BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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| In the Matter of Public Utility Commission of Oregon: Investigation Into Resource Adequacy in Oregon | )<br>)<br>)<br>)<br>)<br>) | DOCKET NO. UM 2143<br><br>CALPINE ENERGY SOLUTIONS, LLC'S COMMENTS ON STAFF'S STRAW PROPOSAL |

## I. INTRODUCTION AND SUMMARY

Calpine Energy Solutions, LLC ("Calpine Solutions") hereby submits its comments on Staff's Straw Proposal to the Public Utility Commission of Oregon ("OPUC" or "Commission"). Calpine Solutions appreciates the opportunity to provide its feedback on the Staff Straw Proposal, as amended by errata filing on October 5, 2022 (hereafter, "Staff's Straw Proposal").

As explained below, Calpine Solutions generally supports the overall concept of Staff's Straw Proposal that would provide three options for an electricity service supplier ("ESS") and long-term direct access ("LTDA") and new load direct access ("NLDA") customers to meet the resource adequacy ("RA") requirements of this Commission. Specifically, Calpine Solutions supports proving the following three general options: (1) the ESS's participation in the Western Power Pool's ("WPP's") Western Resource Adequacy Program ("WRAP") coupled with the filing of a three-year action plan with the Commission; (2) the ESS's compliance with OPUC-administered RA rules coupled with a three-year informational filing to this Commission; *or* (3) the applicable customer's payment to the relevant utility of an RA backstop charge for utility-supplied RA. However, much more detail is needed to clarify these options and allow load responsible entities ("LREs") and direct access customers to evaluate the options to make an informed decision.

Calpine Solutions supports the Commission building off of the work already completed in the WRAP, but also believes there is potential value in an OPUC-specific RA option for non-participants in the WRAP and the third option of an RA backstop charge. There are valid reasons an entity, especially an ESS, may elect to participate in an OPUC-administered option as opposed to the WRAP, depending on its circumstances, including the significant administrative costs of participating in the WRAP and the limited flexibility afforded by the 24-month withdrawal notice for participants in the WRAP. Additionally, certain requirements of the larger WRAP may not be necessary to ensure RA to the two Oregon utility's balancing authorities. Calpine Solutions' comments below will address each of the three options and proposed refinements and clarifications to those option, and we will then address concerns with overlapping Provider of Last Resort ("POLR") issues being addressed in AR 651.

## II. COMMENTS

### A. Option One: WRAP Participation

Calpine Solutions agrees that there should be a specific option to comply through participation in the WRAP, but Staff's Straw Proposal requires significant clarification of how this option would work. As explained below, Calpine Solutions recommends that the WRAP-based option contain two main requirements: (1) demonstration by the LRE that it is a binding participant in good standing in the WRAP; and (2) an information-only filing with the Commission of the LRE's action plans to meet its load requirements for the next three years.

#### 1. WRAP Background

At the outset, it is important to highlight the main requirements of the WRAP for entities that elect to participate in that program.[1] The WRAP contains two binding seasons where its RA

[1] The WRAP requirements, as currently proposed for approval, are contained in detail in the WPP's WRAP Tariff filing in Federal Energy Regulatory Commission Docket No. ER22-

requirements are relevant. Those binding seasons are limited to the summer season, which includes June 1 through September 15, and the winter season, which includes November 1 through March 15.[2] During other times, there are no specific RA requirements in the WRAP. For the binding seasons, there are two basic compliance obligations: the forward showing and the operational program.

**a. WRAP's Forward Showing**

The first major requirement of the WRAP is that each participant provides a forward showing seven months prior to each summer season and each winter season to demonstrate it has available capacity to meet its forecasted load, including a planning reserve margin based on a one-in-10-year probability for a loss of load event ("one-in-10 LOLP").[3] The WRAP Tariff includes very detailed descriptions of the types of resources that can qualify for use to meet the participant's forward showing requirement to satisfy its load obligations. In general, the forward showing capacity requirement may be met with participant-owned resources or resource-specific supply agreements.[4] Thus, except for a limited legacy treatment exception, a traditional "seller's choice" contract that does not specifically identify the resource that will be used to meet the seller's supply obligation may not necessarily be used in the WRAP. However, participants may use contracts such as the Western Systems Power Pool Schedule C ("WSPP Schedule C") that

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2762, available at https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=er22-2762&sub_docket=all&dt_from=1960-01-01&dt_to=2022-11-11&chklegadata=false&pagenm=dsearch&date_range=custom&search_type=docket&date_type=filed_date&sub_docket_q=allsub.

[2] *See* WPP's WRAP Submittal Letter, FERC Docket No. ER22-2762, pp. 17 (Aug. 31, 2022) (hereafter "WPP's FERC Submittal Letter"); WRAP Proposed Tariff, FERC Docket No. ER 22-2762, § 1, definitions of "Binding Season", "Summer Season", & "Winter Season" (Aug. 31, 2022) (hereafter "Proposed WRAP Tariff").

[3] WPP's FERC Submittal Letter, pp. 14-29.

[4] WPP's FERC Submittal Letter, pp. 21-23; Proposed WRAP Tariff, §§ 16.2.6.

identify the supply resource and ensures such resource is not committed for use to meet another entity's RA requirements. Similarly, the WRAP allows use of a "system sale" of capacity from system of resources where the capacity sold is surplus to the seller's estimated needs, and the WRAP includes legacy treatment for certain contracts that might not otherwise comply if the resource to be used can be reasonably ascertained by WRAP.[5] Participants can also rely upon an "RA Transfer" arrangement where another participant effectively assumes all or part of the obligations in the program for another participant.[6] There is also an exception to the forward showing capacity requirement if the participant's resource experiences a catastrophic failure that cannot be repaired with commercially reasonable efforts by the forward showing deadline.[7]

The forward showing also includes a transmission requirement.[8] The WRAP explained to the Federal Energy Regulatory Commission ("FERC") 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."[9] As proposed to FERC, the WRAP Tariff requires that the participant demonstrate firm transmission service rights sufficient to deliver a MW quantity equal to at least 75 percent of the MW quantity of its forward showing capacity requirement for each binding season.[10] It also includes four exceptions to the forward showing's 75-percent firm transmission requirement: the Enduring Constraints exception, the Future Firm Available

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5 WPP's FERC Submittal Letter, p. 22; Proposed WRAP Tariff, § 16.2.6.2).
6 Proposed WRAP Tariff, § 16.2.7.
7 WPP's FERC Submittal Letter, p. 24.
8 Proposed WRAP Tariff, § 16.3.
9 WPP's FERC Submittal Letter, p. 23.
10 *See generally* Proposed WRAP Tariff, § 16.3; WPP's FERC Submittal Letter, pp. 23-24.

