Portland General Electric Company
Legal Department
121 SW Salmon Street • 1WTC1301 • Portland, Oregon 97204
Phone 503-464-7371 • Fax 503-464-2200
portlandgeneral.com

Brendan J. McCarthy
Assistant General Counsel III
brendan.mcarthy@pgn.com

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Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: **UM 2273 - Investigation into House Bill 2021 Implementation Issues**

Dear Filing Center:

Attached for filing is Portland General Electric Company and PacifiCorp d/b/a Pacific Power Joint Initial Cost Cap Brief in the above listed matter.

Sincerely,

Brendan J. McCarthy
Assistant General Counsel III

BJM:mmb

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2273

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation Into House Bill 2021 Implementation Issues.	Portland General Electric Company and PacifiCorp d/b/a Pacific Power Joint Initial Cost Cap Brief

I. INTRODUCTION

Portland General Electric Company (PGE) and PacifiCorp d/b/a Pacific Power (PacifiCorp) (the Joint Utilities) respectfully submit this joint brief in response to the Public Utility Commission of Oregon's (OPUC or Commission) April 15, 2024, request for briefing on select questions of law and policy related to HB 2021's cost cap provisions (ALJ Memo).[1]

The Joint Utilities appreciate the Commission's continued attention to the implementation of HB 2021 and the important interpretative questions that the Commission faces. PGE and PacifiCorp supported HB 2021 and actively participated in its drafting as part of a large coalition. In many cases, HB 2021's adopted language is similar or identical to the language agreed upon by the coalition. In this brief, the Joint Utilities explain our perspectives on the most reasonable and supportable interpretations of this language, consistent with Oregon's longstanding statutory interpretation process. The Joint utilities also offer insight on the meaning of certain cost cap provisions based on our best recollections from those coalition working group meetings. We offer these insights understanding that they do not replace traditional means for statutory interpretation, but ask the Commission give it appropriate weight in this investigation.

II. COMMENTS

In part II.A, the Joint Utilities provide a structural method for analysis of investments and costs for inclusion in the cost cap. In part II.B, we address the issue of forecasted costs and proposed treatment of language in ORS 469A.445 regarding those costs. In part II.C, the Joint Utilities discuss the lack of direct linkage between the cost cap in ORS 469A.070 and ORS469A.445, and propose alternatives for treatment of costs under both caps. Finally, in part

[1] *In re Commission HB 2021 Investigation*, Docket No. UM 2273, Memorandum (Apr. 15, 2024).

II.D the Joint Utilities provide thoughts on annual cost cap determinations and additional considerations.[2]

A. What utility actions does the cost cap apply to?

The ALJ Memo asks whether the "Legislature intend[ed] to capture only those actions that the petitioner can prove the utility would not have taken, except to meet the requirements of HB 2021?" The ALJ Memo also identifies the two different phrases to describe applicable investments and costs, "for the purpose of compliance" and "contributes to compliance," and asks whether there is a reason for the distinction.

1. What investments or costs "meet the requirements of HB 2021"?

Taking the question from the end first, it is important to understand what it means "to meet the requirements of HB 2021." Oregon did not choose a GHG-intensity path or a reduction from a business-as-usual emissions curve. Instead, Oregon chose targets that require actual reductions from a baseline. Thus, to determine whether an investment or cost "contributes to compliance," that investment or cost must be expected to reduce overall GHG emissions from baseline emissions consistent with the GHG emissions targets specified in ORS 469A.410. Investments or expenditures that lower GHG-intensity may potentially *not contribute* to compliance if those investments do not also lower the mass-based emissions of the retail electricity provider. But there are also *requirements* of HB 2021 for which no reductions from baseline are necessary – certain requirements in an acknowledged CEP for example, such as the resiliency or community-based renewable energy requirements found in ORS 469A.415 (4), costs associated with emissions verification and development of community advisory groups. Those investments or costs should be included in the cost cap—even without any specific reduction in GHG emissions from baseline—because they are nonetheless required by the law.

