BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

AR 660

In the Matter of Adoption of Rules Relating to Resource Adequacy	NORTHWEST & INTERMOUNTAIN POWER PRODUCERS COALITION'S OPENING COMMENTS ON PROPOSED RULES

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I. INTRODUCTION AND SUMMARY

The Northwest & Intermountain Power Producers Coalition ("NIPPC") hereby submits its opening comments to the Public Utility Commission of Oregon (the "Commission" or "OPUC") on the Notice of Proposed Rulemaking filed with the Oregon Secretary of State on November 27, 2023 (hereafter, "Proposed Rules").

NIPPC has actively engaged in the informal stage of this rulemaking process and appreciates Staff's efforts to refine the proposed state-level Resource Adequacy requirements. However, as expressed at the Commission's public meeting opening this formal rulemaking, NIPPC has a fundamental concern that the compliance options in the Proposed Rules are, in effect, exclusively limited to full compliance with the terms and conditions of the Western Resource Adequacy Program ("WRAP") Tariff's Forward Showing ("FS") Program. While the draft proposed rules include parallel State Program Requirements for non-participants in WRAP, the State Program Requirements for advance procurement of capacity and transmission merely adopt those in WRAP but at a more stringent level.[1] NIPPC supports participation in WRAP by as many load responsible entities ("LREs") as possible, and agrees that an LRE's procurement of WRAP-compliant capacity and transmission—through direct WRAP participation or

[1] For example, the WRAP requires that the Forward Showing be submitted seven months in advance of the upcoming Summer Season or Winter Season, which are three and half and four and a half months long, respectively—thus requiring a forward capacity and transmission showing that reaches at most eleven and half months into the future and only during the applicable Binding Seasons. WRAP Tariff, Sections 1 & 16. In contrast, the State Program Requirements include a forward showing reaching two years into the future for each month of the year, OAR 860-095-0040(7), including the same 75% firm transmission demonstration than that in the WRAP program except for a period of two forward years rather than under one year in WRAP. Proposed OAR 860-095-0040(9); *compare to* WRAP Tariff, Section 16.3.

demonstration through the Proposed Rules' State Program Requirements—is a logical option for compliance with Oregon's rules. NIPPC is also not opposed to a State Program Requirement that encourages WRAP participation through higher stringency than the WRAP's Forward Showing Requirements.

But NIPPC urges the Commission not to rely solely on WRAP-style compliance because it remains unclear whether all LREs will be able to procure resources fully compliant with WRAP's requirements, especially WRAP's FS Transmission Requirement, which relies very heavily on advance procurement of firm transmission. There is a meaningful chance that the underlying assumption that the specific type of firm transmission is available for all LREs to meet WRAP's specific and new FS Transmission Requirement is wrong. If the Commission moves forward with the Proposed Rules that effectively mandate compliance with WRAP's firm transmission requirement as the only option, then the Commission runs the real risk that the Commission's requirements will be infeasible.

This is a particular danger for electricity service suppliers ("ESSs") who have not, to date, had a commercial or regulatory reason to acquire extensive firm transmission portfolios under the region's preexisting bilateral market structure. Ultimately, such an infeasible Resource Adequacy requirement would undermine the competitive retail market intended by Oregon law. That outcome is not reasonable or in the public interest.

In making this point, NIPPC wishes to underscore that it believes two things may simultaneously be true: 1) there is a mismatch between non-jurisdictional transmission providers' sales practices (specifically Bonneville Power Administration ("BPA")) and the resource adequacy transmission requirements under the WRAP, which have failed to account for how Oregon has implemented direct access; and 2) the Northwest has an overall shortage of transmission needed to construct the generation and storage that will be needed in the current energy transition.

First, neither the WRAP nor the Commission has any direct control or authority over the transmission business practices that govern most of the regional bulk power system, in large part because most of the transmission is owned and controlled by BPA. A transmission procurement requirement to acquire firm transmission service seven months in advance places a burden on purchasers of such transmission with no parallel burden placed on sellers of such transmission. At present, the practices of BPA in particular highlight that a surge of transmission capacity is regularly made available in a short-term basis that is simply not made available to the market seven months in advance. In other words, there is more actual transmission capability that could be used to demonstrate Resource Adequacy in the coming several years than the bilateral market suggests seven months in advance. Current business practices in a bilateral market with point-to-point contract paths, physical rights, and opportunities to exercise market power are poorly designed to maximize regional Resource Adequacy and to maximize Resource Adequacy compliance opportunities. NIPPC notes that a market with flow-based financial transmission rights, transparent nodal pricing, and transmission capability up to the system's reliability limits is the obvious alternative to the Northwest's transmission paradigm and would address this problem, and perhaps the West will move in that direction eventually.

Second, the Northwest does have an overall shortage of transmission needed to bring more generation and storage online, particularly to address load growth, electrification, and meeting state procurement and emissions requirement in Oregon and Washington. This second reality may also make Resource Adequacy requirements infeasible (just as the first one does) if sufficient new or upgraded transmission is not built timely, and NIPPC strongly supports various efforts to address that risk to customers and the reliability of the system. Those efforts will require all load-serving entities, including ESSs (and, by extension, all loads), to contribute to long-term transmission planning and cost recovery.

In these comments, NIPPC focuses on the risk to the competitive retail market of the first transmission problem—a mismatch between non-jurisdictional transmission providers' sales practices and the Resource Adequacy transmission requirements. However, NIPPC does not thereby suggest that the second, long-term transmission problem is not an urgent problem as well as that all transmission customers and load must contribute to solving.

Before requiring ESSs only one practical option to meet their Resource Adequacy obligations, the Commission should ensure that new obligation is meets reliability requirement in a feasible manner in the current electricity market and regulatory structure, or better yet, provide a practical and feasible alternative method of compliance. Thus, NIPPC again urges the Commission to include within its administrative rules a meaningful alternative to such WRAP compliance, at least for ESSs. There are already two reasonable alternatives that have been previously proposed:

> (1) <u>Capacity Backstop Charge</u>: The Commission should include an option that direct access customers pay the utility a Resource Adequacy charge, which meets the customer's ESS's Resource Adequacy obligation for that customer's load; or
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> (2) <u>Request for Offers</u>: If the Commission decides not to adopt a Capacity Backstop Charge, the Commission should at least provide guidelines that would provide some assurance that utilities will not unreasonably refuse to sell to ESSs excess WRAP-compliant capacity and transmission through a mechanism, such as the annual Request for Offers ("RFO") proposed by Calpine Energy Solutions, LLC ("Calpine Solutions").

Although the Proposed Rules do not include either of these options, the Commission clarified at the outset of this proceeding that these two options remain issues to be resolved in the formal rulemaking. In Order No. 23-340, the Commission stated: "As we move forward, we note that the policy issue of whether to require continued work on a capacity backstop charge or a request for offers process is before us in this discussion. Rulemaking participants should review our questions and areas for comments as set forth in the September 21, 2023 Public Meeting discussion."[2] In these opening comments, NIPPC addresses these two alternatives to WRAP-style compliance and addresses the questions posed by the Commissioners at the public meeting on September 21, 2023.

NIPPC continues to recommend that the Commission could further develop either of these proposals in the Docket No. UM 2024 proceeding, as opposed to delaying or extending the rulemaking in this proceeding. At a minimum, if the Commission does not adopt one of these recommendations, then it should state in the rules or in its final order that it will revisit this issue in January 2025 to review whether the WRAP's firm transmission requirement is proving to be unworkable.

Finally, NIPPC does not intend to suggest that any direct access customers should be exempt from contributing to paying their share of regional capacity or transmission planning. To the contrary, under NIPPC's proposal, the incumbent utility would be planning for the long-term capacity and transmission needs of the long-term direct access customer that is paying the "Capacity Backstop Charge," and the customer would be paying the incumbent utility directly

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2 *In re OPUC Investigation into Resource Adequacy in Oregon (UM 2143), and Adoption of Rules Relating to Resource Adequacy (AR 660)*, Docket Nos. UM 2143 & AR 660, Order No. 23-340 at 1 (Sept. 22, 2023).

that cost (as established by the OPUC). Or, the customer choosing to purchase its Resource Adequacy through the ESS would be contributing to capacity and transmission planning through its ESS's participation in WRAP, including the FS Transmission Requirement, or through participation in the parallel State Program with similar transmission requirements. Thus, either way, the capacity and transmission would be planned for by an LRE, and the customer would pay the appropriate LRE. The point of NIPPC's recommendation for inclusion of the Capacity Backstop Charge is to ensure there is at least one commercially viable option available to long-term direct access customers and ESSs in today's market.

In addition to recommending that the Proposed Rules provide a reasonable alternative to WRAP-style compliance, NIPPC's opening comments recommend certain other clarifications that would improve the Proposed Rules.

II. COMMENTS

A. Alternative to WRAP-Style Compliance: The Commission's Administrative Rules Should Provide the Option for a Capacity Backstop Charge for Direct Access Customers, or At Least Provide Provisions and Guidance to Facilitate the Utilities' Offer of Excess Capacity to ESSs on a Timely, Prudent, and Nondiscriminatory Basis

As NIPPC commented when the Commission opened this formal rulemaking, the Commission should provide a reasonable alternative in the administrative rules for ESSs and direct access customers to WRAP-style compliance. In this section of comments, NIPPC summarizes the well-established problem of advanced procurement of firm transmission that is likely to arise with relying solely on WRAP-style compliance, describes the proposed Capacity Backstop Charge and the alternatively proposed RFO, and provides responsive explanations to the Commissioners' inquiries at the public meeting on September 21, 2023.

