BEFORE THE WASHINGTON UTILITIES AND

TRANSPORTATION COMMISSION

In the matter of the PACIFICORP, d/b/a PACIFIC POWER & LIGHT COMPANY, PacifiCorp 2022 All Generation Sources Request for Proposals	DOCKET NO. UE-210979 NORTHWEST & INTERMOUNTAIN POWER PRODUCERS COALITION COMMENTS

I. INTRODUCTION

1. The Northwest & Intermountain Power Producers Coalition ("NIPPC") hereby respectfully submits these comments on PacifiCorp's Draft 2022 All-Source Request for Proposals ("AS RFP"). NIPPC is pleased PacifiCorp has proposed this RFP to meet its needs for significant energy, capacity, and renewable resources. As explained below, NIPPC recommends that the Washington Utilities and Transportation Commission (the "Commission" or "WUTC") require revisions and clarifications identified in these comments to PacifiCorp's Draft 2022 AS RFP.

2. NIPPC recommends the Commission direct PacifiCorp to make changes to its Draft 2022 AS RFP so that a broad number and type of bids are allowed to ensure the least cost and least risk resources are selected. PacifiCorp is planning to submit benchmark bids (utility-owned proposals) into the 2022 AS RFP.[1] Thus, it is important to ensure a wide variety of resource bids are allowed in the 2022 RFP so that the least cost and least risk resources are identified. NIPPC

[1] PacifiCorp Cover Letter to Draft 2022 AS RFP at 2.

recommends that the Commission approve the RFP, subject to the revisions identified in these comments, which fall into two main categories: 1) there are unnecessary restrictions that will reduce the robustness of this RFP by excluding low-cost and low-risk resources; and 2) the RFP is biased in favor of PacifiCorp-owned resources.

3. Below is a Table summarizing NIPPC's recommendation and PacifiCorp's current position as outlined in its Draft RFP.

PacifiCorp Draft RFP	NIPPC's Recommendation
PacifiCorp's Draft RFP would be approved by March 10, 2022.	The Draft RFP should be conditionally approved, and the Commission should reserve the right to make revisions to accommodate potential changes to the Draft RFP in Oregon or Utah. For future RFPs: 1) the Commission should waive the WUTC rules regarding the RFP approval schedule; or 2) the Commission should revise the WUTC rules to allow for a more robust RFP timeline that enables the Commission to take stakeholder comments in other states into consideration when issuing a decision on the RFP
Build Transfer Agreement ("BTA") bids do not include contingency cost adders.	BTA bids should include conservative contingency cost adders after commissioning to fairly compare them to PPA bids which must incorporate such contingencies into their PPA offer price
A terminal value is assigned to BTA and benchmark bids.	The RFP should either state PacifiCorp will not assign terminal value to BTA and benchmark bids, or the RFP must allow PPA bids to elect to achieve an equal score improvement with a reasonable PPA renewal provision. NIPPC's preference is that PacifiCorp not be allowed to assign a terminal value to BTA and benchmark bids.
The draft pro forma PPAs require bidders to potentially post performance assurance in the amount of $200/kw of project capacity upon PPA execution and maintain $100/kw throughout the term of the PPA.	NIPPC recommends that the Commission require that a maximum performance assurance for companies bidding into and having their resources selected should be $100/kw before commercial operation, and $50/kw afterwards.

As part of the section on "credit information" to be included with the bidders' initial application, the Draft RFP appears to require that bidders include a commitment letter from a qualified guarantor or lender that it will provide financial assurance for the bidder.	While it may be reasonable to require bidders to post a reasonable commitment letter upon selection to the final shortlist, there is no basis to require such a commitment letter at any time prior to selection for the shortlist
PacifiCorp uses a price/non-price score ratio of 75/25.	The price/non-price score ratio should be 80/20.
PacifiCorp is requiring new and existing resource bids to achieve a commercial operation date ("COD") and/or begin deliveries to PacifiCorp by December 31, 2026. PacifiCorp is accepting CODs for long-lead time resources (nuclear, pumped storage hydro) of December 31, 2028.	The COD should be extended to December 31, 2028 for all resources.
PacifiCorp is requiring any co-located battery energy storage system with a renewable resource to be AC coupled.	Co-located renewable energy plus storage should not be limited to AC coupled storage resources but also include DC coupled storage resources.
PacifiCorp will only accept and evaluate bids that can demonstrate an ability to interconnect and deliver "firm" energy to PacifiCorp-West or PacifiCorp-East, which appears to be a requirement that off-system bids be supported by long-term *firm* transmission, as opposed to conditional firm or non-firm transmission products.	PacifiCorp should accept conditional firm transmission as a form of firm transmission.
PacifiCorp allows a bid to submit more than one bid per project site subject to certain requirements, but each bid on the same project site requires payment of the bid fee.	PacifiCorp should allow different configurations of bids per project site without requiring the bidder to pay bid fees for each bid.
PacifiCorp is requiring nameplate capacity size of a bid must be "consistent and supported by the interconnection agreement(s)."	The Commission should direct PacifiCorp to provide clarity on what it means when it states the nameplate capacity must be "consistent and supported by" an interconnection agreement.
PacifiCorp is requiring BTA proposal to be directly interconnected to PacifiCorp's system.	PacifiCorp should accept off-system BTA proposals.

The treatment of bids of different term duration, through "term-normalization" analysis, is a critical issue in any RFP, yet PacifiCorp's RFP provides insufficient clarity on this subject.	The Commission should require PacifiCorp to make its term-normalization analysis transparent in this RFP and should direct the Independent Evaluator ("IE") to require PacifiCorp to conduct an analysis that focuses on the annuity-based analysis while not unreasonably penalizing shorter-term PPA bids through use of generic fill costs from the integrated resource plan ("IRP").

