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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of PacifiCorp's 2017 Integrated Resource Plan	DOCKET NO. 17-035-16 **COMMENTS OF RENEWABLE ENERGY COALITION**

I. INTRODUCTION

The Renewable Energy Coalition (the "**Coalition**") submits these comments regarding the 2017 integrated resource plan ("**IRP**") of PacifiCorp ("**PacifiCorp**" or the "**Company**"). The Coalition raises the following issues regarding PacifiCorp's IRP:

- The 2029 date for its first planned major thermal resource acquisition is speculative and should not be acknowledged.
- PacifiCorp's 2021 renewable resource need is real and should be acknowledged.
- PacifiCorp renewable resource need is not just limited to Wyoming wind and any renewable need acknowledgment should be generic and not specific to any location or technology type.
- PacifiCorp's first year of renewable resource deficiency is 2021.
- PacifiCorp should use an independent third party gas forecast.

- Staff and stakeholders should be allowed to use at low or no cost any computer models relied upon in the IRP process.

Significant uncertainties call into question PacifiCorp's 2029 thermal resource date, which make it even less accurate than an educated guess. The specific date of any resource acquisition that is outside of the IRP Action Plan (especially over a decade out) is entirely meaningless for planning purposes, is not rigorously studied in the IRP, and has historically been largely ignored by Staff and the Commission.

The practical impact for avoided cost rate purposes of a 2029 date, however, cannot be overstated because QFs are not paid for capacity during the years prior to the date of the next major resource acquisition. As this self-declared resource sufficiency period continues to get longer, the more reasonable it is to assume that PacifiCorp will actually acquire additional capacity resources earlier than the claimed date of deficiency. Continued use of an arbitrary date for a thermal capacity resource more than a decade out will continue to lead to zero qualifying facilities ("**QFs**") being able sell power to PacifiCorp at standard, non-renewable rates. The Commission should, for the first time in an IRP proceeding, rigorously review PacifiCorp's proposed thermal resource date, and explicitly reject PacifiCorp's 2029 date. Without such an analysis and review, the 2029 date should be considered for informational purposes only and not in any way be used as a basis to determine avoided cost prices.

The Commission should acknowledge PacifiCorp's need for renewable resources beginning January 1, 2021, as the Company has demonstrated early renewable acquisition is reasonable. Despite this renewable resource need, PacifiCorp may be preparing a novel argument that QFs should not be paid a renewable resource rate with a renewable deficiency date of 2021 because the Company is focused on acquiring only

Wyoming wind. The Commission should reject this approach and simply acknowledge a 2021 renewable resource need rather than a specific need for Wyoming wind.

PacifiCorp should study, review, and calculate the capacity benefits provided by QFs renewing their contracts. In the IRP stakeholder process, the Coalition asked PacifiCorp to perform this analysis, which the Company refused to do. PacifiCorp should be required to perform such a study in its next IRP.

Finally, the Commission should require PacifiCorp to use an independent third party for gas price forecasts for all timeframes included within the IRP planning period, and it is long overdue that both Staff and interested parties have access to and the ability (including training) to run and/or review PacifiCorp's IRP models at no cost.

II. COMMENTS

A. PacifiCorp Should Study the Capacity Benefits Provided By Existing QFs

Existing and planned QFs provide capacity value to PacifiCorp, which QFs should be compensated for. Utilities plan and rely on existing QFs to help avoid and defer capacity investments, and utilities should determine that capacity value.

Currently, existing QFs that renew their contracts are providing the utilities with free capacity. Specifically, Utah's avoided cost rates for QFs do not currently recognize that QFs that renew their contracts provide capacity value to their serving utility, which results in the QFs not being paid for capacity during the resource sufficiency years prior to the next major resource acquisition.

The Coalition has advocated in numerous states that avoided cost rates should recognize that existing QFs that renew their contracts provide capacity value to the utilities and that the QFs should be paid for this capacity. Paying existing QFs for capacity is based on the fact that many large and almost all small existing QFs enter into new contracts when their current contracts expire. Without these contract renewals, PacifiCorp and other utilities would need to acquire new, more expensive capacity resources sooner.