1. The WRAP's Firm Transmission Requirement Is Very Problematic and Should Not Be Elevated to a De Facto Mandatory LRE Requirement

The most concerning aspect of the WRAP Tariff's Forward Showing ("FS") requirements (which are also imported into the Proposed Rules' State Program Requirements) is the FS Transmission Requirement.[3] WRAP's FS Transmission Requirement primarily requires advance procurement of firm transmission in a region that has not traditionally relied so heavily on firm transmission. Instead, the regional practice has been for some of the region's major transmission providers, in particular BPA, to release for purchase substantial qualities of reserved but unused transmission capacity on the short-term market relatively close in time to the real-time market.[4]

WRAP has itself acknowledged that "full transmission service seven Months ahead of the Binding Season could serve as a barrier to initial participation" and it "is not essential for reliability, given that most Participants' experience has been that a certain amount of transmission service that is not available seven Months ahead of the Binding Season can be obtained on a shorter-term basis."[5] LREs have been able to reliably serve load with such released transmission capacity for many years without necessarily locking in firm transmission reservations months in advance. But the WRAP Tariff assumes a new and significant shift in

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3 *See generally* WRAP Tariff at § 16.3 (FS Transmission Requirement), available at: https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_12-12-22_W0327945x8DF47_2.pdf; *see also Northwest Power Pool d/b/a Western Power Pool*, FERC Docket No. ER22-2762, Western Power Pool's WRAP Submittal Letter at 23-24 (Aug. 31, 2022) (hereafter "WPP's FERC Submittal Letter") (describing the FS Transmission Requirement).

4 This is a unique feature of BPA's system that NIPPC has previously highlighted both to the WRAP and to this Commission in the informal rulemaking stage. *See* Docket No. UM 2143, NIPPC's Comments at Appendix at 1-2 (Nov. 18, 2021).

5 WPP's FERC Submittal Letter at 23 (citations omitted).

regional practices by requiring all of its participants to rely very heavily on firm transmission. Under the WRAP Tariff's FS Transmission Requirement, each LRE must procure firm transmission at least seven months before the beginning of each Binding Season for at least 75% of its load obligations with very limited exceptions that cannot be consistently relied upon.[6]

In NIPPC's view, the underlying assumption that adequate firm transmission will be available for all LREs to reserve at least seven months in advance to consistently meet WRAP's FS Transmission Requirement has a meaningful probability of being wrong. The lack of adequate firm transmission in the region for purposes of widespread WRAP compliance by all LREs in the region was demonstrated during the informal rulemaking phase in this proceeding. As NIPPC and Calpine explained, Portland General Electric Company's ("PGE") recent regulatory filings succinctly summarize the lack of incremental firm transmission available to parties who do not already hold such firm transmission rights.[7] PGE's 2023 Clean Energy Plan-Integrated Resource Plan ("CEP-IRP") explains:

> Resource portfolios have grown and shifted in response to increasing loads, new large and highly concentrated loads and the significant growth of variable energy resources. However, the delivery capabilities of the Pacific Northwest's transmission system, generally, have not kept pace with these changing demands. *As a result,* ***the region is already constrained, with <u>little or no ATC available across all time horizons</u>***.
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> As discussed by BPA and stakeholders throughout BPA's Transmission Study and Expansion Process 2022 (TSEP), ***BPA's system is fully subscribed***, and *incremental transmission requests*

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[6] WRAP Tariff at §§ 14.2 ("The FS Deadline for each Binding Season shall be seven months before the start of such Binding Season.") and 16.3 (FS Transmission Requirement).

[7] Docket No. UM 2143, NIPPC's Comments at 4-7 (Sept. 18, 2023); Docket No. UM 2143, Calpine Solutions' Comments at 5-7 (June 12, 2023).

> *are unlikely to be granted until the late 2020s or early 2030s*, pending significant upgrades.[8]

BPA's own presentation of results from a recent transmission cluster study describes the situation as follows: "Near full-subscription all over the existing BPA transmission system."[9]

In another recent filing at the Federal Energy Regulatory Commission ("FERC"), PGE sought relief from the requirement to use firm transmission across BPA's system to support dynamic transfer/pseudo ties and BPA apparently agreed.[10] According to PGE's FERC filing, "the region's transmission system is already constrained, with little or no available transfer capability ('ATC') available across all time horizons."[11] PGE also stated that "[r]estricting Pseudo-Ties to the use of firm transmission would unduly constrain use of the regional transmission system …"[12] PGE states that a table included with the filing "clearly illustrates a constrained regional transmission system, especially on transmission paths impacting energy from outside the PGE service area."[13] PGE further concludes that "[t]here are no east to west unconstrained paths available to PGE[,]"[14] and "the region lacks sufficient firm transmission capacity to meet both Northwest utilities' projected load growth and carbon-reduction

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8 *In re PGE 2023 CEP and IRP*, Docket No. LC 80, PGE's CEP-IRP at 217 (Mar. 31, 2023) (emphasis added, internal citations omitted).

9 *TSEP Cluster Study Process Update*, BPA at slide 6 (Sept. 2022), https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/09-20-22-cluster-study-improvements-customer-update.pdf.

10 *See In re Portland General Electric Company*, FERC Docket No. ER23-1123, PGE's Response to Deficiency Letter (May 11, 2023).

11 FERC Docket No. ER23-1123, PGE's Response to Deficiency Letter at 2 (May 11, 2023).

12 FERC Docket No. ER23-1123, PGE's Response to Deficiency Letter at 2 (May 11, 2023).

13 FERC Docket No. ER23-1123, PGE's Response to Deficiency Letter at 4 (May 11, 2023).

14 FERC Docket No. ER23-1123, PGE's Response to Deficiency Letter at 4 (May 11, 2023).

requirements."[15] FERC granted PGE's request because, *inter alia*, "it reflects Portland's particular circumstances in a transmission-constrained region with limited firm transmission service availability on transmission paths that would deliver output from off-system resources to the Portland balancing authority area."[16]

PGE's assessments in its 2023 CEP-IRP and in FERC's own acknowledgment of the lack of incremental firm transmission reaching PGE's system provide important confirmation regarding the lack of adequate firm transmission in the region and should not give the Commission much comfort that all LREs, and particularly ESSs, will be able to reliably meet the WRAP's FS Transmission Requirement. Notably, ESSs are in a worse position than PGE or PacifiCorp because ESSs are not transmission providers who needed to invest in transmission assets as part of their obligation to provide service to their end use consumers or that have the capability expand their own transmission system to cure these problems. If the desire is for all LREs to rely so heavily on advanced procurement of firm transmission, ESSs must rely solely on the region's transmission providers to properly expand the transmission system to make that possible. Additionally, until the WRAP's recent creation of a firm transmission requirement for Resource Adequacy, ESSs have not necessarily had reason to acquire on their existing and prospective customers' behalf extensive firm transmission assets because the Northwest market has been able to successfully serve load without such heavy use of advance procurement of firm transmission.

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15 FERC Docket No. ER23-1123, PGE's Response to Deficiency Letter at 5 (May 11, 2023).

16 *Portland Gen. Elec. Co.*, 184 FERC ¶ 61,012 at P 12 (July 10, 2023) (letter order).

It is not a reasonable course of action at this time to lock in rules that tie an ESS's certification to operate in Oregon to compliance with WRAP or a parallel state program requirement that includes and even amplifies the most problematic firm transmission requirement from WRAP's current requirements. Making such a WRAP-only Resource Adequacy requirement a provision of becoming and maintaining good standing as an ESS in Oregon could create barriers to entry into Oregon's retail market and limit opportunities for customers.

It would be a mistake to assume that because WRAP is already FERC-approved, it is a suitable requirement to impose under Oregon law on all LREs. This is because one of the key premises of FERC's approval of the justness and reasonableness of the WRAP Tariff was its *voluntary* nature. While the WRAP Tariff was approved by FERC, it certainly was *not* approved by FERC as a mandatory compliance standard that must be used by all LREs in the region.

Notably, at FERC, NIPPC objected to the WRAP's stringent firm transmission procurement requirements, which may be practically infeasible in today's market and, in effect, shift transmission planning burdens onto LREs that are not transmission providers.[17] In response, FERC stated as follows: "Further, we disagree with NIPPC's argument that [Western Power Pool's] proposal inappropriately turns the Forward Showing Transmission Requirement into an extension of the planning function of transmission providers. Rather, the WRAP is a *voluntary* program that financially binds all participants to meeting capacity and transmission showing requirements that will, as a result, provide better information to state and local

17 *See, e.g.*, *In re Northwest Power Pool d/b/a/ Western Power Pool, Submission of Tariff to Establish Western Resource Adequacy Program*, FERC Docket No. ER22-2762, NIPPC's Comments at 3-6, 9-24 (Sept. 30, 2022).

regulatory agencies' planning processes."[18]

Thus, FERC approved the WRAP Tariff and excused its potentially infeasible transmission requirement because it was voluntary. This necessarily assumes that there would be other feasible alternatives and would not be the only option for any LRE, particularly ESSs, to meet their Resource Adequacy requirements. But under the Proposed Rules now before this Commission, compliance with the WRAP's potentially infeasible firm transmission requirement would be, for all practical purposes, mandatory.

In sum, NIPPC submits that available evidence does not support that adoption of the WRAP's voluntary FS Transmission Requirement as a mandatory Resource Adequacy compliance option is just and reasonable as the only option for ESS compliance, and the Commission should ensure other options will be made available in its administrative rules.