II. COMMENTS

A. RFP Timeline

4. NIPPC recommends that the final RFP in this docket should be revised to accommodate changes made to it in other states to avoid harm to Washington ratepayers, bidders, PacifiCorp, and the RFP process itself. PacifiCorp is filing this same RFP in Oregon, Washington, and Utah. In Washington, the Commission is expected to make a decision on the Draft RFP on March 10, 2022.[2] However, stakeholders will still have an opportunity to submit comments on PacifiCorp's Draft RFP and IE reports in other states after the Commission issues a decision.[3] Further, in other states there have been changes mandated by other utility commissions after Washington has approved PacifiCorp's draft RFP.

5. Washington has the most expedited schedule in the three states that substantively review PacifiCorp's RFP (Oregon, Utah, and Washington). In Washington, stakeholders must submit comments by February 14, 2022 and the Commission issues a decision on the RFP on March 10,

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2 Notice of Opportunity to File Written Comments on PacifiCorp's Draft RFP at 1 (Jan. 4, 2022).

3 *See* PacifiCorp's 2022 AS RFP Timeline, available at: https://www.pacificorp.com/suppliers/rfps/2022-all-source-rfp.html.

2022.[4] In Oregon stakeholders first set of comments are due on February 18, 2022, and then are able to submit comments on April 11, 2022 after reviewing a Staff Report and view the IE's Report, and the Draft RFP will not be approved in Oregon until April 14, 2022.[5] In Utah, the anticipated schedule is that stakeholders are able to submit comments on the Draft RFP by March 14, 2022, review the IE's comments on the Draft RFP, and submit reply comments by April 1, 2022.[6] The Draft RFP will not be approved in Utah until April 22, 2022.[7] PacifiCorp plans on issuing the final RFP to the bidding community on April 26, 2022.[8]

6. Washington could be materially harmed by not seeing comments from stakeholders in other states and changes required by other states, and not incorporating changes ordered from other states. In rulemaking, NIPPC and PacifiCorp recommended alignment of Washington's RFP process with other states to combat these potential harms.[9] First, reviewing stakeholder

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4 Notice of Opportunity to File Written Comments on PacifiCorp's Draft RFP at 1 (Jan. 4, 2022).

5 *In re PacifiCorp Application for Approval of 2022 All-Source RFP*, Oregon Public Utility Commission ("OPUC") Docket No. UM 2193, Conference Memorandum at 1 (Jan. 18, 2022).

6 *See* PacifiCorp's 2022 AS RFP Timeline, available at: https://www.pacificorp.com/suppliers/rfps/2022-all-source-rfp.html. Note a schedule has not been officially set by the Utah Public Service Commission ("UPSC") in Docket No. 21-035-52.

7 *Id.*

8 *See* PacifiCorp's 2022 AS RFP Timeline, available at: https://www.pacificorp.com/suppliers/rfps/2022-all-source-rfp.html.

9 *See in re Rulemaking to Consider Changes to WAC 480-107, Purchases of Electricity in Light of RCW 19.405, Other Legislative Changes Since 2006 and Changes in the Electric Industry*, Docket No. UE-190837, PacifiCorp Comments at 1-3 (June 29, 2020); *see also* Docket No. UE-190837, NIPPC Comments at 1-2 (June 29, 2020); see also Docket No. UE-190837, PacifiCorp Comments at 7 (Sept. 14, 2020); *see also* Docket No. UE-190837, PacifiCorp Comments at 2 (Dec. 3, 2020).

comments and IE recommendations in other states could have helped the Commission make more informed decisions. In NIPPC's experience, no group of stakeholders or IEs fully identify all issues, and coordination among the various states improves the analysis and information presented to the Commission. The Commission needs to be able to make informed decisions and it cannot do that if it does not have access to all the relevant information. Second, Utah or Oregon could require changes to the RFP that help ensure that PacifiCorp selects the least cost, least risk bids or help ensure that utility-ownership bids are not unfairly advantaged over independent power producer bids.[10]

7. For this RFP, NIPPC recommends that the Commission conditionally approve the final RFP, and reserve the right to make revisions to accommodate potential changes to the Draft RFP in Oregon or Utah. This will ensure the Commission is able to at least ensure that the RFP is as fair and reasonable as other states and obtains resources with the lowest reasonable costs.[11] The bidding community and PacifiCorp will also benefit by ensuring that there is one RFP, and there is not inconsistency or materially different requirements in Washington than other states.

8. In the long-term, to avoid this RFP alignment issue with other states, NIPPC recommends: 1) the Commission waive the WUTC rules regarding the RFP approval schedule; or 2) the Commission revise the WUTC rules to allow for a more robust RFP timeline that

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10 *See, e.g.*, *In re PacifiCorp Application for Approval of 2017R RFP*, OPUC Docket No. UM 1845, Order No. 17-367 (Sept. 27, 2017) (OPUC amending its prior conditional approval of PacifiCorp's 2017 Renewable RFP to add one condition and four modifications to align the OPUC's decision with that of the UPSC).

11 *See generally* WAC 480-107.

enables the Commission to take stakeholder comments in other states into consideration when issuing a decision on the RFP.

B. PPA Provisions and Performance Guarantees That Would Not Apply to the Build Transfer Bids May Bias the RFP Toward Ownership Options

9. The same inherent risk for utility bias in favor of utility ownership exists in BTA bids or benchmark resources bids. The bias is that PacifiCorp may choose a utility owned resource because they will be included PacifiCorp's rate base and reward PacifiCorp's shareholders with return on the undepreciated capital in rate base for the depreciable life of the resource, likely the next 30 years. The risk of bias is no less between BTA bid or benchmark bid because either will be placed in rate base. NIPPC is not opposed to the inclusion of BTA bids in this RFP but recommends that the Commission make a number of changes to limit the opportunity for PacifiCorp to bias the results in favor of utility-owned bids. Other sections of the comments identify specific revisions to the RFP and PPA terms, but in this section NIPPC recommends a basic change to address the bias in favor of BTAs.