Paying renewing QFs full capacity payments would treat QFs more comparably with utility-owned resources. While Utah QFs are not provided the opportunity to obtain capacity payments for their full resource life, PacifiCorp is able to recover its capacity costs for the full useful life of its own generating resources. Not providing existing QFs with full avoided cost pricing (including capacity payments) for their useful lives is inequitable as compared to the treatment afforded utility-owned resources.

PacifiCorp's avoided cost rate models used to calculate Schedule 38 rates recognize that QFs that enter into contracts with the Company reduce the Company's capacity needs. The more QFs that PacifiCorp assumes will operate and sell power, then the lower the Company's assumed future power costs will be. This is because as the Company acquires new QF resources, that defers future resource needs. The same is also true for existing QFs. If these QFs disappeared, then PacifiCorp would need to acquire new generation more quickly. Thus, both new and existing QFs help defer the Company's next generation acquisitions, and these QFs should be compensated for it.

An illustrative example demonstrates how existing QFs are not fully paid for capacity under Utah's avoided cost rate structure. Assume that a hydroelectric QF has a sixty-year useful life, PacifiCorp has ten-year resource sufficiency periods during this time period, and QFs are entitled to fifteen-year fixed price contracts. The QF has no other alternatives to sell its power, and enters into four fifteen-year contracts over its sixty-year useful life. PacifiCorp's ten-year resource sufficiency periods mean that the QF is only paid for capacity based on a thermal resource for five years of each contract. The QF could operate, and PacifiCorp could plan on the QF operating, for sixty years, but the QF would be paid forty years of market prices and only twenty years of capacity payments. In contrast, a PacifiCorp is paid for capacity for its owned resources in each and every year they operate.

Existing QFs in Idaho and all Washington are paid for capacity in all contract years, unlike Utah. The Idaho Public Utilities Commission ("**IPUC**") recognizes the value that renewing QFs provide, ensures that they are paid capacity regardless of the utility's resource "sufficiency" position, and acknowledges that existing QFs should not be paid market based rates and their electricity is not "surplus power." The IPUC explained:

> we find merit in the argument made by the Canal Companies that contract extensions and/or renewals present an exception to the capacity deficit rule that we adopt today. It is logical that, if a QF project is being paid for capacity at the end of the contract term and the parties are seeking renewal/extension of the contract, the renewal/extension would include immediate payment of capacity. An existing QF's capacity would have already been included in the utility's load resource balance and could not be considered surplus power. Therefore, we find it reasonable to allow QFs entering into contract extensions or renewals to be paid capacity for the full term of the extension or renewal.[1]

The IPUC recently reaffirmed this policy.[2] Washington does not distinguish between existing and new QFs, but requires that all QFs to be paid a full capacity payment based

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1 Re the Commission's Review of PURPA QF Contract Provisions, IPUC Case No. GNR-E-11-03, Order No. 32697 at 21-22 (Dec. 18, 2012) clarified in Order No. 32871 (Aug. 9, 2013).

2 Re Idaho Power Company's Petition to Modify Terms and Conditions of PURPA Purchase Agreements, IPUC Case Nos. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03, Order No. 33357 at 25-26 (Aug. 20, 2015).

on a peaking resource during the years before the acquisition of a major thermal resource (when QFs are paid a capacity payment based on the capacity costs of the thermal resource).[3] The Utah Commission, however, does not require the utilities to pay existing (or even any QFs) capacity payments during the years prior to the next major resource acquisition.