2. There Are Reasonable Alternative Resource Adequacy Compliance Options to WRAP Compliance

Two reasonable alternatives to ESS-supplied WRAP-compliant Resource Adequacy were proposed in the informal rulemaking phase and, as noted above, these options remain issues the Commission indicated it would consider in this formal rulemaking.[19] The Commission should adopt one of these proposals, or otherwise expressly set a date certain to revisit the rules to review whether the WRAP requirements are proving to be unworkable.

a. Capacity Backstop Charge: The Commission Should Adopt a Capacity Backstop Charge Payable by Direct Access Customers as a Resource Adequacy Compliance Option

The first proposed alternative is payment of a Resource Adequacy charge to the

[18] *Northwest Power Pool,* 182 FERC ¶ 61,063 at P 85 (Feb. 10, 2023) (emphasis added).
[19] Order No. 23-340 at 1.

applicable utility by the direct access customer. Notably, Staff's initial straw proposal in this proceeding included as one of the compliance options the payment of a "Capacity Backstop charge."[20] While the initial proposal needed certain refinements, Staff instead completely removed the Capacity Backstop Charge as an option in its February 17, 2023 updated straw proposal.[21] At that time, Staff explained that this "major change is to eliminate the capacity backstop charge in this filing while making it clear that an ESS can procure capacity from an IOU through a bilateral contract as a means of compliance."[22] NIPPC and others pointed out that it is not reasonable to expect that the utilities necessarily have any interest in selling excess WRAP-compliant capacity and transmission to their competitor ESSs to serve load within the same utility's own balancing authority, and further that the ESS and its customers may have no means of compliance if the ultimate provisions of the WRAP and products available in that program do not work for the particular ESS.[23] These concerns have not been resolved yet and

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20 *See* Docket No. UM 2143, Staff Straw Proposal, as amended by errata, at 6-7 (Oct. 5, 2022).

21 Docket No. UM 2143, Staff's Updated Process Proposal at 3 (Feb. 17, 2023).

22 Docket No. UM 2143, Staff's Updated Process Proposal at 3 (Feb. 17, 2023).

23 *See* Docket No. UM 2143, NIPPC's Comments at 4 (Mar. 13, 2023) (stating: "Simply stated, for the second option, a Commission-established RA backstop charge is necessary and appropriate to ensure that an ESS has the ability to acquire RA capacity at a just and reasonable price, especially to the extent that a utility has 'uncommitted supply' as recently proposed in Docket AR 651. Absent a backstop charge, regulated utilities would have no incentive to offer RA capacity to competitors." (internal footnote omitted)); *see also* Docket No. UM 2143, Calpine Solutions' Comments at 5-6 (Mar. 13, 2023) (making similar statements); Docket No. UM 2143, Brookfield Renewable Trading and Marketing LP's Comments at 3 (June 12, 2023) (stating: "Following the conclusion of transition charges, [Brookfield Renewable Trading and Marketing] supports a requirement that the utilities offer, through a negotiated rate, RA service to direct access customers, so that such customers have further choices, especially when their ESS is unable to participate in the WRAP."); Docket No. UM 2143, Brookfield Renewable Trading and Marketing LP's Comments at 8-9 ("The ability for a [direct access] customer to purchase RA from the utility is important because it provides optionality, which is consistent with state law, and

remain as a fundamental flaw with the Proposed Rules before the Commission.

b. Request for Offers ("RFOs"): Alternatively, the Commission Should at least Adopt Guidelines Governing a Utility's RFOs from ESSs to Purchase any Excess WRAP-compliant Resource Adequacy

The second proposed alternative to ESS-supplied WRAP-compliant Resource Adequacy was made by Calpine Solutions as a result of Staff's expressed disinterest in developing a Capacity Backstop Charge.[24] Building on Staff's own concept that the ESS could purchase WRAP-compliant capacity and transmission from the utility, Calpine Solutions proposed that the Commission adopt, at a minimum, workable guidelines that the rules require the utilities to follow in offering any excess WRAP-compliant capacity or transmission to ESSs. The goal of these guidelines is to deter the utilities from refusing a reasonable offer by an ESS to buy the utility's excess capacity and/or transmission.[25] This proposal was made as an alternative to be considered only if a fully developed, off-the-shelf Capacity Backstop Charge would not be recommended by Staff or adopted by the Commission.[26] The specific recommendation was that the rules should at least require the public utility to issue an annual RFO from ESSs to buy the utility's excess capacity or transmission that meets the WRAP's definition of Qualifying Resources for use in WRAP's FS Program and/or transmission rights meeting the WRAP's FS Transmission Requirement.[27]

However, Staff declined to include this alternative RFO proposal in the Proposed Rules.

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an additional avenue for ESS compliance with Oregon RA requirements." (internal footnote omitted)).

24 *See* Docket No. UM 2143, Calpine Solutions' Comments at 3-7 (July 21, 2023).

25 Docket No. UM 2143, Calpine Solutions' Comments at 3-7 (July 21, 2023).

26 Docket No. UM 2143, Calpine Solutions' Comments at 3-7 (July 21, 2023).

27 Docket No. UM 2143, Calpine Solutions' Comments at 3-7 (July 21, 2023) (*citing* WRAP Tariff, Definitions ("Qualifying Resource")); WRAP Tariff at Part II (FS Program Requirements); WRAP Tariff at § 16.3.

Staff raised concerns that a state-level RFO may impact the regional program without materially improving the ability of ESSs to procure capacity.[28] NIPPC, however, continues to agree with Calpine Solutions that those concerns are misplaced, and the state-level RFO would serve an important purpose if the Commission will not adopt a Capacity Backstop Charge payable by direct access customers to the utility. The incumbent utility is the most likely entity to control any excess WRAP-compliant generation and transmission deliverable to loads in its balancing authority. The utility is unlikely to choose to sell such resources to ESSs without any encouragement from the Commission through a state-mandated RFO.

The RFO proposal does not require the utility to sell excess capacity and transmission; it merely requires the utility to timely communicate the availability of any such excess capacity and transmission to ESSs, consider offers for the same from ESSs, and report back to the Commission on why the utility rejected any such offers. The goal is to provide transparency to the Commission and stakeholders as to whether the utility is managing its portfolio prudently and whether, as Staff appears to have assumed in drafting the Proposed Rules, the assumption that ESSs can easily obtain excess capacity and transmission bi-laterally from utilities is correct.

NIPPC notes that the RFO requirement would likely benefit cost-of-service customers by ensuring that the utility does not unreasonably decline to sell excess WRAP-compliant generation and transmission to willing buyers serving load in the same balancing authority. NIPPC assumes that the utilities have such excess capacity because direct access customers continue to pay transition charges for capacity that the utilities have claimed they acquired to

[28] Docket No. UM 2143, Staff Report at 6-7 (Sept. 11, 2023).

serve those customers that have left the utility system and is now deemed as excess.[29]

Staff has suggested that the Proposed Rules "as written allow this RFO proposal to be implemented in the future if it appears likely to aid in [Resource Adequacy] planning."[30] However, the Proposed Rules themselves only provide mandatory requirements to participate in WRAP or to otherwise meet the State Program Requirements. There is no mention in the Proposed Rules of development of a Capacity Backstop Charge, an RFO, or any other options. Staff's suggestion is of little comfort that such reasonable alternatives will be timely made available to ESSs and direct access customers, if the WRAP requirements prove unworkable as currently written. Thus, at a minimum, the Commission should set a date certain by which it will revisit this issue in the rules to review whether the WRAP's firm transmission requirement is workable in the evolving market.

3. Response to Commissioners' Questions Regarding Alternatives to WRAP-Style Compliance

As noted above, the Commission's order opening the formal rulemaking stated that "Rulemaking participants should review our questions and areas for comments as set forth in the September 21, 2023 Public Meeting discussion."[31] In this section, NIPPC responds to the Commission's areas for comment on the Capacity Backstop Charge and RFO proposals.

a. WRAP's Most Concerning Aspect: The FS Transmission Requirement is WRAP's Most Concerning Aspect

Chair Megan Decker requested that comments identify the most concerning aspect of the

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29 *See Calpine Energy Solutions LLC v. PUC*, 298 Or App 143, 149-50, 445 P3d 308, 312 (2019) (noting PacifiCorp described its five-year program's charges as "'intended to represent the fixed generation costs incurred by the company to serve all customers offset by the value of freed-up power made available by the departing customers ….'").

30 Docket No. UM 2143, Staff Report at 7 (Sept. 11, 2023).

31 Order No. 23-340 at 1.

WRAP.[32] As expressed at the public meeting and further explained in these comments, the most significant concern with the WRAP Tariff at this time is the FS Transmission Requirement. In particular, NIPPC and member ESSs are very concerned with the WRAP's heavy reliance on procurement of firm transmission in advance, coupled with BPA's practice of releasing of firm transmission only on the short-term market relatively close in time to the real-time market and a general tightening of the availability of firm transmission in the region.

b. PGE's New Load Direct Access ("NLDA") Resource Adequacy Charge ("RAD") Proposal: NIPPC and ESSs Opposed PGE's NLDA RAD Charge Because it was Offered as the Only Resource Adequacy Alternative and Reflected an Inflated Charge

Chair Decker requested explanation of how the current proposals have evolved from PGE's proposed RAD charge in its NLDA compliance proceeding (Docket No. UE 358), and whether PGE's RAD proposal in that docket would now be considered an acceptable charge.[33] NIPPC's current proposal to provide an additional Resource Adequacy compliance option to direct access customers is consistent with its positions taken in Docket No. UE 358 and the Commission's own order in that docket.

In Docket No. UE 358, PGE proposed the Commission's approval of the RAD as a mandatory charge to recover resource adequacy costs from all NLDA customers through Schedule 689. Under PGE's RAD proposal, there was no opportunity for the NLDA customer or its ESS to obtain an alternative to PGE-supplied resource adequacy. PGE initially estimated the RAD charge to be approximately $9.00 per kW-monthly on-peak demand based on the fixed

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32 Public Meeting Recording at 37:50 to 39:20, September 21, 2023.
33 Public Meeting Recording at 39:30 to 40:30, September 21, 2023.

costs of a new proxy capacity plant.[34] However, PGE proposed that if approved by the Commission for inclusion in Schedule 689, PGE would set the charge initially at $0.00, and explained it would determine the proper allocation of resource adequacy costs embedded within PGE's entire portfolio through a cost of service study in a future general rate case.[35] During the proceeding, PGE also conceded that, to the extent such a charge could eventually apply to five-year program customers, it would not apply to customers still paying transition charges because it "is fair that those customers, through their transition adjustments, are effectively paying for the cost of resource adequacy embedded in the utility's portfolio."[36]

While agreeing that Resource Adequacy is "an important objective," Staff, NIPPC, Calpine Solutions, and the Alliance for Western Energy Consumers ("AWEC") opposed adoption of PGE's proposed RAD charge in Docket No. UE 358 for a number of reasons.[37] Those reasons included the following points:

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34 *In re PGE, Advice No. 19-02 (ADV 919) New Load Direct Access Program*, Docket No. UE 358, Order No. 20-002 at 4 (Jan. 7, 2020); *see also* PGE Advice Filing No. 19-02 at 7.