10. NIPPC is not suggesting that BTA bids be barred from the RFP. Instead, NIPPC first recommends that BTA bids include conservative contingency cost adders after commissioning to fairly compare them to PPA bids which must incorporate such contingencies into their PPA offer price. Second, this inherent bias against PPA bids can be partially offset by adopting NIPPC's other recommendations in these comments regarding the Force Majeure provisions in the pro forma PPA, curtailment provisions of the pro forma PPA, and treatment of taxes in the pro forma PPA.

11. In a BTA, PacifiCorp's ratepayers are potentially exposed to any costs to maintain, upgrade, and operate the facility throughout its life. NIPPC understands that the revenue requirement charged to ratepayers for a utility-owned resource, such as the BTA bids, will be

calculated based on the cost of service from the plant over its life, and not the revenue requirement used for purposes of comparing the BTA bid to other bids in this RFP. In other words, cost recovery will be based on actual costs rather than the estimated costs in the utility owned bid. Because the actual revenue requirement of the BTA plant can materially increase beyond what was reasonably expected in the RFP analysis, these BTA bids are, in effect, cost-plus bids. In contrast, the revenue requirement charged to bidders for a winning PPA bid would be the fixed price included in the PPA emerging from this RFP – on a fixed dollars-per-megawatt-hour basis for energy and green tags actually delivered, and fixed dollars-per-megawatt basis of capacity actually available. The PPA bidders must include within their PPA price offer all of the potential cost overrun and underperformance risk of the facility, whereas the BTA bidders do not need to include these potential post-commissioning risks in their bid prices, making these BTA bids cost-plus bids.

12. In this type of RFP, the IE is placed in the difficult position of comparing cost-plus BTA bids against fixed-price PPA bids. Among other issues discussed elsewhere in these comments, this type of RFP requires that the IE and Commission ensure that conservative risk contingencies and conservative performance assumptions be included in the inputs used to develop a revenue requirement for the price scores for all BTA bids in the RFP if the solicitation is to provide a reasonable opportunity for PPA bids to compete. The IE and Commission should also ensure that PPA bidders are not penalized in the scoring process for negotiating reasonable terms into the PPA, which generally speaking will always provide protection of a fixed-price payment only for delivered energy, capacity, and green tags.

13. The RFP document has an important provision to address the ongoing risks after commissioning: requiring that all BTA bids are required to be supported by an Operations and

Maintenance ("O&M") Agreement consistent with the RFP's pro forma O&M Agreement.[12] Ratepayers are exposed to operating cost risk in a BTA. Those costs could include occurrences such as a lower-than-forecasted capacity factor, major equipment failures that prevent operation of the plant, or circumstances beyond anyone's reasonable control. However, PacifiCorp's proposed O&M Agreement is insufficient to protect customers, and should be significantly improved.

14. It is important to recognize the protections of a PPA bid as opposed to a BTA with an O&M Agreement, and that even the best O&M Agreement cannot provide the full protections of a PPA bid. In the PPA structure, the bidder is only paid for delivered energy, capacity, and green tags. A facility can underperform for a wide variety of reasons, including but not limited to a lower-than-bid capacity factor, unexpected outages due to equipment failure, unexpected curtailments of power by the transmission provider or PacifiCorp's transmission function, or even an unexpected force majeure event (such as an earthquake or pandemic, etc.). PacifiCorp and its ratepayers have no obligation to pay the facility under a PPA during the outages because PacifiCorp only pays for delivered energy, capacity, and green tags. Indeed, in cases of unexcused non-delivery, the PPA will even require the Seller to pay PacifiCorp liquidated damages penalties for the failure to deliver.[13]

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12 Draft 2022 AS RFP at 25 (Dec. 29, 2021) ("Any BTA proposal that does not include an O&M proposal that contains pricing, scope and other key terms will be rejected as a nonconforming proposal.").

13 Normally, such penalties for non-performance would include either a mechanical availability guarantee or an output guarantee. In the pro forma PPA, the major performance guarantee is located in Exhibit F, and it includes a proposal for an output guarantee, which is discussed further below.

15. In contrast, in the case of underperformance of a BTA facility after commissioning, the ratepayers will still pay for the same capital costs and return, plus actual O&M costs through their rates. And, except in the rare event where O&M Agreement assigns liability for the lost generation to the contractor, PacifiCorp and the ratepayers still receive no energy, capacity, and green tags or damage payments to make up for the lost operation.

16. A review of key aspects of the pro forma PPA demonstrates the potential advantages to ratepayers of the PPA structure.[14] Typically, one would compare the PPA to the O&M Agreement to understand how exactly ratepayers would be benefited. However, the pro forma O&M Agreement contains no specificity and is not helpful to understand how various provisions of the O&M Agreement would compare to the PPA. In PacifiCorp's 2020 All Source RFP in Oregon, PacifiCorp submitted a much more detailed O&M Agreement that allowed stakeholders to better understand the benefits ratepayers would receive from a PPA bid.[15] Thus, NIPPC recommends the Commission require PacifiCorp to submit a more detailed O&M Agreement so that stakeholders can meaningfully review the agreement and provide feedback.

17. The draft pro forma PPA contains a performance guarantee that requires an *output* guarantee, which is not optional.[16] The pro forma PPA's output guarantee does not merely require that the plant be *mechanically available* to produce net output; it affirmatively requires

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[14] *See generally* Draft 2022 AS RFP, Appendix E-2.1 (PPA Documents – Generating Resource Only PPAs).

[15] *See in re PacifiCorp Application for Approval of 2020 All-Source RFP*, OPUC Docket No. UM 2059, PacifiCorp Final Draft 2020 All Source RFP, Appendix K (Apr. 22, 2020) (O&M Services Contract).

