ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

March 2, 2020

***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 Administrator

RE: **Docket No. 19-035-02 PacifiCorp's 2019 Integrated Resource Plan Reply Comments**

Pursuant to the Scheduling Order and Notice of Technical Conference, issued November 6, 2019, in the above referenced matter PacifiCorp (dba Rocky Mountain Power) submits for electronic filing its reply comments.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred):
datarequest@pacificorp.com
irp@pacificorp.com
Jana.saba@pacificorp.com
jacob.mcdermott@pacificorp.com

By regular mail:
Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Vice President, Regulation

Enclosures

cc: Service List Docket No. 19-035-02

# Response to the Utah Party Comments on PacifiCorp's 2019 Integrated Resource Plan

Docket No. 19-035-02

## I. INTRODUCTION

PacifiCorp (or the Company) filed its 2019 Integrated Resource Plan (2019 IRP) with the Public Service Commission of Utah (Commission) on October 18, 2019.[1] The Company's IRP was prepared in accordance with the Commission's IRP Standards and Guidelines in Docket No. 90-2035-01 and addressed requirements from the 2017 IRP Report and Order in Docket No. 17-035-16. 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 IRP Standards and Guidelines established under Docket No. 90-2035-01, and takes into consideration the "merit and applicability" of public comments.[2]

Consistent with the IRP acknowledgment schedule adopted by the Commission in this proceeding, the Division of Public Utilities (DPU),[3] Office of Consumer Services (OCS),[4] Utah Association of Energy Users (UAE),[5] Interwest Energy Alliance (IEA),[6] Western Resource Advocates (WRA),[7] Sierra Club,[8] Utah Clean Energy (UCE),[9] and jointly, UCE and Southwest Energy Efficiency Project (SWEEP),[10] filed comments and recommendations on February 4, 2020.

PacifiCorp looks forward to continuing to work with the stakeholders in their review of the 2019 IRP. The Company also appreciates the feedback received throughout the IRP development process. With limited exceptions related to certain resources and decisions arising in the action plan, including the Energy Gateway South (GWS) transmission line and demand-side management (DSM), the DPU, WRA, and OCS recommend that the Commission acknowledge the 2019 IRP as complying with the Standards and Guidelines. PacifiCorp appreciates the parties' confirmation that, in their view, PacifiCorp has met the Standards and Guidelines.

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[1] Typically PacifiCorp files its biennial IRPs by April 1 on odd-numbered years but for the 2019 IRP, PacifiCorp obtained extensions to finalize its coal studies to account for reliability costs, as well as to ensure accuracy in certain cost assumptions related thereto.
[2] Public Service Commission of Utah, *Report and Order on Standards and Guidelines* (Docket No. 90-2035-01), p. 33.
[3] Division of Public Utilities, Comments on PacifiCorp's 2019 IRP, dated February 4, 2020 (Initial Comments of DPU).
[4] Office of Consumer Services, Initial Comments, dated February 4, 2020 (Initial Comments of OCS).
[5] Initial Comments of Utah Association of Energy Users, dated February 4, 2020 (Initial Comments of UAE).
[6] Initial Comments of Interwest Energy Alliance, dated February 4, 2020 (Initial Comments of IEA).
[7] Comments of Western Resource Advocates, dated February 4, 2020 (Initial Comments of WRA).
[8] Sierra Club Comments (Confidential), dated February 4, 2020 (Initial Comments of Sierra Club).
[9] Initial Comments of Utah Clean Energy, dated February 4, 2020 (Initial Comments of UCE).
[10] Initial Comments of Utah Clean Energy and Southwest Energy Efficiency Project (Confidential), dated February 4, 2020. PacifiCorp notes that SWEEP did not intervene in this case. Therefore, PacifiCorp will refer to the joint comments of UCE and SWEEP as, "UCE comments."

### *A. The 2019 IRP Satisfies the Commission's Standards for Acknowledgement*

Initially, PacifiCorp generally responds to the recommendation by certain parties that the Commission take no action on the action plan items within PacifiCorp's 2019 IRP. This recommendation is both inconsistent with the process set forth in the Standards and Guidelines and is unnecessary. The Company notes the Commission's finding that "acknowledgment of an acceptable [p]lan will not guarantee favorable ratemaking treatment of future resource acquisitions."[11] By referring to the "plan" as a whole, the Commission finding also covers the action plan in the IRP. In other words, Commission acknowledgement of the IRP (including the action plan contained therein) does not mean that the Commission "approves" the action items that arise from the IRP. In addition, DPU's recommendation is inconsistent with the vast majority of its recommendations related to the action plans in prior IRPs.[12] Specifically, with one exception, the DPU has never recommended that the Commission take no action on PacifiCorp's action plan items within a PacifiCorp IRP. The DPU fails to present a good reason for deviating from the Commission's longstanding process. For that reason, and the support offered herein regarding PacifiCorp's action plan items, PacifiCorp recommends that the Commission reject this recommendation. In the following sections of its reply comments, PacifiCorp responds to each of the parties' comments which recommend that the Commission decline to acknowledge the GWS transmission line and DSM.

In response to the DPU's concern that PacifiCorp is more focused on pursuing resource portfolios that contain low or no carbon emissions than a least-cost, least-risk portfolio is simply not accurate. The 2019 IRP complies with the Standards and Guidelines and includes robust portfolio modeling and prudent planning assumptions that led to the selection of a least-cost, least-risk preferred portfolio. The 2019 IRP preferred portfolio reflects lower emissions over the planning period, but that is not driven by any state-specific policy or requirement to reduce emissions. The IRP assumed a medium gas/medium $CO_2$ price-policy scenario, in which the price for $CO_2$ was informed by reasonable estimates of when a federal policy might be implemented—2025. PacifiCorp also considered how top portfolios performed under other price-policy scenarios that assumed no $CO_2$ price and a high $CO_2$ price as bookends. Further, PacifiCorp also considered a social cost of carbon scenario.

In addition to the foregoing general comments, in these reply comments, PacifiCorp:

- Summarizes the process that was undertaken in the 2019 IRP and the key action items in the 2019 IRP;
- Responds to subject areas that were commented on by multiple parties;
- Responds to individual parties' comments on discreet issues; and

[11] Standards and Guidelines, Docket No. 90-2035-01, p. 33. While the Standards and Guidelines only refer to "future resource acquisitions," PacifiCorp, and likely others, recognize that the Commission's findings also apply to other major resource decisions, including decisions to shutter plants early.

[12] To the Company's knowledge, the only exception was the DPU's recommendation regarding the action items that included the Energy Vision 2020 projects in the 2017 IRP. The Commission's findings in the 2017 IRP about the Energy Vision 2020 projects were issued under unique circumstances, and should not become the norm.

- Responds to parties' recommendations for improvements and modifications to PacifiCorp's next IRP.

## II. OVERVIEW OF THE 2019 IRP

PacifiCorp's 2019 IRP meets the Standards and Guidelines and the preferred portfolio is least-cost and least-risk. Further, the preferred portfolio was selected in a manner consistent with the long-run public interest. It was developed by working through five fundamental planning steps that began with a comprehensive and robust analysis of PacifiCorp's coal units. The narrow scope of the coal study that was required by the Public Utility Commission of Oregon, which focused on unit-by-unit analyses with prescriptive retirement timing assumptions, was not intended to, and did not, inform retirement decisions, but rather informed the more in-depth and refined analysis in the subsequent portfolio development process. The portfolio development process produced a range of different resource portfolios that met projected gaps in the load and resource balance, each uniquely characterized by the type, timing, location, and amount of new resources in PacifiCorp's system that considered a wide range of potential coal retirement dates and other planning uncertainties. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure the comparative cost, risk, reliability and emission levels. This resource portfolio analysis informed selection of a preferred portfolio and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were are also done to produce specific modeling assumptions. Thus, the 2019 IRP and action plan comply with the Standards and Guidelines for resource planning and ensures that PacifiCorp will provide adequate and reliable electricity supply at a reasonable cost.

The 2019 IRP preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate the addition of approximately 6,400 MWs of new renewable resources by the end of 2023, with nearly 11,800 MWs of new renewable resources over the 20-year planning period through 2038.[13] To facilitate the interconnection of new renewable resources, the preferred portfolio also includes the 400-mile GWS transmission line that will connect southeastern Wyoming and northern Utah. These renewable resources will expand and further diversify the Company's portfolio while also meeting changing customer needs.

PacifiCorp's selection of the 2019 IRP preferred portfolio is supported by detailed data analysis using five fundamental steps: (1) a comprehensive and robust analysis of the Company's coal units; (2) development of a wide range of resource portfolios; (3) targeted reliability analysis of the portfolios to ensure that they have sufficient flexible capacity 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.[14] Each of these steps in the

[13] Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third party sales of renewable attributes are included in the total capacity figures quoted.
[14] 2019 IRP Volume I at 6.

2019 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.

The 2019 IRP benefited from modeling advancements including a robust analysis of its coal units, the ability of the System Optimizer (SO) model to endogenously view the estimated costs and benefits associated with specific transmission upgrades and to optimize transmission upgrade selections within the model, targeted portfolio reliability analysis using the Planning and Risk model (PaR), and improved storage modeling through the use of a tool that better optimizes charge and discharge cycles.[15] Through this extensive process, the Company was able to develop a preferred portfolio that meets its long-term goals of providing reliable and affordable service to its customers.