35 Order No. 20-002 at 4; *see also* PGE Advice Filing No. 19-02 at 7; *see also* Docket No. UE 358, PGE's Opening Brief at 14 (Nov. 14, 2019) (proposing that a future general rate case "include a cost-of-service study that considers functionalized resource adequacy costs, and will include a rate spread/rate design approach that ensures customer prices accurately reflect their share of resource adequacy related costs").

36 Tr, p. 24:20 to 25:3, Docket No. UE 358 (Oct. 17, 2019) (Tinker); *see also* Docket No. UE 358, PGE/200, Sims-Tinker/10:17-19 ("[Long Term Direct Access] customers who are in their transition periods, are still contributing (through their transition adjustments) to energy and capacity resources planned and acquired for them.").

37 Order No. 20-002 at 5-7 (summarizing arguments).

- The direct access law allows for customers to procure capacity, as well as energy, from third party suppliers, whereas PGE's RAD framework would mandate PGE-supplied capacity as the only option.[38]
- PGE's proposed RAD charge had an unknown magnitude, and PGE did not even describe the rate calculation methodology in sufficient detail to provide sufficient evidence for the Commission to approve the charge.[39]
- The Commission's administrative rules, OAR 860-038-0740(3)(a), had already adopted a "New Large Load Direct Access Service Transition Rate", set at 20% of the utility's fixed generation costs for five years, to account for costs similar to resource adequacy costs—thus making PGE's RAD potentially duplicative.[40] PGE itself agreed that it was

38 *See* Order No. 20-002 at 6 (noting, "Staff contends that ORS 757.601 requires that all non-residential consumers shall be allowed direct access, including the right to purchase capacity services from a provider other than the incumbent, but that the capacity charges proposed by PGE would require NLDA to obtain capacity-related services from PGE."); Calpine Solutions' Opening Brief at 7-8, Docket No. UE 358 (Nov. 14, 2019) (arguing "the law requires that non-residential customers be allowed to purchase 'electric energy . . . or electric capacity . . . or both' from the market through direct access." (quoting ORS 757.600(14)).

39 *See* Docket No. UE 358, Staff's Opening Brief at 18-22 (Nov. 14, 2019) ("It has been difficult to pinpoint exactly what NLDA customers would be paying for through the RAD charge, as PGE's position seems to have evolved over time."); Docket No. UE 358, Calpine Solutions' Opening Brief at 10 (Nov. 14, 2019) (arguing that "PGE also proposed the charge before completing the necessary cost-of-service study to support PGE's own proposal[,]" and "the record is simply insufficient to approve PGE's proposed RAD charge as just and reasonable"); Docket No. UE 358, AWEC's Reply Brief at 11-12 (Nov. 26, 2019) ("Here, by contrast, PGE is asking the Commission to approve a charge without resolving, or even understanding, how the charge will be modeled").

40 Docket No. UE 358, NIPPC's Opening Brief at 8 (Nov. 14, 2019); Docket No. UE 358, Calpine Solutions' Opening Brief at 14-15 (Nov. 14, 2019); *see also In re Rulemaking Related to a New Large Load Direct Access Program*, Docket No. AR 614, Order No. 18-341 at 2-3 (Sept. 14, 2018) (noting the NLDA transition rate was intended to account for "procurement of reserves that, in part, serve the purpose of facilitating default service, if necessary" and the "inherent risk to the system associated with the NLDA program").

duplicative and that the NLDA transition rate should be credited against the proposed RAD charge.[41]

- The Commission had recently opened Docket No. UM 2024, where parties argued that the resource adequacy issue should be *holistically* addressed for all direct access programs, not just the NLDA program.[42]
- PGE's proposed RAD framework was premature because "[u]ntil such time as the Commission defines the resource adequacy goals it seeks to accomplish, it is not possible to reasonably develop a resource adequacy requirement for ESSs or to develop a just and reasonable capacity charge to be assessed to direct access customers that choose to obtain such a product from PGE instead of an ESS."[43]
- NLDA program caps mitigated any urgency in addressing resource adequacy before approving PGE's NLDA program.[44]

The Commission rejected PGE's RAD charge in Order No. 20-002.[45] The Commission agreed that PGE had not defined resource adequacy sufficiently to provide a "basis for us to explore the feasibility of allowing direct access customers to choose how to support [Resource Adequacy] on their own."[46] The Commission also expressed a preference to explore adoption of "a framework that sufficiently supports reliability while giving customers the opportunity to

41 Docket No. UE 358, PGE/100, Sims-Tinker/18:2-4.
42 Docket No. UE 358, Staff's Reply Brief at 2-4 (Nov. 26, 2019) (arguing "it is more efficient for the Commission to make a single policy determination about reliability charges in a generic proceeding, such as UM 2024"); Docket No. UE 358, NIPPC's Opening Brief at 7 (Nov. 14, 2019); Docket No. UE 358, Calpine Solutions' Opening Brief at 6 (Nov. 14, 2019).
43 Docket No. UE 358, Calpine Solutions' Opening Brief at 9 (Nov. 14, 2019).
44 Docket No. UE 358, NIPPC's Opening Brief at 9 (Nov. 14, 2019).
45 Order No. 20-002 at 8-12.
46 Order No. 20-002 at 8.

deploy resources or tools of their own choosing."[47] The Commission "put all NLDA and [Long Term Direct Access] customers on notice . . . that it is our intention to ensure that all system participants contribute tangibly to BA [Resource Adequacy]," and it explained that "though PGE's NLDA program will commence without the RAD charge, should a similar charge be justified in the future it may be imposed on all customers enrolled in the program or, in the alternative, actions or charges may be imposed on NLDA customers or their supplier ESSs following the completion of the UM 2024 investigation."[48]

Thus, Staff, ESS parties, and direct access customer advocates did not oppose the concept of providing a utility-supplied resource adequacy option, but instead they opposed PGE's proposed RAD framework on the ground that it prematurely proposed PGE-supplied resource adequacy as the *only* option. And the Commission agreed by expressing its own "strong preference for solutions that give direct access customers the opportunity to choose how they support [Resource Adequacy], *whether that be through the utility, third parties, demand response, customer-sited resources, curtailment, or a combination*."[49]

Given that background, arguments made in Docket No. UE 358 and the Commission's order in that proceeding are consistent with the proposal here to provide direct access customers the option to pay a Capacity Backstop Charge, or alternatively, to adopt an RFO framework to facilitate sale of any excess WRAP-compliant capacity or transmission to ESSs by utilities. Indeed, the Commission's Order No. 20-002 expressly contemplated giving direct access customers the option of procuring Resource Adequacy through an ESS or "through the utility."[50]

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47 Order No. 20-002 at 8.
48 Order No. 20-002 at 8.
49 Order No. 20-002 at 9 (emphasis added).
50 Order No. 20-002 at 9.

Now that the Commission has more fully defined the Resource Adequacy expectations through adoption of WRAP-style framework, development of the proposed Capacity Backstop Charge should be much easier than it would have been in Docket No. UE 358, which occurred before the WRAP existed and where PGE had articulated only a broad, conceptual idea for such a charge.

Finally, in response to Chair Decker's question as to whether PGE's RAD proposal of a $9.00 per kW-month would be accepted today, NIPPC doubts that a $9.00 per kW-month charge would be found to be just and reasonable. As noted above, PGE itself provided the $9.00 per kW-month charge as an indicative cost based on the fixed costs of a new gas-fired power plant at the outset of the proceeding. But PGE later conceded in Docket No. UE 358 that the charge should be calculated based on just the portion of its generation portfolio costs that could be properly allocated to Resource Adequacy services for direct access customers. PGE also conceded that customers paying the transition charges in the five-year program would not be subject to an additional Resource Adequacy charge, and that the NLDA transition rate would be credited against the RAD charge. However, because PGE's proposal was premature and incomplete, no other party proposed any alternative rate calculation adjustments. NIPPC anticipates that additional adjustments would be necessary to ensure that a Capacity Backstop Charge accurately reflects the costs of providing the resource adequacy service for direct access customers. These are issues that could be resolved in Docket No. UM 2024 or another appropriate rate proceeding.

c. Consistency with Competitive Framework: A Capacity Backstop Charge or an RFO Requirement are Consistent with the Direct Access Law and Would Support a Competitive Retail Market

Chair Decker requested explanation of how requiring the electric companies to offer capacity to direct access customers (the Capacity Backstop Charge), or to the ESSs (the RFO proposal) is consistent with the notion of the competitive market and NIPPC's competitive principles.[51]

As the foregoing discussion alludes to, providing direct access customers with an additional option to meet the newly required Resource Adequacy requirements is consistent with the policies underlying a competitive retail market because it provides an additional option to direct access customers. The Commission has long recognized that direct access is intended to provide optionality to customers.[52] NIPPC agrees that it would be preferable that the Resource Adequacy product required for compliance with the Commission's rules would be readily available from multiple suppliers in the competitive market, but there is a reasonable likelihood that will not be the case, at least with respect to the WRAP-style firm transmission requirement. Given that risk, requiring a utility backstop offering is necessary to ensure that competitive retail market opportunities exist for other supply options.