Transmission Capability ("ATC") Expected exception, the Transmission Outages and Derates exception,  and the Counterflow of a Resource Adequacy Resource exception.[11] For example, the 75-percent firm transmission requirement is relaxed if the participant can "demonstrate that there was remaining available transmission transfer capability (i.e., non-firm ATC after the fact) for all [Critical Capacity Hours] in the same season of the most recent year for which [Critical Capacity Hours] have been calculated" and other specified evidence of reasonable assurance transmission will be available by the operations period. [12]  However, certain limitations WRAP proposed for two of these four exceptions remains subject to an unresolved protest in the FERC proceeding, and further refinements are possible through the forthcoming business practices or other tariff amendments before the first binding season in 2025.

In the forward showing program, the WRAP will notify the participant of any errors or deficiencies within 60 days of the forward showing, and the participant then has 60 days to cure any deficiencies.[13]  Thus, the forward showing deficiency may remain uncured for up to three months before the binding season.  If the deficiency is not timely cured, the participant is subject to a significant "Deficiency Charge" based on the revenue requirement of a new capacity resource subject to adjustments specifically designed to deter deficiencies.[14]

#### b. WRAP's Operational Program

Distinct from the forward showing, the second major feature of the WRAP is the "Operational Program" where the participant must actually meet its capacity needs and where participants that are surplus can be subject to hold-back and sharing through energy deployment

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11 WPP's FERC Submittal Letter, p. 25.
12 Proposed WRAP Tariff, §§ 16.3.2.1.
13 WPP's FERC Submittal Letter, p. 26.
14 WPP's FERC Submittal Letter, pp. 26-29; Proposed WRAP Tariff, § 17.

orders from their surplus capacity to support participants that are deficient leading up to the operating day.[15] Importantly, the WRAP Tariff does not require the participant to meet its capacity needs with the same exact portfolio identified in its forward showing, but does require updates as the operating day approaches to implement the program's hold-back and sharing requirements for any participant's real-time shortfalls.[16] Thus, similar to other planning exercises, the participant is free to meet its needs in the most economical and reasonable manner available to it, subject to the program's holdback and energy deployment requirements. But if the participant fails to meet its own needs and relies on energy deployment from others, it would be subjected to payments to other participants at prices with opportunity cost adjustments specifically designed to be higher than typical market prices.[17] Thus, in addition to the deficiency charge in the forward showing program, participants are also incented not to fall short in the operational timeframe due to the operational program's pricing design. The WRAP Tariff also includes "Delivery Failure Charges" for participants who fail to respond to WRAP energy deployment to support participants that fell short in the operational program.[18]

Thus, the WRAP provides participants with very strong incentives to meet their own resource adequacy needs in advance, but also provides participants with access to other participants' surplus capacity in the operations timeframe if necessary.

### c. WRAP's binding phase

WRAP moves to its binding phase in 2025. Participants must opt to become binding participants, subject to deficiency charges and the holdback requirements described above, for an

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15 WPP's FERC Submittal Letter, pp. 29-37.
16 WPP's FERC Submittal Letter, pp. 31-32.
17 WPP's FERC Submittal Letter, pp. 38-42.
18 WPP's FERC Submittal Letter, Affidavit of Ryan Roy, ¶¶ 28-33; Proposed WRAP Tariff, § 20.7.

initial binding season between Summer 2025 and Summer 2028.[19] Additionally, while the WRAP only requires that forward showings be made seven months in advance of the binding seasons, the program obligates the binding participants to comply with its requirements for at least 24 months because it contains a 24-month notice requirement to withdraw from the program.[20] Thus, binding participants are basically committed to meet WRAP requirements, including potential deficiency charges, for two years, not just the next forward showing period.

### 2. Comments on the Staff Straw Proposal's WRAP-Based Option

Calpine Solutions supports a WRAP-based option for compliance with any Oregon-specific RA rules, but encourages Staff to revise and clarify its initial proposal so as not to inadvertently deter participation in the WRAP. Along those lines, we offer the following proposed revisions to Staff's initial proposal.

#### a. There should be no OPUC-specific penalties assessed for non-compliance with the WRAP Tariff

First, Staff's Straw Proposal appears to suggest that the OPUC would potentially impose penalties upon an LRE opting to comply with Oregon-based rules through WRAP participation solely because the LRE failed in some manner to comply with the requirements of the WRAP.[21] Calpine Solutions opposes any penalties associated with the LRE's performance under the WRAP Tariff.

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19 WPP's FERC Submittal Letter, p. 68; Tariff, § 15.2; Tariff, § 1 (Definition of "Transition Period" is "Binding Seasons within the time period from June 1, 2025, through March 15, 2028, plus the time period required to implement the requirements and procedures of Part II of this Tariff applicable to Binding Seasons")

20 WPP's FERC Submittal Letter, pp. 65-66.

21 *See* Staff's Straw Proposal, p. 6 (stating the OPUC would require WPP participants to "demonstrate compliance with the regional program"); *id.*, p. 5 (stating "Parties that do not cure deficiencies may be subject to a fine").

