BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 660

In the Matter of Adoption of Rules Relating to Resource Adequacy.	ORDER

DISPOSITION: ADMINISTRATIVE HEARINGS DIVISION RECOMMENDATIONS ADOPTED

This order memorializes our decision, made and effective at the April 16, 2024 Regular Public Meeting, to adopt the Administrative Hearings Division's (AHD) recommendation to adopt proposed permanent rules as presented in Attachment 1 of the AHD April 11, 2024 Public Meeting Report.[1] Further, we direct Staff to investigate resource adequacy responsibilities for 1- and 3-year direct access customers, and 5-year direct access customers currently paying transition charges, in docket UM 2024 prior to the date of the first state program resource adequacy filing. If Staff determines that addressing these issues in the UM 2024 timetable is not feasible, Staff should present a proposal for addressing these issues at an upcoming public meeting.

In adopting these rules, we note that resource adequacy is a regional challenge to which the PUC is contributing solutions. One of those solutions is establishing requirements for our regulated entities to take the actions necessary to support reliability. We also recognize that, in a time of tightening market conditions for resources and transmission, entities who have not previously carried resource adequacy responsibilities may face particularly acute transition challenges.

While all participants in Oregon's competitive retail market move towards greater reliability contributions, we recognize that we need to retain flexibility to navigate through uncertainties over the next few years. Therefore, although we do not adopt the electricity service suppliers' suggestion to develop an alternative that would allow for procurement of resource adequacy products from utilities, we adjust the penalty provisions to communicate that we have ample discretion to design penalties appropriate to the circumstances. Adopting these recommendations from AHD also helps focus staff capacity and resources on efforts to address other issues in the direct access program in UM 2024 as well as broader solutions for improving the resource adequacy and transmission outlook in the region.

[1] We note that the rules attached to the AHD recommendation referenced the term "Electric Service Supplier." We corrected the term to the term used in ORS 757.600(16), "Electricity Service Supplier."

The AHD report with the recommendations is attached as Appendix A.

Made, entered, and effective May 08 2024.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Les Perkins
Commissioner

A person may petition the Oregon Public Utility Commission for the amendment or repeal of a rule under ORS 183.390. A person may petition the Oregon Court of Appeals to determine the validity of a rule under ORS 183.400.

ITEM NO. RM1

PUBLIC UTILITY COMMISSION OF OREGON
AHD REPORT
PUBLIC MEETING DATE: April 16, 2024

REGULAR ___ CONSENT ___ RULEMAKING _X_ EFFECTIVE DATE __N/A__

DATE: April 11, 2024

TO: Public Utility Commission

FROM: Christopher J. Allwein

THROUGH: Diane Davis, Nolan Moser **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION ADMINISTRATIVE HEARINGS DIVISION: (Docket No. AR 660) Requesting adoption of new rules for Chapter 860, Division 95 Resource Adequacy Rules. The proposed rules are presented in Attachment 1.

AHD RECOMMENDATION:

Adopt the proposed, permanent, new rules presented in Attachment 1.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon should adopt the new rules for Chapter 860, Division 95, regarding Oregon resource adequacy.

Applicable Law or Rule

Under ORS 756.060, the Commission "may adopt and amend reasonable and proper rules and regulations relative to all statutes administered by the commission * * *." The Oregon Administrative Procedures Act sets forth the process for rulemaking.

Under ORS 756.040, the Commission has authority to supervise and regulate every public utility in Oregon, and to do all things necessary and convenient within its jurisdiction to obtain for customers adequate service at fair and reasonable rates.

Under ORS 757.659, the Commission has authority to "adopt such rules as are necessary" to implement direct access regulation.

Analysis

Background

On December 29, 2020, the Commission opened docket UM 2143 to investigate resource adequacy (RA) issues in the State of Oregon. Staff subsequently held workshops with stakeholders including regulated, investor-owned utilities (IOUs), Electric Service Suppliers (ESSs), customer advocacy groups, and other interested persons. In January 2022, IOUs and ESSs (load responsible entities or LREs) made a series of informational filings containing load and generation data.

Staff used these informational filings from Oregon LREs, along with an open-source RA model from National Energy Renewable Labs, to assist with the production of an Oregon RA status report. The March 24, 2022 Staff Report included five recommendations and observations:

1. Immediate action regarding RA was not warranted based on the analysis of the informational filings and would not result in a substantive increase in reliability for Oregon customers.

2. Further analysis of the informational filings was not warranted, and Staff should instead focus on long-term solutions for RA concerns, such as integrating RA deeper into IOUs' Integrated Resource Plans (IRPs) and an equivalent set of filings for ESSs.

3. It would be reasonable to require compliance filings to demonstrate RA annually for entities not participating in a regional compliance program and every other year for entities that are participating in a regional compliance program.

4. There is a potential "seams" issue where neither IOUs nor ESSs are planning for long-term opt-out (direct access) customers.

5. As the region continues to trend towards a greener generation mix, Staff recommended that entities continue their involvement with the Western Power Pool's (WPP) emerging regional RA compliance program, the Western Resource Adequacy Program (WRAP).[1]

Between March 2022 and September 2023, Staff instituted an informal rulemaking process and collaboratively developed a set of RA rules intended to close the seams issues, establish a compliance program, and create standardized planning requirements

[1] Staff Report at 3 (Sept. 11, 2023) (citing *Investigation into Resource Adequacy in the State*, Docket No. UM 2143, Staff Report at 8-9 (Mar. 24, 2022).).

for RA. Staff held a variety of stakeholder workshops, conducted five comment periods, hosted a technical workshop at a special public meeting, developed a set of straw rules, and then drafted rule language. Staff's draft rules are meant to promote RA in Oregon by establishing an Oregon-specific RA compliance program that is complementary to the WRAP, creating RA requirements in planning spaces, and giving Staff and stakeholders access to critical RA data where appropriate. During this informal rulemaking period, Staff received comments from several entities, including customer representatives, IOUs and ESS stakeholder groups.

In its September 11, 2023, Staff Report, in addition to recommending the opening of a formal rulemaking, Staff noted that important updates occurred in the RA space since Staff's March 24 report. Most notably, WPP filed a tariff with the Federal Energy Regulatory Commission (FERC) for the WRAP that was approved in February 2023, and all Oregon-regulated IOUs and many Oregon ESSs are currently participating in the WRAP.

Overview

At the September 21, 2023 Regular Public Meeting, the Commission adopted Staff's recommendation to open a formal rulemaking process. AHD filed the notice of proposed rulemaking on November 27, 2023, and served notice on the same day to the Administrative Rule Electric Notification List, the AR 660 and UM 2143 service lists, and to certain legislators as required by ORS 183.335. The proposed rules were published in the *Oregon Secretary of State's December 1, 2023 Bulletin*.

AHD held a rulemaking hearing on January 11, 2024. All Commissioners attended the hearing. Representatives from Staff, the Northwest & Intermountain Power Producers Coalition (NIPPC), Calpine Energy Solutions, LLC (Calpine), PacifiCorp, dba Pacific Power, Portland General Electric Company, and Brookfield Renewable Trading and Marketing LP (Brookfield) provided comment at the hearing.

Written comments were due January 25, 2024. NIPPC, Calpine, PacifiCorp and PGE (collectively, the Joint Utilities), Staff, and Brookfield timely submitted comments. After the due date, Idaho Power filed comments and a motion requesting that its late-filed comments be accepted. On January 30, 2024, the Administrative Law Judge issued a ruling accepting Idaho Power's comments and extending the comment deadline to February 13, 2024. NIPPC, Calpine and Brookfield (collectively, the ESS Group) timely submitted joint reply comments.