2. There are three broad categories of investments or costs that could be relevant to the cost cap.

During coalition discussions in development of HB 2021, the Joint Utilities supported cost cap provisions to ensure that, should the costs of achieving HB 2021's significant greenhouse gas reductions cause customers rates to rise by a legislatively determined level, the Joint Utilities could be temporarily excused from making additional HB 2021 policy-driven investments that would increase rates further. In supporting the cost cap, the Joint Utilities sought a pure revenue requirement analysis that would determine the actual effect on rates from utility investments or costs that reduced greenhouse gas emissions or that were otherwise driven by policy requirements of HB 2021.

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[2] The Joint Utilities note that this brief does not address matters of cost recovery for investments made for the purpose of HB 2021 compliance, including those above and below the cost cap. ORS 469A.445(5) state that a cost cap decision "shall have no effect on and may not be used as collateral or presumptive evidence in any other proceeding that determines rate recovery of the investment or cost...". Thus, investments that exceed the cost cap, including those that trigger it following an investigation under ORS 469A.445(1), may be recovered consistent with traditional prudency principles.

Understanding, however, that some activities could have multiple purposes (a large investment might be used to serve load and reduce emissions), the Joint Utilities thought it best to create a process where specific investments could be considered to determine what portion of the investment or cost, if any, was made for reducing greenhouse gas emissions consistent with complying with HB 2021. Additionally, parties in the legislative discussion agreed that in many cases, the purpose for the investment or cost would likely be known ahead of that investment or cost being made or incurred and, for that reason, the language allowed for assumed future investments to be investigated for their rate impact.

With this initial background, the utilities believe there are three broad categories of utility actions that should inform the Commission's cost cap analyses: investments that do not fall under the cost cap at all; investments for which a portion could be included; and investments where all of the costs could be included in the cost cap.

First, some investments and costs should not fall under the reach of the cost cap because they are not made for the *purpose* of reducing emissions consistent with HB 2021 compliance but are made for a different purpose and do not reduce emissions. For example, both utility Clean Electricity Plans anticipate increased load growth over HB 2021's pre-compliance period (now through 2030). With increasing prevalence of data centers and other new industrial and commercial load, this load may significantly exceed forecasts when HB 2021 was enacted. To comply with HB 2021, serving that new load will have to be accomplished largely with non-emitting resources.[3] But merely because the resources used to serve this increased load are non-emitting does not mean that the investments are necessarily subject to cost cap treatment. In this circumstance, the investment and associated rate impact of a new wind or solar facility is not made for the "purpose of compliance" or reducing emissions, but instead, exclusively to meet load.[4] The Clean Energy Plan guidelines specify that the "primary goal" of the combined planning process includes the selection of a portfolio with GHG reductions.[5] This exercise would require creation of separate portfolios to understand which resources could be understood to meet load (e.g. a traditional IRP analysis) and which resources do that and exert the desired downward pressure on GHG emissions (e.g., the new IRP/CEP analysis).[6]

Other examples of investments that might not be for the *purpose* of HB 2021 compliance might be certain demand-side actions supported by a utility's Integrated Resource Plan such as energy efficiency costs charged pursuant to ORS 757.054 for all cost-effective conservation or

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[3] New, natural gas-fired, utility-scale facilities were barred from siting in Oregon by HB 2021. Coal-fired resources are barred by action of SB 1547 (2016). Any addition of emitting resources to the supply-side makes the reductions required from baseline even harder to achieve.

[4] ORS 469A.410 requires retail electricity providers to reduce GHG from a baseline. Thus, new non-emitting resources that serve only new load do not increase GHG and thus the drive toward reductions, but they also do not help drive reductions, which fundamentally is what is required. HB 2021 did not adopt a GHG-intensity standard, but a mass standard.

[5] Commission Order No. 23-060, at 5, "The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers, the pace of greenhouse gas emissions reductions, and community impacts and benefits."