Although the 2019 IRP uses a 20-year planning horizon, the Commission has historically focused on the action plan, which identifies the specific resource actions PacifiCorp intends to undertake in the next two to four years.[16] The key resource actions in the 2019 IRP action plan include the following items:

- **Action Items 1b, 1c and 1d:** PacifiCorp will initiate the retirements of Cholla Unit 4, Jim Bridger Unit 1, and Naughton Units 1-2. These units are currently expected to be retired by year end 2020, 2023 and 2025, respectively.
- **Action Item 2a:** PacifiCorp will issue an all-source request for proposals to procure resources that can achieve commercial operations by the end of December 2023 (All Source RFP, or 2020AS RFP).
- **Action Items 3a, 3f and 3g:** PacifiCorp will seek to develop new transmission capacity through the GWS, Boardman-to-Hemmingway (B2H), and Energy Gateway West projects. These projects will allow the Company to facilitate the interconnection of new resources.
- **Action Item 4a:** PacifiCorp will acquire cost-effective energy efficiency resources with state specific targets. Acquiring additional energy efficiency throughout the Company's service territory will provide benefits to all customers.

The combination of these key action items will allow the Company to move into the future with a reliable, diverse portfolio that minimizes risk and costs to PacifiCorp's retail customers.

## III. RESPONSE TO PARTIES' INITIAL COMMENTS

### *A. PacifiCorp's coal study assumptions are reasonable*

PacifiCorp appreciates the initial comments that acknowledge the Company's analysis of its coal units and is carefully reviewing the stakeholder feedback that will facilitate additional improvements in the 2021 IRP cycle. The Company also notes that PacifiCorp will continue to update stakeholders as developments in the timelines associated with coal retirements occur. PacifiCorp has continued to actively pursue the retirement dates identified in the 2019 IRP

[15] 2019 IRP Volume I at 19.
[16] *Id.* at 12.

preferred portfolio and associated action plan. On January 5, 2020, PacifiCorp notified IRP participants that PacifiCorp plans to retire Cholla Unit 4 by the end of 2020. This closure date will be reflected in the Company's RFP analysis. The Company will also continue to re-evaluate the economics of its coal units in future IRPs, as suggested by Sierra Club and WRA.

i. <u>The Company has appropriately accounted for environmental compliance costs associated with its coal units.</u>

Sierra Club claims that PacifiCorp's decision to keep Jim Bridger Units 3 and 4 operating through 2037, rather than retiring those units in the mid-2020s, is not well supported by the evidence provided in this IRP. WRA also states that Jim Bridger Units 3 and 4 are costly units that merit further analysis. PacifiCorp disagrees with Sierra Club's claim, as explained in more detail below. Nevertheless, the Company agrees with WRA that Jim Bridger Units 3 and 4 merit ongoing analysis in the context of the 2021 IRP, and commits to doing so. PacifiCorp intends to continue to analyze these units in subsequent IRP cycles, and any changes in the lives of its coal units will be potentially influenced by and reflected in subsequent IRPs.

Sierra Club also contends that, because the Company did not include any costs associated with SCRs for the Hunter and Huntington units, PacifiCorp failed to accurately capture reasonably foreseeable environmental compliance costs. To address this concern, Sierra Club suggests that PacifiCorp should quantitatively capture and evaluate these potential costs.

The costs associated with SCRs for Hunter and Huntington were not reasonably foreseeable at the time the coal study was developed or even at the time of filing these comments. During the period when the coal study was performed, EPA's Regional Haze Federal Implementation Plan (RH FIP) for Utah (where Hunter and Huntington are located) that required SCRs for Hunter Units 1 and 2, and Huntington Units 1 and 2 had been stayed by the United States Tenth Circuit Court of Appeals pending EPA's reconsideration. Compliance with the Utah State RH FIP for these units therefore continues to be stayed by the Court. Utah has submitted a revised RH SIP for EPA's consideration; the revised Utah RH SIP does not require installation of SCRs on Hunter Units 1 and 2 or Huntington Units 1 and 2. At this time there are no foreseeable requirements that SCRs will even be required for these units and it was appropriate not to include any such costs in the Company's IRP analysis.

PacifiCorp's modeling of SCR costs was consistent throughout the IRP analysis and based on current legal requirements. The only legally required SCRs at the time of the coal study and 2019 IRP modeling were for Jim Bridger Units 1 and 2 and they were appropriately included in the benchmark case since PacifiCorp filed an application in 2019 for a Regional Haze Reassessment of the Wyoming RH SIP with the Wyoming Department of Environmental Quality.

WRA states that while alternative retirement timing for the Hayden units was not evaluated as part of this IRP cycle, they are PacifiCorp's most costly on a real levelized basis and that PacifiCorp should extract itself from the units as quickly as possible.

PacifiCorp disagrees. The Hayden units were included in the coal analysis both before and after the public-input meeting discussion of the initial coal study results on June 28, 2018. The Hayden retirement analysis was specifically included in five of the ten stacked studies that were fundamental to the initial cases developed for the 2019 IRP (cases identified as C37 through C41). Similarly the Craig retirement analysis was included in three of the ten stacked studies (cases identified as C39 through C41). The Company intends to continue analysis of these units in its 2021 IRP.

ii. A correction to the Jim Bridger coal mine costs is necessary but results in no changes to the action plan.

Sierra Club's comments state that the coal mine costs associated with Jim Bridger included in the preferred portfolio are incorrect. PacifiCorp reviewed these costs and determined that Sierra Club correctly identified an error. During the portfolio development process, while correcting for coal mine reclamation cost assumptions, PacifiCorp incorrectly modeled mine capital costs in P-45 based on an "Opt E Mine Plan," under which the Bridger Surface Mine closes in 2022, rather than an "Opt F Mine Plan," under which it closes in 2028. The impact on a PVRR basis is that P-45 is understated by roughly $29 million. PacifiCorp's Resource Planning department reviewed all other cases to ensure the correct match of mine capital costs between master assumptions and the model and found no other instances where the incorrect mine plan was modeled. PacifiCorp also reviewed the mine reclamation plan correction to ensure accuracy. In addition, the Company assessed its review and validation processes in light of this error consistent with the Company's commitment to continual improvement.

Correcting for this inadvertent error means that, under the medium gas/medium $CO_2$ price-policy assumption as shown in Table 8.14 of the 2019 IRP, P-45CP moves from the least-cost portfolio to third on a PVRR basis. P-48CP (Jim Bridger 3 and 4 retire 2033) is shifted to the least-cost, followed by P-47CP (Jim Bridger 3 and 4 retire in 2035) as the second least cost on a PVRR basis. However, the only impact of the reordering of these closely related variants is to the timing of Jim Bridger 3 and 4 retirements in the last six years of the study period. Each of the cases (P-45CP, P-47CP and P-48CP) would support the same 2019 IRP action items.

If P-48CP had been selected as the preferred portfolio based on the correction of the error, there would be minor variances in certain resource selections within the action plan window. Specifically, the selection of front office transactions and energy efficiency would change, and a there would be a swap of 54 MW of Utah solar with battery storage for the same amount of Utah wind in year 2023. These variances are small and arbitrary, with a net portfolio change ranging from zero to 8 MW in each year, which averages less than 5 MW over the action plan window. The resulting portfolio differences remain small through 2029, averaging less than 20 MW.

Sierra Club correctly states that the mine capital cost error makes P-45 less cost-effective relative to other portfolios, including P-36CP (Jim Bridger 1-4 retire 2025), but this does not change the ranking of the initial portfolios. PacifiCorp reviewed all C series and CP series portfolios and did not find a misalignment of the mine capital costs in any other case besides P-45. With the mine capital cost correction to P-45CP, case P-36CP remains behind P-45CP in four of the five scenarios, and remains ahead of P-45CP only in the social cost of carbon scenario. P-36CP remains the least cost-effective case in three of the five price-policy scenarios, and trails P-45CP by $190 million in the expected case (medium gas/medium $CO_2$). Additionally, the preferred portfolio, P-45CNW, was reduced by $15 million in value based on the exclusion of Dave Johnston (DJ) wind (excluded on the basis of heavy curtailments). The heavily curtailed DJ wind resource is not removed in cases P-47CP or P-48CP, and doing so would likely close the already narrow gap by a similar amount. In summary, correcting the error in the Jim Bridger mine cost marginally shuffles the order of closely related cases P-45CP, P-47CP and P-48CP, only in the medium gas/medium $CO_2$ price-policy scenario, which results in no impacts to the action plan, and no meaningful net impacts in the front ten years of the study.

Sierra Club also argues that the Company's Bridger fuel cost assumptions were unreasonably low and create a bias in favor of continued operation of these units. The Company disagrees. Sierra Club bases its assertion on the costs reported by the Company to the Energy Information Administration. However, the costs reported by PacifiCorp to EIA "includes all costs incurred in the purchase and delivery of the fuel to the plant." The fuel costs included for the Bridger plant in the IRP model are based on a cash cost that excludes non-cash expenses including depreciation, depletion, and amortization. The costs are also net of reclamation costs and are added in as a separate input in the model so that they do not inappropriately influence dispatch costs. Therefore, Sierra Club's comparison to the EIA reported costs is not apples-to-apples and its allegation that a bias exists is incorrect.

iii. <u>Emissions reductions</u>

Sierra Club claims that emissions reductions in the preferred portfolio are a function of dispatch assumptions and not retirements. The 2019 IRP states that by 2030, PacifiCorp will reduce its greenhouse gas emissions by nearly 60 percent from 2005 levels. Sierra Club asserts that nearly half of those emissions reductions only occur after 2027, and that through 2027 the majority of emissions reductions are only achieved by reduced dispatch, a purely operational assumption.