[16] *See* Draft 2022 AS RFP, Appendix E-2.1 (PPA Documents – Generating Resource Only), Exhibit F.

delivery of a minimum amount of net output.[17] It therefore subjects the Seller in the PPA to annual variations in available wind, solar, or other motive. The pro forma PPA sets the annual output guarantee at 90% of the estimated annual energy amount, which is an unreasonably high level of guaranteed output, at least for a wind farm where wind availability can vary significantly from year-to-year. In addition to being an output guarantee, the draft pro forma PPA's output guarantee has narrow excuses. For example, ratepayers make no payments to the Seller in the PPA under any circumstance of undelivered energy, capacity, or green tags for whatever reason. Typically, with an O&M Agreement ratepayers will still pay for capital, return and O&M during an output shortfall.

18. A review of a few other common PPA provisions contained in the pro forma PPA further demonstrates this point. The PPA excuses the performance of Seller in an event of Force Majeure (such as an earthquake, volcanic eruption, pandemic, etc.).[18] But as proposed in the pro forma PPA, PacifiCorp may terminate the PPA if a Force Majeure event causes non-performance by the Seller for over 180 days. As drafted in the pro forma PPA, it appears PacifiCorp might even exercise this right to opportunistically acquire lower priced resources in the circumstance of

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[17] *See id.* at § B.1 ("Seller agrees to deliver to PacifiCorp no less than the Annual Guaranteed Amount of Net Output during each Contract Year"); § B.2 (assigning liquidated damages at PacifiCorp's "Cost to Cover" for an unexcused output shortfall); § A ("'Annual Guaranteed Amount' means, in respect of any Contract Year, (a) ninety percent (90%) of the Expected Annual Net Output… in such Contract Year (in MWh), less (b) the sum of: (i) the Compensable Curtailment Energy in such Contract Year (in MWh); and (ii) the Non Compensable Curtailment Energy in such Contract Year (in MWh).").

[18] *See* Draft 2022 AS RFP, Exhibit E-2.1 (PPA Documents – Generating Resource Only) at § 14.

advances in technology. While NIPPC believes 180 days is too short of a period to include in the pro forma PPA for termination during force majeure, the fact that the PPA would contain *any* right for PacifiCorp to terminate due to an extended force majeure event is a major distinction from a BTA/O&M Agreement arrangement. Under a BTA, in contrast, PacifiCorp typically cannot terminate its acquisition of a rate-based plant after commissioning due to a force majeure event; instead, the ratepayers would be required to continue paying for the capital investment and PacifiCorp's shareholder returns on the plant no matter how long a force majeure event may last.

19. Another example is the curtailment provisions of the pro forma PPA. These provisions allow PacifiCorp to curtail the facility without payment to the Seller ("Non-Compensable Curtailment") if PacifiCorp's transmission arm curtails the facility for any reason, among other specified reasons.[19] The PPA also includes "Compensable Curtailment" under which PacifiCorp may curtail for any reason it chooses, including economic reasons, if it pays the Seller the specified curtailment price that is potentially distinct from the contract price for delivered energy, capacity, and green tags. NIPPC does not necessarily object to this general concept in the PPA, which is typical in a PPA. But there is no corresponding mechanism where PacifiCorp's shareholders, as opposed to its ratepayers, lose revenue and return from the utility-owned plant during Non-Compensated Curtailment events and potentially pay less than normal revenue requirement on the plant during all other curtailment events.

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[19] *See* Draft 2022 AS RFP, Exhibit E-2.1 (PPA Documents – Generating Resource Only) at § 4.5.1.

20. The treatment of taxes is yet another area where the pro forma PPA provides protections well beyond what exists in a typical BTA/O&M Agreement. The pro forma PPA requires the Seller to pay all existing *or new* sales, use, excise, severance, ad valorem, and any similar taxes to the extent they are assessed on the product up to the point of delivery.[20] Again, NIPPC does not necessarily take issue with this treatment in the pro forma PPA as a general matter, but it demonstrates another risk to ratepayers that exists only in the BTA/O&M Agreement, under which PacifiCorp's ratepayers will be responsible for not just existing and known taxes on the facility at the time of this RFP, but also any future taxes or increases beyond estimates used in the RFP to generate the bid's revenue requirement. This is not a purely hypothetical circumstance because at least one state in PacifiCorp's service territory has previously enacted an excise tax on wind production and recently considered increasing it.[21]

21. In sum, an O&M Agreement would likely provide nowhere near the protections for ratepayers as the pro forma PPA, or likely any PPA. While the BTA structure may provide protections against initial cost overruns as opposed to a pure utility self-build structure, a BTA arrangement does *not* provide the same type of contractual protections from ongoing cost overruns, unexpected outages, capital upgrades, underperformance, or numerous other

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[20] *See* Draft 2022 AS RFP, Exhibit E-2.1 (PPA Documents – Generating Resource Only) at § 5.4.

[21] *See* Ashleigh Cotting & Justin Horwath, S&P Global, *How Wyoming went from leader to laggard in wind energy* (Apr. 10, 2019), https://www.spglobal.com/marketintelligence/en/news-insights/trending/WDrrAH2joStLEQyVTq5BaA2 (discussing Wyoming's imposition of a $1/MWh tax on wind production and efforts to increase it to $5/MWh).

unexpected occurrences for which the risk is allocated to the independent power producer ("IPP") under a long-term PPA.