B. Pacific Power Has Identified a Renewable Resource Need that Warrants Early Acquisition

PacifiCorp appropriately recognizes that the costs of renewable resources have dramatically dropped, and early acquisition may provide customers with the greatest benefits at the lowest cost. For wind generation at least, the gradual phase down of the production tax credits ("**PTC**") represents a significant cost savings for ratepayers. As explained by PacifiCorp, it is proceeding with the addition of up to 1,100 MW of wind resources by the end of 2020 "to fully achieve the benefits of federal wind production tax credits".[4]

While the size of PacifiCorp's renewable resource need has increased, the Company had identified a significant need for renewable resources in the pre-IRP filing

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3 E.g., WUTC v. Pacific Power & Light Co., Docket No. UE-144160, Order 04 at 37-38, 42 (Nov. 12, 2015) (The Washington Utilities and Transportation Commission rejected PacifiCorp's proposed avoided cost rate proposal that would have eliminated capacity payments during the years before the next major resource acquisition.); Puget Sound Energy Advice 2016-31—Schedule 91 – Cogeneration and Small Power Production, Docket No. UE-161240, Staff Open Meeting Memo (Feb. 9, 2017) (Puget Sound Energy withdrew its proposal to pay QFs either no or an extremely low market capacity payment during years prior to the next major resource acquisition). Thus, Washington has twice rejected Utah's approach of paying little to no capacity to QFs during resource "sufficiency" years.

4 PacifiCorp 2017 IRP at 2 (Apr. 4, 2017), available at https://www.pacificorp.com/es/irp.html.

stakeholder process. In the IRP stakeholder process, PacifiCorp provided justification for the acquisition of 428 MW of new wind in 2021, with 300 MW in Wyoming and 128 MW in Idaho.[5] While PacifiCorp did not fully analyze increasing the amount of renewable power in the stakeholder process, it would be reasonable for PacifiCorp to test the market to see if larger amounts of renewable resources would be cost effective, especially in light of the decline in solar prices and the expiration of the PTC.

C. The Commission Should Acknowledge PacifiCorp's 2021 Renewable Resource Need, But Not Acknowledge the Action Plan's Proposed Wyoming Wind Resources

PacifiCorp has a renewable resource need in 2021, but that need can be filled with renewable resources other than simply Wyoming wind. All renewable resources in all locations should be acquired, if they are the least cost, rather than just Wyoming wind facilities that the Company will own alongside its planned Gateway West transmission line.

PacifiCorp's IRP is proposing to meet its 1,100 MW renewable resource need with only Wyoming wind resources.[6] PacifiCorp has not provided sufficient support that potentially low cost Wyoming wind coupled with expensive new transmission is lower cost or less risky than the acquisition of renewable generation in other states, including solar generation in Utah. Therefore, the Commission should not acknowledge or provide any weight to the information, analyses and strategies regarding an acquisition plan that relies only upon Wyoming wind.

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5 PacifiCorp General Public Input Meeting 8 Presentation at 7 (Mar. 2-3, 2017), available at http://www.pacificorp.com/es/irp/pip.html.

6 PacifiCorp 2017 IRP at 2-3, 16-17.

PacifiCorp justifies the Wyoming wind approach based on the state's high capacity factor[7] and the expiration of the PTC, and further explains that the "project will provide extraordinary economic development benefits to the state of Wyoming."[8] PacifiCorp is already moving forward with its 2017 renewable RFP, which was originally limited to only accepting Wyoming resources. PacifiCorp also links the need for Wyoming wind with the construction of the 140-mile, 500 kV Aeolus to Bridger transmission line that it has been trying to build for years.[9] As this Commission already recognized in its 2017 Renewable RFP, there is no reason why non-Wyoming wind should not be allowed to compete, and that there is good reason to allow solar generation to also be considered.[10] The least cost and least risk resources should be acquired, regardless of location or resource type.

PacifiCorp has not provided sufficient analysis or support demonstrating that Wyoming wind, plus the required transmission construction, is the most reasonable resource option. PacifiCorp's 2017 IRP development process did not thoroughly analyze this approach, as it was introduced with the publication of its 2017 IRP. PacifiCorp filed its IRP on April 4, 2017, and PacifiCorp's last pre-IRP stakeholder meeting on March 2-3, 2017 proposed acquiring 428 MW of wind by 2021, including 128 MW of Idaho wind. That presentation contemplated an additional 1,030 MW of new wind and 1,157 MW of new solar capacity acquisitions (357 MW in the west and 800 MW in the east), but not

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7 PacifiCorp's IRP estimates that Wyoming wind resources have a 5 percentage point advantage over wind resources in Oregon, Washington and Idaho. PacifiCorp 2017 IRP at 120.