Sierra Club is correct that operational assumptions are a significant driver for the reduced emissions. To the extent that coal resources supply a valuable service to the system portfolio, the elimination of a single coal facility could actually prompt remaining units to generate more energy, and therefore more emissions. However, IRP outcomes as well as real world conditions do not appear to be having this effect. Rather, the role of remaining coal facilities is changing from one of consistent base load provider to a mixed service provider, supporting the addition cost-effective renewables, primarily through increasing flexibility and reserve carrying. This means that as more renewables are brought onto the system, remaining thermal facilities may generate less and less, but at the same time provide critical support that would be necessary for a lower-emissions future.

### *B. Transmission Resources*

Several parties commented on the transmission resources included in the preferred portfolio and the action plan. For example, while WRA and other parties support the proposed GWS transmission line, WRA recommends that the Commission direct PacifiCorp to conduct a workshop to discuss the appropriate approach for accounting for reliability needs. Other parties' question the need for additional resources, including the resources to be acquired through the upcoming All-Source RFP (2020AS RFP) and the proposed transmission upgrades set forth in the Company's action plan. For example, the DPU concludes that the transmission analysis is inconclusive and that the IRP model results may not reflect the true least-cost, least risk portfolio since not all transmission options were available to be endogenously selected by the model. Also, Sierra Club asserts that the need identified in the Company's IRP appears disconnected from the proposed 2020AS RFP and action plan (where transmission upgrades are presented). UAE and

OCS recommend that the Commission partially decline to acknowledge the part of the IRP that includes the selection in the preferred portfolio of the GWS transmission line for several reasons. Contrary to these comments, the IRP identifies a resource need that is appropriately met through a combination of actions including the 2020AS RFP and transmission upgrades, as explained in more detail below. Therefore, PacifiCorp asks that the Commission reject parties' recommendations to decline to acknowledge the part of the 2019 IRP that includes the GWS transmission line.

i. Transmission need

PacifiCorp plans to issue the 2020AS RFP to procure resources identified in the preferred portfolio. This will include resources in eastern Wyoming that would be reliant on the GWS transmission line. PacifiCorp will evaluate these proposals through the 2020AS RFP process and will only select projects reliant on the GWS transmission line for the final shortlist if those resources and the associated transmission investment are part of the least-cost, least-risk mix of resources relative to other alternatives bid into the 2020AS RFP. The GWS project is an element of PacifiCorp's least-cost, least-risk preferred portfolio for which the Company seeks acknowledgement. Acknowledgement of an action item is not a pre-approval of that action item, so the Company understands that acknowledgement of the GWS action item will not, in and of itself, lead to the construction of this transmission line.

ii. Production tax credits.

The DPU expresses concerns about the timeline of some of the projects proposed in the 2019 IRP action plan, noting that a recent federal appropriations package extended production tax credits (PTC) for another year, which the DPU notes could change the economics of some of the modeled portfolios. Therefore, the DPU recommends further analysis on PTC deadlines before a Certificate of Public Convenience and Necessity (CPCN) for the GWS transmission line is issued. The DPU further requests that the Company explain how the changes to PTC dates affect the timing of the GWS transmission line. UAE similarly contends that the inclusion of the GWS transmission line in the preferred portfolio is based on an outdated assumption about the expiration of PTCs.

After the 2019 IRP was filed, on December 20, 2019, the federal government signed the Further Consolidated Appropriations Act of 2020 extending the PTC by one year. The 2019 PTC legislation allows for projects that begin construction in 2020 and achieve operational status before December 31, 2024 (modeled as January 1, 2025) to receive a 60 percent PTC benefit. The 1,920 MW of new wind enabled by the transmission and identified in the 2019 IRP preferred portfolio would also qualify for 60 percent PTCs, with an in-service date of December 31, 2023. In light of this legislative change, PacifiCorp re-ran its preferred portfolio resulting in incremental addition of wind in 2025, located at Goshen, Idaho (450 MW), Utah (300 MW), Southern Oregon (500 MW), and Yakima, Washington (395 MW). The re-run of the preferred portfolio reported a PVRR(d) benefit of $517 million resulting from incorporation of the 60 percent PTC wind credit that increased the value of previously selected GWS wind and also created incentives for wind to be selected by the SO model compared to the preferred portfolio under a medium gas and medium $CO_2$ price-policy scenario. These findings however, do not change the 2019 IRP action plan's 2020AS RFP to procure new resources over the near term. Instead, the results highlight the fact that new wind resources offering bids into that All-Source RFP may be more competitive as a result of the new legislation. Based on PacifiCorp's reanalysis the Commission should not grant the DPU's recommendation that the Company perform further analysis prior to seeking a CPCN for the GWS project, as it is unnecessary.

iii. Acquisition of new resources and transmission upgrades

As an initial matter, PacifiCorp responds to comments that question the need for additional resources including the resources to be acquired through the upcoming 2020AS RFP and the proposed transmission upgrades set forth in the Company's action plan.

The DPU asks if the Company assumes that the winner of the 2020AS RFP will be Wyoming wind that is interconnected by GWS and questions if GWS will be underutilized in 2024 if the winner of the 2020AS RFP is another resource. The DPU requests the Company clarify if the 2020AS RFP will specify a particular capacity being sought.

PacifiCorp intends to include a topology chart specifying targeted procurement levels by geographical area on PacifiCorp's electrical system that is based on the 2019 preferred portfolio as part of the 2020AS RFP. This information is also provided for P-45CNW in the 2019 IRP, Volume II, Appendix M. Consistent with its preferred portfolio, PacifiCorp anticipates seeking to procure up to approximately 4,400 MW of new generating resources and up to 600 MW of energy storage resources. Considering that the 2020AS RFP is an "all-source" RFP, it is possible that the types of resources selected to the final shortlist will differ from those included in the preferred portfolio. Should these resources have capacity contribution values that differ from those in the preferred portfolio, the ultimate mix and amount of capacity procured may vary from the total capacity included in the preferred portfolio.

IEA and Sierra Club recommend that the 2020AS RFP be filed with the Commission for approval in advance to ensure a level playing field. IEA also states that PacifiCorp should not be allowed to build GWS without filling the resource needs of the preferred portfolio solely from the RFP. Specifically, IEA is concerned that PacifiCorp should not be able to build the line and then have the option of choosing not to acquire a full slate of resources to complete the preferred portfolio from the 2020AS RFP. Rather, the approved scenario should be established and then the utility should be required to fulfill it through a fair and predictable 2020AS RFP.

The Company disagrees that there should be a firm expectation of RFP outcomes from which selection amounts and potential future actions are not allowed to deviate. Any predetermined limitation on options could only have the effect of devaluing opportunities as represented by the bidding process and as represented by future emerging conditions. Such constraints would also serve to undermine the purpose of the RFP and by inference, the IRP. The RFP process will by design select the optimal resource selections from among those available without prejudging the outcome of the process.

The IRP process establishes a proxy-driven guide as to a least-cost, least-risk future. However, it cannot be known in advance what bids may materialize in terms of technology, pricing and location. The RFP process may lead to the selection of more efficient resources that would therefore be required in lesser nameplate amounts than are represented in the IRP. It is also possible (but highly unlikely) that the RFP process would lead to no new resources, assuming there are no bids that would be cost- and location-effective in realizing the potential benefits identified in the preferred portfolio. It is also the case that the combination of selected resources may vary due to interactions among projects that cannot be considered in advance of the RFP.

In addition to Commission approval, Sierra Club also recommends that PacifiCorp's 2020AS RFP process include a level of transparency similar to the IRP process and that an independent evaluator (IE) be retained and that PacifiCorp explain any substantial deviations between the IRP preferred portfolio and the near-term resource plans that result from the 2020AS RFP process. Sierra Club asserts there is a lack of clarity on whether existing resource retirement decisions would be impacted by 2020AS RFP results.

Two independent evaluators (IE) will be retained as required by Utah and Oregon requirements. The issuance of the RFP is expected to resolve many potential ambiguities, and will be reviewed with input provided by the IEs. Regarding retirement assumptions, the 2019 IRP established the preferred retirements under conditions relevant to the studied portfolios; the RFP is the process aimed at soliciting and evaluating the resource bids necessary to fulfill on the potential established in the preferred portfolio. The RFP process does not contemplate repeating the 2019 IRP's months-long coal studies, displacing the preferred portfolio and essentially starting the portfolio development process over from scratch.

iv. <u>Interconnection queue reform</u>

DPU and IEA seek additional information about whether and how the interconnection queue reform proposal that PacifiCorp's transmission function filed with the Federal Energy Regulatory Commission (FERC) on January 31, 2020 will affect the 2020AS RFP. As proposed to FERC, the proposal intersects with the 2020AS RFP in two key respects, both related to timing.

First, as discussed at length in the six-month stakeholder process leading up to the FERC filing, PacifiCorp's transmission function appreciated the stakeholder concern that, if a proposal to modify PacifiCorp's Open Access Transmission Tariff (OATT) interconnection processing rules is pending before FERC *during* the 2020AS RFP, it would create significant uncertainty for the development community. Stakeholders therefore asked that PacifiCorp either: (1) file its request with FERC in time for FERC to approve it before the start of the 2020AS RFP; or (2) hold the request until after the 2020AS RFP is completed. PacifiCorp elected the former route, filing on January 31, 2020 and asking FERC to grant an effective date of the proposed reforms of April 1, 2020.