As noted above, an LRE that fails to adequately meet the WRAP's forward showing and/or operational program requirements will be subjected to significant, and potentially severe, economic penalties under the WRAP Tariff. Additionally, the WRAP Tariff is designed to ensure that even if the participant experiences a shortfall in the operational program, the other participants would likely step in to assist with holdback capacity and energy deployment, subject of course to the payment at a hefty price. Thus, there would likely be no shortfall in energy needs, and any harm associated with the participant's shortfall would be charged to the participant that failed to meet its own load under the WRAP Tariff. In these circumstances, any additional penalty assessed by the OPUC would serve only to deter LREs from participating in the WRAP.

Further, it would be difficult to define what level of "non-compliance" with the WRAP would trigger such an OPUC-specific penalty. In the WRAP framework, "non-compliance" could arguably include many different actions or inactions, including: deficiencies in the initial forward showing; forward showing deficiencies that remained uncured after the 60-day cure period; a participant's request for holdback capacity and energy deployment from other participants in the operational program; a participant's failure to respond to energy deployment orders with its surplus capacity; or some subset or combination of those or other failures. Without specificity in the Commission's rules, LREs would be left to guess as to whether OPUC-imposed penalties may be triggered for different events or not. Any ambiguity would deter participation in the WRAP and frustrate the day-to-day decision-making process for any entity that decided to participate in WRAP.

In short, OPUC-imposed penalties for non-compliance with the WRAP would be counterproductive. At a minimum, the concept would require extensive further clarity and discussion before being proposed in rules. If, however, the Commission will adopt any such penalties, it is imperative that the provisions should apply equally to not only ESSs, but also to the utility's shareholders in the case of a utility that opts to meet the OPUC's RA requirement through the WRAP.

**b. The proposed three-year plan should be a non-binding action plan**

Second, the proposed three-year "action plan" included in Staff's Straw Proposal should be informational only, not a WRAP-style forward showing of capacity procured three years into the future. There should certainly be no penalties or adverse consequences for adjusting the manner of meeting the WRAP participant's RA requirements in the WRAP forward showing or operational program.

Specifically, Staff's Straw Proposal states: "RA plan must include three-year action plan that meets RA standard up to the following levels: 95% 1 year out, 90% 2 years out, 75% 3 years out."[22] Staff's Straw Proposal contains the same requirement for non-participants of WRAP, except that non-participants of WRAP would be assigned 5% higher levels of RA compliance as follows: 100% 1 year out, 95% 2 years out, 80% 3 years out.[23] The straw proposal also suggests that for both WRAP participants and non-participants the Commission may order the LRE to correct any deficiencies found in the plan.[24] Although not stated, it appears that curing a deficiency may require procurement of resources, i.e., a procurement of generation and/or transmission one to three years forward, if the Commission finds there is a deficiency. Based on

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22 Staff's Straw Proposal, p. 6.
23 Staff's Straw Proposal, p. 6
24 Staff's Straw Proposal, p. 5 (stating: "The Commission will direct LRE on how to cure deficiencies," and "Parties that do not cure deficiencies may be subject to a fine").

discussions at the workshop, it is not entirely clear what is intended with this description in the straw proposal, but Calpine Solutions offers the following comments.

If the proposal is for a three-year informational action plan to be filed with the Commission, Calpine Solutions has no objection but recommends that appropriate clarifications be included. Having a plan in place to serve expected load requirements based on existing load commitments and expectations at the time of the plan could be reasonable. However, the necessary clarifications include that such planning requirement is limited to existing long-term opt-out customers, i.e., the ESS's existing LTDA and NLDA program load only. One-year and three-year customers are already included in the utility's load and resource balance in its IRP action plan and continue to pay for utility generation, subject to transition adjustments.[25] Thus, it is not clear that one-year and three-year program customers need to be included in the ESS's RA plan. Additionally, the ESS's planning requirement for LTDA and NLDA customers would presumably be based on the assumption that such customers will remain with the same ESS for the full three-year planning period, but that point should be clarified in the rules.

However, if the three-year plan proposed in Staff's Straw Proposal is intended as a binding procurement requirement where the ESS must demonstrate it has already procured resources one to three years in advance (similar to WRAP forward showing requirements but three years forward), Calpine Solutions opposes such requirement as applied to either WRAP participant ESSs and non-WRAP participant ESSs. As a general matter, a procurement requirement on ESSs would contradict the current paradigm where direct access customers do not have an obligation to procure energy or capacity on up to a three-year forward basis. Consequently, it is not reasonable to assume that all of an ESS's existing customers would

[25] OPUC Docket No. UM 1056, Order No. 07-002, p. 19.

always necessarily be committed to buy from the same ESS for three full years. In some cases, direct access customers may not wish to commit to supply contracts three years out. LTDA and NLDA customers are committed to long-term direct access and are taking the risk that should they return earlier than requisite notice to the utilities' cost-of-service supply, they would be exposed to market prices for two to four years (depending on utility and vintage of program enrollment), plus any applicable POLR charges for capacity under discussion in AR 651. But nothing currently requires the customer to sign a contract with a single ESS for three years, and some customers do not wish to do so, which enables them to exercise options, e.g., to switch ESSs or switch supply. Similarly, an ESS is not an investor-owned utility, and the ESS has no service territory with guaranteed load. In short, therefore, it is not reasonable to order ESSs to procure capacity without customers committed to purchase it.

Ultimately, a three-year forward showing program would require *customers* to lock in resources three years out and by doing so it would limit retail choice. While that may be the Commission's desire, the Commission should recognize this would be a fundamental change to direct access before adopting such a requirement.