[6] Note that the CEP guidelines require all portfolios to "at minimum, demonstrate year over year emissions reductions on an expected basis." A portfolio submitted that merely addressed load growth needs would likely not receive acknowledgment but would be necessary to separate the investment treatment under the cost cap.

costs associated with cost-effective demand response.[7] The policy driver of energy efficiency investments and demand response is the assumption that EE operates to reduce the costs to customers through more cost-effective investments than new generation and demand response efforts reduce the need for spinning reserves. While these investments or costs could have an effect on reducing emissions, the foundation for these investments pre-date HB 2021, support traditional notions of resource planning, and would not be made "for the purpose of" reducing emissions and thus the costs might not be applicable to the cost cap.[8] Not only that, but the Legislature would have known of the requirement to plan for and acquire EE and DR pursuant to either the former public purpose charge in ORS 757.612, or of the modified charge created through HB 3141 in the same legislative session that it adopted HB 2021.[9]

Second, some investments in renewable generation or other resources might occupy a middle ground where either a *portion* of the cost or investment could be relevant for cost cap purposes or where the investment/cost is not made directly for the *purpose* of HB 2021 compliance, but where the investment nonetheless is consistent with and aligns with HB 2021 goals, and is required by statute – e.g., increasing renewable resource penetration or reducing GHG emissions. If a resource is identified in an IRP and CEP, and cannot be clearly disaggregated as suggested above, a portion of the investment and associated rate impact of a new, non-emitting resource would be made for the "purpose of compliance," and a portion of these costs should be included in the cost cap.[10]

Statutorily-required resources that could occupy this "middle ground" include acquiring qualifying renewables pursuant to the Renewable Portfolio Standard in ORS 469A.052, the costs of purchasing energy from qualifying facilities to meet the small-scale renewable requirement under ORS 469A.210, or the costs of purchasing exported energy from net metered or community solar facilities pursuant to ORS 757.300 and 757.386. The costs imposed on customers are imposed by separate statutory requirements, not by HB 2021; the *purpose* of the investment, in the strictest sense, is not for HB 2021 compliance. But the fundamental reason for those statutory requirements relate to the same policies underpinning HB 2021: increase

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[7] While energy efficiency and demand response have potential reductive effects on emissions, and the Joint Utilities recognize that ORS 469A.415 provides that CEPs may include EE and DR, for decades utilities have operated or invested in these programs for the system benefits they provide. For example, the Residential Energy Conservation Act was adopted in 1981 and required utilities to have conservation programs. The public purpose charge for energy efficiency was imposed in 1999. ORS 757.054 was first adopted in 2016 as part of SB 1547 and required utilities to plan for and acquire EE and DR.

[8] E.g., IRP Guideline 7 directs utilities to evaluate demand response resources on par with other options for *meeting* energy, capacity, and transmission needs (emphasis added); Guideline 6b directs evaluation of conservation programs "for *meeting* projected resource needs" and "specifying annual savings targets." (emphasis added).

[9] Note that the findings and declarations in ORS 757.054 do not specifically discuss emissions reduction as a benefit of EE and DR, instead discussing lower energy bills, efficient use of existing resources, reducing the need for procuring new power generation, reducing reliance on imported fuels and, generally, improved environmental benefits.

[10] This could occur, for example, with a large-scale investment where part of the resource is needed for energy and capacity to serve load growth and part of the investment would be expected to provide downward pressure on GHG emissions.

renewable energy generation or reduce emissions.[11] That is, from a policy standpoint the purposes are the same. Because these investments/costs will reduce emissions from baseline, the Joint Utilities argue that portions of these costs can be attributed toward the cost cap if the actions reduce total mass-based emissions.[12]

Finally, some investments may be made with the express *purpose* to comply with HB 2021 because they are directly consistent with the intent of ORS 469A.400 through .475,[13] such as acquiring community-based renewable energy.[14] This category would also include resources that would be expected to reduce GHG emissions, for example, costs associated with fossil-generation retirement and replacement power that are required by HB 2021, including potentially coal-to-gas conversion.[15] In these cases, all of the costs are for the "purpose of compliance" and would be subject to the cost cap.