Second, PacifiCorp proposed to transition its interconnection queue from the current serial-order methodology to a first-ready, first-served cluster methodology by performing its first cluster study—which is also referred to as the "transition cluster" in the FERC filing—in October 2020. Large, FERC-jurisdictional generator interconnection customers (who make up approximately 37,000 MW of the 40,000 MW of requests in the queue) seeking to participate in the transition cluster will need to demonstrate commercial readiness[17] using one of the objective criteria set forth in PacifiCorp's proposed OATT—criteria that include demonstration that the generator has been selected in a load-serving entity's competitive solicitation. Thus, if FERC approves PacifiCorp's proposal, then short-listed bidders in PacifiCorp's upcoming 2020AS RFP would qualify to be part of the first transition cluster study as long as the bidders have been selected (and submit evidence of that selection to PacifiCorp transmission) by the October 2020 OATT deadline.

The DPU seeks information about the likelihood of FERC approval of PacifiCorp's queue reform proposal. While it is difficult to make that assessment, PacifiCorp can offer that it recognized the challenges previously faced by other similarly situated transmission providers attempting to secure FERC approval to move to a first-ready, first-served cluster study methodology, and PacifiCorp therefore styled its proposal to adhere to the existing precedent as closely as possible. PacifiCorp can also note that, after its January 31, 2020 filing, roughly fifteen intervenors to the FERC docket, including IEA, filed comments on February 21, 2020. The comments were largely complimentary of PacifiCorp's months-long stakeholder process and generally supportive of PacifiCorp's proposed reforms overall. Intervenors did request that FERC direct PacifiCorp to make certain small to moderate adjustments to its reform proposal. PacifiCorp is currently preparing a reply to those comments, slated for filing on March 9, 2020. FERC will be required to take some action on PacifiCorp's request within 60 days of the initial filing, or by April 1, 2020, but a merits decision on that date is not assured (FERC could toll a merits decision by seeking additional information).

Apart from the timing elements discussed above, the DPU and IEA raises questions about how the 2020AS RFP process and requirements will be adjusted to account for either FERC approval or FERC rejection of PacifiCorp's queue reform proposal. At this point, PacifiCorp is developing its 2020AS RFP process for bid evaluation, scoring, modeling, and selection in a manner that assumes FERC approval of PacifiCorp transmission's first-ready, first-served cluster study methodology as described in its January 31, 2020 application to FERC. PacifiCorp will revise its eligibility requirements or evaluation criteria in the 2020AS RFP as necessary to align with either: (1) any directed modifications to the final version of a first-ready, first-served cluster approach approved by FERC; or (1) if FERC rejects the queue reform proposal, the currently effective OATT serial-queue interconnection processing approach, before the 2020AS RFP is finalized and issued to the market.

That said, the crux of the expected difference between the two types of interconnection processing (*i.e.*, the current serial-queue processing vs. the proposed "first-ready, first-served, cluster" processing) is *when* during the 2020AS RFP process PacifiCorp could consider a bidder's interconnection documentation. More specifically, under a first-ready, first-served, cluster interconnection process, as proposed by PacifiCorp in its January 31, 2020 filing with FERC, PacifiCorp will need to evaluate interconnection documentation later in the 2020AS RFP process because some bidders may need to wait until the proposed October 15, 2020 transitional cluster study is completed to have an interconnection study. This means PacifiCorp will not require an interconnection study or agreement at the outset of the 2020AS RFP process, and the cost for any direct assigned and transmission network upgrades associated with the interconnection of a

[17] As discussed in more detail in PacifiCorp's filing before FERC, there are certain exceptions to the commercial readiness requirements for generators that are at a late stage in the interconnection study process or have an executed interconnection contract.

proposed project to PacifiCorp's transmission system will not be included in the initial shortlist price evaluation. PacifiCorp will, however, include among the minimum eligibility requirements for RFP conformance demonstration by the bidder that its project bid conforms with the project's interconnection documentation, which under the proposal currently before FERC could be: (a) only an interconnection request, as long as it was submitted by the interconnection customer to PacifiCorp's transmission function on or before January 31, 2020; (b) serial-queue interconnection study documentation if the bidder has the option to keep that documentation under the parameters of PacifiCorp's proposed interconnection queue reform transition process; or (c) an executed interconnection agreement.

If FERC rejects PacifiCorp transmission's queue reform proposal and PacifiCorp transmission must continue processing interconnection requests using the status quo serial-queue process, PacifiCorp could evaluate a bidder's interconnection documentation earlier in the 2020AS RFP process. This is because no bidder's ability to receive an interconnection study would depend on satisfaction of the proposed queue reform commercial readiness criteria and PacifiCorp transmission's completion of a future interconnection cluster study. Rather, under a serial-queue process, a bidder will either have a serial-queue interconnection study or interconnection agreement with the requisite demonstrations by the applicable 2020AS RFP deadline, or it will not. Therefore, PacifiCorp would require an interconnection study or agreement at the outset of the 2020AS RFP process.

On a related note, PacifiCorp disagrees with IEA's conclusion that, if FERC rejects PacifiCorp's queue reform proposal and PacifiCorp transmission must continue serially processing its queue, that PacifiCorp will hold "an unintended and yet unworkable advantage in an RFP bid review process, tilting the playing field in favor of projects higher in the queue, regardless of their relative overall cost." This is not an "advantage" for *PacifiCorp*. It could be more accurately characterized as an advantage for the third-party developers who hold the highest queue positions—but hardly an unfair one given that the federal interconnection processing rules that have been in place since 2003 created that first-mover advantage. PacifiCorp agrees that serial-queue processing can lead to extreme interconnection study results where an interconnection queue is congested, which is why PacifiCorp transmission put significant time and resources over the last year into its queue reform stakeholder process and subsequent FERC filing. Unless and until FERC approves that proposal, however, the perceived "advantage" is one required by a long-standing federal construct, and is not one held by PacifiCorp.

Finally, DPU asks whether PacifiCorp expects that FERC acceptance of the queue reform proposal would increase or decrease the amount of Qualified Facilities (QFs) for the years 2020 to 2023. PacifiCorp has no information on whether QF development would increase or decrease if queue reform is accepted. PacifiCorp transmission is not planning to apply the commercial readiness test associated with a first-ready, first-served processing approach to QF interconnection requests during the 2020 transition period because those types of generators are not primary contributors to the queue backlog issues at this time. PacifiCorp transmission will, however, continue to monitor its queue activity and may reconsider that approach as necessary going forward. That said, PacifiCorp also sought FERC approval to limit the group of requests eligible for the October 2020 transition cluster to those projects that had queued interconnection requests as of the date of PacifiCorp's January 31, 2020 filing with FERC. This eligibility criteria will be applied across all queued requests—small and large FERC-jurisdictional, small and large state-jurisdictional—to ensure the queue can be effectively cleared out and no one type of generator has an unfair advantage over another type of generator.[18]

v. Modeling issues

a. Transmission Line Alternatives/Options

The OCS claims the Company included the GWS transmission line in all cases but did not provide a base case without the line for comparison. The OCS questions whether the preferred portfolio truly represents the least-cost, least-risk portfolio because, it claims, no analysis was provided that explored cases without the line. Based on this, the OCS recommends conditional acknowledgement because OCS contends that PacifiCorp has not provided requested analyses concerning the GWS transmission line and customer rate impacts.

Throughout the 2019 IRP modeling process, GWS was endogenously selected by the SO model in nearly every resource portfolio. In the preferred portfolio, the year-end 2023 in-service date enables 1,920 MW of new wind capable of qualifying for 40 percent of the full value of PTC before they expire. The persistence of the SO model selection of GWS in nearly every portfolio obviated the need for a counterfactual case that eliminates GWS from the preferred portfolio. Nonetheless, PacifiCorp recognized the broad stakeholder interest in understanding how the preferred portfolio and system costs might be impacted if GWS is assumed to be removed from the preferred portfolio. This analysis was provided in response to OCS Data Request 2.1, including three distinct cases for analysis, and concluded that quantified benefits from GWS and associated new wind range between \$267 million and \$1.09 billion. These benefits are conservative as they do not include the non-quantified benefits associated with the new transmission line (described in both the 2019 IRP and the response to OCS Data Request 2.1).

The Company disagrees with OCS's statement that the "PacifiCorp's response to OCS 2.1 did not remove GWS but instead included a smaller version of the GWS line, a 230 kV transmission line along the same route as GWS". GWS is removed from each of the three cases used in the analysis. The response to OCS explains that the smaller 230kV line is included in one of three cases because:

> [i]t is unrealistic to assume that PacifiCorp transmission would not be obligated to construct any transmission system upgrades out of eastern Wyoming to accommodate Federal Energy Regulatory Commission (FERC) jurisdictional requests for open access transmission tariff (OATT) interconnection service and transmission service. Indeed, both PacifiCorp's interconnection queue and its separate transmission service queue currently contain requests for service that are contingent upon GWS being constructed.[19]

The inferred case in OCS's comments, where the Company removes a major endogenously selected transmission project without a realistic consideration of alternative transmission activity,

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[18] All generators will also be subject to other elements of the queue reform proposal, such as increased study deposits and withdrawal penalties.

[19] See PacifiCorp response to OCS 2.1, which was attached to Initial Comments of OCS, filed February 4, 2020.

would lack analytic value. The Company therefore recommends a full acknowledgement of its 2019 IRP.