Fundamentally, the problem is that WRAP has adopted a new requirement that has not previously been required—firm point-to-point transmission procured several months in advance––and this Commission's adoption of that same requirement would make firm transmission procurement a de facto requirement to participate in Oregon's long-term direct access market as

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51 Public Meeting Recording at 40:30 to 41:00, September 21, 2023.

52 *See In re PGE's Customer Choice Pilot Program, In re PacifiCorp's Petition for Declaratory Ruling Regarding the Applicability of ORS 757.205 and 757.225 and ORS 757.310 to 757.330 to Direct Access Pilot Programs*, Docket Nos. UE 101 & DR 20, Order No. 97-408, 1997 Ore. PUC LEXIS 250 at **17-18 (Oct. 17, 1997) ("One customer may want firm power, another may want interruptible, a third may want a 50-50 blend of firm and interruptible, and a fourth may want a different blend of firm and interruptible. Other customers may want to combine buying electricity with a purchase of natural gas or other energy services. Even customers who may want the same service may contract for that service at different times, when the market prices of those services are different. The possibilities are endless.").

an ESS. This challenge is more acute for ESSs, who would be expected to rely more heavily on BPA to reach the direct access loads from market hubs, and who have not previously had reason to reserve extensive long-term, firm, point-to-point transmission capacity for at least 75% of their existing or potential future loads. In contrast, the incumbent utilities have significant native load not eligible for long-term direct access programs to justify substantial procurement of long-term, firm, point-to-point transmission to the extent it is needed for their off-system resources. For example, PGE's 2023 CEP-IRP reports that "PGE currently holds over 4,000 MW of long-term firm transmission under contract with BPA."[53] The incumbent utilities also would be expected to inherently rely less on BPA transmission than ESSs due to their reliance on substantial generation resources connected to their own systems.

Without requiring incumbent utilities to offer a backstop charge to enable direct access customers to also be assured they can meet the Commission's new Resource Adequacy requirement, it appears that new WRAP-style firm transmission requirement may impair the option for customers to enter, or remain in, the retail market. With a Capacity Backstop Charge, customers would still have extensive retail choice to purchase their chosen energy supply from various ESSs; but without the Capacity Backstop Charge, it appears likely that retail choice could be severely hampered if ESSs are not able obtain the firm transmission. Thus, it is consistent with competitive principles to enable meaningful continued participation in the competitive market while the region undertakes to expand the transmission system to make firm transmission available in the market.

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53 *In re PGE 2023 CEP and IRP*, Docket No. LC 80, PGE's CEP-IRP at 217 (Mar. 31, 2023).

Additionally, requiring the incumbent utility to offer a cost-of-service capacity product while the customer purchases its energy supply in the competitive market is consistent with Oregon's statutory framework. The direct access law provides: "All retail electricity consumers of an electric company, other than residential electricity consumers, shall be allowed direct access beginning on March 1, 2002."[54] "Direct access" is specifically defined to mean "the ability of a retail electricity consumer *to purchase electricity* and certain ancillary services, as determined by the commission for an electric company . . . directly from an entity other than the distribution utility."[55] In turn, "Electricity" is defined as "electric energy, measured in kilowatt-hours, *or* electric capacity, measured in kilowatts, *or both*."[56] Thus, the law requires eligible customers must be provided "the ability . . . to purchase electricity",[57] including "electric energy, measured in kilowatt-hours, *or* electric capacity, measured in kilowatts, *or both*"[58] from an ESS. The precisely phrased words in the law clearly contemplate the customer having the option to purchase only energy from an ESS and continuing to purchase capacity from the utility.

d. Risk of "Arbitrage": Commissioner Tawney's Concern with Risk of Arbitraging Resource Adequacy Options Can Be Eliminated with Significant Notice Periods Prior to Switching Resource Adequacy Elections

Commissioner Letha Tawney expressed a concern with giving direct access customers the option of "arbitraging" between cost-of-service and competitive Resource Adequacy options to the potential detriment of other customers and reliability.[59] NIPPC submits that the risk of

54 ORS 757.601(1).
55 ORS 757.600(6) (emphasis added).
56 ORS.757.600(14) (emphasis added).
57 ORS 757.600(6).
58 ORS.757.600(14) (emphasis added).
59 Public Meeting Recording at 1:18:08 to 1:19:05, September 21, 2023.

customers arbitraging can be eliminated by requiring significant notice requirements for customers to switch from ESS-supplied to utility-supplied Resource Adequacy. NIPPC envisions a framework where the notice required to switch Resource Adequacy provider would be similar to the notice period to switch back and forth from cost-of-service to direct access service. Adequate notice periods will give the utility time to adjust its portfolio, and there should be no risk to other customers.

e. Modifications to WRAP Tariff: NIPPC Agrees with Then-Commissioner Thompson's Suggestion That the WRAP Tariff Should Be Corrected, but neither NIPPC nor the Commission Has the Power to Do So

At the public meeting, then-Commissioner Mark Thompson asked parties to address whether, in lieu of providing compliance alternatives to WRAP's requirements, it would be more appropriate to work to address any flaws with WRAP's firm transmission requirement through the WRAP.[60] As explained below, NIPPC would certainly support revising WRAP's firm transmission requirement, but does not support deferring development of a Capacity Backstop Charge or alternative RFO requirement in the hopes of successfully changing the WRAP Tariff.

NIPPC engaged in the WRAP process as a non-LRE and consistently expressed its concerns with WRAP's firm transmission requirement during the development phase of the program.[61] After the WRAP Tariff was submitted for FERC approval, NIPPC protested approval of the firm transmission requirement and, more specifically, the limited opportunity for use of exceptions to the FS Transmission Requirement. However, as noted above, FERC

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60 Public Meeting Recording at 1:08:35 to 1:09:05, September 21, 2023.

61 *See* Docket No UM 2143, NIPPC's Comments at 1-2 & Appendix at 2 (Nov. 18, 2021) (containing NIPPC's comments to WRAP during the program's development phase, which opposed the 75% source to sink firm transmission requirement due in the Forward Showing timeframe).

approved the WRAP Tariff, including the firm transmission requirement, and rejected NIPPC's arguments specifically on the ground that the WRAP Tariff is a voluntary program, not a mandatory requirement on all LREs.

Given that NIPPC, its ESS members, and the Commission have no direct power to change the WRAP Tariff, NIPPC discourages the Commission from approving the Proposed Rules without change in the hopes that the WRAP Tariff will be altered. To the extent the FS Transmission Requirement may prove to be impossible for certain existing or prospective WRAP participants, there is no reason to assume WRAP will take steps to make compliance feasible because, as FERC noted in approving the WRAP Tariff, it is a voluntary program. WRAP is also a membership-based program that is made up largely of traditional vertically-integrated utilities who likely have less difficulty complying with the FS Transmission Requirement than ESSs and apparently had fewer structural concerns with the FS Transmission Requirement during the WRAP Tariff's development. Thus, it would appear to be very unlikely that the WRAP Tariff will be changed in response to concerns of a small minority of existing participants.

The Commission should also not defer solely to the WRAP process because doing so would be inconsistent with Oregon law and policy encouraging retail markets. In contrast to WRAP, this Commission has a responsibility to "eliminate barriers to the development of a competitive retail market between electricity service suppliers and electric companies."[62] At a minimum, the Commission should not harm the existing retail market. That is a state responsibility that other states do not share within WRAP's footprint. And WRAP's

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[62] ORS 757.646(1).

requirements, and Resource Adequacy generally, do not supersede this Commission's statutory directive to eliminate barriers to a competitive retail market. Instead, the goals of ensuring resource adequacy and encouraging retail competition must be reconciled.

In this case, reconciliation requires not second-guessing WRAP per se, but including a secondary option for Resource Adequacy in Oregon that addresses the market power of the utilities in the current bilateral market for Resource Adequacy and transmission. It is not WRAP's responsibility to protect retail competition in Oregon, nor is the incumbent LRE-driven membership approach of WRAP designed to protect retail competition. WRAP is currently structured to allow utilities in general to override ESSs who have a small minority of votes on the program's critical decision-making Resource Adequacy Participant Committee.[63, 64] In short, WRAP is not designed to satisfy the Commission's obligation in Oregon's direct access law to "mitigate the vertical and horizontal market power of incumbent electric companies …."[65] If the region ever moves to an RTO, this interim step of WRAP, with bilateral transmission sales and scheduling of contract paths, would likely be resolved. In the meantime, WRAP has improved

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63 The ESS LREs are outnumbered by traditional utility LREs by two to 18 in WRAP's currently participant pool. Current WRAP participants include eight investor-owned utilities, 10 consumer owned utilities or power marketing agencies, and only two independent power producers or ESSs. The current participants are as follows: Arizona Public Service Company, Avista, BPA, Calpine, Chelan Public Utility District, Clatskanie Public Utility District, Eugene Water and Electric Board, Grant Public Utility District, Idaho Power Company, NorthWestern Energy, NVEnergy, PacifiCorp, PGE, Powerex, Puget Sound Energy, Salt River Project, Seattle City Light, Shell Energy, Snohomish County Public Utility District, and Tacoma Power. *See Westen Resource Adequacy Program*, Western Power Pool, available at: https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

64 *See* WRAP Tariff at § 4.1.1 ("The RAPC shall be the highest level of authority for representation of Participants in the WRAP governance structure and shall represent the interests of Participants directly to the Board of Directors").

65 ORS 757.646(1).

the chance of maintaining reliability but also created a new opportunity for intentional or coincidental exercise of market power by incumbent transmission owners and holders of transmission rights that states with retail choice need to guard against.

In sum, while NIPPC agrees with and supports the objective of revising WRAP's firm transmission requirement, the Commission should not defer to WRAP to correct the firm transmission requirement, or any other program elements, which may frustrate retail choice in Oregon.