Similarly, because HB 2021 sets absolute emissions targets in 2030, 2035, and 2040, all strategies or resources that are made "for the purpose of" reducing utility greenhouse gas emissions should be relevant for cost cap purposes, including strategies or resources that do not involve installing non-emitting resources. For example, development of new transmission and supporting infrastructure, changes in system operations or other necessary actions, if supported by appropriate analysis and motivated by HB 2021 compliance, could be included in the cost cap.[16]

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[11] *Compare* ORS 469A.405 and: 1) the preamble to the Oregon Renewable Energy Act (SB 838 (2007)) includes the language that "the Legislative Assembly finds that it is necessary for Oregon's electric utilities to decrease their reliance on fossil fuels for electricity generation;" 2) ORS 758.525 (2)(a) states that it is the goal of Oregon to "[p]romote the development of a diverse array of permanently sustainable energy resources;" 3) ORS 469A.210 states that "renewable energy projects . . . are an essential element of this state's energy future;" and 4) the preamble to HB 3219 (1999) (Ch. 944, Oregon Laws 1999) that created net metering states that the "Legislative Assembly finds that a net energy metering program for customers with small-scale, renewable-fuel electric generating facilities . . . enhances the continued diversification of this state's energy resources."

[12] The Joint Utilities do not opine directly on what should occur regarding compliance with these other statutory requirements if the cost cap were reached, merely that some of these costs are potentially includable in the cost cap pursuant to ORS 469A.445. It is possible however, the collateral impact on those other requirements may require consideration of modifications to administrative rules governing these other programs, especially the small-scale requirement of ORS 469A.210. The cost cap exemption, by operation of language in the cost cap statute, does not directly apply to other statutory requirements – ORS 469A.445 (4) states that "the commission shall provide an exemption from further compliance with the requirements of ORS 469A.400 to 469A.475" if the cost cap is breached. As discussed in both utility CEPs, the small-scale requirement presents material procurement needs that have significant cost implications for our customers. While the Legislative Assembly has not created a statutory small-scale requirement cost cap, the Commission stated in AR 622 that it had the authority to adopt administrative rules implementing the statutory requirement and thus, arguably, has the authority to revise its small-scale requirement rules to mitigate these potentially large costs, especially where continuing to procure small-scale resources would only add to costs above the cost cap.

[13] As required by ORS 469A.445(1).

[14] ORS 469A.415 requires an assessment of community-based renewable energy and CEP guidelines direct inclusion of CBRE in the annual goals utilities provide.

[15] Some of these costs may be properly in the "middle ground" as they could be required by ORS 757.518, the coal transition portion of SB 1547 (2016); however, they can also be driven by inclusion in a CEP due to ORS 469A.415 (5) "retirement of existing generation facilities."

[16] ORS 469A.415 (5).

3. The Joint Utilities recommend a two-step process for resolving these cost cap issues

The Joint Utilities see a two-step process to determine what utility strategies and investments the cost cap should apply to. The first step would determine whether the investment or cost was incurred for the *purpose* of compliance by evaluating the basis for the investment or cost, the analysis supporting the decision, and any other relevant, empirical support for that proposition. As noted above, it may be difficult to disaggregate particular investments or costs, especially considering the nature of the IRP/CEP process. One way to accomplish this would be to ask the utilities to model IRP portfolios as if HB 2021 did not exist. That would allow a comparison between the acknowledged slate of investments and costs from the IRP/CEP, and a counterfactual slate of investments and costs without the policy driving mechanism of HB 2021. If an investment was in both the acknowledged IRP/CEP and the counterfactual portfolio, then it would not be eligible for cost cap treatment: because the utility would have proposed it anyway. That is, it would not have been made for the *purpose* of compliance. That could then be the end of the Commission's inquiry.

If, however, the investment or cost *contributes* to compliance because it is in an acknowledged IRP/CEP, though not in the counterfactual, or if the investment or cost is clearly required by HB 2021, then the Commission would proceed to the second step. Here, the proponent for including the investment or cost in the cost cap should have the opportunity to show that compliance is at least partly the reason for the investment, and for the Commission to determine what portion or percentage of the investment or cost assists the utility in reducing emissions consistent with the targets even if required by a separate, underlying statutory requirement.[17]

This two-step analysis is supported by the text with ORS 469A.445 (1) and creates a logical flow to the analysis that also gives meaning to both terms – "purpose of" and "contributes to". The Joint Utilities believe that the wording in the statute is intentional and that different terms within the same statute carry different meanings.[18] The Joint Utilities believe that the Oregon Legislature included these two terms, because it was understood that some investments or costs would not necessarily be "100% in" or "100% out," and that a Commission investigation would have to determine what portion of the investment or cost contributed to compliance. The two-step example analysis described above would facilitate this type of investigation.