UAE's main criticism about the selection of the GWS transmission line in the preferred portfolio is that it is not supported by a robust analysis of potential transmission economic alternatives. Specifically, UAE argues the that Northern Tier Transmission Group (NTTG) Report includes evidence of a reliable and lower cost alternative transmission configuration, and that PacifiCorp has been unwilling to evaluate whether this alternative could more economically meet the needs of the Company's customers. In addition, UAE suggests that PacifiCorp has been unwilling to run a test case for transmission configuration using the SO model, and that the Company has refused to run a case that would evaluate the proposed NTTG economic alternative. Finally, UAE contends that the Company has not provided a publicly available transmission study or evaluation of economic alternatives during the past decade during which it has developed the GWS transmission line.

UAE's requested study is beyond the scope of the IRP and would not be performed as part of the IRP process. PacifiCorp develops its resource plan as a single system, which is consistent with system operations. Consequently, as part of its planning process, PacifiCorp does not evaluate how energy from specific resources is flowing across the transmission topology to meet load in specific jurisdictions. From a transmission perspective, the existing transmission system and transmission service contracts provide the ability to import up to 1,600 MW from Wyoming to Oregon. In addition, PacifiCorp participates in NTTG as part of its compliance with FERC Order 1000 regional planning requirements. As an NTTG member, PacifiCorp participated in transmission planning studies evaluating impacts of a high Wyoming wind scenario with and without B2H. These studies evaluate the impacts of the Wyoming renewables on the greater transmission system and the ability of the combined resource portfolio and transmission system to reliably serve the load requirements of each member. The NTTG Regional Transmission Plan for 2018-2019 evaluated impacts of the high Wyoming wind scenario without B2H in seven unique scenarios representing various other transmission builds and the null case of no additional transmission to evaluate the system benefits and reliability impacts of each scenario using both power flow and production cost model analysis. The December 19, 2019 version of the NTTG Regional Transmission Plan is publicly available.[20]

The NTTG Report relies on an analysis that is not comparable to the 2019 IRP analysis. The 2019 IRP analysis and the regional planning process performed by the NTTG are two distinctly different processes that address two different needs. The IRP analysis specifically focuses on forward-looking resource needs of PacifiCorp including inputs of planned or required transmission upgrades necessary to deliver resources. The NTTG planning process is a transmission reliability analysis using projects submitted by the funding members included in their local transmission planning process to identify the least cost or most efficient regional transmission plan. The NTTG planning process evaluates the entire regional planning footprint of its members, which is much broader in scale than the IRP analysis performed by PacifiCorp. For this reason, it is not

[20] See: https://nttg.biz/site/index.php?option=com_docman&view=download&alias=3288-nttg-2018-2019-regional-transmission-plan-for-steering-approval-12-19-2019&category_slug=steering-committee-meeting-material-12-19-2019&Itemid=31.

appropriate to use the alternative that is set forth in the NTTG report, nor is it appropriate to rely on the NTTG planning process to determine the benefits of a particular project for PacifiCorp. Therefore, the selection of the GWS transmission line has been properly supported and should be acknowledged. In addition and as WRA noted in its comments supporting the GWS transmission line, PacifiCorp will be required to support evidence and justification for the transmission line in subsequent proceedings.

b. Reliability Requirements

IEA and Sierra Club claim that PacifiCorp arbitrarily added a 500 MW reserve requirement that is not necessary for reliability purposes, that it overstates the costs and skews the portfolio toward less effective resource mix. Sierra Club elaborates that the portfolios that PacifiCorp developed already account for the significant day-ahead, hour-ahead and real-time "unknowns" in market supply through the Company's application of a target planning reserve margin (PRM), hourly operating reserves requirements, and conservative market reliance limits. UCE also asserts that the Company's reliability resource methodology is overly conservative or likely added unnecessary resources, and in particular does not acknowledge the roles of EIM in its reliability analysis.

The analysis provided in the 2019 IRP was developed over the course of the public-input process with ongoing stakeholder participation.[21] PacifiCorp introduced the importance and need for additional reliability considerations in the first 2019 IRP public-input meeting on June 28, 2018, and continued to pursue these considerations throughout the public-input process. One result of these considerations was the establishment of the analytically determined 500 MW uncertainty requirement. The analysis demonstrates that the uncertainty requirement is data-driven, conservative, and demonstrably necessary. Reliable system operation is a prerequisite for any portfolio considered as a candidate for the preferred portfolio. In light of developing trends in resource types, capabilities and costs, the Company reasonably determined that without this robust reliability assessment, portfolios would not achieve an adequate level of reliability to meet its load and reserve obligations. The deterministic model runs used to establish the portfolio-specific reliability requirements were performed using detailed hourly measurements on a regional and seasonal basis, accounting for all resources and system requirements. The results quantified the reliability shortfalls and demonstrated the necessity of both the uncertainty requirement and the reliability resource methodology.

As explained in the 2019 IRP, Volume II, Appendix R, Flexible Reserve Study (FRS), the deterministic hourly modeling required to make the proper assessment necessarily assumes "perfect foresight," in that it lacks the stochastic variation required to serve as a complete proxy for real world conditions. This uncertainty is in fact the basis of the additional capacity held in reserve in actual operations and the basis that the Company used to determine its uncertainty requirement. As set forth in the 2019 IRP:

> The 500 MW incremental requirement relative to a deterministic forecast of loads, outages, market prices, and hydro generation was established upon review of operational data and with consideration of operational

[21] See, e.g., Slide 9 of the June 28, 2018 public-input meeting presentation, available at: https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

> experience. In operations, capacity held in reserve for contingency, forecast error and intra-hour variability is approximately 16 percent of peak load. In the summer months, additional capacity is held in reserve to mitigate risks associated with high volatility in load and resource availability. In 2018, capacity held in reserve that is incremental to the 13 percent planning margin for contingency, forecast error, and intra-hour volatility totaled 295 MW. In 2018, capacity held in reserve to mitigate risk during peak load conditions in the summer months was approximately 241 MW. Combined, these sum to 536 MW. PacifiCorp conservatively adopted the 500 MW figure for planning purposes in the 2019 IRP.[22]

The "unknowns" referenced in Sierra Club's comments are thus not incorporated in the 13 percent PRM, and the stochastic unknowns are also not included in the deterministic studies. The uncertainty requirement addresses these facts directly.

Contrary to Sierra Club's claim that the uncertainty requirement is "unsupported", the 2019 IRP uses existing, tested models to measure and correct a readily demonstrable issue, and does so in a way that allows for targeted model optimization to meet specific and quantifiable requirements with flexible resources only when and where necessary. Both the need and the method are therefore well-founded and valid. Nevertheless, PacifiCorp expects that it will continue to refine its reliability resource methodology in the 2021 IRP. The Company is exploring alternative model software and techniques that may allow for a more direct assessment of reliability. Further stakeholder involvement will continue to be a valuable component of any future changes to this methodology.

c. Optimizing Renewables in Modeling

Regarding PacifiCorp's use of its models to optimize renewable resources, UCE is incorrect that PacifiCorp limited "the IRP model's ability to see and utilize all potential benefits from renewable energy, such as spinning and non-spinning reserves". The SO model optimizes resource selection to meet load requirements and the PRM. The SO model, however, does not account for the ability of those resources to meet contingency and regulating reserves as mandated by regulatory requirements on an hourly dispatch basis, which is captured when resource portfolios are modeled in PaR. This discrepancy is exacerbated by the shift in cost-effective renewable resource selections coming out of the SO model, which lack the level of flexible dispatch relative to other resource alternatives (*i.e.*, thermal units) that can deliver differing types of operating reserves (*i.e.*, contingency, spinning, non-spinning, and regulating) in sufficient quantities across all hours to produce a reliable portfolio. PaR is capable of assessing detailed operating reserves while accounting for the increased complexity imposed by a larger amount of renewables on the system selected by the SO model.

As noted above, the PRM is incapable of accounting for the increasingly complex needs of a system which relies heavily on renewables, and this is a shortcoming which the Company anticipated and subsequently identified, quantified and mitigated. When the reliability of a

[22] 2019 IRP Volume I at 610-611.

portfolio is assessed using a more granular tool with visibility into operating reserves (deterministic runs), the shortfalls are real and readily identifiable. If IEA/Sierra Club/UCE claims that the methodology likely added unnecessary resources is accurate then no meaningful deficiencies would have been identified among portfolios in the absence of this requirement. Instead, the deterministic reliability studies show significant shortfalls in specific years, regions and seasons even if the (necessary) uncertainty requirement were to be excluded.[23]

d. Energy Imbalance Market

UCE and Sierra Club claim that EIM was not accounted for in the Company's PRM, FRS or coal studies, and that adding an additional 500 MW resource requirement, effectively supplementing the requirements of both the PRM and FRS for only part of the IRP analysis, undercuts the value of PacifiCorp's own reserve and flexibility studies. This reflects a misunderstanding of IRP modeling and the role of EIM. To participate in the EIM in each hour, a utility must bring sufficient resources to serve its forecasted loads and provide sufficient flexible ramping capability to meet its own obligations, less an allocated share of the diversity benefits associated with serving aggregate rather than individual requirements. The diversity benefits associated with EIM participation are included in PacifiCorp's FSR, in the form of reduced regulation reserve obligations. EIM does not provide any further capacity or reliability benefits and each participating utility independently retains its obligation to operate reliably in accordance with all North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards.