Additionally, a binding procurement requirement three years out may deprive the LRE of the flexibility to serve load in the most economical and prudent manner available. The utilities' IRPs are not necessarily binding on the actual procurement activities of the utilities.[26] Utilities may deviate from the action plans in their IRPs, and there remains no requirement or penalty to a utility that fails to secure Commission acknowledgement of its IRP or some aspect of the action

[26] *See* OPUC Docket No. UM 1056, Order No. 07-002, p. 24 ( "Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment. Similarly, inconsistency with the plan will not necessarily lead to unfavorable rate-making treatment, although the utility will need to explain and justify why it took an action inconsistent with the plan." (quoting OPUC Order No. 89-507, p. 7).

plan contained therein. Nor is there a penalty for a utility that deviates from the acknowledged action plan in its management of load and resources. While Commission acknowledgement increases the chances of a prudence finding in a subsequent rate case if the utility adheres to its approved action plan, there appears to be no circumstance where the Commission orders the utility to procure a specific resource to cure a deficiency in the action plan. Accordingly, it would be unreasonable to make a three-year forward plan binding in some respect (be it 75%, 90%, or some lesser amount) on the ESS's procurement for two or three years. Doing so would arguably subject ESSs, and direct access customers, to a level of oversight and management of business decisions beyond that applicable to even the regulated utilities.

More specifically with respect to WRAP participants, a binding three-year procurement requirement would be far more stringent than the seven-month forward showing requirement deemed sufficient by the WRAP and likely to soon be approved by FERC. As noted above, the WRAP's forward showing requirement does not bind the participants to the specific portfolio used in the forward showing, and it requires no showing whatsoever more than seven months in advance of the binding season. While participants are effectively bound to meet the WRAP's requirements for at least two years (due to the two-year notice to withdraw), the program operates on a seven-month forward showing paradigm. An OPUC-specific requirement for a three-year forward showing on top of the WRAP program's seven-month showing would deter participation in the WRAP by imposing a more stringent requirement that applies whether the LRE joins the WRAP or not. There would be little apparent benefit to joining the WRAP. To the extent such a plan is binding, it would also potentially frustrate a WRAP participant's (again, ESS or utility) ability to supply surplus capacity to other WRAP participants in the operational program and deprive the program the participant from the reliability and financial benefits of having surplus capacity in a time of regional need.

In sum, Calpine Solutions urges the Commission to clarify that the three-year plan aspect of any rules is merely an informational plan subject to the clarifications proposed above.

**B. Option Two: OPUC-Based RA Requirement for WRAP Non-Participants**

Calpine Solutions also supports adoption of an alternative to WRAP participation under which the LRE would conduct a forward showing and RA compliance. Given the work that has been completed in the WRAP, there is no need to reinvent the wheel by creating a new framework from the ground up, and instead the Commission should start the OPUC-specific requirement with the well-developed WRAP framework. Because there would be no holdback capacity and energy deployment sharing elements to an OPUC-specific RA compliance requirement, certain elements of the WRAP requirement are not necessary in an OPUC compliance requirement for non-participants in the WRAP. But the WRAP is a solid framework to begin an OPUC-specific design. Whatever requirement the Commission elects to adopt, Calpine Solutions stresses the importance of including the detailed requirements for the OPUC-specific requirement in the rules to provide assurance to LREs of what actions will or will not meet the requirements. In the following sections, Calpine Solutions offers comments on specific elements to an OPUC-specific RA requirement that should apply for WRAP non-participants.

**1. The proposed three-year plan should be a non-binding action plan**

For the reasons explained above, the three-year action plan should be non-binding and not designed as a three-year forward procurement requirement even for WRAP non-participants. The three-year plan would be a forward look at the ESS's current plans to meet its existing

LTDA and NLDA loads based on the assumption that those existing customers remain with the ESS for the next three years.

### 2. Near-Term Forward Showing Requirement for WRAP Non-Participants

As noted above, it is not clear that the proposed three-year action plan in Staff's Straw Proposal was intended to require demonstration of procurement of resources in the amounts identified (100% one year out, 95% two years out, 80% three years out), but Staff had earlier suggested in this proceeding that it was considering inclusion of a near-term seasonal RA showings for non-participants in the WRAP.[27] If the Commission elects to adopt a WRAP-style forward showing requirement for non-participants of the WRAP, Calpine Solutions would support use of the requirements of the WRAP, subject to the following modifications to the WRAP framework given Oregon's unique circumstances.

Binding Seasons: As with the WRAP, an OPUC-administered forward showing requirement should be limited to specific winter and summer "binding seasons" of RA concern. Staff's Straw Proposal does not specifically delineate the months for which RA must be demonstrated, but a year-round showing is not typical of RA programs and should not be the requirement in Oregon. Calpine Solutions preliminarily recommends that using the same winter and summer binding seasons as the WRAP program (June 1 to Sept 15 and Nov 1 to March 15) may be appropriate, but it may be that those dates should be adjusted to target the RA risks for Oregon load more specifically.

Load Forecast: Calpine Solutions also supports use of the WRAP's same 1-in-10 LOLP planning margin in an OPUC requirement. Additionally, the WRAP program provides a lower

27 Staff's Process Proposal and RA Solution Straw Proposal, p. 6 (Oct. 15, 2021).

peak requirement for shoulder months within the binding season,[28] and any OPUC-administered forward showing should adopt the same type of shaping for shoulder months.

Capacity Resources: An OPUC-administered forward showing should use the same capacity resource requirements as used in the Proposed WRAP Tariff. As discussed above, the WRAP will generally require use of identified generation resources not otherwise committed to serve other load, and the WRAP Tariff contains a detailed explanation of the requirements that could be imported into OPUC rules.

Transmission Requirement: If the Commission adopts an OPUC-specific forward showing requirement, Calpine Solutions recommends a different forward showing transmission requirement than that used in the Proposed WRAP Tariff. The current WRAP requirement may be difficult to implement in an OPUC-administered program, because the Proposed WRAP Tariff's forward showing transmission requirement relies on four exceptions to the 75-percent firm requirement that require detailed review and evaluation by the WRAP program administrator. WPP developed the exceptions out of recognition that firm transmission may not be available months in advance, but that the region's major transmission providers, especially Bonneville Power Administration, typically release firm or non-firm transmission on critical paths closer in time to the operational timeframe. As noted above, the WRAP's forward showing transmission requirement has been a subject of protest in the FERC proceeding surrounding how the exceptions may be used, which remains unresolved at the time of submitting these comments. Even if the WRAP's forward showing transmission requirement is approved by FERC, it may be subject to revision before the program moves to the binding phase in 2025. WPP has already committed to report back to FERC on the implementation of the

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28 WPP's FERC Submittal Letter, pp. 18-19.

transmission requirement during non-binding phase before 2025.[29] Additionally, the requirement may be further refined in business practices. Thus, the Proposed WRAP Tariff's 75-percent firm requirement for transmission, subject to exceptions, remains uncertain to some extent.

