of Jim Bridger units 1 and 2 forces a less economic acceleration of solar with storage which is later met by non-emitting peaker resources to meet reliability requirements. These non-emitting peaker resources are also an acceleration as in 2038, considering Jim Bridger units 1 and 2 were already retired at the end of 2023, the case without gas conversion avoids an advanced nuclear resource and non-emitting peaker resources that are required in the P02-MM portfolio when the converted units would have otherwise retired.

Excluding new emitting gas resources, nuclear and peaker resources are the least costly options available to meet system requirements in the later years of the study horizon. This conclusion is emphasized again in the Company's reply to individual party comments regarding the exclusion of new natural gas resources. Specifically, in addition to unique risks of new gas development, PacifiCorp has observed that there is very limited development activity for new

[101] Sierra Club Comments at 53.
[102] 2021 IRP Volume I at 269.

natural gas facilities. This was most recently evident in the Company's 2020AS RFP, which did not result in a single bid for new natural gas resources. Nonetheless, PacifiCorp produced a sensitivity in the 2021 IRP that allowed new natural gas proxy resources.

d. Idaho Power Company's Exit Plans

At the time of the 2021 IRP, Idaho Power Company had not issued its IRP showing an early exit from the Jim Bridger Power Plant. PacifiCorp therefore made no assumptions regarding whether or how Idaho Power Company will handle its property, because to do so would be speculative and outside of PacifiCorp's control. Idaho Power Company's potential early exit from the Jim Bridger plant is a complex issue requiring a legal agreement around the transfer of its 33 percent ownership in units 1 to 4, common facilities and funding its share of the reclamation, transferring water rights, and its portion of the coal agreements. Until a settlement is reached and there is certainty on the outcome, the 2021 IRP appropriately models PacifiCorp's ownership share. As more information becomes available and as stakeholder questions arise, they can be addressed through the stakeholder input process in the 2023 IRP.

## CONCLUSION

PacifiCorp's 2021 IRP complies with the Commission's Guidelines. The 2021 IRP includes robust and extensive portfolio modeling under a wide-range of price-policy scenarios and other prudent planning assumptions discussed with, and reflective of, stakeholder input resulting in the 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 continues to support stakeholder participation throughout the IRP development process to foster constructive dialogue and inform its long-term resource planning efforts. Therefore, PacifiCorp requests that the Commission acknowledge the 2021 IRP and the 2021 IRP action plan.

Respectfully submitted this 7th day of April, 2022.

Emily Wegener

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