B. Additional Clarifications: The Proposed Rules Contain At Least Four Other Areas Needing Further Clarification

Although many important details regarding the new Resource Adequacy requirements were clarified in the informal rulemaking stage, the Proposed Rules still contain at least four other issues that should be further clarified before the rules become binding.

1. Applicable Direct Access Loads: The Proposed Rules Should Be Revised to Clarify that the Incumbent Utility Will Be the Provider of Resource Adequacy to Customers in the One-Year and Three-Year Direct Access Programs, as well Five-year Program Customers Still Paying Transition Charges

For the reasons explained in this section, the Proposed Rules should clearly state that the incumbent utility is the entity responsible for providing Resource Adequacy for customers enrolled in the one-year and three-year programs,[66] as well as five-year program customers still paying transition charges.

[66] NIPPC hopes issue of applicability of the rules to one-year and three-year customers is just a clarification. The issue was raised in the informal phase of the rulemaking. *See* Docket No. UM 2143, Calpine Solutions' Comments at 10 (Nov. 21, 2022). No party appeared to oppose excluding the one-year and three-year program customers from the ESS's resource adequacy obligations. However, the final rules do not clearly include any clarification on this important issue. The Commission should clarify the point in the final administrative rules.

a. One-Year and Three-Year Program Customers

The Commission's extant orders require the incumbent utility to include the load of one-year and three-year program customers as the utility's load for planning purposes in its integrated resource plan ("IRP"). Under the Commission's IRP Guideline 9, "An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier."[67] The Commission stated that because "a customer signed up for direct access under the existing one- or three-year options as 'effectively committed to service' from an ESS only during that contract period," the incumbent utility must include those customers in their IRP's load-resource balance.[68] In contrast, customers in a five-year opt-out program "are 'effectively committed to service' under direct access and should be excluded from the IRP load-resource balance over the planning horizon, until they provide notice of their return to cost-of-service status."[69] That means the transition charges paid by one-year and three-year program customers include the capacity costs of the utility's existing and planned generation resources. As PGE's direct access website states, "[t]he transition adjustment for the 3-year opt out will incorporate costs for both existing *and new resources*, if any, expected to begin providing service to customers during the 3-year term and will be known at the time the customer opts-out."[70] Thus, only customers enrolled in the five-year program and the New

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67 *In re OPUC Investigation Into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at 19 (Jan. 8, 2007); *In re OPUC Investigation Into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-047, Appendix A at 6 (Feb. 9, 2007).

68 Docket No. UM 1056, Order No. 07-002 at 19.

69 Docket No. UM 1056, Order No. 07-002 at 19.

70 *Market-Based Pricing FAQ*, PGE at "Are the Schedule 129 transition adjustments different for the 3-year or 5-year opt out?" (emphasis added), available at: https://portlandgeneral.com/about/info/pricing-plans/market-based-pricing/market-based-pricing-faq.

Large Load Direct Access programs are excluded from the incumbent utility's generation planning and are ever relieved of the costs of the utility's acquisition of long-term capacity resources.

The Commission's Resource Adequacy rules should follow this same framework. Because the utility will include one-year and three-year program customers in their IRP's load-resource balance, those one-year and three-year program customers should also be included by the utility in its load-resource balance in its Resource Adequacy Informational Filing and in its Forward Showing for the Regional Program or State Program. That treatment is consistent with the ongoing payments for the utility's capacity through transition charges. Requiring the one-year and three-year program customers to also pay an ESS to supply WRAP-compliant Resource Adequacy (through the Regional Program or State Program) would charge such customers twice for the same product. Additionally, although a one-year or three-year program customer receives a credit for the value of the energy that can be produced and sold on the market from utility's generation resources freed up by their direct access election, the customer must compensate the utility for any extra energy costs associated an early return to cost-of-service rates if it is allowed to return to cost-of-service rates during the one-year or three-year term.[71] Thus, in addition to paying for the utility's capacity resources through the transition charges, the one-year and three-year program customers are required to insulate non-participating customers from harm of extra energy costs associated with an early return.

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[71] *See PacifiCorp Schedule 201* at 4 (charging a "Returning Service Payment" for "the increased cost of serving such returning Consumer due to an increase in market price as compared to the market price used in determining the Consumer's applicable transition credit as specified under Schedule 294.") available at: https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rates/201_Net_Power_Costs_Cost-Based_Supply_Service.pdf.

Logistical and implementation considerations also support requiring the incumbent utility to supply the Resource Adequacy for the one-year and three-year program customers. It would be difficult for an ESS to cost-effectively plan for and provide Resource Adequacy to one-year and three-year program customers. During much of the one-year or three-year term of service, the ESS would not have adequate notice of whether to include the customer in its Forward Showing in the Regional Program or State Program because it is expected that the customer will return to utility service at the end of its one-year or three-year term. Thus, at a minimum, the Commission would need to carefully work through the logistical issues with requiring an ESS to provide Resource Adequacy for one-year or three-year program customers—if that is indeed the intent of the Proposed Rules.

For example, consider a PacifiCorp customer electing to enroll in the one-year program for the 2025 term of service. Such a customer would enroll in the program during an election window beginning on November 15, 2024, and it would thereafter be committed to buying energy supplied by the ESS only during January 1, 2025, through December 31, 2025.[72] But an ESS's Forward Showing for WRAP's Summer Season (June 1 to September 15, 2025) would have been due by November 1, 2024[73]—before the customer even enrolled in the one-year program.

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72 *PacifiCorp Schedule 294* at 1, available at: https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rates/294_Transition_Adjustment.pdf (providing transition adjustment rates "for the 12-month period from January 1 through December 31 of the calendar year subsequent to the announcement date"); *see also 2024 Power Options*, Pacific Power at 1, available at: https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/savings-energy-choices/oregon-direct-access/PP_OR_DirectAccess_Booklet_2024.pdf.

73 WRAP Tariff at §§ 14.1-14.2.

The ESS cannot reasonably be expected to include that customer in its Summer Season Forward Showing due on November 1 before the customer has even enrolled in direct access or committed to buy from the particular ESS. The final details of when load forecasts may be updated are still under development in WRAP's business practice manuals.[74] Regardless, the new one-year program customer cannot be included in the ESS's 2025 Summer Season Forward Showing in WRAP. Additionally, the ESS could not reasonably plan for the customer's load during the subsequent Forward Showing for WRAP's Winter Season, which would run from November 1, 2025, to March 15, 2026, because the one-year term of direct access service ends December 31, 2025. While the customer could theoretically begin a new term of direct access service by so electing in the enrollment window beginning November 15, 2025, the ESS would not be aware of that election at the time its Winter Season Forward Showing is due on April 1, 2025. Similar timing and logistical issues would exist for the first and last years of any three-year customer's three-year term on direct access.

It appears that the logistical situation with PGE's programs would be even more complicated because PGE has three election windows each year.[75] Unlike PacifiCorp's one-year program, PGE's "short-term" direct access customers end a direct access term by electing to return to cost-of-service during the November window,[76] but the PGE customer enrolled in

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74 WRAP Tariff at § 16.1.1; *see also Western Resource Adequacy Program Detailed Design*, Western Power Pool at § 2.2 (March 2023), available at: https://www.westernpowerpool.org/private-media/documents/2023-03-10_WRAP_Draft_Design_Document_FINAL.pdf.

75 *See Market-Based Pricing FAQ*, PGE at "When are Election Windows?", available at: https://portlandgeneral.com/about/info/pricing-plans/market-based-pricing/market-based-pricing-faq.

76 *See Market-Based Pricing FAQ*, PGE at "When are Election Windows?", available at: https://portlandgeneral.com/about/info/pricing-plans/market-based-pricing/market-based-pricing-faq.

short-term direct access still has the right to return to service after the first one-year period. And PGE's three-year program customers are similarly expected to return to cost-of-service after the end of their three-year term.

b. Five-Year Program Customers Still Paying Transition Charges

Five-year program customers still paying transition adjustments should also be covered by the incumbent utility's Resource Adequacy showings and not also included within an ESS's Resource Adequacy showings.[77] Five-year program customers still continue to pay for the utility's resources during the five-year period, including resources planned prior to their departure that come online during the five year period.[78] As noted above, PGE itself agreed during the debate over its proposed RAD charge for NLDA customers that, to the extent such a charge could eventually apply to five-year program customers, it would not apply to customers still paying transition charges because it "is fair that those customers, through their transition adjustments, are effectively paying for the cost of resource adequacy embedded in the utility's portfolio."[79] Requiring such customers to pay the transition charge while also paying their ESS to procure capacity would therefore result in a double charge. Additionally, the same logistical issues with the first year after the initial direct access election (as described above) will apply

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77 The situation with a five-year program customer is distinct from that of a one-year and three-year program customers because, as noted above, the utility stops planning for the five-year customer's load in its IRP during the customer's five-year transition period.

78 *Market-Based Pricing FAQ*, PGE at "Are the Schedule 129 transition adjustments different for the 3-year or 5-year opt out?" (emphasis added), available at: https://portlandgeneral.com/about/info/pricing-plans/market-based-pricing/market-based-pricing-faq (stating, "The transition adjustment for the 5-year opt-out will reflect only those resources that have been approved by the OPUC (Oregon Public Utilities [sic] Commission); however, it will be adjusted during the 5-year term to reflect any new generation resources approved by the OPUC.").

79 Tr, p. 24:20 to 25:3, Docket No. UE 358 (Oct. 17, 2019) (Tinker).

equally to the five-year program customer. Thus, NIPPC recommends that the incumbent utility should remain the Load Responsible Entity in WRAP or the State Program for five-year program customers still paying transition charges.