Calpine Solutions recommends that an OPUC-specific forward showing requirement should allow use of non-firm transmission on external systems to reach the load's balancing authority ("BA"). The Commission has recently recognized in the procurement context that "increasing constraints on the transmission system, particularly on the west side of the PacifiCorp system, make it important to begin to more seriously consider alternative transmission products that may deliver a significant portion of the value that some resources offer the system."[30] There, the Commission directed PacifiCorp to consider allowing use of alternatives to firm transmission in future competitive procurements, which could include capacity value adjustments where appropriate. Here, if the Commission elects to include a specific transmission requirement, it should provide flexibility and alternatives to long-term firm transmission contracted months in advance of delivery. Calpine Solutions recommends allowing use of non-firm transmission at the time of the forward showing would be reasonable.

Timing: An OPUC-specific forward showing for WRAP non-participants could deviate from the WRAP program with respect to timing of the forward showing and cures to any deficiencies because there would be far fewer parties and less process without the holdback and energy deployment sharing provisions of the WRAP. Calpine Solutions recommends that the LRE would make its initial showing six months before the binding season begins, and the OPUC would issue an order approving or identifying deficiencies within 60 days of the filing. If

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29 WPP's Answer, FERC Docket No. ER22-2762, p. 11 (Oct. 24, 202).
30 OPUC Docket No. UM 2193, Order No. 22-130, pp. 3-4.

deficiencies are identified, the LRE should cure the deficiencies no later than 45 days prior to the binding season. This 45-day deadline for the final 100-percent procurement requirement is generally consistent with the California Public Utilities Commission's state-level RA program.[31]

Deficiency Charges/Penalties: Calpine Solutions recommends that WRAP non-participants that fail to cure deficiencies in their forward showing could be subjected to similar deficiency charges as those used in the WRAP program. However, as with the WRAP program, non-participants should be provided the flexibility to meet their load obligations through any means that is available to them in the operational timeframe. In other words, there should be no penalty for meeting load commitments through use of resources other than the RA resources included in the forward showing where circumstances change or the more economical means of serving load become available.

### 3. ESSs Complying with the OPUC-Specific RA Requirement Should Not Be Subjected to Preferential Curtailment

An ESS that is in compliance with the OPUC-specific RA requirements should not be subjected to preferential curtailment. Instead, the Commission should design an OPUC-specific RA option for non-participants in the WRAP that does not require preferential curtailment. Calpine Solutions is concerned that Staff's Straw Proposal would, in effect, subject LTDA and NLDA customers to preferential curtailment even where their ESS is complying with the OPUC's RA requirements, and we urge revision to any such outcome suggested in Staff's Straw Proposal.

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[31] Cal. Pub. Utils. Comm'n, *2023 Resource Adequacy Guide*, pp. 16-17, at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/final-2023-ra-guide-clean-93022.pdf.

Specifically, Staff's Straw Proposal states: "To avoid Capacity Backstop charge, non-participant ESS must show compliance for every year of the three year action plan *and ensure that its long-term opt out customers can be preferentially curtailed*."[32] This statement suggests that even if the ESS/customers elect the OPUC-specific RA rule for WRAP non-participants and fully comply with those OPUC-approved RA rules, they still must be subject to preferential curtailment. That result is not reasonable.

Many customers will not wish to be subjected to preferential curtailment. Thus, if adopted as written, this aspect of Staff's proposal will deter ESSs and direct access customers from enrolling to comply with the OPUC-specific RA rules for WRAP non-participants. That would potentially result in more customers than necessary simply opting to pay the utility's RA backstop charge without even trying to supply RA in any form from the ESS. In effect, arbitrarily imposing curtailment on ESSs that comply with an OPUC-specific RA requirement would likely negate the need to even offer that option.

Instead, the Commission should design an OPUC-specific RA option that does not require preferential curtailment, such as Calpine Solutions' proposal above for a near-term forward showing under Option Two. If the ESS is complying with the RA rules the OPUC has deemed to be prudent procurement, there is no apparent basis that such ESS's customers should be preferentially curtailed. Under an OPUC-specific requirement, an ESS could be incented to meet a WRAP-like, near-term forward showing requirement or be subjected to significant deficiency penalties (as described above). Thus, Calpine Solutions recommends development of a non-WRAP option that allows the customer to avoid preferential curtailment.

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[32] Staff's Straw Proposal, p. 7 (emphasis added).

### C. Option Three: RA Backstop Charge

Calpine Solutions continues to support the OPUC providing ESSs and direct access customers the option of paying the utility an RA backstop charge in lieu of demonstrating compliance with any RA requirement. In other words, in lieu of participating in the WRAP (Option One, above) or electing compliance with the OPUC-specific RA requirement for non-participants in WRAP (Option Two, above), the ESS would pay the RA backstop charge for a utility-supplied RA product. As explained below, however, certain elements of Staff's Straw Proposal should be clarified and revised.

First, it would be helpful if Staff could provide guidance on how it anticipates such an RA backstop charge would be calculated. For example, there are readily available templates for similar charges in the form of utility standby charges for customers with onsite generation, who pay a reduced capacity charge for the limited capacity used to serve them in the event of forced outage of their standby generation. The standby rates would likely be a good starting point for development of a capacity backstop charge for direct access customers. However, if Staff has a particular calculation method in mind, it would be helpful to discuss whether a specific method to calculate the charge should be included in administrative rules to limit the scope of any rate proceedings to calculate such a charge for individual utilities. As noted above, key decision points regarding binding participation, or not, in the WRAP are moving on independent timelines from this proceeding, and ESSs and customers would prefer to know sooner rather than later the likely magnitude of an RA backstop charge.