C. The RFP Should Not Assign Any Terminal Value to Utility Owned-Resources

22. The Commission should ensure that the RFP does not bias utility-ownership structures by assigning a speculative terminal value to utility-ownership bids. This is a subject that has been a frequent point of contention in Oregon RFPs, where Oregon utilities have historically boosted the scores of utility-owned bids by assigning them a scoring benefit for assumed terminal value and the ability to re-develop a site after the useful life of the initially installed facility. In Oregon, if a utility wishes to use a terminal value in an RFP, it must also provide PPA bidders with the option of bidding a renewal right into their PPA to overcome the potential scoring bias on this point.[22] The OPUC has noted the potential bias in favor of utility owned bids when a terminal value benefit applies to utility owned bids without a comparable renewal benefit for PPA bids.[23] In PacifiCorp's 2020 RFP in Oregon, the OPUC stated the IE would assess and monitor the impact of the terminal value especially related to the short list.[24]

23. PacifiCorp's draft RFP indicates there will be a terminal value assigned to BTA and benchmark bids.[25] It is unclear if PPA bidders will have the option of bidding a renewal right

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[22] *In re OPUC Investigation Regarding Competitive Bidding*, OPUC Docket No. UM 1182, Order No. 14-149 at 5-6 (Apr. 30, 2014).

[23] OPUC Docket No. UM 1845, Order No. 18-178 at 12 (May 23, 2018) (OPUC stating "we share concerns raised by participants about PacifiCorp's treatment of PTC benefits and use of a terminal value adder ... the IE found that the terminal value adder applied to company-owned resources added significant benefits to PacifiCorp's portfolio but not to the PPA portfolio.").

[24] OPUC Docket No. UM 2059, Order No. 20-228 at 5 (July 16, 2020).

[25] Draft 2022 AS RFP at 34.

into their PPA. Thus, the RFP should either state PacifiCorp will not assign terminal value to BTA and benchmark bids, or the RFP must allow PPA bids to elect to achieve an equal score improvement with a reasonable PPA renewal provision. NIPPC's preference is that PacifiCorp not be allowed to assign a terminal value to BTA and benchmark bids.

D. The Draft RFP's Credit Requirements Will Preclude Otherwise Qualified Bidders from Participating

24. The draft pro forma PPAs' requirement for bidders to potentially post performance assurance in the amount of $200/kw of project capacity upon PPA execution and maintain $100/kw throughout the term of the PPA is excessive and should be reduced.[26] To illustrate the excessiveness, a prevailing 400 MW bidder would need to provide a guarantee or letter of credit in the amount of $80 million upon execution of a final contract. It is not commercially reasonable for a developer to post a letter of credit in this amount, which limits bidding to very large companies or to developers with very large partners who can post a qualified guaranty. NIPPC recommends that the Commission require that a maximum performance assurance for companies bidding into and having their resources selected should be $100/kw before commercial operation, and $50/kw afterwards. Those amounts would be at the high end of more reasonable market practice for larger companies and fairer to PPA bidders.

25. Notably, while the draft RFP imposes the same $200/kw amount on BTA bids between contract execution and commercial operation, the draft RFP relieves the BTA bids of the need to maintain security of $100/kw over the facility's operating life. Because it costs money to

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[26] Draft 2022 AS RFP, Appendix D at 3.

maintain the excessive financial assurance after operation, the PPA bidders will need to build that extra cost into their bids – making this yet another example of how the RFP favors BTA bids.

26. The problem of excessive credit assurances is particularly acute and unreasonable for smaller companies, which may have excellent projects under advanced development but have inherently less access to credit markets. Smaller companies will not be able to qualify for a letter of credit from a financial institution at the $200/kw level and may have difficulty even with the reduced amounts proposed by NIPPC, and will need to use a guaranty instead, which will require partnering with larger firms. In turn, the smaller firm will need to increase its bid prices to facilitate this transaction and post the excessive financial assurance proposed by PacifiCorp. If the maximum performance assurance is not reduced, ratepayers may be deprived of valuable assets under development by smaller firms.

27. Furthermore, in addition to this onerous level of the proposed performance assurance, the draft RFP appears to also include onerous security requirements to even participate in the RFP, which should also be revised. As part of the section on "credit information" to be included with the bidders' initial application, the draft RFP appears to require that bidders include a commitment letter from a qualified guarantor or lender that it will provide financial assurance for the bidder. Specifically, for bidders relying on a third party for credit support, the draft RFP's credit requirements section explains:

> Describe relationship to bidder and describe type of credit assurances to be provided (e.g., parental guaranty, cash deposit, or a letter of credit from an acceptable financial institution). *Bidder must provide to Company a letter to Company from the entity(ies) providing the credit assurances on behalf of the bidder executed by an authorized signatory and indicating their form of credit assurances it will provide*. It should be noted that more than one

> commitment letter, or more than one form of commitment letter, may be necessary.[27]

Yet, confusingly, the draft RFP later suggests the commitment letter will be required upon reaching the shortlist, as follows:

> If necessary, the bidder will be required to demonstrate the ability to post any required credit assurances in the form of a commitment letter from a proposed guarantor or from a financial institution that would be issuing a Letter of Credit. PacifiCorp will require each bidder to provide an acceptable commitment letter(s), if applicable, twenty (20) business days after the bidder is notified that the bidder has been selected for the Final Shortlist.[28]

28. These commitment letters are not free to all bidders, and, for the same reasons noted above, requiring such commitments during the RFP will inhibit smaller companies and those submitting PPA bids more than larger companies and those submitting BTA bids. While it may be reasonable to require bidders to post a reasonable commitment letter upon selection to the final shortlist, there is no basis to require such a commitment letter at any time prior to selection for the shortlist. Indeed, it is not clear what amount would be required before PacifiCorp completes its evaluation of the bid's unique credit circumstances. Therefore, the draft RFP should be corrected and/or clarified on this point to ensure the RFP unambiguously relieves bidders of the requirement to provide commitment letters prior to selection to the final shortlist.

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27 Draft 2022 AS RFP, Appendix D at 1 (emphasis added).
28 Draft 2022 AS RFP, Appendix D at 2.