B. To what extent should forecasted costs, and to what degree of certainty, be included when evaluating HB 2021's cost cap?

[17] As discussed above, some resources may occupy both camps: required by a separate statute and required by HB 2021. Community-based renewable energy facilities may be required by HB 2021 and ORS 469A.210 the costs for which would then be entirely includable within the cost cap, or new non-emitting resources might be needed to meet new load growth while also reducing greenhouse gas emissions.

[18] See, e.g., *Marshall v. PricewaterhouseCoopers, LLP*, 371 Or. 536, 555, 539 P.3d 766 (2023) (absent more direct evidence of legislative intent the court will "generally assume that when the legislature uses different terms – at least in the same statute – it intended different meanings" *citing Dept. of Transportation v. Stallcup,* 341 Or. 93, 101, 138 P.3d 9 (2006) (use of different terms in real estate appraisal statute suggests that each was intended to have different meaning)).

During coalition working group discussions, the Joint Utilities sought to create this cost cap process that would allow for investigations of actual or forecasted investments or costs prior to rate proceedings.[19] Bill drafters wanted to allow for the investigation of costs from anticipated actions, while at the same time allow for retroactive adjustments once actual costs were known.[20] This method would also provide certainty to the regulated community. For example, in advance of deploying significant capital, stakeholders could initiate investigations on particular investments or compliance strategies to inform cost cap implications of the strategy, or whether the Commission agreed that the action was relevant to the cost cap at all.[21]

Consistent with this understanding, the Joint Utilities suggest that costs should include estimated future costs to the extent that those future costs would affect rates (e.g., assumed annual purchased generation resulting from power purchase agreements (PPAs); rate base implications from build-transfer agreements (BTAs); anticipated transmission cost charges for delivering energy), as well as anticipated actions and their costs (e.g. actions acknowledged in an IRP that were relatively certain to be accomplished, but not yet taken).

For that second category of anticipated actions, the Joint Utilities believe there should be some sense that the actions will likely be taken prior to the Commission opening an investigation into the costs – thus mere IRP acknowledgement should not be sufficient to trigger an investigation. A higher standard of certainty should be required, for example, a project that has been determined to be on a short-list in an RFP. For projects acquired outside of an RFP (due to an exception or because the type of investment is not subject to being bid in an RFP), a utility could determine the likely certainty of the project before asking to open an investigation and would, regardless, bear the burden of showing that the cost would likely contribute to compliance.[22]

C. How does HB 2021's cost cap relate, if at all, to Oregon's RPS cost cap?

The Joint Utilities believe that the Commission should decline to issue any formal guidance on this issue, and instead, allow for fact-specific resolution of this issue in future proceedings.

Utilities can comply with Oregon's RPS though the use of bundled or unbundled renewable energy credits (RECs), or alternative compliance payments;[23] utilities comply with

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[19] *E.g.,* ORS 469A.445 (1) "to provide accounting for investments made, costs incurred or forecasted costs;" ORS 469A.445 (5) provides that the rate impact determined under the cost cap may have no collateral or presumptive effect on any other proceeding.

[20] ORS 469A.445 (3)(a) allows for the anticipated rate impact to be "adjusted by any change in net costs expected or foreseeable at the time of inclusion and (3)(b) allows for "any adjustments to the cumulative rate impact if the initial rate treatment was calculated on the basis of forecasted rate impact."

[21] Which is not to say that every investment decision would have to be run through cost cap analysis or that the ultimate decision made on an RFP short-list would depend on cost cap treatment. A retail electricity provider is not prohibited from making an investment that would cause the entity to exceed the cap – the cap only exempts the provider from further compliance and does not prohibit the investment. Moreover, the cost cap treatment cannot be used as evidence in any proceeding determining actual rate recovery by operation of ORS 469A.445 (5).

[22] ORS 469A.445 (2)(b).

[23] ORS § 469A.070.

HB 2021 through demonstrating reduced greenhouse gas emissions as reported to Oregon's Department of Environmental Quality.[24] RECs are not relevant for HB 2021 compliance.[25]

Because compliance is based on different mechanisms (RECs as opposed to emissions factors), in many cases the costs to comply with HB 2021 would not trigger the RPS cost cap, or vice versa. For example, any utility purchase of unbundled RECs to comply with the RPS would not be relevant for HB 2021 purposes. Similarly, any actions that further HB 2021 compliance – such as a transmission investment allowing delivery of non-emitting resources, certain actions to further equity, etc. – that do not increase the supply of renewable energy (and thus RECs) would not implicate the RPS cost cap. Further, the cost caps are fundamentally structured differently, one based on incremental costs, and the other based on rate impacts.

However, there would be overlapping costs when a utility needs to procure new resources to satisfy both HB 2021 and the RPS—where utilities need additional resources to reduce greenhouse gas emissions to satisfy HB 2021, while at the same time require bundled RECs from these resources to satisfy the RPS, and where, as stated above, there is some incremental GHG-emissions reduction through investment in an RPS-compliant resource.

In these circumstances, it seems the Commission could take one of several approaches to these overlapping costs: costs could inform both cost caps; costs could inform only one cost cap; or costs could be shared between the two cost caps, based on the costs contributed to either HB 2021 or RPS compliance.

Yet as a practical matter, because HB 2021 will almost certainly require more investments than the RPS, the RPS cost cap will become less relevant over time. Instead of resolving this issue in the current proceeding, the Commission should conclude that HB 2021 provides enough flexibility to address this issue in fact-specific proceedings in the future. For example, the law allows parties in any cost cap proceeding to "propose alternative rate or accounting treatment" of HB 2021 costs to "limit the potential rate impact of the investment or cost."[26] Applied here, if a utility incurs HB 2021-related costs that exceed the cost cap, and the resources from these costs also generated bundled RECs that were necessary to comply with the RPS, parties could propose appropriate rate mitigation alternatives in that specific proceeding.

This approach would ensure that the Commission has appropriate flexibility and discretion to resolve issues on a case-by-case issue in the future.

D. Does the cost cap require an annual determination?

The Joint Utilities agree that the cost cap only applies in individual years, based on the relevant costs as a percentage of that utility's annual revenue requirement.

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[24] *See, e.g.,* ORS § 469A.410.
[25] Order 24-002, at 13 ("For the above reasons, we interpret the text and context of HB 2021—including its direct statements on the subject, its emissions framework standing in contrast to the REC-based RPS, and its direction to rely on DEQ's existing emissions accounting system—to be an unambiguous expression of legislative intent not to require RECs to demonstrate compliance with emission reduction requirements.").
[26] ORS § 469A.445(3)(c).

That said, if it is reasonably certain that a utility will exceed the cost cap based on actual or forecasted costs for multiple years, nothing in HB 2021 appears to limit a continuing cost cap exemption. For example, if utilities were to procure several rate-based assets, and the cumulative costs from these resources was projected to exceed the cost cap throughout the depreciable lives of the assets (20-35 years, for example), the Commission would be justified in allowing a continuing cost cap exemption for the depreciable lives of these resources (assuming that an annual cost cap compliance filing demonstrates that the relevant costs continue to exceed six percent of a utility's then-current annual revenue requirement).

III. CONCLUSION

The Joint Utilities continue to appreciate the Commission and Commission Staff's diligent efforts with HB 2021-related issues, and respectfully request the Commission consider the Cost Cap comments provided above.

In working through the questions posed in the ALJ Memo, the Joint Utilities believe there may be benefit to all parties if the ALJ were to allow for workshops or other collaborative discussions prior to the date for submission of reply briefs. For example, the process that developed the cost cap for the RPS was conducted as a rulemaking, and involved multiple staff workshops and rounds of comments.[27] The Joint Utilities would support a similar approach for cost cap issues.

Respectfully submitted May 23, 2024,

Brendan J. McCarthy, OSB No. 963556
121 SW Salmon Street, 1WTC 1301
Portland, OR 97204
(503) 464-7371
Brendan.McCarthy@pgn.com
PGE Attorney

/s/ Zachary Rogala
Zachary Rogala, OSB No. 222814 1407
W North Temple, Suite 310 Salt Lake
City, Utah
(435) 319-5010
zachary.rogala@pacificorp.com
PacifiCorp Attorney

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