In the alternative, at the minimum, the rules should not require the ESS to be the Load Responsible Entity for newly enrolled five-year program customers until after completion of the first Summer Season in the WRAP. As explained above with respect to newly enrolled one-year and three-year program customers, the ESS cannot reasonably be required to include such new direct access customer within its Summer Season Forward Showing due to WRAP on November 1, before the customer enrolls and contracts with the ESS in the first place in PacifiCorp's election window that opens on November 15.

c. NIPPC's Recommended Edits to the Proposed Rules

For the reasons set forth above, NIPPC recommends the following edits to clarify the applicability of the rules:

> Proposed OAR 860-095-010(16) "Regional Participant" means a Load Serving Entity that is a participant in or is officially committed to becoming a participant in a Qualified Regional Program at least 30 days prior to the Binding Forward Showing filing date of the State Program. <u>A Regional Participant that is an electric company must include in its Regional Forward Showing the loads for which it has long-term planning responsibility in its Integrate Resource Plan and five-year program customers paying transition adjustment charges. A Regional Participant that is an electricity service supplier must include in its Regional Forward Showing the loads of customers contracted to purchase electricity from the ESS during the forecast period that are enrolled in the new large load direct access program and customers enrolled in the five-year program that are no longer paying transition adjustment charges.</u>
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> * * * *
>
> Proposed OAR 860-095-0020(2) The Informational Filing for an Electric Company must include:
> (a) A monthly P50 Peak Load Forecast <u>of cost-of-service and direct access loads for which the electric company has long-term planning responsibility in its Integrated Resource Plan and five-year program customers paying transition adjustment charges</u> and Effective Load Carrying Capability curve over a period of the greater of four years or the

longest available timeline from a Qualified Regional Program using methods consistent with outputs of the Qualified Regional Program's Advisory Forecast.

* * * *

Proposed 860-095-0030(2) (2) The Informational Filing for an Electric Service Supplier must include:
(a) A monthly P50 Peak Load Forecast of loads of customers contracted to purchase electricity from the ESS during the forecast period that are enrolled in the new large load direct access program and customers enrolled in the five-year program that are no longer paying transition adjustment charges and Effective Load Carrying Capability curve over a period of the greater of four years or the longest available timeline from a Qualified Regional Program using methods consistent with outputs of the Qualified Regional Program's Advisory Forecast.

* * * *

Proposed 860-095-0040(4) (4) State Participants must use a Planning Reserve Margin and Qualified Capacity Contribution consistent with a Qualified Regional Program or other Commission-approved methodology. A State Participant that is an electric company must include within its load forecasts all loads for which it has long-term planning responsibility in its Integrate Resource Plan and five-year program customers paying transition adjustment charges. A Regional Participant that is an electricity service supplier must include within its load forecasts the loads of customers contracted to purchase electricity from the ESS during the forecast period that are enrolled in the new large load direct access program and customers enrolled in the five-year program that are no longer paying transition adjustment charges.

2. Protected Treatment of ESS Filings: The Proposed Rules Should Be Revised to Provide the Same Confidentiality Protections of an ESS's Informational Filing as Was Adopted with Respect to an ESS's Emissions Planning Reports

The Proposed Rules contain a requirement that ESSs submit a Resource Adequacy Informational Filing with the Commission every other year and state that such Informational Filing "may be filed as a part of the Emissions Planning Report filing."[80] The Informational Filing will contain commercially sensitive information, including a discussion of how the ESS's resource strategy interacts with Resource Adequacy concerns, a load forecast, a discussion of existing transmission rights, a discussion of the strategy to secure additional transmission rights,

[80] Proposed OAR 860-095-0030(1)(a).

a discussion of the expected constraints or difficulties filling any open positions, and the most recent forward showing submission to the Qualified Regional Program.[81] The rules must provide adequate protection for such commercially sensitive information to prevent harm that would result from disclosure of market positions and strategies for compliance. It is imperative that such information be shielded from an ESS's competitors, potential supplier Counter parties, and its existing and potential customers. However, as explained below, the Proposed Rules do not provide such protection.

It is important to bear in mind that ESSs are different from Oregon's investor-owned utilities in that ESSs must compete with each other for all of their load, and ESSs therefore have a very strong interest in shielding their market position and compliance strategies from such competitors. In contrast, while the utilities have commercially sensitive information, the utilities also have a much larger captive customer base that is not potentially at risk of switching to another supplier (i.e., all load not eligible for available direct access programs) and have far more market power in the wholesale market than Oregon's ESSs. Thus, it is not necessarily reasonable to expect the level of transparency in the utility's public resource planning filings for ESSs or to presume that it would be reasonable to require ESSs to publicly publish their Resource Adequacy positions and strategies in the same manner that an investor-owned utility might in an integrated resource plan.

The Commission has already recognized the need to protect commercially sensitive data of ESS's in its recent promulgation of the rules governing Emissions Planning Reports. Indeed, given that the Resource Adequacy Information Filing at issue will be filed with the Emissions

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[81] Proposed OAR 860-095-0030(1)(b), (2)(a)-(b), & (4).

Planning Report,[82] it would be logical to expect that the same rules governing confidential treatment of the commercially sensitive information would apply to both the Informational Filing and the Emissions Planning Report. The Emissions Planning Report will even contain some of the very same commercially sensitive information required in the Informational Filing, including the following items: "[a] load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers"[83], and "[a]n action plan that specifies annual goals and resources, including specified and unspecified market purchases, that the ESS plans to use to meet the load and emissions forecast consistent with the [Department of Environmental Quality 'DEQ'] emissions reporting methodology[.]"[84]

The Emissions Planning Report rules contain detailed specifications for protective orders governing disclosure of this material by an ESS, and the rules also state the Commission will develop a unique protective order for such proceedings.[85] The rules for protective treatment of ESSs' Emissions Planning Reports were collaboratively developed by ESS representatives and public interest parties with an interest in reviewing the material, and those provisions were ultimately uncontested in the rulemaking and approved by the Commission. The Emissions Planning Report rule states:

> (8) Availability of Information:
>
> > (a) Information regarding an analysis of the $/MWh (levelized if under different pricing structure) that the customer will be charged for service related to

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[82] *See* Proposed OAR 860-095-0030(1)(a) ("The Informational Filing may be filed as part of the Emissions Planning Report filing.").

[83] OAR 860-038-0405(3)(c); *see also* Proposed OAR 860-095-0030 (2)(a) (requiring load forecast in Resource Adequacy Informational Filing).

[84] OAR 860-038-0405(3)(e); *see also* Proposed OAR 860-095-0030 (2)(b) (requiring discussion of strategy to fill open positions in Resource Adequacy Informational Filing).

[85] OAR 860-038-0405(3)(a) ("A uniform template for the cover page checklist and Protective Order will be provided on the Commission website under the Reports & Forms section").

> compliance for each of the next 3 years, as required by section 3(f) of this rule will be available for review only by Qualified Statutory Parties, meaning any Commission Staff and any representatives of the Citizen's Utility Board, who executed a modified protective order.
> (b) The following information shall be available for review only by Non-Market Participants that have executed a modified protective order:
>> (A) Action plan that specifies annual goals and resources, including specified and unspecified market purchases, that the ESS plans to use to meet the load and emissions forecast consistent with the DEQ emissions reporting methodology, as required in Section 3(e) of this rule;
>> (B) Information regarding the load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers, as required by Section 3(c) of this rule; and
>> (C) The summary of the specific electricity-generating resources and MWh generation from those resources, as required by Section 3(b) of this rule.
>
> (c) For purposes of this rule. Non-Market Participants includes Commission Staff, the Citizen's Utility Board, and nonprofit organizations engaged in environmental advocacy that do not otherwise participate in electricity markets.[86]

However, Proposed Rule OAR 860-095-0030 does not adopt the same, uncontested framework for the Resource Adequacy Informational Filing as the administrative rules governing Emissions Planning Reports. It states only as follows:

> (4) A Regional Participant's most recent Regional Forward Showing submission to its Qualified Regional Program must be made available to Qualified parties [sic] upon request pursuant to a Modified Protected Order.

Qualified Parties are elsewhere defined as Staff and the Citizens' Utility Board ("CUB").[87] There are at least two distinct problems with how Proposed Rule OAR 860-095-0030 addresses protection of ESS's commercially sensitive information.

First, the treatment of access to an ESS's Regional Forward Showing submission to the Qualified Regional Program in Proposed Rule OAR 860-095-0030(4) is misworded if it was intended to be a limitation on access to parties other than the Qualified Parties (i.e., CUB and

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86 OAR 860-038-0405(8).

87 Proposed OAR 860-095-0010(13).

Staff). The wording of proposed rule requires this commercially sensitive material be provided to Qualified Parties, if they request it and sign the modified protective order, but the wording does not foreclose the potential requirement to also supply the material to other parties. That is in distinct contrast to the rules governing Emissions Planning Reports, which clearly state that *only* certain parties—CUB, Staff, and Non-Market Participants—may access the certain categories of commercially sensitive information. Thus, at a minimum, Proposed Rule OAR 860-095-0030(4) should be reworded to clearly state that parties other than Qualified Parties cannot obtain access to the ESS's Regional Forward Showing submission to the Qualified Regional Program.

Second, Proposed OAR 860-095-0030 does not place any restrictions at all on access to the other confidential material in the Informational Filing. Those other commercially sensitive items include the ESS's discussion of how the ESS's resource strategy interacts with Resource Adequacy concerns, a load forecast, existing transmission rights, strategy to secure additional transmission rights, and expected constraints or difficulties filling any open positions.[88]

As with the Emissions Planning Report rules, the Resource Adequacy Rules should affirmatively address all expected categories of commercially sensitive information and affirmatively state the parties to whom that material will, and will not, be provided. In particular, the rules on the Resource Adequacy Informational Filing should affirmatively state that only non-market participants may obtain commercially sensitive information and only after executing a modified protective order. The rules developed for confidential treatment of ESSs' Emissions Planning Reports were collaboratively developed by ESS representatives and public interest

[88] Proposed OAR 860-095-0030(1)(b) & (2)(a)-(b).

parties with an interest in reviewing the material, and they should also apply to the same type of information in the Resource Adequacy Informational Filing to preserve the intent of adopting those unique levels of protection in what will ultimately be part of the same filing. NIPPC is not aware of any explanation for the decision not to align the protective treatment of these two interrelated filings in the Proposed Rules and, to NIPPC' knowledge, no party opposed repeated recommendations during the informal phase that Proposed Rules do so.