Proposed Rules

The proposed rules and rule amendments are presented in Attachment 1 to this report. Upon adoption, the proposed rules will appear in Chapter 860, Division 95. Staff developed and refined the proposed rules using three principles:

1. Operational RA concerns are best addressed at the regional level rather than the state level. Any Staff proposal to address RA in Oregon should be complementary to the WRAP, incentivize WRAP participation, and be something that Staff has the skills and time to implement.

2. RA rules should provide transparency and close the seams issues that arise from mismatching planning timelines and planning methodologies. For example, the WRAP operates with a seven-month forward-looking compliance period, while Oregon planning dockets look far deeper into the future.

3. These rules are a first effort to address a new and changing area of state regulation. Staff expects discussion and refinement to continue through implementation and has focused the proposed rules on practices that are most likely to result in meaningful improvements to RA for Oregon ratepayers.

The proposed rules contain a scope and applicability section, definitions, separate rule sections listing reporting requirements for electric company and ESS regional program participants, respectively, and a description of requirements for state program participants (*i.e.*, those entities not participating in a regional program).

The discussion below addresses outstanding substantive items, presents areas of disagreement between stakeholders and/or Staff, and provides recommendations for resolution based on information in the September 11 report and comments received from rulemaking participants during the formal phase of this rulemaking.

Below, we address the transmission forward showing requirement, including a proposed modification of the waiver provision for this requirement, and proposed alternatives of either a capacity backstop charge or request for offers (RFO) process. We also discuss RA provisions for one, three, and five-year direct access program participants and present recommendations submitted by rulemaking participants.

1. Transmission Forward Showing

Proposed rule sections OAR 860-095-0040(7) and (9) are resource and transmission forward showing (TFS) requirements which require a state program participant (defined as an LRE that is not a participant in a regional program, such as the WRAP) to provide a two-year forecast, showing that its resource adequacy compliance resources "meet 95 percent of its monthly forecasted * * * load for twelve months beginning July 1 of the filing year and 80 percent of the monthly forecasted * * * load for the following twelve months * * * " and to demonstrate that "it has firm or conditional firm transmission rights to deliver 75 percent" of the compliance resources "from generation to load sink."[2]

[2] Proposed OAR 860-095-0040(7) states in part: "A State Participant must demonstrate that its Compliance Resources meet 95 percent of its monthly forecasted P50 load for twelve months beginning July 1 of the filing year and 80 percent of the monthly forecasted P50 load for the following twelve months plus a Planning Reserve Margin each month." Proposed Section (9) states in part: "A State Participant must demonstrate that it has firm or conditional firm transmission rights to deliver 75 percent of the Compliance Resources from generation source to load sink."

The state program requirements allow participants to request a waiver for a portion of the TFS if: (a). the participant is experiencing enduring transmission constraints; (b). future firm transfer capability is expected; (c). an applicable portion of existing transmission service rights are expected to be derated or out of service, or; (d). expected counterflow "directly between two balancing authority areas from another entity supports the State Participant's transmission of energy from generation source to load sink."[3] The rules prohibit State Participants from requesting a waiver for consecutive compliance periods due to enduring transmission constraints or the expectation of future firm transfer capability.[4]

As discussed below, the Joint Utilities support Staff's proposed requirements. NIPPC, Brookfield and Calpine recommend alternative options to the TFS requirement in the form of a backstop capacity charge or a RFO process. Brookfield also recommends a modification to the waiver process.

a. Staff's Proposal

Staff notes that the goal of the proposed rules is to create a state program that complements the WRAP (the current "qualified regional program") and incentivizes participation in the WRAP, but also creates a framework to ensure RA needs are met if an entity does not join the WRAP. In accord with learnings from workshops presented by WPP and the Western Electricity Coordinating Council leadership, Staff believes that regional coordination provides substantial insulation against potential RA problems. Staff further states that an entity that eschews a regional RA compliance program creates a larger RA risk and should therefore be subject to stricter RA standards. Staff acknowledges the difficulty in procuring resources with a longer lead time and points to lower compliance thresholds in the second year as a means of addressing these difficulties. Staff is concerned that any additional lowering of the compliance thresholds would limit the value of RA planning and make the less efficient state program more attractive to LREs than the WRAP.[5]

b. Joint Utilities (PGE and PacifiCorp)

The Joint Utilities support the proposed rules and state that a TFS is a "cornerstone of the RA program," that ensures that LREs can plan and provide reliable service "in an evolving and increasingly transmission-constrained market and promotes long-term investments in system reliability."[6] The Joint Utilities note that the TFS will require IOUs and ESSs alike to adapt their historical business practices to demonstrate RA. The Joint Utilities point out that the proposed rules allow for a reduced demonstration of

[3] Proposed OAR 860-095-0040(7)(a)-(d).
[4] Proposed OAR 860-095-0040(7)(e).
[5] Staff Report at 9.
[6] Joint Utilities Opening Comments at 2 (Jan. 25, 2024).

transmission rights relative to load requirements, and therefore, additional modification of the proposed rules is unnecessary.[7]

The Joint Utilities opine that this shift in regional transmission practices, away from procurement of short-term capacity to serve load, is necessary to ensure continued system reliability as Oregon implements clean energy goals via the ongoing transition to renewable generation. They point to the existing constraints of the regional transmission system and argue that the state program should align with regional transmission planning efforts to incentivize efficient and near-term transmission system investments. According to the Joint Utilities, relieving State Participants from a TFS requirement will not enhance transmission system reliability and will incentive ESSs to not participate in the WRAP, which the Joint Utilities characterize as directly contrary to one of Staff's key principles.

The Joint Utilities state that utilities and ESSs have the "identical ability to secure transmission rights" under FERC's open access transmission policies that prohibit discriminatory practices by public utilities that own transmission against third-party generator access.[8] The Joint Utilities note that their merchant entities must request and purchase transmission rights from their utility transmission functions in the same manner and subject to the same constraints as all other LREs. Similarly, the Joint Utilities state that their merchant entities are also in the same position as ESSs when seeking transmission service across third-party transmission systems, including the Bonneville Power Administration (BPA). Thus, the Joint Utilities disagree with the argument that ESSs have a disadvantage when competing for transmission service.

The Joint Utilities also contend that concerns regarding utilities hoarding transmission or generation capacity are unfounded. FERC prohibits transmission providers' merchant functions from exercising their market power by hoarding available transmission capacity. The Joint Utilities state they will not hoard unused generation capacity because the WRAP operations program will commit excess capacity to other WRAP participants who are short. The Joint Utilities also note that if unused generation is not committed through WRAP, holding it will increase their costs by preventing off-system sales.[9]

c. NIPPC, Calpine and Brookfield

In separate and joint reply comments, NIPPC, Calpine and Brookfield (collectively, the ESS Group) support the Commission's efforts to develop a viable RA framework for all Oregon loads but contend that the proposed rules could significantly diminish the opportunity for ESSs to supply direct access customers. The ESS Group recommends that the Commission not rely solely on WRAP-style compliance (via direct WRAP participation or through a parallel state program) arguing that it is uncertain whether all LREs will be able to procure resources fully compliant with WRAP's requirements. The

[7] *Id.* at 4.
[8] *Id.* at 6.
[9] *Id.* at 8.

ESS Group expresses particular concern regarding WRAP's TFS requirement, asserting that the underlying assumption—that the type of firm transmission needed to meet WRAP's specific and new TFS requirement is available for all LREs—is likely wrong.[10]

The ESS Group states that if the Commission mandates compliance with WRAP's TFS requirement as the only option, that requirement will be infeasible for ESSs who have not, to date, had a commercial or regulatory reason to acquire extensive firm transmission portfolios under the region's existing bilateral market structure. NIPPC notes in separate comments that the practice for some of the region's major transmission providers, including BPA, is to release substantial qualities of reserved but unused transmission capacity for purchase on the short-term market relatively close in time to the real-time market. NIPPC states that LREs have been able to reliably serve load with this transmission capacity for many years without necessarily locking in firm transmission reservations months in advance.[11] The ESS Group concludes that infeasible RA requirements would undermine the competitive retail market intended by Oregon law, and that such an outcome is not reasonable nor in the public interest.