The 500 MW resource requirement in PacifiCorp's reliability analysis is not intended to be incremental to the PRM level. 500 MW is intended to reflect a reasonable buffer to account for variations in forecasted loads, hydro conditions, and generator outages that are not represented in the deterministic view used in the reliability analysis. In the PRM analysis these effects are incorporated stochastically, and vary from study to study. For example, if a zero MW requirement was used in the reliability analysis, the resulting portfolio would be expected to result in loss of load in half of all years, whenever load was above the median (*i.e.,* one in two year) level included in the deterministic view. As a result, an incremental requirement is necessary to ensure a deterministic baseline achieves the reliability identified in the stochastic PRM analysis.

PacifiCorp would also note that the PRM study in the 2019 IRP did not contain the level of wind and solar resource additions included in the preferred portfolio (and the vast majority of all portfolios evaluated). The specified PRM level is only an accurate measure of system reliability to the extent the resources used to meet it have capacity contributions that accurately reflect their contribution to reliable system operation, in conjunction with the other resources in a portfolio and the loads and operating reserve requirements that must be met. PacifiCorp's reliability analysis shows that some combinations of resource selections do not result in adequate resources throughout the year to meet requirements, and identifies incremental resources to fill in those gaps and meet a uniform 500 MW baseline. The 500 MW baseline applied to every portfolio evaluated, so it does not undercut the value of particular resource types.

[23] 2019 IRP public data disc, \Public\Assumptions & Inputs\PaR Reliability Summary\P IRP Study Reliability Requirements for SO RP 1 (09252019).xlsx.

It is not clear what additional capabilities and benefits UCE believes should be incorporated. PacifiCorp's modeling of proxy renewable resources allows them to be dispatched down and to provide operating reserves when doing so. This is the same treatment as traditional resources. The modeling in the 2019 IRP allows for a fair and consistent portfolio selection and evaluation.

### *C. DSM Actions*

UCE criticizes PacifiCorp because it believes the Company did not compare DSM to other supply-side resources on a consistent and comparable basis, as the Standards and Guidelines require. UCE states that during the public process, it asked PacifiCorp to run several scenarios which the Company declined to do. For future IRP cycles, UCE recommends that PacifiCorp develop low, medium, and high cases for technically achievable potential in the conservation potential study (CPA) by working with stakeholders to adjust assumptions around cost and availability of DSM resources. Further UCE recommends that PacifiCorp update the assumptions and the modeling of Class 1 DSM resources to represent program costs and use the "full benefits" of Class 1 DSM to integrate variable renewable energy resources. In addition, UCE asks that PacifiCorp include an analysis as part of the 2021 CPA comparing measure-level levelized cost and supply assumptions from the 2019, 2017, and 2015 CPAs with historical measure-level cost and program Utah-specific achievements. UCE also recommends that the Commission direct PacifiCorp to increase DSM targets and spending if the program performance differs from the targets modeled in the IRP. UCE believes that the level of DSM identified in any IRP action plan should not be treated as a target that the utility may not exceed, and that the utility must be allowed the flexibility to deviate from the action plan between IRPs. In addition, UCE believes that the Company should be open to updating targets and procuring more DSM resources if additional resources are available at a reasonable cost. Finally, UCE believes that the Company should regularly compare its modeled values and costs with "real-world" experience. Based on the foregoing, UCE asks that the Commission decline to acknowledge the DSM portion of the IRP, and that the Commission find that 105 percent of the Class 2 DSM resources selected in the IRP is not a cap on DSM resources if additional cost-effective resources are available.

The Company disagrees with UCE that PacifiCorp did not meet the Standards and Guidelines which require, in part, that PacifiCorp evaluate all resources on a consistent and comparable basis. All supply-side resources, including DSM, must compete on the basis of how it contributes to meeting peak demand, which includes considerations of reliability and availability across days, months and seasons. PacifiCorp's SO model is appropriately designed to account for this critical factor for all supply-side resources. In fact, DSM is modeled with appropriate inherent advantages relative to other supply-side resources. DSM resources are modeled as a "use it or lose it" resource, meaning that the model selects economic DSM before other supply-side resources. In-addition, DSM resource are given credits for the additional value they provide in transmission and distribution, operating reserves and capacity.

Despite the advantages of DSM, low-cost resources are not always the most cost-effective when all factors, such as contribution timing, are considered. The modeling process is robust and objective to ensure the planning process is optimizing the best possible information available at the time of the development of the resource assumptions informing the IRP.

Regarding UCE's request that PacifiCorp (i) include an analysis as part of the 2021 CPA comparing measure-level levelized cost and supply assumptions from the 2019, 2017, and 2015 CPAs with historical measure-level cost and program Utah-specific achievements, and (ii) develop low, medium, and high cases for technically achievable potential in the CPA by working with stakeholders to adjust assumptions around cost and availability of DSM resources, the Company is open to working with stakeholders to identify potential improvements to the CPA methodology and other modeling changes, including how these resources are evaluated with the IRP model. The Company will work with stakeholders to consider and address feedback received through the CPA workshops for the 2021 IRP and has started that public-input process earlier in the IRP development process to allow for more meaningful engagement and participation.[24]

i. <u>The modeling/scenarios used in the 2019 IRP for DSM resources was appropriate</u>.

PacifiCorp met the Standards and Guidelines requiring that the Company evaluate all resources on a consistent and comparable basis. Any questions surrounding the valuation of DSM should not hold up the acknowledgement of the Company's DSM action items which are also rooted in thorough and time-tested analytics and evaluation. Recent improvements to the modeling practices for DSM for the 2019 IRP include the ability to assess programs targeted to deliver ancillary services as well as the application of state-specific transmission and distribution cost credits. For the 2021 IRP, additional improvements to how DSM, including demand response, is represented in the model are under development and will be discussed during the CPA stakeholder workshops for the 2021 IRP. The Company has extensive DSM experience including operation of the "Coolkeeper" program in its Utah service territory for nearly 92,000 customers. The Company will continue to leverage this experience to implement DSM programs as they become cost-effective.

The Company appreciates UCE's interest and willingness to engage with PacifiCorp to ensure that its modeling of DSM resources is evolving. As part of the 2021 IRP and CPA development, PacifiCorp has two public-input meetings dedicated to CPA development (one was held on January 21, 2020 and one is scheduled for February 18, 2020). In addition to these meetings, stakeholders will have many opportunities for discussion on the 2021 CPA such as reviewing the CPA statement of work and associated measures list during the CPA stakeholder review process. The Company is open to having an additional CPA meeting to discuss DSM methodologies and assumptions and will schedule a meeting in April of 2020.

However, the Company disagrees with the suggestion that the IRP's optimal selections of any resource should be overridden within the context of the IRP, or that the IRP should not be acknowledged on the basis of concerns that are unrelated to correct and optimal valuations resulting from IRPs modeling.

[24] January 21, 2020 – Conservation Potential Assessment Technical Workshop #1 – Pre-2021 IRP Public Input Meeting;
CPA Scope of Work February 18, 2020 – Conservation Potential Assessment Technical Workshop #2 – Pre-2021 IRP Public Input Meeting;
CPA Draft Measures April 16, 2020 – Conservation Potential Assessment Technical Workshop #3 – Pre-2021 IRP Public Input Meeting

ii. The Company continues to pursue additional cost-effective DSM Class 2 resources and improvements to its system-wide approach to acquisition of these resources.

UCE believes that the level of DSM identified in any IRP action plan should not be treated as a target that the utility may not exceed, and that the utility must be allowed the flexibility to deviate from the action plan between IRPs. In addition, UCE believes that the Company should be open to updating targets and procuring more DSM resources if additional resources are available at a reasonable cost. In response to these concerns, PacifiCorp notes that the Standards and Guidelines already state that PacifiCorp must account for such considerations and permit flexibility in the planning process so the Company can take advantage of opportunities as they arise. In other words, the Standards and Guidelines already prevent the premature foreclosure of options.

As with any supply-side resource, the actual DSM programs and costs will inevitably vary from the IRP's proxy recommendation. Also as with any supply-side resource, real world availability and performance are directly tested and applied downstream from the IRP's proxy selections.

### *D. Renewable Resources*

IEA notes that the battery storage in the 2019 IRP action plan, coupled with utility-scale renewable resources can replace baseload units by providing firm energy and capacity throughout the day without inertia. IEA praises PacifiCorp's Energy Storage Potential Evaluation as a good step towards recognizing these benefits in its modeling and resource planning.

PacifiCorp agrees that the ability to dispatch energy storage resources up and down creates more flexibility in several measures than can be achieved with traditional "baseload resources." Energy storage resources can generally ramp very rapidly, and the ability to charge is a lot like having a minimum operating level that is less than zero. However, the benefits of this flexibility are somewhat tempered by limited hours of storage capability. While coal resources have very long up and down times, and slower ramp rates, they have very flexible day to day energy dispatch. In addition, PacifiCorp has been working to reduce the minimum operating levels of its coal fleet to increase their ability to ramp up and down across the day. The minimum operating levels of PacifiCorp's coal units already represent a smaller proportion of their peak output than the minimums at PacifiCorp's combined cycle combustion turbine (CCCT) gas units. While CCCTs can ramp more quickly between minimum and maximum output, their relatively high minimum operating levels and minimum up and down times can result in less flexibility overall. A mix of resources with varied capabilities gives PacifiCorp needed flexibility to meet its customers' needs under a range of scenarios, and therefore that mix results in a more cost-effective portfolio.