E. Price/Non-Price Score Allocation

29. The Commission should require PacifiCorp to use a price/non-price score ratio of 80/20 instead of 75/25 as currently proposed.[29] Non-price factors are inherently subjective and allow for the opportunity to unfairly bias the evaluation of bids. Further, non-price factors limit the IE from applying a mostly quantitative analysis. NIPPC understands that there will always be certain factors or characteristics of a specific resource proposal that cannot be fully reflected in the bidders proposed pricing, but non price factors should be eliminated as much as possible because of the potential bias in results.

30. The key principles that should inform what are appropriate non-price scoring factors to include in an RFP are:

- The weighting of any specific non-price scoring factors should reflect the magnitude of costs or benefits of that factor relative to the price evaluation score, so that the weighting of evaluation factors reflects PacifiCorp's best estimate of the actual costs or benefits to ratepayers of any non-price factor relative to the total costs and benefits of the resource.
- Non-price Scoring Factors should not result in double-counting costs or savings that have already been captured in the Price Scoring Evaluation or in the minimum bid requirements (i.e., no double-counting of costs or benefits already embedded in the bidder's bid price and contracting requirements). To do otherwise will distort the true cost and value of the proposed resource to the detriment of PacifiCorp ratepayers.
- The assignment of non-price "points" to any resource in the evaluation process should be explained and justified based on a clear nexus between the direction (i.e., cost or benefit) and magnitude of the non-price cost or benefit to ratepayers, and the assignment of non-price points added or subtracted from the price score assigned to each bid must be directionally correct (i.e., non-price evaluation factors that represent costs not embedded in the bid price should be subtracted

[29] Draft 2022 AS RFP at 31.

from the price score and benefits that are not captured in the bid price score should result in points added to the bid price score).

- All non-price scoring factors should be applied uniformly and objectively to all ownership types in a non-discriminatory manner.

31. NIPPC believes that if the RFP non-pricing scoring framework is revised consistent with these principles, that actual weighting of price to non-price factors will be empirically based and supportable, and most likely result in a lower weighting of non-price factors relative to price factors. Specifically, the Commission should require PacifiCorp to increase the scoring percentage for price factors from 75% to 80%, and the non-price factors should be reduced from 25% to 20%. This could be achieved by eliminating certain subjective or vague criteria included in the present non-price scorecard.

32. NIPPC notes that PacifiCorp's non-price scorecards are detailed and appear to be targeted as items that can be self-scored, and NIPPC appreciates the work that PacifiCorp has put into this part of the RFP. However, there remain provisions that have a certain amount of subjectivity and ambiguity that will make self-scoring difficult, including the following:

- Bidder's Financing Plan demonstrates ability to finance project construction and ongoing operations – 1 point

- Bidder's Supply chain and contracting plans demonstrate ability to secure materials and complete construction, including securing safe harbor equipment, if applicable. Bidder has demonstrated a process to adequately acquire or purchase major equipment (i.e., wind turbines, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries) and other critical long lead time equipment. – 1 point

- Critical Issues Analysis has not identified any fatal flaw that would prevent resource from reaching commercial operations by the deadline. – 1 point[30]

[30] Draft 2022 AS RFP, Appendix L.

33. PacifiCorp's non-price factors could be more limited, and allocating less overall points to these criteria would appropriately allocate points more heavily to the price score. As non-price factors are inherently subjective, overemphasis of non-price factors could allow PacifiCorp the opportunity to unfairly bias the evaluation of bids. Thus, the Commission should require PacifiCorp to use a price/non-price score allocation of 80/20 instead of 75/25.

F. Extend COD if a Large Number of Projects from Cluster Study Show the Time to Interconnect will Extend Beyond End of 2026

34. The COD should be extended if a large number of projects for a Cluster Study result shows the time to interconnect the generating facilities will extend past the end of 2026. PacifiCorp is requiring new and existing resource bids achieve COD and/or begin deliveries to PacifiCorp by December 31, 2026.[31] PacifiCorp is accepting CODs for long-lead time resources (nuclear, pumped storage hydro) of December 31, 2028.[32] NIPPC assumes that PacifiCorp's benchmark will be able to meet the December 31, 2026 COD, and precluding longer CODs will effectively limit the number of bids that will be able to compete against the utility owned option.

35. This RFP will likely see similar issues to PacifiCorp's 2021 RFP where projects without large generator interconnection agreements ("LGIAs") are disadvantaged during the interconnection study process. Projects from the last cluster study are seeing study results indicating a timeline for construction to build network upgrades of 60 months or more, which

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[31] Draft 2022 AS RFP at 2.
[32] Draft 2022 AS RFP at 2.

means these projects would not be able to achieve COD by the end of 2026.[33] Thus, in the absence of a demonstration by PacifiCorp of the need to bring a particular amount of energy or capacity online through this RFP by the end of 2026, the RFP COD should be extended until December 31, 2028 to account for the extended construction timeline for network upgrades that have been indicated in PacifiCorp cluster study results.

36. Additionally, it is expected a large volume of projects will be studied in Cluster 2 because of PacifiCorp's future resource need identified in its IRP,[34] which will cause very large network upgrades and extended construction timelines. This will result in a large number of projects with CODs well after the end of 2026, and many projects will not qualify for consideration in PacifiCorp's RFP and projects with existing LGIAs will be the few selected. Thus, the Commission should extend the COD until the end of 2028 to accommodate more cost-effective projects.

G. Allow AC Coupled and DC Coupled Co-Located Renewable Energy Plus Storage Bids

37. Co-located renewable energy plus storage should not be limited to AC coupled storage resources but also include DC coupled storage resources. Currently, PacifiCorp is requiring any co-located battery energy storage system with a renewable resource to be AC coupled.[35] In PacifiCorp's 2020 RFP, PacifiCorp accepted bids from co-located storage and stand-alone

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33 *See generally*, PacifiCorp Cluster Study 1 Results available at: https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/pacificorpcliaq1.htm (See projects in Areas 1, 2, 3, 5, 6, 7, and 12 (Wyoming, Idaho, Utah, and Southern Oregon).