The ESS Group explains that Oregon's direct access market developed in reliance on the existing system, based on the rules and policies previously adopted by the Commission. The ESS Group argues that RA requirements were not contemplated when Oregon's direct access market was established or when existing direct access customers elected to enroll in direct access. The ESS Group requests the addition of an alternative compliance option to ensure the transition to the new RA planning framework leaves all direct access customers with a viable path forward and does not have the unintended consequence of limiting retail choice opportunities for customers.[12]

The ESS Group disagrees that ESSs are on a level playing field with utilities when it comes to transmission rights and explains that incumbent utilities hold extensive BPA transmission rights.[13] An ESS that does not already possess extensive rights or acquires a new direct access load in excess of whatever rights it might have, does not have equal ability to meet the TFS requirement as the incumbent utilities for that reason. The ESS Group notes that utilities have a larger captive customer base and incumbent status that make it much easier to meet the 75 percent firm transmission requirement. The ESS Group states that utilities are entitled to stranded cost charges enabling them to procure years of forward capacity and transmission beyond the term of their customers' commitments. The ESS Group contends that due to the utilities' incumbent monopoly position and existing transmission rights holdings, ESSs are not in

[10] ESS Group Joint Reply Comments at 1-2 (Feb. 13, 2024).
[11] NIPPC Opening Comments at 7 (Jan. 8, 2024).
[12] ESS Group Joint Reply Comments at 3.
[13] *Id.* at 10-12 (NIPPC quoting PGE's 2023 IRP/CEP stating that "PGE currently holds over 4,000 MW of long-term firm transmission under contract with BPA."); NIPPC Opening Comments at 24 (citing *In re PGE 2023 CEP and IRP*, Docket No. LC 80, PGE's CEP-IRP at 217 (Mar. 31, 2023).).

the “same position” as the utilities when seeking transmission across third-party systems.[14]

Brookfield asserts that the proposed TFS requirement is “not workable” and expresses support for NIPPC’s recommendations.[15] Brookfield argues the TFS requirement is problematic for ESSs by requiring that a state participant acquire 75 percent of the transmission necessary to move the respective year’s generation forward showing to load, for both one and two years in advance. Brookfield notes that the intent of this requirement was to align the state program TFS requirement with adequacy levels required by the WRAP and maintains that while the 75 percent levels are aligned with WRAP, the one- and two-year TFS requirements are not.[16]

Brookfield points out that in contrast, WRAP requires a showing of firm transmission rights sufficient to deliver 75 percent of the participant’s compliance resources only seven months in advance. Brookfield notes that the WRAP tariff transmittal letter acknowledged that it requires a 75 percent showing, rather than 100 percent, because participants’ experience was that “a certain amount of transmission service that is not available seven [m]onths ahead of the Binding Season can be obtained on a shorter-term basis.”[17] Brookfield speculates that “if certain amounts of transmission rights which will be eventually available are not typically available seven months in advance, then even fewer such transmission rights will be available one and two years in advance.”[18]

Brookfield notes that the WRAP is a voluntary program, but states that the onerous state program TFS requirement and proposed penalties will force ESSs to join the WRAP because of the inability to obtain required (but eventually available) firm transmission. Brookfield states that while the WRAP has value, “the program should be tested and thoroughly vetted prior to mirrored (and more onerous) adoption in Oregon.”[19]

The ESS Group disagrees with the Joint Utilities’ assertion that ESSs could procure excess capacity from the WRAP operations program. The ESS Group explains that the WRAP operations program is not a wholesale market, but rather “an option of last resort” for WRAP participants.[20] The ESS Group argues that participants cannot rely on the WRAP’s operations program to meet its load obligations, as an LRE may do in regions with organized wholesale markets and cannot defer or resolve TFS requirements here by using the operations program. The ESS Group notes that doing so would expose the ESS and/or its direct access customers to significant financial consequences.

[14] *Id.* at 11.
[15] Brookfield Opening Comments at 3 (Jan. 25, 2024).
[16] *Id.* at 3.
[17] *Id.* at 4 (citing *WRAP FERC filing*, Charles Hendrix Aff., ¶ 42.).
[18] *Id.*
[19] *Id.* at 6.
[20] The ESS Group Joint Reply Comments at 9.

NIPPC separately provides several examples from PGE's 2023 IRP, BPA and WRAP documents that demonstrate a constrained, and nearly fully subscribed transmission system.[21] Thus, the ESS Group asserts that "forcing ESSs to attempt to procure long-term, firm BPA point-to-point transmission that is not available, or incurring draconian penalties" or decertification if they are unable to do so, does not resolve near-term transmission issues.[22]

2. Brookfield's Recommended Modification to the State Program TFS Waiver

Brookfield advocates for elimination or modification of the waiver restriction in proposed OAR 860-095-0040(9)(e):

> A State Participant cannot use waiver condition (9)(a) or (9)(b) for the same path for consecutive compliance periods.

Brookfield acknowledges this provision is similar to the waiver restriction in the WRAP tariff but explains that, in the WRAP, the above restrictions apply only in two specific circumstances. WRAP participants cannot claim either the "enduring constraints" or "available transfer capacity expected" exceptions "for the same path (or across the same constraint) for the same season of the subsequent year" if: (1) firm transmission is available prior to the transmission forward showing deadline and (2) the firm transmission path is only posted for more than one year.[23]

Brookfield explains that the purpose of the limitations in the WRAP tariff are to prevent participants from claiming these exceptions to the TFS requirement when transmission capacity is available. Thus, while the WRAP rule contains limitations on the continued and consecutive use of these two exceptions, these limitations apply only in specific, defined circumstances. If there are enduring constraints or if firm available transmission capacity is expected and multi-year transmission capacity is not available—a likely scenario in the Pacific Northwest—then WRAP participants can claim the same exception consecutively. However, that option is unavailable under the proposed state TFS requirements. Specifically, Brookfield argues the proposed state program would more stringently apply the limitation to any instance where either exception is claimed. Brookfield urges that this rule provision be eliminated.

In the alternative, if the Commission chooses to keep the restrictions on the waiver requests, Brookfield recommends adding language to the provision so that it is no more restrictive than the WRAP:

> A State Participant cannot use waiver condition (9)(a) or (9)(b) for the same path for consecutive compliance periods <u>if the Qualified Regional Program would preclude use of such waiver</u>.

[21] NIPPC Opening Comments at 8-9.
[22] ESS Group Joint Reply Comments at 8.
[23] Brookfield Opening Comments at 7 (citing to *WRAP FERC filing*, Charles Hendrix Aff., ¶ 48.).

The ESS Group agrees and requests that the Commission adopt Brookfield's elimination or modification of the waiver restriction.

3. Capacity Backstop Charge or Request for Offers Process as a TFS Alternative

The ESS Group, separately and collectively, urges the Commission to adopt and establish a capacity backstop charge (CBC), which would be a rate developed and approved by the Commission that the IOUs would charge direct access customers for RA. The ESS Group notes that their proposed CBC is intended as an alternative to the TFS rather than a replacement.

Similarly, the ESS Group recommends a RFO process as a second option, in the event a CBC is not adopted as an alternative to the TFS. The ESS group proposes a requirement that a public utility issue an annual RFO from ESSs to purchase the utility's excess capacity or transmission that meets the WRAP's definition of qualifying resources for use in WRAP's forward showing program and/or transmission rights meeting the WRAP's TFS Requirement.

a. NIPPC

NIPPC urges the Commission to include either a CBC or an RFO process as an alternative to WRAP or WRAP-style compliance, at least for ESSs. NIPPC notes that either alternative could be developed in docket UM 2024 rather than delaying or extending these rulemaking proceedings.[24] In the alternative, NIPPC recommends that the Commission state in the rules or in its final order that the issue will be revisited in January 2025 to review whether the TFS requirement is proving unworkable.

Through a CBC, NIPPC argues that direct access customers would be contributing to paying their share of regional capacity or transmission planning. Under NIPPC's proposal, the incumbent utility would plan for the long-term capacity and transmission needs of the long-term direct access customer that is paying the CBC. The customer would pay the incumbent utility directly. For a customer choosing to purchase RA through an ESS, would contribute through the ESS' participation in the WRAP or the state program.

NIPPC states that a CBC is appropriate due to this Commission's long recognition that direct access is intended to provide optionality to customers. NIPPC prefers that an RA product required for compliance would be readily available from multiple suppliers in the competitive market but notes that is unlikely, at least with respect to the proposed WRAP-style TFS requirement. Thus, NIPPC contends that requiring a utility backstop offering is necessary to ensure that competitive retail market opportunities exist for other supply options.[25]

[24] *In the Matter of Alliance of Western Energy Consumers, Petition for Investigation Into Long-Term Direct Access Programs*, Docket No. UM 2024.
[25] NIPPC Opening Comments at 23.

NIPPC opines that the proposed TFS requirement, without other options, may endanger the opportunity for customers to enter, or remain in, the retail market. With a CBC, NIPPC maintains that customers would retain retail choice to purchase their chosen energy supply from various ESSs. NIPPC asserts that without the CBC, retail choice could be severely hampered if ESSs are not able obtain firm transmission. NIPPC concludes that "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."[26]

NIPPC states that requiring an incumbent utility to offer a capacity product for a customer that purchases energy supply from the competitive market is consistent with Oregon law.[27] To address the potential for arbitrage, NIPPC recommends requiring a customer to provide notice to switch RA providers, similar to the notice required to switch back and forth from cost-of-service to direct access service, in order to provide sufficient time for a utility to adjust its portfolio, without risk to other customers.

Regarding the RFO process, NIPPC explains that the incumbent utility is the most likely entity to control any excess WRAP-compliant generation and transmission deliverable to loads in its balancing authority. NIPPC assumes that the utilities have such excess capacity because direct access customers continue to pay transition charges for capacity acquired by utilities to serve those customers. NIPPC contends that a utility is unlikely to choose to sell such resources to ESSs unless encouraged via a state mandated RFO. The RFO proposal would 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 offers.

NIPPC further explains that the goal of this process is to provide transparency to the Commission and stakeholders as to whether the utility is managing its portfolio prudently. NIPPC argues that it will also test Staff's assumption that ESSs can easily obtain excess capacity and transmission bi-laterally from utilities. NIPPC notes that an RFO requirement may benefit cost-of-service customers by ensuring that a utility does not unreasonably decline to sell excess WRAP-compliant generation and transmission to willing buyers serving load in the same balancing authority.

NIPPC states that deferring solely to the WRAP process "would be inconsistent with Oregon law and policy encouraging retail markets."[28] NIPPC notes the Commission's statutory responsibility—separate from the WRAP—is to "eliminate barriers to the development of a competitive retail market between electricity service suppliers and

[26] *Id.* at 24
[27] *Id.* at 25.
[28] *Id.* at 27.

electric companies."[29] Therefore, NIPPC maintains that the Commission must protect the Oregon competitive retail market by allowing alternatives to the TFS requirement.

b. Calpine

Calpine supports the Commission's efforts to develop an RA framework applicable to LREs but expresses its concerns with the lack of a CBC or RFO process option. Like NIPPC, Calpine states that the proposed rules "could have a serious adverse effect on the competitive retail market in Oregon" if no alternative option is adopted for ESSs and direct access customers.[30] Calpine expresses full agreement with NIPPC's recommendations.

c. Staff

Staff explains that it does not support the inclusion of a CBC or RFO. Staff notes that it originally included a placeholder for a CBC to facilitate discussion of its merits and that a CBC was discussed with parties during the informal rulemaking phase. Staff concludes that including a standardized CBC is not aligned with Staff's goals of promoting RA in Oregon and may not be in Oregon IOU customers' best interests at this time.[31] Staff opposes including an RFO, arguing that given the timeline constraints presented in current IRP and other planning proceedings, it is unlikely any ESS bid would be accepted in an RFO scenario, and thus would provide no actual RA benefits near-term. Staff also notes that, as written, the rules would allow for an RFO proposal to be implemented in the future if it appears likely to aid in RA planning.[32]

Staff opines that entities have sufficient options to comply with the state program, including:

- Building out their own resources executing their own contracts,
- Bilateral negotiation for capacity products with a third party, and
- Joining the WRAP and therefore not being subject to the state compliance program.[33]

In addition, Staff notes that the WRAP's operational program allows for capacity sharing. Staff explains that proposed rule language surrounding bilateral agreements for capacity products is meant to be sufficiently broad to allow an RFO or other capacity backstop solutions to count towards compliance should those solutions be adopted outside this docket.[34]

[29] *Id.* (citing ORS 757.646(1).).
[30] Calpine Opening Comments at 2 (Jan. 10, 2024).
[31] Staff Report at 6.
[32] *Id.* at 7.
[33] *Id.* at 10.
[34] *Id.* at 10.

d. Joint Utilities

The Joint Utilities oppose the proposed CBC or RFO alternatives, which they characterize as a replacement of the TFS requirement.[35] The Joint Utilities warn that adopting these recommendations would undermine the basic purpose of the RA program, potentially result in significant cost-shifting from direct access to cost-of-service customers, in contravention of ORS 757.607(1), and require the Commission to engage in wholesale market activities which are the exclusive jurisdiction of FERC.

The Joint Utilities opine that if an ESS shifts its RA obligation to the utility, there is no guarantee that the utility will have sufficient excess generation to meet the ESS's RA obligation. If the utility is short, it must procure the resources in the market. When the utility has excess generation resources, it must either commit those resources to the WRAP operations program or it forgoes the opportunity to make market sales using those excess resources if they must instead meet ESS RA obligations, negating benefits that are included in the transition adjustments for direct access customers.

The Joint Utilities assert that any CBC compensation would be less than market prices, explaining that otherwise the ESS would have met its RA obligations with market products. Thus, the Joint Utilities contend that cost-of-service customers will incur higher costs than they otherwise would have incurred and will not be fully compensated for those costs. They maintain that a CBC would thus impermissibly shift costs by requiring cost-of-service customers to subsidize the RA compliance obligation of ESSs.

The Joint Utilities assert that all LREs should be subject to the same RA compliance obligations. They contend that requiring utilities to backstop ESS obligations undermines competition by insulating ESSs from a basic obligation to provide reliable service to its customers. The Joint Utilities argue that if the ESS cannot meet its RA obligations in the market, as the Joint Utilities must do, then cost-of-service customers should not be required to step in and bail out the ESS. The Joint Utilities state that while sufficient notice requirements may dampen the impact of cost-shifting, notice alone cannot eliminate it. The Joint Utilities note that there is still a risk that cost-of-service customers may end up paying more to subsidize the ESS's RA obligation because notice does not change the cost differential between the market and an "administratively determined CBC."[36]

The Joint Utilities also argue that a CBC would violate FERC's exclusive jurisdiction. First, they assert that a CBC essentially mandates that utilities provide a capacity product for sale to meet the ESS's RA obligation. The Joint Utilities state that the Commission cannot force a utility to sell certain capacity products in the FERC-jurisdictional wholesale market to specific counterparties. Second, they argue that Commission cannot set the price for the sale of capacity products in the FERC-jurisdictional wholesale market. Thus, the Commission may not require the Joint Utilities

[35] Joint Utilities Opening Comments at 2.
[36] *Id.* at 10-11.

to engage in specific wholesale transactions at prices set by the Commission. The Joint Utilities conclude that such activity "impermissibly regulates wholesale markets."[37]

The Joint Utilities point out that WRAP participants will be required to take part in the WRAP operations program and must be ready to hold back surplus capacity to meet the capacity shortfalls of other WRAP participants on a rolling weekly basis during binding seasons. They argue that requiring WRAP participants to also make excess capacity available to the state program may hinder the WRAPs capacity sharing mechanism and undermine the regional program's ability to leverage the resource and load diversity in its footprint.[38]

The Joint Utilities state that an RFO, while not requiring utilities to enter wholesale transactions, also raises jurisdictional concerns because it creates a state-mandated wholesale market to only a subset of potential purchasers. The Joint Utilities argue that this scenario "undermines the wholesale market and provides a competitive advantage to Oregon ESSs."[39]The Joint Utilities also object to the RFO, asserting it is contrary to the WRAP process by forcing a utility, rather than the WRAP to determine whether it has sufficient or excess capacity, ignores opportunities within the WRAP to trade load obligations, and may interfere with a utility's participation in day-ahead markets.[40]

e. The ESS Group

The ESS Group reiterates that a CBC is an alternative to the state TFS requirement, intended to ensure a commercially viable option for direct access customers. The ESS Group points out that PGE has "extensive capacity" connected to its system and that, if the Joint Utilities lack sufficient capacity and transmission to offer a CBC, they may present evidence in docket UM 2024.

The ESS Group argues that a CBC would not violate federal law and is consistent with the Commission's authority to establish retail rates charged to the end-use customers of PGE and PacifiCorp.[41] The ESS Group notes that Oregon law allows non-residential customers to purchase energy, capacity, or both from an ESS.[42] The ESS Group characterizes the cases referenced by the Joint Utilities in their arguments as "off-point and irrelevant" and distinguishes the CBC proposed here from the circumstances of those cases.[43] The ESS Group clarifies that the proposed CBC is a cost-based rate charged by a utility to a direct access customer to include the direct access customer within the utility's own WRAP forward showings, and not a forced sale of capacity to ESS.[44]

[37] *Id.* at 11-12.
[38] *Id.* at 13.
[39] *Id.* at 14.
[40] *Id.* at 14-15.
[41] ESS Group Joint Reply Comments at 13 (citing FERC v. *Elec. Power Supply Ass'n,* 577 U.S. 260, 267 (Jan. 25, 2016).).
[42] *Id.* at 14, generally referencing ORS 757.601(1), 757.600(6) & 757.600(14).
[43] *Id.* at 14-15.
[44] *Id.* at 15.

The ESS Group asserts that in arguing the CBC would cause cost-shifting, the Joint Utilities assume that a CBC would be set too low to recover the utility's reasonable costs of supplying RA service. The ESS Group explains that under this recommendation, the CBC would be developed in docket UM 2024, where the utilities could propose a reasonable charge .[45] The ESS Group notes that in developing the CBC, the Joint Utilities also could account for lost opportunity costs, just like any other cost-of-service rate, any risk of fluctuating costs to provide RA may be resolved via periodic rate updates. The ESS Group concludes that if customers choose a cost-based utility CBC because the charge is lower than the equivalent product on the market, that is a more efficient outcome that does not harm customers. Finally, the ESS Group notes that the issue is whether it is commercially feasible for ESSs to meet the WRAP or state program TFS requirements at all.[46]

The ESS Group states that the Joint Utilities mischaracterize this proposal and argue that the RFO would be a reporting mechanism to ensure the utilities are not imprudently abusing their market power by withholding WRAP-compliant capacity or transmission from ESSs making reasonable offers to purchase it. The ESS Group notes that, contrary to Staff's assertions, the Joint Utilities' response to the RFO proposal indicates that the utilities may not offer such capacity bilaterally to ESSs.[47]

Analysis

The ESS Group provides sufficient evidence, individually and collectively, that acquisition of transmission capacity in the region to satisfy the TFS requirement in either the WRAP or state program will be difficult, given the current transmission practices and existing transmission constraints in the region. Accordingly, some adjustment to Staff's proposal is necessary to allow for near-term flexibility. Brookfield suggested a change, which should be included to ensure that the waiver limitations are not more restrictive than those under the WRAP tariff.

The ESS Group's recommendation is that the Commission establish an alternative to the TFS in the proposed rules, to maintain and facilitate continued development of Oregon's competitive retail market. The ESS Group recommends that the Commission direct stakeholders in docket UM 2024 to work on an alternative to the TFS requirement. In the alternative, NIPPC requests the Commission conduct a status update prior to the first state program filing.

The Joint Utilities correctly point out that the proposed rules represent a change from current transmission procurement in the region and are designed to require all LREs, utilities and ESSs alike, to ensure RA by meeting the same capacity and transmission requirements. However, it is not clear that utilities and ESSs currently possess the

[45] *Id.* at 16.
[46] *Id.* at 19.
[47] *Id.* at 20.

"identical" ability to obtain long-term firm transmission in every situation, as the Joint Utilities claim. Staff and Joint Utilities list procurement options that may not be viable or available in the near-term and may not provide ESSs with the ability to secure adequate, long-term transmission commitments for the near future. The Joint Utilities contend that a potential jurisdictional issue may prohibit the adoption of the proposed alternatives.

Staff acknowledges that the rules are an initial attempt to promote RA in Oregon and Staff further "expects discussion and refinement to continue through implementation."[48] Staff also notes that an RFO alternative may be considered in the future if it would aid in RA planning.

In addition, Staff and the Joint Utilities both note that state program participants may request a waiver for a portion of the TFS in the near-term. Brookfield's proposed modification to the waiver restrictions provide a reasonable resolution to address the current difficulties of transmission procurement and to align the state and regional program waiver requirements. Neither the Joint Utilities nor Staff provided comment on Brookfield's proposal.

Recommendation:

Adopt Staff's proposed rules for the state program, as modified by Brookfield's recommended, additional language to 860-095-0040(9)(e):

A State Participant cannot use waiver condition (9)(a) or (9)(b) for the same path for consecutive compliance periods <u>if the Qualified Regional Program would preclude use of such waiver</u>.

4. *Direct Access Customers Participating in One- and Three-year Programs, and Five-year Program Customers Paying Transition Adjustments*

NIPPC recommends that the proposed rules should clearly state that the incumbent utility is the entity responsible for providing RA for customers enrolled in the one-year and three-year direct access programs, as well as five-year direct access program customers still paying transition charges. Calpine and Brookfield support this position. The Joint Utilities oppose this recommendation.

a. NIPPC

NIPPC states that the Commission's IRP guidelines require an electric utility to include one- and three-year program customers in its load-resource balance. NIPPC presents a description of transition charges from PGE's website for three-year opt out customers that states transition adjustment charges "will incorporate costs for both existing and new resources, if any, expected to begin providing service to customers during the

[48] *See* Staff's rulemaking principles, summarized above at 3-4.

[three] -year term and will be known at the time the customer opts-out."[49] NIPPC states that 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. NIPPC asserts that because the utility is including one-year and three-year program customers in their IRP load-resource balances, those one-year and three-year program customers should also be included in the utility's load-resource balance in its RA informational filings and TFS in either the WRAP or state program.

NIPPC argues that requiring the one- and three-year program customers to pay an ESS to supply WRAP-compliant RA via either program would be charging such customers twice for the same product. Additionally, NIPPC contends it would be logistically difficult for an ESS to cost-effectively plan for and provide RA to one-year and three-year program customers. NIPPC explains that 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 TFS requirement because it is expected that the customer will return to utility service at the end of its one- or three-year term. NIPPC asserts that the different election windows used by the utilities also inhibit an ESS from effectively planning RA for such customers.

NIPPC also recommends that five-year program customers still paying transition adjustments should also be covered by the incumbent utility's RA showings. NIPPC explains that PGE itself agreed with this position during the debate over its proposed resource adequacy capacity (RAD) charge for new load direct access customers, arguing 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."[50] NIPPC concludes that requiring such customers to pay the transition charge while also paying their ESS to procure capacity would therefore result in a double charge.

In the alternative, NIPPC proposes that at a minimum, the rules should not require the ESS to be the LRE for newly enrolled five-year program customers until after completion of the first Summer Season in the WRAP. NIPPC recommends following changes in several, proposed rule provisions to enact its recommendations:

> 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 Integrated Resource Plan and five-year program</u>

[49] NIPPC Opening Comments at 30.
[50] *Id.* at 34

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.

* * * *

Proposed OAR 860-095-0020(2): The Informational Filing for an Electric Company must include: (a) A monthly P50 Peak Load Forecast 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 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 Integrated 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.[51]

b. Joint Utilities

The Joint Utilities oppose NIPPC's recommendation. While the Joint Utilities note they are required to continue to plan to serve one- and three-year program customers, that planning is premised on the assumption that the customers will return to cost-of-service rates upon the end of the one- or three-year period. The Joint Utilities explain that during the time when the direct access customer is served by an ESS, however, the Joint Utilities are not planning to serve those customers.

The Joint Utilities note that the transition adjustments specifically assume that the Joint Utilities are not holding resources back to serve direct access customers but are instead using those freed-up resources for the benefit of remaining cost-of-service customers. The Joint Utilities argue that requiring utilities to assume the costs of RA compliance for one- and three-year program customers will undermine the premise of the transition adjustments because there will be no freed-up resources for purposes of calculating the transition adjustment.

The Joint Utilities note that the statements used by NIPPC, appearing to show that PGE retains responsibility for securing RA, were made in advance of development of the WRAP framework, which adopted a specific and narrower definition for RA focused on a year-ahead forward showing. They contend that the statements cited by NIPPC refer to a broader provider of last resort reliability function encompassing operational and planning time horizons and hence are not relevant to the current state program. They explain that PGE's planning for short-term direct access customer load encompasses the broader provider of last resort obligation but not the specific definition of RA contained in the WRAP framework. Further, they note that transition adjustments may be a credit to customers. The Joint Utilities state that PGE offered to pay customers leaving cost of service certain amounts last fall. PGE argues that it makes no sense that PGE could pay customers to leave, and "simultaneously provide a valuable service on the same terms that it provides an identical service to cost of service customers at a higher price."[52]

c. ESS Group

The ESS Group states that the Joint Utilities' arguments are contrary to PGE's previous position. The ESS Group notes that PGE previously agreed that customers still paying transition charges, such as one-year and three-year customers, should not be subject to an RA or RAD charge in docket UE 358. The ESS Group explains that this issue was raised in the informal phase of this rulemaking, but no utility expressed any reason why

[51] NIPPC Opening Comments at 35-36 (Jan. 8, 2024).
[52] Joint Utilities Opening Comments at 15-16.

ESSs should be responsible to conduct duplicative long-term RA planning for one- and three-year customers when the utility already does so. NIPPC's recommendation in the formal rulemaking is based on the lack of prior objection from the utilities and on PGE's own prior representations to the Commission in docket UE 358. The ESS Group asserts that, even if PGE's statements were made prior to the institution of the WRAP, the transition adjustments and/or CBC could be adjusted for one-year and three-year customers to ensure any added costs of WRAP compliance are included in the applicable charges to the customer.

Analysis

The basis for NIPPC's recommendation is reasonable given the short time frame of direct access customers' service by ESSs and the proposed alignment with the IRP load-resource balance process. However, it is not clear from the information submitted by stakeholders in this docket whether the transition charges paid to utilities by one-, three- and five-year direct access customers are intended to or actually support RA efforts for those customers. For example, Joint Utilities' comments indicate they do not plan RA for direct access customers in the way envisioned by the WRAP or proposed state program. Accordingly, resolution of this question is necessary before NIPPC's recommendation can be adopted.

Recommendation:

Direct Staff, utilities, and stakeholders to investigate address RA responsibilities for direct access customers in docket UM 2024 prior to the date of the first state program RA filing, proposing adjustments to the UM 2024 procedural schedule to accomplish this. Should Staff determine that addressing these issues on that timetable in UM 2024 is not feasible, Staff should present a proposal for addressing these issues at an upcoming public meeting.

5. *Other Proposed Rule Changes and Modifications*

   f. Idaho Power

OAR 860-095-0010(7): *Informational Filing* definition:

Idaho Power proposes modifications to the definition of "Informational Filing", intended to simplify and clarify the meaning and purpose of an "Informational Filing." The proposed definition includes a general requirement for "* * * all underlying or related data needed to support such explanation". Idaho Power states that, definitions should not include requirements and that requirements should be distinct from definitions. Idaho Power states that the draft rules separately identify what "must" be submitted as part of an Informational Filing. For clarity and refinement, Idaho Power proposes to strike text from the definition as follows:

> "Informational Filing" means a written explanation of a Load Serving Entity's strategy to address Resource Adequacy ~~and all underlying or related data needed to support such explanation~~.

OAR 860-095-0010(15): *Regional Forward Showing* definition:

Idaho Power proposes a modification to the definition of "Regional Forward Showing." Idaho Power explains that the WRAP is two distinct elements—a forward showing program and an operations program. Because the proposed RA rules only focus on the forward showing work, Idaho Power explains it is not appropriate for regional participants to provide both forward showing and operations "data, forecasts, or submittals" as required for compliance with the (WRAP) regional program. Idaho Power proposes an addition to the definition of *Regional Forward Showing* to only include data that support forward showing, or planning, program compliance:

> "Regional Forward Showing" means any data, forecasts, or submittals required by a Qualified Regional Program to support planning program compliance by a Regional Participant.

OAR 860-095-0020(2)(a): *Qualified Regional Program Data*:

For similar reasons as addressed above, Idaho Power proposes the following refinements to 860-095-0020(2)(a) of the Informational Filing requirements:

> Qualified Regional Program data as provided by the Regional Participant that was developed for utilization in ~~A monthly P50 Peak Load Forecast and Effective Load Carrying Capability curve over a period of the greater of four years or the longest available time timeline from a Qualified Regional Program using methods consistent with the outputs of~~ the Qualified Regional Program's Advisory Forecast and mirrors the number of years of information provided in the Advisory Forecast.

OAR 860-095-0020(2)(b): *Transmission Rights Narrative*:

Idaho Power notes that the WRAP is based on two seasons of the year and is not a year-round program. Idaho Power states that OAR 860-095-0020(2)(b) should align with the seasonal aspect of WRAP and recommends the following proposed modifications:

> A high-level discussion, not to include confidential information, ~~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 any open position, and any expected constraints or difficulties in filling any open positions. The information supplied should cover the time period of the two forthcoming Qualified Regional Program operating seasons.

OAR 860-095-0020(c): *Advisory Forecast Inputs*:

Idaho Power states that the intent of this subpart is to compare inputs rather than outputs. Idaho Power contends it can provide meaningful explanations of any differences between what it supplies to WPP to create the Advisory Forecast and can then distinguish those inputs from what is used in Idaho Power's IRP. Idaho Power recommends the following modifications:

> A description of information supplied to produce the Advisory Forecast and explanation of any differences between that information and comparable inputs to ~~any notable deviations between the load forecast, Qualified Capacity Contributions, or Planning Reserve Margin contained in a Qualified Regional Program's Advisory Forecast and what is used in~~ the Electric Company's Integrated Resource Plan analysis and associated action plan.

The ESS Group noted in its reply comments that it does not oppose the above clarifications to the proposed rules.[53] No other comments on Idaho Power's proposed modifications were submitted. The recommended modifications provide clarity to the definitions and the input comparison and aligns the narrative with WRAP.

Recommendation:

Adopt the above changes as recommended by Idaho Power.

g. Staff

OAR 860-095-0040(11): *Penalties for Non-compliance*:

Staff explains that the intent of proposed OAR 860-095-0040(11) is to provide the penalty for noncompliance under the state program pursuant to the Commission's authority set forth in O.R.S. § 756.990. A "fine" is generally associated with criminal penalties. Staff adds that the use of the term "fine" could lead to confusion regarding agency fees, which requires legislative approval. Staff proposes modifying proposed OAR 860-095-0040 to eliminate any ambiguity while retaining the original intent for the Commission to impose penalties for noncompliance with RA rules.[54] Staff suggests that OAR 860-095-0040(11) be modified to read as follows:

> A State Participant whose plan is not approved 60 days after the Commission identified deficiencies shall be subject to an appropriate penalty as determined by the Commission ~~a fine,~~ including revocation of

[53] ESS Group Joint Reply Comments at 3 n 2.
[54] Staff Opening Comments at 1-3 (Jan. 10, 2024).

Electric Service Supplier certification ~~or some other appropriate penalty determined by the Commission~~.

(a) The Commission shall assess ~~fines~~ penalties on a per-MW basis for monthly capacity or transmission deficiencies and based on the ~~fining~~ methodology of a Qualified Regional Program.

(b) Revocation of Electric Service Supplier certification shall only be considered after twice failing to cure a deficiency and following an investigation by the Commission.

No comments on Staff's proposed modifications were submitted. Staff provides a sufficient explanation that modification will eliminate potential ambiguity and confusion. Further, Staff's proposed language of "an appropriate penalty as determined by the Commission" is a sufficient description of the Commission's discretion under O.R.S. § 756.990. The additional language that follows may arbitrarily limit the Commission's actions in certain scenarios. Therefore, AHD recommends eliminating the proposed rule language after "an appropriate penalty as determined by the Commission:"

> A State Participant whose plan is not approved 60 days after the Commission identified deficiencies shall be subject to an appropriate penalty as determined by the Commission.

Recommendation:

Adopt the above changes as recommended by Staff and modified by AHD.

h. Joint Utility

OAR 860-095-0020(2): *Electric Company Information Filing Contents*:

The Joint Utilities state concern that the language in proposed OAR 860-095-0020(2) requires the provision of certain information that reveals a utility's position with regards to transmission rights. The Joint Utilities explain that the market for transmission is even less liquid than that for generation capacity, and publicly providing this information to market competitors participating in utility IRP proceedings could harm to cost-of-service customers. They argue that disclosure of this information to other entities that are competing for the same transmission rights would be inappropriate.[55] The Joint Utilities recommend protecting such information at the same level as the inputs to the regional forward showing. The Joint Utilities request that certain information in the informational filing be made available only "Qualified Parties"—defined in the proposed rules as the Commission, Commission Staff, and the Oregon Citizens' Utility Board (CUB). The Joint

[55] Joint Utilities Opening Comments at 17.

Utilities propose adding the following subsection (d) to proposed OAR 860-095-0020(2) of the proposed rules:

> <u>(d) Commercially and Competitively-sensitive information and data provided in the Informational Filing may be redacted or provided only to Qualified Parties.</u>

No comments on the Joint Utilities' proposed modification were submitted. The additional, proposed language provides additional protection for sensitive utility data.

Recommendation:

Adopt the above addition as recommended by the Joint Utilities.

i. NIPPC

OAR 860-095-0030(4): *Protected Treatment of ESS Filings*:

NIPPC states that the proposed rule would require this commercially sensitive material be provided to qualified parties, if they request it and sign the modified protective order, but does not foreclose the potential requirement to also supply the material to other parties. NIPPC explains that is in contrast to the rules governing emissions planning reports, which state that only certain parties—CUB, Staff, and non-market participants—may access certain categories of commercially sensitive information. NIPPC recommends modification to clarify that parties other than qualified parties cannot obtain access to the ESS's Regional Forward Showing submission to the WRAP. NIPPC recommends the following modification to proposed OAR 860-095-0030(4):

> (4) <u>Availability of Information:</u>
>
> <u>(a)</u> A Regional Participant's most recent Regional Forward Showing submission to its Qualified Regional Program must be made available <u>for review only</u> to Qualified Parties <u>and only</u> upon request pursuant to a Modified Protected Order.
>
> <u>(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.</u>

> (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.

OAR 860-095-0040(5): *State Program Confidentiality Protections*:

NIPPC states that 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. NIPPC explains that ESSs 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.

NIPPC argues that, as drafted, the proposed rules might allow parties other than Staff to 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." NIPPC opposes review of a state participant's Binding Forward Showing by non-Staff parties.

NIPPC contends that information regarding an ESS's current market position and compliance resources is highly sensitive. In the parallel WRAP, no party other than the necessary WPP employees, agents, consultants or Independent Evaluators will be permitted to review the highly sensitive Forward Showing.

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 wants 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 RA 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 WRAP participant's most recent Regional Forward Showing as follows:

Alternative proposed OAR 860-095-0040(5) addition: 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.

OAR 860-095-0040(9): *State Program TFS Requirement*:

NIPPC continues to recommend that if the WRAP-style firm transmission requirement is included in Oregon's rules, the rules should, at a minimum, 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: * * *.

No comments on NIPPC's proposed modifications were submitted, other than general statements of support from Brookfield and Calpine. NIPPC's proposed edits for confidential information, including its proposed alternative for proposed OAR 860-095-0040(5) provide availability of the information to non-market participants in addition to Staff and CUB via a modified protective order. The additional language proposed OAR 860-095-0040(9) provides clarity regarding the transmission types that will satisfy the requirement and mirrors WRAP requirements.

Recommendation:

Adopt the above changes as recommended by NIPPC, including the alternative, proposed modification for 860-095-0040(5).

AHD RECOMMENDATION:

Adopt the proposed, permanent, new rules presented in Attachment 1.

AR 660 – Draft Attachment 1

RULES PROPOSED:

860-095-0000, 860-095-0010, 860-095-0020, 860-095-0030, 860-095-0040

ADOPT: 860-095-0000

RULE TITLE: Scope and Applicability of Rules

RULE SUMMARY: Provides the purpose of the Division 860-095 rules establishing resource adequacy filing requirements and a resource adequacy state-level compliance program administered by the Public Utility Commission of Oregon.

RULE TEXT:

(1) The rules in this division prescribe the filing requirements for provision of Resource Adequacy information, and the filing requirements and binding elements for the Public Utility Commission of Oregon (Commission) - administered Resource Adequacy program.

(2) Upon request or its own motion, the Commission may waive any of the rules in this division for good cause shown. A request for waiver must be made in writing, unless otherwise allowed by the Commission.

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756

STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 757.649, ORS 757.659

ADOPT: 860-095-0010

RULE TITLE: Definitions for this Division

RULE SUMMARY: Establishes definitions for the purposes of these rules.

RULE TEXT:

(1) “Advisory Forecast” means any modeling outputs created by a Qualified Regional Program that are presented but not used as part of the Qualified Regional Program’s binding elements.

(2) “Binding Forward Showing” means a filing used by a State Participant to show compliance with the State Program.

(3) “Compliance Resource” means the resource(s) or resource-specific contracts used by a State Participant to meet the load requirements of the Binding Forward Showing.

(4) “Electric Company” has the same meaning as ORS 757.600(11).

(5) “Electricity Service Supplier” has the same meaning as ORS 757.600(16).

(6) “Emissions Planning Report” means a filing made by an Electricity Service Supplier to show compliance with ORS 757.649(1)(f).

(7) “Informational Filing” means a written explanation of a Load Serving Entity’s strategy to address Resource Adequacy~~ and all underlying or related data needed to support such explanation~~.

(8) “Integrated Resource Plan” means an Electric Company’s written plan to satisfy the requirements of OAR 860-027-0400 and Commission Order Nos. 07-002, 07-047, and any future orders impacting filing requirements.