8 Id. at 2.

9 See id. at 2-3, 17.

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until 2036.[11] Despite not adequately analyzing this option (significant and immediate investment in Wyoming wind and transmission) in the planning process, and initially keeping this information from stakeholders, PacifiCorp was actively acquiring wind turbines and locking up key sites along the transmission line for Company-owned wind generation projects to be built. The Commission should be highly skeptical of any proposals that were not fully studied in an IRP, especially when they may result in utility ownership of over 1,100 MW of new generation and the construction of a major new transmission line.

PacifiCorp may not be fully accounting for the costs and risks of the Aeolus to Bridger transmission line and additional upgrades to the Gateway West transmission plan. There may be insufficient transmission capacity from Bridger West to integrate the new wind capacity that PacifiCorp wishes to build in eastern Wyoming, even if the Aeolus/Bridger line is built. The transmission system west out of Bridger is constrained, and may not be able accommodate incremental power flows when the Jim Bridger plant is operating at full load. Consequently, building more transmission from the east to Jim Bridger eastward alone (i.e., the proposed transmission line from Bridger east to the proposed Aeolus substation) may not have the benefits that PacifiCorp claims because it may not relieve the Bridger West transmission constraint. At least at this time, PacifiCorp cannot justify building Gateway West in its entirety and has adopted a strategy to build a remote segment first, "justified" by building wind capacity interconnected to it. PacifiCorp will likely propose in its next IRP to build the next

[11] PacifiCorp General Public Input Meeting 8 Presentation at 7.

segment of Gateway West (Bridger to Populus) to relieve transmission constraints created by these new wind acquisitions.

PacifiCorp should be willing to acquire the best renewable resources, regardless of their location or whether they allow PacifiCorp to justify the construction of a new transmission line. The Aeolus to Bridger/Anticline transmission line should be considered part of the costs of new, large scale Wyoming wind generation that cannot serve PacifiCorp load without the transmission line. The costs of PacifiCorp's Wyoming wind plus the cost the Aeolus to Bridger transmission line should be compared to other renewable resource options in other locations (plus any associated incremental transmission needed to deliver that power to PacifiCorp's system). If the total all-in costs for renewable resources in Utah, Washington or Oregon with lower transmission costs and line losses are a better alternative, then they should be acquired and avoid the need to build potentially unnecessary transmission assets. In other words, Wyoming wind may be the least cost and least risk resource; however, Wyoming wind plus the construction of a new transmission line may not be.

The Commission should specifically call out and refuse to recognize PacifiCorp's plan to exclude potentially lower cost and less risky non-Wyoming generation resources. The Commission should also refuse to allow or provide rate recovery for any resource acquisitions that do not fairly evaluate lower cost resources located outside of southeastern Wyoming. Southeastern Wyoming wind plus the Aeolus to Bridger transmission line may be the least cost and risk manner of acquiring renewable resources; however, that assumption should be proven, especially given that PacifiCorp has an incentive to bolster its long-standing proposal to construct Gateway West.

D. PacifiCorp Has Not Demonstrated that a Wind Only Resource Strategy Is Reasonable or the Least Cost-Risk for Customers

PacifiCorp should consider allowing all resource types to meet its renewable resource needs, and should not reject potentially lower cost renewable resources like solar, biomass, geothermal and renewable storage. PacifiCorp should be required to fairly consider the least cost mix of renewable energy supply resources that will meet its system demand and renewable portfolio standard requirements, and not ignore other potentially cost effective resource options.