34 *In re PacifiCorp 2021 Electric IRP*, Docket No. UE-200420, PacifiCorp 2021 IRP, Chapter 1 – Executive Summary at 2-3 (Sept. 1, 2021).

35 Draft 2022 AS RFP at 17.

storage that was DC or AC connected.[36] PacifiCorp has asserted it cannot accept DC-coupled storage resources because the California Independent System Operator ("CAISO") has not certified any DC meters. If this is correct, then NIPPC notes that a COD at the end of 2026 is several years out and there easily could be CAISO certified DC meters by then if there already are not now. DC-coupled storage resources should not be precluded from bidding into the RFP.

38. PacifiCorp should acquire the least cost and least risk bids including DC-coupled storage resources. DC-coupled storage resources can provide several benefits including higher efficiencies due to less AC-DC conversions, clipping recapture, and cost savings. These benefits can be even more significant with Washington's 100 percent clean energy standards. Thus, the Commission should require PacifiCorp accept AC and DC coupled co-located storage and renewable resources.

H. Transmission Requirement

39. PacifiCorp should accept conditional firm transmission as a form of firm transmission. Currently, PacifiCorp will only accept and evaluate bids that can demonstrate an ability to interconnect and deliver "firm" energy to PacifiCorp-West or PacifiCorp-East, which appears to be a requirement that off-system bids be supported by long-term *firm* transmission, as opposed to conditional firm or non-firm transmission products.[37] Conditional firm is a form of firm transmission, and it should be an acceptable form of transmission.

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[36] PacifiCorp 2020 All-Source RFP at 4 (Jul 7, 2020) (available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/suppliers/rfps/2020-all-source-request-for-proposals/documents/main-documents-appendices/2020AS_RFP_Main_Document_July_7_2020.pdf).

[37] Draft 2022 AS RFP at 3, 20-21, 23, 27-28.

40. PacifiCorp should acquire the least cost and least risk bids regardless of whether the transmission service is delivering firm energy or conditional firm, especially if the bids are required to have completed an interconnection study or signed an interconnection agreement. A project developer that has long-term transmission rights or that demonstrates a strong likelihood that it can obtain those rights and transfer them to PacifiCorp, should be able to sell its project to PacifiCorp without restriction. Thus, the Commission should require PacifiCorp accept firm and conditional firm transmission service, and the manner in which such different transmission products will impact a bid's score should be clarified.

I. Alternative Bids

41. The Commission should direct PacifiCorp to allow different configurations of bids per project site without requiring the bidder to pay bid fees for each bid. Currently, PacifiCorp allows a bid to submit more than one bid per project site subject to certain requirements.[38] Additionally, each bid on the same project site requires payment of the bid fee.[39] A bidder should be allowed to submit different alternatives for the project under a single bid. In Portland General Electric's ("PGE's") most recent RFP, PGE is proposing to allow "one base proposal in addition to two alternatives for the same bid fee."[40] PGE allows alternative bids to account for variations in "technology, volume, contract term, in-service date, and/or pricing structure for the same resource at the same location."[41]

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38 Draft 2022 AS RFP at 16-19.

39 Draft 2022 AS RFP at 16.

40 *In re PGE 2021 All-Source RFP*, OPUC Docket No. UM 2166, PGE's 2021 All-Source RFP – Final Draft at 9 (Oct. 15, 2021).

41 OPUC Docket No. UM 2166, PGE's 2021 All-Source RFP – Final Draft at 9.

42. NIPPC believes PacifiCorp should allow alternatives bids like PGE does. Allowing alternative bids at the same location without requiring bidders pay additional fees will help ensure PacifiCorp receives the least cost, least risk resources. If bidders were required to pay bid fees for every single alternative, then bidders would likely be discouraged from submitting alternatives. A design like PGE's allows bidders to submit reasonable alternatives and ensures PacifiCorp will receive more eligible, cost-effective bids. Thus, PacifiCorp is better equipped to select the least cost, least risk resources. Therefore, the Commission should require PacifiCorp to allow alternative bids from bidders without the bidder having to pay a new bid fee similar to PGE's proposal in its 2021 RFP.

J. Clarification on Consistent Nameplate Capacity

43. The Commission should direct PacifiCorp to provide clarity on what it means when it states the nameplate capacity must be "consistent and supported by" an interconnection agreement. PacifiCorp is requiring nameplate capacity size of a bid must be "consistent and supported by the interconnection agreement(s)."[42] For example, NIPPC is unsure if this would allow bids that are oversized relative to their AC interconnect. Bids that are oversized relative to their AC interconnect should be allowed especially as it can increase efficiency of a project. PacifiCorp should acquire the least cost, least risk bids including bids that are oversized relative to their AC interconnect.

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[42] Draft 2022 AS RFP at 17.

K. Allow Build Transfer Agreement Proposals to Be Off-System

44. The Commission should direct PacifiCorp to accept off-system BTA proposals for its 2022 RFP. Currently, PacifiCorp is requiring BTA proposal to be directly interconnected to PacifiCorp's system.[43] PacifiCorp is allowing PPA and tolling agreement proposals to be off system if they secure firm point-to-point transmission service,[44] but will not do the same for BTA bids. NIPPC is not aware of PacifiCorp's justification for this exclusion. PacifiCorp should acquire the least cost and least risk bids regardless of whether it is located on its system or not. A project developer that has long-term transmission rights or that demonstrates a strong likelihood that it can obtain those rights and transfer them to PacifiCorp should be able to sell its project to PacifiCorp without restriction.

L. The RFP Should Be Revised to Provide Reasonable Term Normalization Scoring

45. The treatment of bids of different term duration, through "term-normalization" analysis, is a critical issue in any RFP, yet PacifiCorp's RFP provides insufficient clarity on this subject. The Commission should require PacifiCorp to make its term-normalization analysis transparent in this RFP and should direct the IE to require PacifiCorp to conduct an analysis that focuses on the annuity-based analysis while not unreasonably penalizing shorter-term PPA bids through use of generic fill costs from the IRP.