(9) “Load Serving Entity” means an Electric Company or Electric Service Supplier.

(10) “P50 Peak Load Forecast” means a peak load forecast prepared on a basis, such that the actual peak load is statistically expected to be as likely to be above the forecast as it is to be below the forecast.

(11) “Planning Reserve Margin” means an increment of supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages, or lower availability of resources, expressed as a percentage of the applicable peak load forecast.

(12) “Qualified Capacity Contribution” means the portion of the nameplate capacity of a compliance resource that can be expected to provide capacity to meet customer demand calculated using a Commission or Qualified Regional Program approved methodology.

(13) “Qualified Parties” means Commission Staff and Oregon Citizens’ Utility Board employees who execute a modified protective order.

(14) “Qualified Regional Program” means a Commission-approved regional reliability planning and compliance program that addresses Resource Adequacy through processes and conditions established in a FERC-approved tariff.

(15) “Regional Forward Showing” means any data, forecasts, or submittals required by a Qualified Regional Program to support planning program compliance by a Regional Participant.

(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

(17) “Resource Adequacy” means the expected ability of a Load Serving Entity to supply aggregate electric power and energy to meet the requirements of their consumers with a sufficient degree of reliability and plan to meet future demand with sufficient supply-side and demand side resource.

(18) “State Participant” means a Load Serving Entity that is not a Regional Participant.

(19) “State Program” means the Resource Adequacy compliance program administered by the Commission applicable to State Participants.

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756

STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 757.649, ORS 757.659

ADOPT: 860-095-0020

RULE TITLE: Electric Company Informational Filing Requirements

RULE SUMMARY: Establishes resource adequacy filing requirements for Electric Companies regulated by the Public Utility Commission of Oregon.

RULE TEXT:

(1) Electric Companies must provide an Informational Filing to the Commission as a part of their Integrated Resource Plan. The Electric Company's Informational Filing must be included as a chapter to the Integrated Resource Plan that incorporates the Advisory Forecast from a Qualified Regional Program and contains a discussion about how the overall resource strategy interacts with Resource Adequacy concerns.

(2) The Informational Filing for an Electric Company must include:

(a) Qualified Regional Program data as provided by the Regional Participant that was developed for utilization in ~~A monthly P50 Peak Load Forecast 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 and mirrors the number of years of information provided in the Advisory Forecast.

(b) A high-level discussion, not to include confidential information, ~~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. The information supplied should cover the time period of the two forthcoming Qualified Regional Program operating seasons.

(c) A description of information supplied to produce the Advisory Forecast and explanation of any differences between that information and comparable inputs to ~~any notable deviations between the load forecast, Qualified Capacity Contributions, or Planning Reserve Margin contained in a Qualified Regional Program's Advisory Forecast and what is used in~~ the Electric Company's Integrated Resource Plan analysis and associated action plan.

(d) Commercially and Competitively-sensitive information and data provided in the Informational Filing may be redacted or provided only to Qualified Parties.

(3) All outputs of a Qualified Regional Program's most recent Advisory Forecast must be included with the Informational Filing. These may be included in the Informational Filing or as an Appendix chapter to the Integrated Resource Plan.

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

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756

STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 756.070, ORS 756.105, ORS 757.659

ADOPT: 860-095-0030

RULE TITLE: Electricity Service Supplier Informational Filing Requirements

RULE SUMMARY: Establishes resource adequacy filing requirements for Electricity Service Suppliers regulated by the Public Utility Commission of Oregon.

RULE TEXT:

(1) Electricity Service Suppliers must submit an Informational Filing with the Commission every other year.

(a) The Informational Filing may be filed as a part of the Emissions Planning Report filing.

(b) The Informational Filing must contain a discussion about how the overall resource strategy interacts with Resource Adequacy concerns.

(2) The Informational Filing for an Electricity Service Supplier must include:

(a) A monthly P50 Peak Load Forecast 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.

(b) 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.

(3) All publicly available outputs of a Qualified Regional Program's most recent Advisory Forecast must be included with the Informational Filing. These may be included as an appendix chapter.

(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 Oregon Citizens' Utility Board, and nonprofit organizations engaged in environmental advocacy that do not otherwise participate in electricity markets.

(5) As part of the forecast of monthly P50 Peak Load Forecast and monthly forecast of transmission requirements, an Electricity Service Supplier must use current load levels or provide reasonable substitutes of the load forecast. An Electricity Service Supplier is responsible for demonstrating that the substitute load forecast is reasonable.

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756

STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 756.649, ORS 757.659

ADOPT: 860-095-0040

RULE TITLE: State Program Requirements

RULE SUMMARY: Establishes a resource adequacy compliance program.

RULE TEXT:

(1) Any Electric Company or Electricity Service Supplier that is not a Regional Participant must comply with the State Program requirements.

(2) State Participants must file a Binding Forward Showing with the Commission for approval no later than April 1 of every odd-numbered year. A State Participant's initial Binding Forward Showing must be filed no later than April 1, 2025.

(3) State Participants must use a 1 event-day in 10-year Loss of Load Expectation standard when submitting their Binding Forward Showing.

(4) State Participants must use a Planning Reserve Margin and Qualified Capacity Contribution consistent with a Qualified Regional Program or other Commission-approved methodology.

(5) The Commission Staff ~~and Parties~~ should complete its compliance review for each State Participant within 90 days of filing the Binding Forward Showing. 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.

(6) A State Participant shall provide its monthly P50 Peak Load Forecast for the two-year period beginning July 1 of the filing year as part of their Binding Forward Showing.

(7) A State Participant must demonstrate that its Compliance Resources meet 95 percent of its monthly forecasted P50 load for twelve months beginning July 1 of the filing year and 80 percent of the monthly forecasted P50 load for the following twelve months plus a Planning Reserve Margin each month. A State Participant is not bound to meet its load with its Compliance Resources in actual operations.

(8) As part of the forecast of monthly P50 Peak Load Forecast and monthly forecast of transmission requirements, an Electricity Service Supplier must use current load levels or provide reasonable substitutes of the load forecast. An Electricity Service Supplier is responsible for demonstrating that the substitute load forecast is reasonable.

(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:

(a) The State Participant is experiencing enduring transmission constraints;

(b) Future firm Available Transfer Capability is expected;

(c) An applicable portion of the State Participant's existing transmission service rights is expected to be derated or out-of-service; or

(d) Expected counterflow directly between two balancing authority areas from another entity supports the State Participant's transmission of energy from generation source to load sink. This counterflow cannot already be offsetting transmission of energy for another State Participant or Regional Participant. The State Participant requesting the exception shall include a written acknowledgement from the other entity that it is aware of such an exception request.

(e) A State Participant cannot use waiver condition (9)(a) or (9)(b) for the same path for consecutive compliance periods if the Qualified Regional Program would preclude use of such waiver.

(10) If the Commission deems that a State Participant's Binding Forward Showing does not meet the criteria for approval, the Commission shall identify deficiencies and give the State Participant 60 days to remedy their Binding Forward Showing to meet the criteria for approval.

(11) A State Participant whose plan is not approved 60 days after the Commission identified deficiencies shall be subject to an appropriate penalty as determined by the Commission. ~~revocation of Electric Service Supplier certification~~.

~~(a) The Commission shall assess on a per-MW basis for monthly capacity or transmission deficiencies and based on the fining methodology of a Qualified Regional Program.~~

~~(b) Revocation of Electric Service Supplier certification shall only be considered after twice failing to cure a deficiency and following an investigation by the Commission.~~

STATUTORY/OTHER AUTHORITY: ORS 183, ORS 756

STATUTES/OTHER IMPLEMENTED: ORS 756.040, ORS 756.070, ORS 756.105, ORS 756.990, ORS 757.649, ORS 757.659