PacifiCorp's IRP and its proposed renewable RFP focused solely upon wind generation to the exclusion of all other types of renewable electric generation resources. Given that PacifiCorp's preferred plan to acquire 1,100 MW of wind was not included or fully vetted in the IRP planning process, it is impossible to determine if it is reasonable to exclude potentially lower cost solar, biomass, renewable storage and geothermal resources. For example, PacifiCorp has twenty-four non-qualifying facility renewable resources, eighteen of which are wind generation located in Wyoming.[12]

It is unclear whether PacifiCorp has fairly analyzed the impact that adding over a thousand megawatts of the same type of generation in the same geographic area will have on the Company's operations and costs of integration. Further collocation of PacifiCorp's wind fleet (owned and contracted) may increase PacifiCorp's integration, regulation reserve and other costs. These additional costs should be accounted for in comparing PacifiCorp's Wyoming resources with other technologies and locations, including off-system power purchase agreements. In addition, PacifiCorp does not

[12] See PacifiCorp Renewable Energy Sources, available at http://www.pacificorp.com/es/re.html.

appear to have demonstrated that the risks and benefits associated with other resource types and a more diverse generation portfolio would be more beneficial to ratepayers.

It is entirely possible that adding only southeastern Wyoming wind may be the least cost and least risk resource due to the potentially uniquely economic and fleeting opportunity presented by the intersection of wind technology gains and the PTC phase-out. This opportunity exists across the West, not just in Wyoming, and can only be confirmed as uniquely economic when compared with other combinations of technology and geography, as adjusted for risk, transmission, losses and other costs. In addition, PacifiCorp made a last-minute decision in its IRP to change its resource plans to increase its reliance upon a specific technology in a specific location, and postponed acquiring the more diverse resources that it originally considered in its planning process.

In the end, PacifiCorp should not discriminate in favor of any particular resource but ensure that its renewable RFP is open to all renewable generation types to truly test the market. Therefore, the Commission should refuse to acknowledge PacifiCorp's plan to exclude potentially lower cost and less risky non-wind generation resources or wind farms in other states, and not allow rate recovery for any resources acquired in a process that does not allow all generation types an opportunity to fairly compete.

D. The Commission Should Not Acknowledge PacifiCorp's Proposed Repowering

PacifiCorp has refused to provide a transparent financial analysis that supports the Company's proposed repowering project. PacifiCorp's proposal may be cost effective, but that is impossible to determine based on the information the Company has provided. In addition to not acknowledging the repowering, the Commission should require PacifiCorp to demonstrate the reasonableness of its repowering proposal by including its each resource proposed for repowering as a benchmark bid in its upcoming RFP to test its overall cost effectiveness.

E. PacifiCorp Is Likely to Acquire a Major Baseload Capacity Resource Well Before 2029

PacifiCorp's 2017 IRP is not a least cost and risk plan because it is inaccurate. Specifically, the plan to not acquire a major capacity resource until 2029 is vague, suspect, and does not account for the actual capacity additions that the Company is likely to need. Although PacifiCorp acknowledges that it will lose significant amounts of capacity in the near future, the Company does not address how those reductions are accounted for. Specifically, PacifiCorp states that Naughton 3 will retire in 2019 (losing 100 MW), Cholla 4 will retire in 2021 (losing another 100 MW), and then in 2028 all four Dave Johnson units will retire (losing 400 MW). Perhaps the wind repowering, which may happen immediately, or new Wyoming wind, which must happen before 2020 to take advantage of federal tax credits, will make up for some of those capacity reductions. These variable wind resources are unlikely to fully replace the capacity value of baseload coal.

PacifiCorp's IRP fails to explain how its plan demonstrates the lowest reasonable cost manner of replacing its coal capacity resources. PacifiCorp has taken the position in its current resource planning that it will not acquire a major new resource until 2029. PacifiCorp acknowledges that it has a huge need for new capacity resources over its planning period. PacifiCorp's preferred portfolio calls a new SCCT (300 MW) resource in 2029, a new CCCT (436 MW) resource in 2030, another new SCCT (200 MW) resource in 2033, and another new CCCT (477 MW) resource in 2033. This portfolio includes retirements of Naughton 3 in 2019, Cholla 4 in 2021, Craig 1 in 2036, all four

Dave Johnston units in 2028, Naughton 1 and 2 in 2030, Hayden 1 and 2 in 2031, Gadsby 1 through 6 in 2033, and Craig 2 in 2035. These capacity resource acquisitions are likely to occur much earlier than 2029. It also includes new demand side management ("**DSM**") investment, and significant annual short term purchases (around 700 average MW over the next 10 years).

Several additional uncertainties raise questions about PacifiCorp's claim that 2029 is the next year that a major new non-renewable resource will be added:

- Federal clean air rules under the Clean Power Plan are currently unknown and could require early closure of some coal plants and acquisition of replacement power.

- Federal Regional Haze regulations may also require earlier coal plant retirements. This is now the major environmental rule driving near-term coal plant decisions. It has been finalized by EPA for Utah and Wyoming. If allowed to operate within PacifiCorp's model, it would require earlier shut-down of some of the Company's coal units and acquisition of replacement power.

- State clean air rules are in flux, but will require additional renewable resources and perhaps retirement of some coal plants which would lead to the acquisition of a major resource much sooner than 2029.

- Adequate transmission may not be available. It is already constrained in northeast Wyoming, Oregon, and southern Utah.

- The Company may have difficulties achieving its aggressive demand side management targets.

- There will be increasing, uncertain amounts of distributed generation in the coming 20 years.

- There is pending litigation regarding certain emission control equipment on Hunter 1 and 2, Huntington 1 and 2, Craig 1, and Wyodak.

- The wholesale market may become constrained, leading to volatile pricing. The Company identifies 400 MW available at Mid-Columbia, 400 MW at DOB, 100 MW at NOB, and 300 MW at Mona. Still, PacifiCorp acknowledges that there may be a Pacific Northwest deficit around 2021, and all of the Western Electricity Coordinating Council's sub-regions may be sufficient only through the 2025 winter and summer seasons. Additionally, coal plant retirements in the region may lessen the availability of wholesale market purchases and trading hub liquidity.

F. PacifiCorp Should Use a Neutral Third Party Gas Forecast

Aside from the Company's questionable assumptions underlying its projected year of acquisition of a major new resource, a second major objection to PacifiCorp's IRP is that the gas price forecast comes from the Company's own expert instead of a widely recognized and accepted gas price forecast like the Energy Information Administration ("**EIA**"). Although there may be arguments for a Company-paid expert, the use of such an expert raises questions of bias and objectivity that have not been resolved. The IRP discusses the development of the natural gas price forecast only briefly, and never mentions EIA. And the figures show little variation between low, medium and high forecasts. PacifiCorp should explain why and how it has deviated from its past gas forecasts.

G. Stakeholders and Staff Should Have Reasonable and Low Cost Access to PacifiCorp's Models

Finally, the Company's use of a capacity expansion model is opaque to interested parties, unless they have the means and expertise to acquire the model and use it to verify the Company's results. It seems imprudent that major resource decisions are made without requiring reasonable access to the tools that establish the IRP's results. The second stage of IRP modeling is the stochastic investigation to determine production costs under changing input assumptions. It is also opaque. We encourage the Commission to authorize the necessary funding to the Commission Staff to acquire these models and run them to verify the veracity of the inputs. In PacifiCorp's 2015 IRP review, Sierra Club's expert acquired the capacity expansion model and identified modeling constraints that the Company never advised the stakeholder group about, such as inputting coal plan unit retirements rather than allowing the model to determine the most reasonable retirement years. There are toggles within the model that allow or restrict certain behaviors that must be verified. Only a non-Company review of the modeling can determine if those toggles have been used. Given the size of the investment at stake, PacifiCorp's modeling needs third-party auditing.

III. CONCLUSION

Thank you for the opportunity to provide comments in this proceeding. We look forward to the next phase of this investigation into PacifiCorp's 2017 IRP.

DATED this 24th day of October, 2017.

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served on this 24th day of October, 2017 upon the following as indicated below:

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