Accordingly, NIPPC recommends the following edit to Proposed OAR 860-095-0030(4) resolve this outstanding issue:

> (4) Availability of Information:
> (a) A Regional Participant's most recent Regional Forward Showing submission to its Qualified Regional Program must be made available for review only to Qualified Parties and only upon request pursuant to a Modified Protected Order.
> (b) The following information shall be available for review only by Non-Market Participants that have executed a Modified Protective Order:
>
> > (A) A discussion about how the overall resource strategy interacts with Resource Adequacy concerns, as required by Section 1(b);
> > (B) A monthly P50 Peak Load Forecast and Effective Load Carrying Capability curve, as required by Section 2(a) of this rule; and
> > (C) A discussion covering at least four years of the transmission rights necessary to serve P50 load, the transmission rights currently owned or used, the steps that will be taken to procure transmission rights to fill in any open position, and any expected constraints or difficulties in filling any open positions, as required by Section 2(b) of this rule.
>
> (c) For purposes of this rule. Non-Market Participants includes Commission Staff, the Citizen's Utility Board, and nonprofit organizations engaged in environmental advocacy that do not otherwise participate in electricity markets.

3. <u>State Program Confidentiality Protections</u>: The Proposed Rules Should Clarify that a State Participant's Binding Forward Showing Will Only Be Available to and Reviewed by Staff Or, Alternatively, Contain Comparable Confidentiality Protections to the Informational Filing

The Commission should clarify that appropriate confidentiality protections will exist for a State Participant's Binding Forward Showing by either limiting review to Commission Staff or, alternatively, providing comparable confidentiality protections as recommended above with respect to the Informational Filing.

ESSs had previously understood that a State Participant's Binding Forward Showing would be reviewed only by Staff, and therefore had not previously recommended detailed provisions limiting access to non-market participants as with the Informational Filing. However, the wording of the Proposed Rules suggests that parties other than Staff may also access a State Participant's Binding Forward Showing. Specifically, Proposed OAR 860-095-0040(5) provides: "The Commission Staff *and Parties* should complete its compliance review for each State Participant within 90 days of filing the Binding Forward Showing."[89] This language suggests that the State Participant's Binding Forward Showing would be the subject of a formal docket at the Commission, or that other non-Staff parties would be allowed to review the State Participant's Binding Forward Showing.

To be clear, NIPPC opposes participation of non-Staff parties in a docket to review a State Participant's Binding Forward Showing. This contemporaneous information regarding an ESS's current market position and compliance resources is highly sensitive. In the parallel WRAP, no party other than the necessary Western Power Pool employees, agents, consultants or Independent Evaluators will be permitted to review the highly sensitive Forward Showing.[90] The WRAP Tariff even allows participants to withdraw prior to the normally applicable notice periods if the Western Power Pool discloses the participant's confidential information over its

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89 Proposed OAR 860-095-0040(5) (emphasis added).

90 *See* WRAP Tariff at § 10.3 (except for limited exceptions related to aggregated data, "no Participant, entity owning a Qualifying Resource, or any third party shall have the right hereunder to receive from WPP or to otherwise obtain access to any documents, data or other information that has been identified as or deemed to be confidential or commercially sensitive under Section 10.2 of this Tariff by a disclosing Participant.").

objection.[91] Thus, in the Commission's State Program, comparable treatment would limit access to a State Participant's Binding Forward Showing to Staff. When Staff solicited Informational Filings with this type of information from LREs in Docket No. UM 2143, the sensitive load and resource information was submitted through a secure Huddle page available only for Staff's review, and Staff publicly shared only aggregated data.[92]

Accordingly, NIPPC recommends the following edit to Proposed OAR 860-095-0040(5):

> The Commission Staff ~~and Parties~~ should complete its compliance review for each State Participant within 90 days of filing the Binding Forward Showing. The Binding Forward Showing will not be available to persons other than Commission Staff.

Alternatively, to the extent that the Commission wishes to provide certain other parties with access to a State Participant's Binding Forward Showing, the administrative rules should at least provide comparable confidentiality protections as those applicable to the Emissions Planning Reports and as proposed above for the Resource Adequacy Informational Filing. The reasons explained with respect to the Informational Filing are equally applicable to the Binding Forward Showing. Thus, NIPPC alternatively recommends at least adding the same limitation on availability of the information as applies to the Regional Participant's most recent Regional Forward Showing as follows in Proposed OAR 860-095-0040:

> Availability of Information: A State Participant's Binding Forward Showing submission to the Commission will be available for review only by Qualified Parties and only upon request pursuant to a Modified Protected Order.

4. <u>State Program Transmission Requirement</u>: The State Program's Firm Transmission Requirement Should Be Further Clarified

The Proposed Rules need further clarification to the description of firm transmission

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[91] WRAP Tariff, Attachment A, Western Resource Adequacy Program Agreement at § 9.2.1.3.

[92] *See* Docket No. UM 2143, Staff Report (March 24, 2021).

products that will meet the State Program's Transmission Requirement to ensure that the State Program uses a standard comparable to the WRAP's firm transmission requirement.

During the informal rulemaking phase, Calpine Solutions recommended that the requirement for use of "firm transmission" in the State Program should be no more stringent than the requirements of the WRAP. In WRAP, transmission qualifies for use in the Forward Showing program, and is thus for WRAP's purposes "firm," if it is "NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service."[93] NERC Priority 6 includes *conditional* firm point-to-point transmission and *secondary* network transmission, which are therefore acceptable forms of firm transmission in the WRAP.[94] Staff and other parties expressed support in the informal phase for aligning the State Program's firm transmission requirement with that in WRAP, and Staff appears to have intended to so align the requirements in the Proposed Rules. However, during the informal phase, Staff's edit departed from the language used in the WRAP Tariff and, by doing so, created a significant difference between the State Program's firm transmission requirement and the WRAP's firm transmission requirement. This issue has now been carried through into the Proposed Rules.

Specifically, Proposed OAR 860-095-0040(9) uses the descriptor "firm or conditional firm" to describe acceptable transmission products, but unlike the WRAP Tariff the Proposed

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93 WRAP Tariff at § 16.3.1.

94 *Puget Sound Energy, Inc*., 144 FERC ¶ 61,198 at P 7 (Sept. 12, 2013) ("Conditional firm point-to-point transmission service, during the conditional period, has a curtailment priority of Priority 6 …."); *Conditional Firm Service, BPA Transmission Business Practice, V27* at 2, 7-8 (Oct. 30, 2023), available at https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/conditional-firm-service-bp.pdf (stating conditional firm service has curtailment priority 6 or 7, depending on the circumstances); *PGE's Network Integration Transmission Service Business Practice*, OASIS at 9, available at http://www.oasis.oati.com/pge/ ("Secondary Network Service has a NERC 6 curtailment priority, identified on electronic tags as 6-NN.").

Rules do not use the terms "NERC Priority 6 or NERC Priority 7." This change in wording from that used in the WRAP Tariff could result in ambiguity as to whether secondary network integration transmission service qualifies in the State Program as it clearly does in the WRAP. Secondary network transmission is NERC Priority 6, but is not necessarily the same as "conditional firm," which is typically a point-to-point transmission product not a network transmission product. As BPA Business Practice explains, "[Conditional Firm Service] is a form of Long-Term Firm (LTF) Point-To-Point (PTP) Transmission Service that allows the Transmission Provider to curtail the reservation at the Curtailment Priority Code 6."[95] In contrast, Secondary Network Transmission carries the same NERC Priority Code 6,[96] but it is a form of *Network* Transmission used to "deliver energy to Network Loads from resources that have not been designated as Network Resources."[97] Simply put, the Proposed Rule's description of "conditional firm transmission" would not normally be understood to encompass secondary network transmission service, even though conditional firm point-to-point transmission service and secondary network transmission service both have NERC Priority 6. Thus, NIPPC recommends use of the terms "NERC Priority 6 or NERC Priority 7" to avoid potential misunderstandings and confusion as to the State Program's firm transmission requirement.

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95 BPA's Conditional Firm Service Business Practice V27 at 1 (Oct. 30, 2023), available at: https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/conditional-firm-service-bp.pdf.

96 *See, e.g.*, *Conditional Firm Service, BPA Transmission Business Practice, V27* at 8 (Oct. 30, 2023), available at: https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/conditional-firm-service-bp.pdf.

97 *Network Integration (NT) Transmission Service, BPA Transmission Business Practice, V13* at 10 (March 24, 2023), available at: https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/network-integration-transmission-service-bp.pdf; *see also Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12,266, at P 1592 (March 15, 2007).

In sum, NIPPC continues to recommend that if the WRAP-style firm transmission requirement will be imported to Oregon's rules, the rules should at least allow use of the same types of firm transmission as WRAP, which includes NERC Priorities 6 and 7. Thus, NIPPC recommends the following edit to Proposed OAR 860-095-0040(9) to remove the ambiguity on whether secondary network transmission service will be an allowed form of firm transmission in the State Program:

> (9) A State Participant must demonstrate that it has NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service ~~firm or conditional firm transmission~~ rights to deliver 75 percent of the Compliance Resources from generation source to load sink. A State Participant may request a waiver of a portion of the transmission requirement if it can demonstrate that at least one of the following conditions applies:
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> * * * *

III. CONCLUSION

NIPPC appreciates the opportunity to comment on the proposed Resource Adequacy rules, and urges the Commission to make the revisions detailed above.

Dated this 8th day of January, 2023.

Respectfully submitted,

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