Sierra Club and IEA questioned whether the solar operations and maintenance (O&M) cost assumptions used in the IRP were overstated. Sierra Club argues that the costs included in the IRP modeling were too high and therefore resulted in fewer coal retirements. In support of its argument, Sierra Club points to Lazard, an industry-standard source for such data. Notably, the referenced Lazard study includes a footnote providing more detail about the costs cited by the Sierra Club: "Left column [$12/kW-yr] represents the assumptions used to calculate the ***low end*** LCOE for single-axis tracking. Right column [$9/kW-yr] represents the assumptions used to calculate the high end LCOE for fixed-tilt design" (emphasis added). All of the solar resources considered in the Company's 2019 IRP are single axis tracking, and therefore fixed O&M costs are expected to be higher than Lazard's low end estimate of $12/kw-yr. The Company is confident that its O&M costs for solar are within industry standards. PacifiCorp will, however, continue to monitor cost trends for utility scale single-axis tracking photovoltaic solar generation resources in the Company's service territory and update those costs in future IRP cycles. The 2020 renewable resource assessment will specifically address differences from the Lazard and National Renewable Energy Laboratory studies which were both referenced in the Sierra Club's comments.

Sierra Club also raises concerns with Utah's Community Renewable Energy Act, HB 411 (HB 411). HB 411 allows municipalities and counties in Utah to opt into a commitment to receive a net 100 percent of all energy served by PacifiCorp from renewable resources by 2030. Sierra Club claims PacifiCorp's current renewable energy plans will be stretched thin by this commitment.

The 2019 IRP does not include any customer projects that would fall under HB 411. The 2019 IRP reflects communities' choice to achieve desired energy resource transition goals through the customer preference settings in the base model, specifically to reflect communities like those seeking to take advantage of a community renewable energy program in Utah. A higher customer preference sensitivity representing both Oregon and Utah communities with similar plans are reflected in case S-08. To give a range of results, case S-07 shows the impact on the 2019 IRP preferred portfolio with no customer preference. PacifiCorp's 2019 IRP, specifically Volume II, Appendix M, page 395 includes the customer preference loads chart.

The Company developed the customer preference forecast in October 2018, before HB 411's passage in March 2019. The complete list of Utah communities passing resolutions to enable participation in the community renewable energy act became available after the 2019 IRP was published (October 18, 2019) since communities had until the end of the year to pass a resolution adopting a net 100 percent renewable goal. Therefore, the 2019 IRP does not reflect the full community list. Detailed development of the program, including specific strategy and timeline for the communities to achieve of the targets is expected to occur over the next year and will be incorporated into future IRPs as necessary.

### *E. Response to Individual Party Comments or Miscellaneous*

In the sections above, the Company has provided responses to topics that were raised by multiple parties in their comments. In the section below, the Company responds to remaining issues raised in those comments.

i. <u>Securitization</u>

Sierra Club alleges that PacifiCorp may be influenced in its decision making process to retire coal resources by the risks for disallowance for remaining asset balances. Sierra Club proposes securitization as a potential solution to the negative influence disallowance risk it alleges PacifiCorp is being influenced by. Sierra Club explains that securitization is a mechanism that several states have adopted. Securitization provides ratepayer-backed bonds to finance the undepreciated portion of retiring plants, and other retirement related costs. The mechanism returns outstanding capital to the utility, extends the repayment period for ratepayers, and also reduces the return on investment (resulting in savings for ratepayers). Sierra Club does note that the Company is not currently authorized to securitize its remaining coal assets in Utah or Oregon. As an initial matter, cost recovery of remaining asset balances did not influence PacifiCorp's analysis of coal retirements. While the Company has explored securitization a means to recover the unrecovered net book balance for its existing coal plants, securitization presents a unique challenge for a multi-jurisdictional utility like PacifiCorp. Unless all six states in which the Company operates enact securitization legislation and the corresponding state regulatory commissions issue financing orders, the Company cannot move forward. Legislation in all six states is necessary because, in most cases, all six states are allocated costs and benefits associated with PacifiCorp's coal-fired resources. As such, unless an single state is willing to securitize the full net book value of a coal-fired resource with PacifiCorp's customers in that state supporting repayment of the resulting bonds, as opposed to only paying that state's share, PacifiCorp could face a scenario in which only a portion of a coal-fired resource is securitized. The likelihood of partial-securitization dramatically limits the potential benefits of securitization for PacifiCorp.

Through its discussions with financial institutions, PacifiCorp has identified several other risks associated with securitization. These risks include the following:

- The upfront costs are likely to make transactions sized below $250 million and $350 million uneconomic;
- A special purpose, bankruptcy remote subsidiary of the PacifiCorp would need to be created to protect the revenues to the bond holders, which adds even more cost to the overall project;
- PacifiCorp would need to clearly establish the irrevocability of the financing orders from the regulatory commissions and that the state and/or the commissions may not take or permit any action that impairs the value of the security property;
- Asset backed securitization transactions generally result in a bond coupon equivalent to that of a single A rated corporate bond although the bonds themselves are generally AAA rated;
- The threat of technological disruption (e.g., customer adoption of self-generated renewable energy and distribution generation) may cap tenor (i.e., length of time to maturity) of bonds; and
- Rating agencies may have concerns about shrinking number of ratepayers in the 20+ year horizon.

With these risks in mind, the Company will continue to monitor proposed securitization legislation. Despite the PacifiCorp specific and general securitization challenges, the Company intends to evaluate and to take advantage of any opportunities that may arise that could benefit its customers.

ii. <u>Load Forecast Methodology</u>

In general, the DPU concludes that the Company's load forecast was conducted with modeling and techniques appropriate to the industry; however, it raises several concerns with the load forecast used in the 2019 IRP. The DPU claims that the Company has a tendency to overestimate its load and requests that in future IRP filings the Company be required to provide graphs and analysis comparing forecasts to actual results, including system load and natural gas prices. The DPU also recommends that separate electric vehicle (EV) forecasts, with sensitivity scenarios, be included in the load forecast used in the 2021 IRP.

As identified by the DPU, the data in DPU Figures 1 and 2 compares actual retail sales to the forecasted load at system input before the impact of DSM selections. This comparison is inapt for a few important reasons. First, the forecast are overstated, relative to actual retail sales, only because DSM impacts are included in the actuals, but those impacts are not accounted for in the forecasts presented in the Figures. Additionally, the forecasts are at the generation level, which include line losses, and the actual retail sales are at the retail level. A better comparison would be between actual retail sales and the post-DSM retail level forecast.

The Company disagrees with the DPU's recommendation that PacifiCorp, provide graphs and analysis comparing forecasts to actual results, including system load and natural gas prices in future IRP filings. The Company already provides the data required to compare forecast to actual retail sales as part of current IRP filings. For example, Table A.5 in the 2019 IRP Appendix A provides the weather-normalized actual retail sales over the 2000 – 2017 timeframe. A comparison of prior IRP retail level post-DSM forecasts, such as the data provided in Table A.8 of the 2019 IRP, can be made to the weather-normalized actual retail sales presented in Table A.5. The Company will continue to provide this level of detail so stakeholders can make these comparisons. However, to partially accommodate the DPU's request, as part of future filings, the Company will incorporate Figures similar to Division's Figures 1 and 3 in future filings.

With respect to the DPU's desire to include electrification separate from EV forecasts, with sensitivity analysis, in the load forecast, the Company did not explicitly incorporate a forecast of EVs into the 2019 IRP. However, EV load is currently captured and reflected in the load forecast that informs the 2019 IRP because historical sales to EV owners inform the actual sales used within the load forecast. Thus, the load forecast used for the 2019 IRP development does project EV adoption consistent with observed historical EV adoption throughout the Company's service territory. In recognition of the potential for future, accelerated growth, the Company is developing an explicit forecast of EV load growth within its service territories similar to that requested by the DPU, and that will be incorporated into future IRP development.

iii. Evaluation of resources on a consistent and comparable basis.

UAE states that PacifiCorp has failed to use a status quo benchmark portfolio and, instead, uses a "benchmark" portfolio that "purports" to include some of the most expensive new resource additions identified in the preferred portfolio. UAE further alleges that PacifiCorp fails to evaluate resources on a "consistent and comparable basis." UAE then requests that the Commission decline to acknowledge the 2019 IRP unless PacifiCorp offers a comparison of the 2019 IRP preferred portfolio with the 2017 preferred portfolio. UAE states that this comparison should include the comparative cost and risk analysis as described in the 2019 IRP, Vol. 1, Chapter 7.

PacifiCorp disagrees with UAE's contentions and with its recommendation of a comparison to the 2017 IRP preferred portfolio. The primary focus of IRP portfolio development is the selection of the least-cost, least-risk preferred portfolio. An alternative benchmark provided for comparative purposes only would have no impact on IRP outcomes. Theoretically, any case could be declared the benchmark for comparative purposes without impacting data inputs, model runs, analysis or outcomes. In practice, a recent IRP portfolio is often used as the benchmark out of convenience. In the case of the 2019 IRP, the benchmark was administratively established starting with the coal studies. This benchmark was retained for the 2019 IRP to maintain a consistent comparative basis and to avoid potential confusion throughout the 2019 IRP public-input meeting process. Nevertheless, both the 2017 and 2019 preferred portfolios are publicly available for comparison if a party wishes to perform that analysis.

### *F. Recommendations for modifications to, or improvements in, 2021 IRP*

The DPU indicated that the public-input process was sufficient, the 2019 meetings were not rushed, that PacifiCorp gave participants time to ask questions, and that the Company handled the subject of possible early coal plant closures with tact and sensitivity. However, it claims that PacifiCorp did not fully adhere to Guideline 3 because it did not provide meeting materials at least three business days in advance. Similarly, WRA and UCE indicate that they would like to receive meeting materials in advance of the stakeholder meetings because they did not have time to thoroughly review these before the public input meetings.