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[43] Draft 2022 AS RFP at 24-26, 27-28.
[44] Draft 2022 AS RFP at 23-24, 27.

1. The Term-Normalization Problem

46. The term-normalization issue is a problem inherent in a solicitation that attempts to equitably compare a longer-term obligation placed in rate base (typically 30-plus years) and the shorter-term PPA or other IPP structure. With all other factors being equal, the IPP option will be far less expensive to the ratepayer in the early years, and the utility-owned resource will be far more expensive in the early years due to front loading of rate-based costs and returns in normal rate-of-return ratemaking. Additionally, the longer-lived utility-owned resource requires the RFP evaluation to include present value and levelization analysis to compare the ratepayer costs of these resources in the RFP. NIPPC believes that assumptions favoring longer-lived utility-owned generation can be a major contributing factor in a utility's ability to "win" RFPs with utility-owned bids.

47. Utilities have in past RFPs use a "generic fill" for the costs of the shorter-lived resource after its term expires in the process of selecting the final short list from the initial short list. In other words, the IPP's actual bid price is substituted for a hypothetical assumed cost (the "generic fill") in the latter years simply because the bid has a shorter term than the longer-lived utility-owned bids. There is obviously a significant risk of intentional or unintentional errors in of the use of generic fill costs. The risk of error is particularly acute given the fact that utilities have stated they traditionally used current costs from their current IRPs as the basis for the assumed replacement costs of the IPP resource in future years. Use of today's costs in the IRP as the likely replacement costs 20 years from now is unreasonable because the costs of renewable energy and storage have been precipitously falling over the past decade and are likely to continue doing so. In short, NIPPC is very concerned that RFPs have been conducted to assume that the

30-year to 45-year bid for utility-owned projects is the norm, and errors have been introduced (through generic fill) to accommodate that type of bid.

48. For further background on this subject and a reasonable solution, Boston Pacific has prepared an excellent analysis of the issue that recommends use of an "annuity" analysis instead of the use of generic fill.[45] As Boston Pacific persuasively explained:

> Our research indicates that, out of these five methods, the Equivalent Annual Annuity Method (the Annuity Method) should be among the methods required in an evaluation, if not the preferred method. The central appeal of the Annuity Method is that it essentially allows the bid to speak for itself, thereby minimizing the discretion of the bid evaluator. The other methods add needless complexity and uncertainty to the bid evaluation process, and all give too much discretion to the bid evaluator.[46]

NIPPC agrees. An annuity is the equal annual payment over the life of the alternative that has the same present value as the actual, unequal annual costs that are expected to be incurred, and the annuity analysis thus allows the bids to speak for themselves without any manipulation. It provides no advantage to any bid solely by virtue of its longer duration, as the use of generic fill is likely to do. In contrast, PacifiCorp has in the past used the "Filler Method" described in the Boston Pacific white paper[47] to develop the final shortlist. According to Boston Pacific, under this filler method "the evaluator can significantly bias the" shorter term bids by assigning it filler costs after the end of its bid term.[48]

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45 Attachment A (Boston Pacific Company, Inc., Bid Evaluation Methods in Competitive Solicitations: A White Paper on Techniques Used to Evaluate Power Supply Proposals with Unequal Lives).

46 *Id.* at 1.

47 *Id.* at 5-7.

48 *Id.* at 7.

49. These problems are compounded in the RFPs because the utility (which is an inherently interested party) conducts the bulk of this analysis without meaningful oversight from the IE, and certainly without any meaningful participation from stakeholders or Commission Staff.

2. NIPPC's Proposed Solution for PacifiCorp's RFP

50. In this RFP, the Commission should ensure transparency on this issue by requiring complete disclosure as to the methods of conducting term-normalization analysis. This RFP presents the term-normalization issue because PPA bids typically will have a 15-year to 25-year term, but if a utility-owned generation bid prevails it will be placed in rates for its depreciable life, likely 30 or more years for a renewable plant.

51. However, in this RFP, it is not entirely clear how PacifiCorp will conduct term normalization. It appears that PacifiCorp may use the filler method to develop the initial shortlist. The draft RFP states PacifiCorp will use IRP modeling to identify an "optimized portfolio" of resources, presumably including use of generic fill, in development of the initial shortlist of bids.[49] Additionally, the draft RFP states "PacifiCorp will not make any of the IRP evaluation models available to the IEs, bidders, or stakeholders" and instead will only "summarize for the IEs how the IRP evaluation models function" and allow the IE to view the model inputs and outputs.[50] PacifiCorp should provide the IE and Commission Staff with full

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[49] Draft 2022 AS RFP at 35.
[50] Draft 2022 AS RFP at 35.

access to these models and inputs so that the IE and Commission Staff can effectively evaluate PacifiCorp's results.

52. NIPPC proposes that the Commission provide the following clarification for how PacifiCorp should implement a term-normalization analysis in this RFP:

- No generic fill of PPA bid prices or utility-owned generation costs may be used to evaluate bids of unequal term lengths to develop the initial shortlist.
- The price score should be calculated with the annuity method consistent with the Boston Pacific white paper and without force ranking the bids.

PacifiCorp must commit to produce complete sensitivity analysis results for the impact of any generic fill or other term normalization techniques used in the final IRP modeling analysis to develop the final short list, with adequate transparency and time for stakeholders, the IE, and the Commission Staff to fully evaluate and comment on the results.

III. CONCLUSION

53. For the reasons stated above, the Commission should require PacifiCorp to make the recommended changes to its Draft RFP and provide additional clarification were requested.

Dated this 14th day of February 2022.

Respectfully submitted,

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