Second, Staff's Straw Proposal is unclear on whether the ESS must elect to pay the RA backstop charge for all of its load or whether the ESS (or individual customers) would pay the charge per customer. Calpine Solutions recommends that the RA backstop charge should be available on a per-customer basis as opposed to requiring the ESS's entire portfolio of customers to opt into the RA backstop charge. Similarly, the customers should have a reasonable opportunity to switch between the RA backstop charge and ESS-supplied RA product, subject to appropriate notice to the ESS and the utility providing the RA backstop. We are uncertain how much notice the utilities would require and look forward to further discussing that issue.

**D. Interaction with POLR**

Finally, Calpine Solutions is concerned with the risk of duplicative charges and requirements on direct access customers across this docket (UM 2143) and the related direct access rulemaking where a new POLR charge is under discussion (AR 651). This risk of double charges would be minimized if the POLR charge that is adopted is limited to a charge that applies only upon the LTDA or NLDA customer's early return to utility-supplied energy, but some parties, and even Staff's currently proposed administrative rules, are also proposing an advance POLR charge that would apply while the customer is still being served by an ESS. In that scenario, the utility collecting such advance POLR charge would procure an RA/capacity product to potentially serve the LTDA or NLDA customer at the same time that the customer's ESS is also procuring RA products (Options One and Two, above) or alternatively paying the utility for the RA backstop charge (Option Three, above). Such an advance POLR charge would be plainly duplicative to an RA backstop charge, and it would also likely require the customer to pay for duplicative RA products to the ESS and the utility under Options One or Two above. Thus, Calpine Solutions strongly opposes the implementation of such an advance POLR charge on top of imposition of the RA requirement discussed in these comments.

Calpine Solutions provided detailed comments on the related POLR issue in AR 651, and attaches those comments here to ensure the record in this proceeding is complete and consistent with the position stated in AR 651.

DATED: November 21, 2022.

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Of Attorneys for Calpine Energy
Solutions, LLC

Attachment 1

Calpine Solutions' POLR Comments in AR 651

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

AR 651

| | | |
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| In the Matter of Rulemaking Regarding Direct Access Including 2021 HB 2021 Requirements | ) ) ) ) ) ) | CALPINE ENERGY SOLUTIONS, LLC'S COMMENTS REGARDING PROVIDER OF LAST RESORT PROPOSALS |

## I. INTRODUCTION

Calpine Energy Solutions, LLC ("Calpine Solutions") hereby submits its comments to the Public Utility Commission of Oregon ("Commission") regarding provider of last resort ("POLR") proposals. Specifically, these comments address issues surrounding Staff's most recent straw proposal for POLR issues, as included in the Commission's proposed administrative rules (Proposed Rule 860-038-0290), PacifiCorp's POLR proposal circulated November 2, 2022 ("PacifiCorp's Nov. 2nd Proposal"), and discussions at the workshop held on November 2, 2022. Calpine Solutions is also engaged in Docket No. UM 2143 regarding Staff's straw proposal for resource adequacy ("RA") rules. The RA and POLR issues are closely related, and Calpine Solutions is concerned that duplicative charges or requirements could be developed for electricity service suppliers ("ESS") and direct access customers where the RA and POLR issues are being addressed in different proceedings. In particular, the Proposed Rule 860-038-0290(5)(a)-(b) appears to impose a duplicative capacity-based POLR charge on any direct access customer still taking service from an ESS even where the ESS is in full compliance with applicable RA requirements or alternatively pays a capacity-based RA backstop charge to the utility. That arrangement for duplicative charges to direct access customers is not reasonable.

As explained further below, Calpine Solutions generally supports the framework presented by PacifiCorp's proposal circulated on November 2, 2022, which would assess a POLR energy and capacity charges to long-term direct access ("LTDA") or new load direct access ("NLDA") customers that cease purchasing energy from an ESS sooner than the required notice to return to cost-of-service rates. However, Calpine Solutions opposes development of a POLR charge that would apply to customers who are still purchasing energy from an ESS. Resource adequacy for such customers should be met through either the ESS's compliance with an RA requirement or through an RA backstop charge paid to the utility.

## II. COMMENTS

As explained below, Calpine Solutions generally supports the framework proposed by PacifiCorp for moving forward with development of additional POLR requirements for Oregon's direct access customers and offers certain changes and clarifications to the specific proposal made by PacifiCorp. However, these comments will first address the existing rules governing return to utility service because there appears to be some misunderstanding on the current rules in place, which should inform the extent of changes necessary.

### A. Oregon's Existing Rules and Rates for Return to Utility Service

In discussion of the POLR issue, there appears to be a significant misunderstanding by some parties regarding the Commission's existing rules. Both utilities continue to suggest, or directly state, that an LTDA or NLDA customer returning early without proper notice would use the utility's cost-of-service supply and pay the utility's rates for that cost-of-service supply. For example, PacifiCorp's Nov. 2nd Proposal asserted that "a utility can only keep a returning customer on emergency service for five days, at which point the customer can transition to Cost of Service rates."[1] PacifiCorp also asserted that an early-return customer would cause the utility to "purchase high-price market power to serve returning customers," the costs of which, absent new and additional protections, "will be passed through to *all customers* through the utility's net power cost proceedings."[2] These assertions are inconsistent with the existing regulatory framework.