First, Guideline 3 states, in part, that "PacifiCorp will provide ample opportunity for public involvement and the exchange of information during the development of its Plan." PacifiCorp believes that it met this requirement. PacifiCorp held an extensive number of public-input meetings, 18 in total, over the 18-month development process of the 2019 IRP, in addition responding to over 120 stakeholder feedback forms with over 500 questions, and was responsive to as many stakeholder requests as possible during the public-input process. PacifiCorp clearly met Guideline 3's requirement, which does not require PacifiCorp to provide materials by a certain number of days in advance of scheduled meetings.

PacifiCorp appreciates the comments from the DPU on the handling of the 2019 IRP public-input process and the complementary nature of the feedback regarding PacifiCorp's facilitation and time management of the meetings. Even though it met Guideline 3's requirements, parties' request for receipt of meeting materials at least three full business days in advance of the meetings is a reasonable one in most cases. PacifiCorp can to commit to making its best efforts to meet this request; so long as there is no undue penalty if, despite those efforts, it is not attainable. PacifiCorp needs some leeway on the three business day request, because meeting it may be challenging during the portfolio-development process where work is occurring throughout the weekends and runs are often processing up to the last minute before a meeting. There also may be unforeseen reasons that the materials need to be modified. A firm requirement to provide materials in advance, could mean that some material may not be available at the time they would be required to be released publicly, and that could lessen the quality of discussion or ability to discuss time-sensitive results during development of the IRP. In addition, PacifiCorp wants to avoid a firm three business day requirement to preserve its flexibility to accommodate as many stakeholder requests to study various future scenarios as it can, given time constraints. A best efforts commitment, without a penalty, lowers the risk that PacifiCorp would have to shorten or cancel public-input meetings, whereas a firm requirement to circulate meeting materials by a date certain before public-input meetings would make it more likely. PacifiCorp has scheduled public-input meetings for its 2021 IRP and starting in June 2020 is moving to what it anticipates to be two full-day public-input meetings every six weeks. PacifiCorp has adopted the goal of providing meeting materials at least three full business days in advance, consistent with these comments.

The OCS requests the Company provide an estimate of customer rate impacts of all new resources in the preferred portfolio as compared to the revenue requirement of the base year especially considering the proposed projects in the 2019 IRP action plan are projected to have a significant cost. The OCS notes that this information has been provided in past IRPs and has been provided to commissions in other states. The Company is not aware of having provided such a comparison in other states. Moreover, the IRP focuses on a comparative analysis of different portfolio alternatives. In the case of the 2019 IRP, all of the top-performing portfolios have very similar levels of near-term resources (i.e., renewable resources, battery storage resources, and transmission upgrades inclusive of GWS). Each of these portfolios support advancing forward with the 2019 IRP action plan. PacifiCorp's analysis of the relative rate pressures among top performing portfolios developed within the 2019 IRP is summarized in Volume I, Chapter 8, pages 237-2038. Moreover, including estimated revenue requirement impacts are not likely to lead to useful information for the Commission's acknowledgement since the IRP considers proxy resources and it does not consider the specific ratemaking mechanisms or cost allocations in each state.

The DPU also states that it hopes PacifiCorp will file the 2021 IRP on time, and that it reserves the right to contest the appropriateness of certain IRP assumptions in later proceedings, even if the DPU did not object to them in this proceeding. First, several of PacifiCorp's jurisdictions require the Company to file its IRP biennially and PacifiCorp plans to file its 2021 IRP by April 1, 2021. Second, while it is appropriate for parties to raise their concerns with certain IRP assumptions in the IRP proceeding, whether it is in the public interest to acquire a resource, or take a certain action related to an existing resource is not appropriate in the IRP proceeding, and is properly raised in later proceedings where approval of the acquisition or action is directly before the Commission.

The DPU raises the issue of regional capacity and reliability with respect to the possible planning margin shortfalls in certain regions by 2027 or 2028. The DPU does not recommend action at this time, but believes the regional resources in the 2023-2027 and projected jump in summer front office transactions (FOT) should be watched for possible required action in the 2021 IRP.

Resources selected in the action plan period of the preferred portfolio contribute to the sixty percent decline in summer peak FOTs in years 2020-2027 when compared to the 2017 IRP preferred portfolio. This decline is largely driven by the improving economics of renewable resources, displacing FOTs as a mechanism to meet system need. As further noted in the 2019 IRP, this outcome mitigates risk by reducing PacifiCorp's reliance on market purchases over a period where there are regional resource adequacy concerns. PacifiCorp is also actively involved and supportive of regional efforts working with the Northwest Power Pool to develop a voluntary regional resource adequacy program to improve visibility and minimize risk in this area.

UCE recommends that the Commission direct PacifiCorp to include an economic analysis of its coal fleet, looking at each unit individually and in stacked combination, to gauge cost effectiveness of each coal unit relative to alternate resources. Such direction is unnecessary, as PacifiCorp will continue to re-evaluate the economics of its coal units in future IRPs.

UCE also recommends that the Commission direct PacifiCorp to consider whether new modeling software considers flexibility benefits from existing and new clean energy resources, including demand response. Further, if PacifiCorp does not adopt new modeling software, it recommends that the Commission direct PacifiCorp to make necessary changes to the SO model and PaR to fully integrate capabilities and benefits of flexible loads, demand response and renewable energy resources.

PacifiCorp is motivated to continue its ongoing pursuit of modeling tools capable of performing integrated assessments of resource flexibility, and in particular, their ability to contribute to system reliability. Barriers to identifying an appropriate modeling suite have included identified inadequacies in other areas of prospective models capabilities, the relative newness of intensified flexibility requirements in the face of a changing technology, and the increasing complexity and variability of regulatory requirements. While PacifiCorp agrees with UCE that an integrated methodology is preferable to adoption of distinct tools and processes, the Company is nevertheless confident in its valuation strategy and the results of that strategy, and that resource technologies are being fairly and consistently compared.

WRA states that the way PacifiCorp employed the "family tree" method of portfolio development was conceptually sound, but that it did not clearly lead to an optimal solution and potentially distorted results. It then recommended that, to consistently provide comparability across resource portfolios, the family tree should have a common portfolio as its root and examine one set of factors at a time, all else held constant. Further, WRA recommends that the Commission provide guidance to the Company to improve its portfolio development process so that results can be meaningfully compared to one another. The portfolio-development process results in many different portfolios—each of them identifying a different combination of the type, timing, location, and amount of resources required to maintain reliable operation of the system under a given set of planning assumptions. Any single portfolio can be compared to any other portfolio to evaluate how resource selections change and how those resource selections affect system costs and risks under different price-policy scenarios. WRA's recommendation to initiate this process from a single starting point and to isolate changes to one set of factors at a time is inefficient and not practical. PacifiCorp proceeded through the portfolio-development process with transparency, explaining its rationale for choosing specific cases based on observed modeled results developed over time. Moreover, many of the cases in the family tree were developed in direct response to explicit stakeholder feedback. If WRA's recommendation were adopted, the Company may still be performing model runs, and it certainly would not have been able to file the 2019 IRP in October 2019.

## IV. CONCLUSION

PacifiCorp's 2019 IRP complies with the Commission's standards and guidelines. The 2019 IRP includes robust portfolio modeling and prudent planning assumptions that led to selection of a least-cost, least-risk preferred portfolio. The 2019 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.

PacifiCorp respectfully requests that the Commission acknowledge the 2019 IRP and the 2019 IRP action plan.

**CERTIFICATE OF SERVICE**

Docket No. 19-035-02

I hereby certify that on March 2, 2020, a true and correct copy of the foregoing was served by electronic mail to the following:

**Utah Office of Consumer Services**

| | |
|---|---|
| Cheryl Murray | cmurray@utah.gov |
| Michele Beck | mbeck@utah.gov |

**Division of Public Utilities**

dpudatarequest@utah.gov

**Assistant Attorney General**

| | |
|---|---|
| Patricia Schmid | pschmid@agutah.gov |
| Justin Jetter | jjetter@agutah.gov |
| Robert Moore | rmoore@agutah.gov |
| Steven Snarr | stevensnarr@agutah.gov |

**Utah Association of Energy Users**

| | |
|---|---|
| Gary A. Dodge | gdodge@hjdlaw.com |
| Phillip J. Russell | prussell@hjdlaw.com |

**Utah Clean Energy**

| | |
|---|---|
| Hunter Holman | hunter@utahcleanenergy.org |
| Kate Bowman | kate@utahcleanenergy.org |

**Stadion, LLC**

| | |
|---|---|
| R. Bryce Dalley | rbd@fb.com |
| John Lucas | johnlucas@fb.com |
| Richard Lorenz | rlorenz@cablehuston.com |

**Interwest Energy Alliance**

| | |
|---|---|
| Lisa Tormoen Hickey | lisahickey@newlawgroup.com |

**Western Resource Advocates**

| | |
|---|---|
| Sophie Hayes | sophie.hayes@westernresources.org |
| Nancy Kelly | nkelly@westernresources.org |
| Steven S. Michel | smichel@westernresources.org |

**Sierra Club**

| | |
|---|---|
| Gloria D. Smith | gloria.smith@sierraclub.org |
| Ana Boyd | Ana.boyd@sierraclud.org |
| Julian Aris | julian.aris@sierraclub.org |

**Rocky Mountain Power**

| | |
|---|---|
| Data Request Response Center | datarequest@pacificorp.com |
| Jana Saba | jana.saba@pacificorp.com;<br>utahdockets@pacificorp.com |

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations