Portland General Electric Company
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January 25, 2024

Via Electronic Filing

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

Re: **AR 660 – In the Matter of Adoption of Rules Relating to Resource Adequacy**

Dear Filing Center:

Please find enclosed for filing in the above-captioned docket, PacifiCorp's and Portland General Electric Company's Comments.

Thank you in advance for your assistance.

Sincerely,

Erin Apperson
Assistant General Counsel

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

AR 660

In the Matter of Adoption of Rules Relating to Resource Adequacy	**COMMENTS OF PACIFICORP AND PORTLAND GENERAL ELECTRIC COMPANY**

I. INTRODUCTION

In accordance with the Ruling issued on January 23, 2024, by Administrative Law Judge Christopher Allwein, PacifiCorp d/b/a Pacific Power (PacifiCorp) and Portland General Electric Company (PGE) (together, the Joint Utilities) submit these comments to the Public Utility Commission of Oregon (Commission). In these comments, the Joint Utilities address the proposed rules that will implement a resource adequacy (RA) program for Oregon and specifically respond to the comments filed on January 8, 2024, by the Northwest & Intermountain Power Producers Coalition (NIPPC) and on January 9, 2024, by Calpine Energy Solutions LLC (Calpine Solutions).

The Commission should adopt the proposed rules with minimal changes. The rules result from a robust, multi-year stakeholder process and represent a reasonable and workable proposal for implementing an RA program in Oregon. In these comments, the Joint Utilities recommend a minor modification related to confidential treatment of certain transmission service information that will be included in the utility filings. With this minor modification, the Joint Utilities fully support the proposed rules and recommend their adoption.

The Joint Utilities oppose the recommendations from NIPPC and Calpine Solutions that the Commission jettison the transmission forward showing requirement and replace it with either a Capacity Backstop Charge or a Request for Offers (RFO) process. Adopting these recommendations would undermine the basic purpose of the RA program, create potentially significant cost-shifting from direct access to cost-of-service customers, in contravention of ORS 757.607(1), and require the Commission to impermissibly wade into wholesale market activities subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission (FERC).

The transmission forward showing is a cornerstone of the RA program that ensures utilities and Electric Service Suppliers (ESSs) can provide reliable service in an evolving and increasingly transmission-constrained market and promotes long-term investments in system reliability. The fact that the transmission forward showing will require utilities and ESSs alike to adapt their business practices to demonstrate resource adequacy should be viewed as a positive, because it will better ensure that all load responsible entities (LREs) are able to plan and provide reliable service. Oregon state energy policy requires a fast-paced transition to largely intermittent generation and for that transition to be successful *all* LREs—utilities and ESSs—must continue to provide reliable service. The RA program embodied in the proposed rules is a vital step in the right direction and should not be watered down simply because ESSs have historically operated under a business model that can no longer ensure reliable service to their customers or contribute to the overall RA required to ensure service to Oregon load.

NIPPC's and Calpine Solutions' request to replace a foundational element of any meaningful RA program with either a Backstop Capacity Charge or RFO process would allow ESSs to impermissibly lean on cost-of-service customers to subsidize their RA obligations.

Put simply, if an ESS wants to serve Oregon customers, then the ESS should be subject to the same reliability requirements as utilities. Applying less stringent requirements for ESSs creates an uneven playing field that hampers the development of a truly competitive market.

Moreover, requiring cost-of-service customers to cover their own RA obligations *and* ESS RA obligations as proposed by Calpine and NIPPC will likely result in unwarranted cost-shifting. When a utility is required to meet the ESS RA obligation, it must do so by either purchasing capacity products in the market—the same capacity products the ESS could have purchased—or using its own resources that are then unable to serve customers or support market sales. And given that the utility and ESS have access to the same market information, a direct access customer will presumably rely on the Capacity Backstop Charge only if it is less than the expected price for the equivalent product purchased in the wholesale market. This dynamic will very likely result in cost-of-service customers paying more for the ESS RA obligation than will be recovered through the Capacity Backstop Charge, otherwise the ESS would have met its own RA obligation at a lower cost to its direct access customer.

Finally, both the Capacity Backstop Charge and RFO process infringe on FERC's exclusive jurisdiction to regulate wholesale markets and transactions.

II. DISCUSSION

A. The Joint Utilities largely support the proposed rules.

The proposed RA rules were developed through an extensive and robust public process spanning several years and with numerous opportunities for stakeholder input.[1] When drafting the proposed rules, Staff indicated they are intended (1) to be complementary to and incentivize participation in the Western Resource Adequacy Program (WRAP) developed by the Western

[1] *See* Staff Response to NIPPC's Motion to Modify Schedule at 2 (Jan. 19, 2024).

Power Pool (WPP); (2) to provide transparency and close the seams issues that arise from mismatching planning timelines and planning methodologies between the state program and WRAP; and (3) are most likely to result in meaningful improvements to resource adequacy for Oregon customers.[2] The Joint Utilities agree with Staff that the proposed rules are consistent with these principles and will create an important RA framework that will enable Oregon to achieve its clean energy goals without compromising system reliability. The Joint Utilities therefore recommend adoption of the proposed rules largely without change.

The Joint Utilities also appreciate Staff's efforts to balance transparency for coordinated resource adequacy concerns with confidentiality of business-sensitive information. However, certain information required by Section 3, subsection (b) of the rules could require the provision of extremely competitively sensitive information regarding a utility's purchased and open positions for transmission rights directly to the utility's competitors who are often participants in the integrated resource planning process. The Joint Utilities recommend that the Commission modify the rule to allow for the redaction of this information so only the Commission, Commission Staff, and the Citizens' Utility Board have access to this information.

B. The transmission forward showing requirement is reasonable and necessary.

Transmission availability plays a critical role in assessing and ensuring system reliability. Given the increasingly constrained regional transmission system, it is imperative that RA include a robust showing of sufficient transmission capacity to support reliable load service. A lynchpin of the state RA program created by the proposed rules is the requirement that as part of its forward showing a "State Participant must demonstrate that it has firm or conditional firm transmission rights to deliver 75 percent of the Compliance Resources from generation source to load sink."[3]

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[2] Staff Report at 4-5 (Sept. 11, 2023).
[3] Staff Report, Attachment A at 5 (Sept. 11, 2023).

Demonstrating sufficient generation capacity to meet the RA requirements would be of little value without sufficient firm transmission to deliver that generation to load, and the proposed rules already allow for a reduced demonstration of transmission rights relative to load requirements. The transmission forward showing requirement is critical for a successful and meaningful state RA program and should not be reduced further.

1. The transmission forward showing requirement promotes long-term investments in system reliability.

The basic purpose of the state RA program is to ensure reliable service for Oregon customers. To that end, the forward showing requirement plays a critical role to both ensure near-term system reliability and to incentivize long-term investment in the transmission system to ensure sufficient capacity exists so that all market participants can reliably serve their customers.

NIPPC argues that the transmission forward showing requirement is an unnecessary barrier because it requires a showing of firm transmission service seven months ahead of the binding season.[4] NIPPC argues that LREs have historically been able to serve load using short-term capacity and therefore the RA program unreasonably "assumes a new and significant shift in regional practices by requiring all of its participants to rely very heavily on firm transmission."[5] This shift in regional transmission practices, however, is necessary and critical to ensure continued system reliability, particularly to achieve Oregon clean energy goals through the ongoing transition to renewable generation. What has worked in the past will not necessarily work in the future, which is precisely why the region is focused on RA issues now. There is no dispute that the regional transmission system is currently constrained,[6] and the RA program should work together with

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[4] Northwest & Intermountain Power Producers Coalition's Opening Comments on Proposed Rules at 7 (NIPPC Comments); *see also* Calpine Energy Solutions, LLC's Opening Comments On Proposed Rules at 2-3 (Calpine Solutions' Comments).
[5] NIPPC Comments at 7-8.
[6] NIPPC Comments at 2-3.

regional transmission planning efforts to incentivize efficient and near-term transmission system investments. Relieving state RA program participants from the transmission forward showing requirement does nothing to enhance transmission system reliability and leaves the state RA program incomplete. Removing the transmission forward showing from the Oregon program will also incentive ESSs to not participate in the WRAP, which is directly contrary to one of Staff's key principles governing the Oregon RA program.

2. Utilities and ESSs have equivalent opportunities to secure long-term transmission.

NIPPC argues that the transmission forward showing requirement disadvantages ESSs because "ESSs are in a worse position than PGE or PacifiCorp because ESSs are not transmission providers who [have historically] needed to invest in transmission assets as part of their obligation to provide service to their end use consumers or that have the capability [to] expand their own transmission system to cure these problems."[7] This argument, however, misconstrues how the Joint Utilities procure transmission service for purposes of serving retail load, and ignores the fact that the Joint Utilities and ESSs have identical ability to secure transmission rights.

In its landmark Order No. 888, FERC established its open access transmission policies to prohibit public utilities from using their ownership of the transmission system to unduly discriminate against third-party generators.[8] The cornerstone of open access, non-discriminatory transmission service is the premise that a public utility may not refuse access to its transmission

[7] NIPPC Comments at 10.

[8] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

system.[9] A utility's transmission function cannot provide an advantage to the utility's merchant function when providing transmission service. Put another way, federal law prohibits the Joint Utilities' transmission function from discriminating against ESSs seeking access to the transmission system. This means that even though the Joint Utilities' transmission functions own transmission assets, the transmission function must provide access to those assets on a non-discriminatory basis to all LREs, including ESSs, that request transmission service. The Joint Utilities' merchant functions must request and purchase transmission rights from the transmission functions in the same manner and subject to the same constraints as all other LREs. Similarly, the Joint Utilities' merchant functions are in the same position as ESSs when seeking transmission service across third-party transmission systems, including the Bonneville Power Administration (BPA). NIPPC's perceived disadvantage therefore does not exist—the utilities and ESSs compete for the same transmission service using the same processes and subject to the same constraints.

NIPPC suggests it is unfair to require ESSs to acquire firm transmission service, like that acquired by the Joint Utilities, because in the past ESSs have not had a commercial reason to do so.[10] Again, however, the purpose of the state RA program, like the WRAP, is not to capture in perpetuity historical practices that are unlikely to work in the future. ESSs commercial practices must evolve just as utilities must evolve with the changing energy landscape and account for critical RA issues, including the need to plan for and acquire long-term firm transmission. While procuring long-term firm transmission on an annual basis can be more expensive for ESSs, doing so is a necessary investment for ongoing system reliability in an increasingly constrained transmission system. Moreover, if the Joint Utilities are required to incur the costs of long-term

[9] As the U.S. Supreme Court stated, prior to Order No. 888 "[t]he utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions." *New York v. FERC*, 535 U.S. at 8-9.
[10] NIPPC Comments at 10.

firm transmission as part of their participation in the WRAP, NIPPC's recommendation would provide a competitive advantage to ESSs, who would be relieved of that obligation under the state RA program. Such an approach runs directly counter to the directive in ORS 757.646 to eliminate barriers to a competitive market.

NIPPC also claims that the Joint Utilities may use their market position to hoard unused transmission or generation resources to prevent competition from ESSs.[11] These concerns are unfounded. First, FERC prohibits transmission providers' merchant functions from attempting to exercise their market power by hoarding available transmission capacity.[12] Second, the Joint Utilities will not hoard unused generation capacity because first, the WRAP operations program will commit excess capacity to other WRAP participants who are short; if unused generation is not committed through WRAP, holding will increase their costs by preventing off-system sales. Existing processes at both the state and federal levels address NIPPC's concerns and there is no need to weaken the RA program as a remedy for a problem that does not currently exist and that has existing remedies if it occurs.

C. The Commission should reject the Capacity Backstop Charge.

Allowing an ESS to shift its RA obligations onto cost-of-service customers is likely to inappropriately shift costs and raises significant legal issues. First, the Capacity Backstop Charge shifts costs by allowing an ESS to avoid its obligation to procure sufficient generation to serve its customers and instead requires the utility to do so. The actual cost the utility incurs to meet the ESS's RA obligation, however, is not recovered directly from the ESS or the direct access customer. Instead, the Commission will set the RA compliance costs through the Capacity

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[11] NIPPC Comments at 28-29.

[12] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-B at ¶ 82, 123 FERC ¶ 61,299 (June 23, 2008).

Backstop Charge and cost-of-service customers will be left on the hook for the difference between actual costs incurred by the utility and the Capacity Backstop Charge set by the Commission. Given that both the ESS and utility are competing in the same wholesale markets for the same capacity products for their forward showings, the ESS or direct access customers will only choose the Capacity Backstop Charge when it is lower cost than the market, meaning that by design the Capacity Backstop Charge will inherently result in cost-of-service customers paying more to procure RA compliance generation or losing out on revenue that could have been earned by the sale of RA compliance generation in the market. Either case is an impermissible shifting of costs.

Second, by essentially dictating a wholesale market price for generation needed to meet the ESS's forward showing, the Commission would intrude on FERC's exclusive jurisdiction to regulate wholesale market activities. The fact the direct access customer pays the Capacity Backstop Charge does not matter; creating an alternative compliance path that allows the ESS to bypass the wholesale market in favor of de facto paying the utility for a wholesale product effectively creates a state-mandated alternative wholesale market structure, which would impermissibly interfere with an area of exclusive FERC jurisdiction.

1. The Capacity Backstop Charge creates unwarranted cost-shifting.

The provision of direct access "must not cause the unwarranted shifting of costs to other retail electricity consumers of the electric company."[13] By design, the Capacity Backstop Charge requires cost-of-service customers to subsidize an ESS's RA obligation, which will impermissibly shift cost and risk onto cost-of-service customers, in contravention of ORS 757.607(1), simply because a direct access customer would never choose to use the Capacity Backstop Charge unless it costs less than an equivalent market product.

[13] ORS 757.607(1).

Under NIPPC's proposal, an ESS would have two RA compliance options: (1) procure the necessary generation resources from the market to make its forward showing, like the Joint Utilities; or (2) force the Joint Utilities, and by extension cost-of-service customers, to procure the necessary generation resources from the market to meet the ESS's RA obligation. The ESS, through the direct access customers, decides whether to meet its RA obligations on its own or through the Capacity Backstop Charge and economics will presumably govern that decision—i.e., if the Capacity Backstop Charge is lower cost than the market alternatives, then the ESS will choose to meet its RA obligation with the Capacity Backstop Charge. If the ESS shifts its RA obligation to the utility, however, there is no guarantee that the utility will have sufficient excess generation to meet the ESS's RA obligation. When the utility is short, it must then procure the resources in the market. And even when the utility has excess generation resources, it must either commit those resources to the WRAP operations program, or it forgoes the opportunity to make market sales using those excess resources if they must instead meet the ESS's RA obligation, negating benefits that are included in the transition adjustments for direct access customers. In either case, the utility will be compensated by a Capacity Backstop Charge that is presumably less than market prices, otherwise the ESS would have met its RA obligations with market products. Therefore, cost-of-service customers will incur higher costs than they otherwise would have incurred and will not be fully compensated for those costs. The Capacity Backstop Charge therefore impermissibly shifts costs by requiring cost-of-service customers to subsidize the RA compliance obligation of ESSs.

By impermissibly shifting costs to cost-of-service customers, the Capacity Backstop Charge also undermines the very competitive market NIPPC claims to support. All LREs should be subject to the same RA compliance obligations, regardless of whether the LRE is a utility or an

ESS. Requiring utilities to backstop ESS obligations undermines that competition by insulating ESSs from the most basic obligation to provide reliable service to the customers the ESS has chosen to serve. If the ESS cannot meet its RA obligations in the market, just as the Joint Utilities must do, then cost-of-service customers should not be required to step in and bail out the ESS.

NIPPC argues that the Commission can eliminate the risk of cost-shifting by imposing sufficient notice requirements on direct access customers choosing to relieve their ESS of the RA compliance obligation.[14] While sufficient notice requirements may dampen the impact of cost-shifting, notice alone cannot eliminate it. And even with sufficient notice, there is still a very real risk that cost-of-service customers would end up paying more to subsidize the ESS's RA obligation than they would if the ESS met the obligation on its own because notice does not change the cost differential between the market and administratively determined Capacity Backstop Charge.

2. The Capacity Backstop Charge impermissibly interferes with wholesale market activities.

The Federal Power Act ("FPA") gives FERC exclusive jurisdiction to regulate the transmission and wholesale sale of electric energy in interstate commerce.[15] Under this exclusive jurisdiction, FERC has "responsibility for ensuring that all rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of [FERC] . . . shall be just and reasonable."[16]

The proposed Capacity Backstop Charge violates FERC's exclusive jurisdiction in two ways. First, the Capacity Backstop Charge essentially mandates that the Joint Utilities provide a capacity product for sale to meet the ESS's RA obligation. The Commission cannot, however, force a utility to sell certain capacity products in the FERC-jurisdictional wholesale market to

[14] NIPPC Comments at 26.
[15] 16 U.S.C. § 824(b)(1).
[16] *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154, 136 S. Ct. 1288, 1292 (2016) (internal citations omitted).

specific counterparties. Second, the Commission cannot set the price for the sale of capacity products in the FERC-jurisdictional wholesale market.[17] Because the Capacity Backstop Charge would effectively require the Joint Utilities to engage in specific wholesale transactions at prices set by the Commission, the Capacity Backstop Charge is preempted by federal law.[18]

The fact the direct access customer pays the Capacity Backstop Charge as opposed to the ESS does not resolve the jurisdictional issue. Indeed, NIPPC's comments outline exactly why the Capacity Backstop Charge is impermissible.[19] As Staff explained when it eliminated the Capacity Backstop Charge from its proposed rules, ESSs and the utilities are free to transact on the FERC-jurisdictional wholesale market as a means of complying with the RA program requirements.[20] NIPPC argues that the Joint Utilities may be unwilling to sell excess capacity to ESSs through the FERC-jurisdictional wholesale markets, so the Capacity Backstop Charge is intended to force the Joint Utilities to do what the Commission cannot require them to do directly without infringing on FERC's exclusive jurisdiction. The RA compliance obligation is the ESSs, not the customers, and inserting an intermediary between the ESS and utility does not change the underlying reality of the transaction the Commission is regulating. Allowing an ESS to force a utility to transact (or forgo transacting) in the wholesale markets and setting compensation for that wholesale market activity (or lack thereof) at the Capacity Backstop Charge impermissibly regulates wholesale markets.

NIPPC argues that the proposed Capacity Backstop Charge resolves the key issues that led NIPPC and others to oppose the Resource Adequacy Charge (RAD) PGE previously proposed for

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[17] *See Hughes*, 578 U.S. at 163 (Maryland impermissibly guaranteed a wholesale rate different from that approved by FERC).
[18] *Northern Natural Gas Co.* v. *State Corporation Comm'n of* Kan., 372 U.S. 84, 91, 83 S. Ct. 646 (1963) (the FPA "leaves no room either for direct state regulation of the prices of interstate wholesales" or for regulation that "would indirectly achieve the same result.").
[19] NIPPC Comments at 13.
[20] *See* NIPPC Comments at 13 (explaining Staff position).

new load direct access.[21] However, in doing so, it becomes a completely different mechanism than the starting point proposed by PGE nearly five years ago prior to the initiation of this investigation and a proposal for a universally applicable RA program or the details known today regarding the WRAP. Requiring electrical companies to make excess capacity available to ESSs in the State Program would likely have negative ramifications for the WRAP. Under the WRAP, Regional Participants will be required to take part in the WRAP Operations Program and must be ready to holdback surplus capacity to meet the capacity shortfalls of other Regional Participants on a rolling weekly basis during binding seasons. Requiring Regional Participants to also make 'excess capacity' available to the State Program would likely hinder the WRAPs capacity sharing mechanism and undermine the regional program's ability to leverage the resource and load diversity in its footprint.

Additionally, any resource adequacy charge or capacity backstop charge concept has always posed difficulty for multi-jurisdictional utilities like PacifiCorp. These programs would require a situs-assigned resource and would contribute to additional cost-shifting and risk-shifting from Direct Access customers to cost-of-service customers.

D. The RFO proposal is also unworkable.

NIPPC and Calpine Solutions recommend that the Commission require the Joint Utilities to issue an annual RFO to solicit offers from ESSs to purchase excess capacity in the FERC-jurisdictional wholesale markets.[22] While the RFO proposal does not require that the Joint Utilities actually enter into wholesale transactions, it still raises jurisdictional concerns because the Commission would essentially create a state-mandated wholesale market for the sale of FERC-

[21] NIPPC Comments at 17.
[22] NIPPC Comments at 14; Calpine Solutions' Comments at 4-5.

jurisdictional products to only a subset of potential purchasers.[23] If a utility has excess capacity that could potentially meet another market participant's RA obligation, then the utility should market that capacity to every potential counterparty through the existing bilateral markets. By limiting the RFO proposal to only Oregon ESSs, the proposal undermines the wholesale market and provides a competitive advantage to Oregon ESSs.

In addition, the proposed RFO process is inconsistent with WRAP and compromises the important objective of consistent requirements for all WRAP participants by imposing unique requirements on entities serving load in Oregon. The proposed requirement to WRAP-participating Oregon utilities to forecast their capacity position and conduct an RFO up to a year in advance of an operating day is contrary to the WRAP's tariff requirements. The WRAP, not the Joint Utilities, determines whether the Joint Utilities have sufficient capacity to meet their forecasted load obligations and forward showing requirements and until the WRAP certifies the forward showing it will be unclear what excess capacity is available.

The RFP proposal also ignores opportunities within the WRAP to trade load obligations. If an ESS wants to have its load obligation met by another party, the WRAP offers a mechanism for other WRAP participants—not just Oregon utilities—to provide this service. Oregon ESSs can choose to participate in WRAP, and if they do, they could trade load obligation on the same terms as the Joint Utilities – indeed, potentially even *with* the Joint Utilities. This mechanism pulls from a far larger pool of potential capacity and does not raise the same fairness and competitiveness issues as the RFO proposal.

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[23] *See, e.g., FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 288-289, 136 S. Ct. 760, 780 (2016) ("A State could not oversee offers, made in a wholesale market operator's auction, that help to set wholesale prices. Any effort of that kind would be preempted.").

Under the WRAP, Regional Participants will be required to take part in the WRAP Operations Program and must be ready to holdback surplus capacity to meet the capacity shortfalls of other Regional Participants on a rolling weekly basis during binding seasons. Requiring Regional Participants to also make "excess capacity" available for the state RA program would hinder the WRAP's capacity sharing mechanism and undermine the regional program's ability to leverage the resource and load diversity in its footprint.

Additionally, by making this "excess capacity" available for the state RA program, it could interfere with a utility's participation in day-ahead markets. Instead of allowing this capacity to be identified, optimized, and dispatched in a day-ahead market, it must now be held back for the ESS that has purchased that capacity. This would interfere in a utility's ability to participate fully in those day-ahead markets and could potentially add costs to customers.

Finally, like the Capacity Backstop, the RFO creates similar concerns that the purpose is to enable the ESS to avoid its RA obligations and heft the cost of that obligation onto cost-of-service customers, thereby shifting both cost and risk.

E. ESSs should be required to include direct access customers participating in the one- and three-year programs in their RA forward showings.

NIPPC and Calpine Solutions argue that the Joint Utilities' RA obligations should include direct access load in the one- and three-year programs because the Joint Utilities continue to plan for those direct access customers.[24] While the Joint Utilities are required to continue to plan to serve one- and three-year customers, that planning is premised on the assumption that the customers will return to cost-of-service rates upon the end of the one- or three-year period. During the time when the direct access customer is served by an ESS, however, the Joint Utilities are *not* planning to serve those customers. Indeed, the transition adjustments specifically assume that the

[24] NIPPC Comments at 31; Calpine Solutions' Comments at 7-8.

Joint Utilities are not holding resources back to serve direct access customers but are instead using those freed-up resources for the benefit of remaining cost-of-service customers. If the Joint Utilities are required to assume the costs of RA compliance for one- and three-year customers, then it will undermine the premise of the transition adjustments because there will be no freed-up resources for purposes of calculating the transition adjustment.

NIPPC cites PGE statements that appear to show a position by PGE that PGE retains responsibility for securing resource adequacy for short term direct access customers and long term direct access customers who are still subject to transition adjustments and that transition adjustments are to some extent duplicative with a capacity backstop charge.[25] However, these statements were made in advance of development of the WRAP framework, which adopted a specific and narrower definition for resource adequacy focused on a year ahead forward showing. The statements cited by NIPPC refer to a broader provider of last resort reliability function encompassing operational and planning time horizons and hence are not relevant to the current details of the State RA Program. PGE's planning for short term direct access customer load encompasses that broader provider of last resort obligation, but *not* the specific definition of RA contained in the WRAP framework. Further, transition adjustments can actually be a *credit* to customers: for example, last fall, PGE offered to pay customers leaving cost of service ($XX/unit). It makes no sense that PGE could *pay* customers to leave, and simultaneously provide a valuable service on the same terms that it provides an identical service to cost of service customers at a higher price.

[25] NIPPC Comments at 19-20 and 34.

F. The Joint Utilities recommend a minor addition to allow for the protection of Commercially Sensitive Information in the Integrated Resource Plan Informational Filing.

The Joint Utilities are concerned that the language in Section 3 requires the use of certain information that reveals a utility's position with regards to transmission rights. The market for transmission is even less liquid than that for generation capacity, and publicly providing this information to market competitors who participate in utility IRP proceedings could lead to extremely problematic situations which could detrimentally harm cost of service customers. Disclosure of this information to other entities that are competitive for those same transmission rights is inappropriate. The Joint Utilities would recommend this information be protected at the same level as the inputs to the Regional Forward Showing. This means that certain information in the Informational Filing may be made available only to the Commission, Commission Staff, and the Citizens' Utility Board. To support that position, the Joint Utilities propose the following addition sub-bullet D to section 3, subsection (b) of the proposed rules:

> *D. Commercially and Competitively-Sensitive information and data provided in the Informational Filing may be redacted or provided only to Qualified Parties.*

III. CONCLUSION

For the foregoing reasons, the Joint Utilities recommend that the Commission adopt the proposed rules, subject to the proposed modification for the protection of non-public transmission information. The Joint Utilities further recommend that the Commission reject the proposed Capacity Backstop Charge and RFO process and affirm that ESSs are required to account for one- and three-year direct access customers in their RA forward showing. Finally, the Joint Utilities recommend the Commission adopt the proposed language regarding the protection of commercially and competitively sensitive information in the IRP informational filing.

Dated January 25, 2024.

Erin Apperson
Portland General Electric Company

Ajay Kumar
PacifiCorp, dba Pacific Power

Attorneys for Portland General Electric Company and PacifiCorp, dba Pacific Power