As a general matter, the Commission's administrative rules already go a long way towards protecting cost-of-service customers from an LTDA or NLDA customer that ceases purchasing from an ESS for whatever reason. The rules provide an "emergency default" service option when an ESS ceases serving a customer, and require that the utility move the customer from emergency default service to "standard offer service" within five days.[3] However, the rules do *not* require the utility to move the customer to cost-of-service rates before expiration of the applicable notice period in the LTDA or NLDA program. The administrative rules state that the nonresidential standard offer rate "shall be . . . priced based on supply purchases made on a competitive basis from the wholesale market plus the transition credit or transition charge, if any, and all other unbundled costs of providing standard offer service."[4] Further, a "standard offer rate *must* reflect the full costs of providing standard offer service."[5] The rules also provide that "an electric company *may* offer a cost-of-service rate to large nonresidential consumers in lieu of a one-year standard offer rate option."[6] But there is no obligation that the utility offer a cost-of-service rate in lieu of the standard market-based pricing.

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1 PacifiCorp's Nov. 2nd Proposal, p. 2.
2 PacifiCorp's Nov. 2nd Proposal, p. 2 (emphasis in original).
3 OAR 860-038-0280; OAR 860-038-0720.
4 OAR 860-038-0250(2)(a).
5 OAR 860-038-0250(2)(a) (emphasis added).
6 OAR 860-038-0250(2)(g) (emphasis added).

Thus, there is no basis in the utilities' arguments that customers returning early from the LTDA or NLDA programs can access cost-of-service rates before expiration of the applicable notice period for return to service, unless the utilities are voluntarily allowing or encouraging that to happen. And the allegation that such customers would shift costs to other customers by doing so, if it would occur, is due solely to the unilateral decisions of the utilities to offer such customers cost-of-service rates. In sum, the utilities are already fully empowered by the existing rules to charge the LTDA or NLDA customer returning early the market prices incurred to serve such customers. The only circumstance where the utility may need to use its own cost-of-service portfolio to serve an early-return customer is where there is literally no energy available whatsoever in any accessible wholesale market or other wholesale transaction. However, nothing in the existing rules precludes the utilities from including in their standard offer tariffs a capacity-based charge to ensure capacity to serve the customers is available to the extent such a charge is justifiable in addition to an energy-based charge.

In the case of both utilities, existing tariffs provide that the early-returning NLDA or LTDA customer may not return to cost-of-service rates until a multi-year notice period expires, and the customer must take so-called "standard offer" service in the interim. Portland General Electric Company's ("PGE's") LTDA tariffs state two or three years notice must be provided (depending on vintage of enrollment) to terminate service in PGE's five-year program, and then be treated like any other cost-of-service customer.[7] While waiting for that notice period to expire, the customer can be served at the "Company Supplied Energy" in PGE's LTDA program tariff, which is described as an Intercontinental Exchange Mid-C index plus 2 mills.[8] PGE's

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7 *E.g.*, PGE's Schedule 485, p. 5.
8 *E.g.*, PGE's Schedule 485, p. 2.

NLDA tariff applies a three-year notice requirement and the same "Company Supplied Energy" option at the market index plus 2 mills.[9] Thus, PGE's standard offer rate is already a market price plus an added price. Similarly, PacifiCorp's LTDA and NLDA tariffs unambiguously bar the customer from moving to cost-of-service rates until the applicable notice period is over, which in PacifiCorp's case is four years.[10] PacifiCorp's Schedule 220, Standard Offer Service, currently provides an energy price based on a blend of the Platts indices for four market hubs and "thermal" cost weighting.

To the extent that PacifiCorp or PGE's standard offer tariffs include some element cost-of-service rates (as PacifiCorp's Schedule 220 appears to do with a "thermal" cost element), the utilities are already fully empowered to remove such cost-of-service elements from the standard offer under the existing administrative rules. If the utilities are truly concerned that early-return customers should not be allowed to receive cost-of-service prices, their standard offer tariffs should be enforced as written or revised to the extent already allowed by the rules. Similarly, if the energy-only pricing based on an index is believed to be insufficient to ensure capacity will be available in all hours to serve such customers, nothing in the rules precludes adoption of a capacity-based element to the POLR charge for capacity contracts the utilities could purchase upon early return of such customers.

Additionally, the suggestion that no LTDA or NLDA customers ever pay anything for the utility's capacity resources is incorrect. An LTDA customer still within the period of payment of

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9 PGE's Schedule 689, p. 3-4.

10 PacifiCorp's Schedule 293, p. 3 (NLDA); PacifiCorp's Schedule 296, p. 1 (LTDA); *see also* PacifiCorp's Rule 21, p. 9 (stating: "If the Company receives a request for Cost-Based Service from a Consumer ineligible for such service under this Rule, then the Company will notify the Consumer of its ineligibility and request a new authorization from the Consumer for Standard Offer Service").

its ongoing valuation transition charges is already paying the utility for capacity through the continued applicability of charges for fixed generation costs. That would include customers within five years of their opt out election in the case of PGE and within 10 years of their opt out election in the case of PacifiCorp, which employs a 10-year ongoing valuation charge. Similarly, NLDA customers must pay a charge equal to 20 percent of the utility's fixed generation costs for five years.[11] Because such LTDA and NLDA customers are effectively paying for some increment of capacity, it would be unreasonable to charge them again for such capacity, especially before they even return to being served by the utility's capacity. The utilities have presented no evidence or argument that the existing charges paid by customers in these five and 10-year transition periods are insufficient to cover the cost of the POLR products needed to potentially serve such customers who would also pay market-based prices for electricity upon early return.

### B. Comments on Revision to POLR Rules

Against the above backdrop, the utilities have advocated for enhanced POLR charges, and the Commission published a proposed administrative rule containing Staff's proposed revisions that would implement preferential curtailment of direct access customers as one option to address the POLR issue. With respect to preferential curtailment, the Commission has expressed interest in allowing sophisticated direct access customers to elect to be subject to curtailment during emergencies to avoid paying certain POLR charges. The Alliance for Western Energy Consumers has expressed that contractual curtailment should be an option such that the customer could be assessed liquidated damages in the event that it did not comply with a curtailment order from the utility. Calpine Solutions does not object to the Commission

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[11] OAR 860-038-0740(3)(a).

providing the proposed curtailment options, but also recommends that it is important to develop reasonable alternative charges that would apply in lieu of such curtailment election. Both utilities have expressed a position that not all customers would even be eligible to commit to curtailment. PacifiCorp asserts no customer under 25 MW could be curtailed, and PGE asserts certain categories of essential service providers (e.g., hospitals) should be ineligible for curtailment. Additionally, some customers may prefer not to be subjected to preferential curtailment. Thus, while providing a preferential curtailment option may be attractive to certain customers, such as customers who have back-up or other onsite generation to serve critical needs, Calpine Solutions urges the Commission to develop reasonable terms and/or charges that would allow customers to opt out of preferential curtailment, without being subject to duplicative capacity charges.

As explained above, the existing rules already allow for development of significant energy and capacity charges for POLR service through the existing standard offer framework, to the extent such costs are justifiable, and the Commission is also concurrently developing an RA requirement, with an RA backstop charge option, applicable to ESSs and direct access customers. Given that related regulatory structure, the following key principles should apply to any rule revisions regarding the POLR issue.

First, customers of an ESS complying with RA requirements of the Western Resource Adequacy Program ("WRAP") or an OPUC-specific RA requirement for non-participants in the WRAP should not also have to pay an advance POLR charge while the customer is being supplied by such RA-compliant ESS. The utilities have not disclosed the likely POLR product they would procure or the likely costs, but imposing a large POLR charge on customers whose ESS is already meeting the RA requirements deemed to be prudent procurement of capacity is discriminatory and unfair. No electric utility service provider, including the investor-owned utilities, is 100% reliable, and making direct access customers alone pay for extra POLR insurance, while also meeting prudent RA requirements, is discriminatory. That is not to say that an NLDA or LTDA customer leaving service of an ESS in an emergency or on a longer-term basis without providing adequate notice should pay nothing for the energy supplied to it. But such customers already must pay the market price for the power. If the market price spikes, such customer is still bound to pay the market prices to the utility until the applicable notice period expires. If the utility is serving the customer with cost-of-service plants, that is solely because the utility chose to do so. Customers that remain in the LTDA and NLDA program served by an RA-compliant ESS should not be penalized through an advance capacity-based POLR charge when the utility is empowered to charge such customers the full energy and capacity costs to serve such customers upon such early return.

Second, customers paying the RA backstop charge in lieu of purchasing an RA product through their ESS should certainly not also have to pay the POLR charge. Otherwise, the customer would pay the utility for capacity for emergency return twice: once with the RA backstop charge and a second time through the advance POLR charge. PGE appears to be the only utility strongly advocating for this outcome, but it has not identified or explained the cost of any of the potential capacity products it would procure, much less explained how this arrangement is not a duplicative double charge to direct access customers.

Third, if any POLR charge will be assessed to a customer still being served by an ESS (which Calpine Solutions opposes), the Commission should adopt strict requirements for such a charge in its rules. Those rules should require the utility to transparently identify the resources or option contracts it is procuring in support of the charge it assesses. The utility should not be allowed to just collect the charge and then not take any action to procure any product that is needed to provide the POLR service. The Commission should also reassess the need for the POLR charge annually. If PUC determines no resources are needed to provide POLR service in the upcoming year (e.g., if the regional energy market has sufficient depth that advance procurement of capacity products is unnecessary), then there should be no advance POLR charge assessed.

### C. Response to PacifiCorp's POLR Proposal

Calpine Solutions believes that PacifiCorp's POLR proposal, circulated on November 2, 2022, provides a useful framework to develop revisions to existing POLR tariffs in a reasonable manner. The comments below will highlight the key elements of PacifiCorp's proposal as we understand it, and then propose some modifications and clarifications to the framework PacifiCorp proposed.

Under PacifiCorp's proposal, curtailable and non-curtailable customers would be treated distinctly. However, because PacifiCorp's proposed 25-MW threshold for curtailment means that most customers would necessarily be non-curtailable customers, Calpine Solutions focuses on the proposal for such non-curtailable customers.

<u>POLR Charge:</u> Upon return to the utility, the "non-curtailable" customer would pay a capacity-based and energy-based standard offer rate for four years before being allowed to move to cost-of-service rates.[12]

Calpine Solutions agrees that this aspect of the proposal is reasonable subject to certain clarifications. First, LTDA and NLDA customers within the five or 10-year period who return to utility service early and pay the proposed POLR rates should not also be assessed their otherwise

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12 PacifiCorp's Nov. 2nd Proposal, p. 3.

applicable transition charges during this four-year period. Second, if these new charges are adopted, they should replace all or part of the special charges assessed to early return customers under the current tariff, such as Schedule 201's "Returning to Service Charge" and Schedule 293's forward looking rate adder applied to customers returning to cost of service.[13] In general, however, Calpine Solutions strongly supports limiting the new POLR charge to a charge that applies upon the customer's return to standard offer service by the utility, *not* while the customer is still being served by its ESS, especially where the ESS is in compliance with the applicable RA requirement adopted in UM 2143 or paying the utility an RA backstop charge. Notably, nothing in the Commission's existing administrative rules appears to preclude PacifiCorp or PGE from implementing POLR capacity and energy charges similar to those proposed in PacifiCorp's November 2, 2022 proposal. Indeed, as noted above, the Commission's rules already state that a "standard off rate *must* reflect the full costs of providing standard offer service."[14]

<u>Program Caps</u>: PacifiCorp proposes that POLR pricing proposal is contingent upon use of program caps to mitigate the need for an advance POLR charge paid while a direct access customer is still being served by an ESS, and conversely suggests that if the caps were to be increased beyond their current level, the Commission should implement such an advance POLR charge.[15]

In the abstract, without knowing the level to which the caps might be raised, it is difficult to specifically comment on this aspect of PacifiCorp's proposal. However, Calpine Solutions agrees that program caps are a method that could be employed to limit the need for capacity payments to the utility of any type, including an advance POLR charge. Where enrollment in the

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13 *See* OAR 860-038-0720(3) (requiring such charge to be included in NLDA tariffs)
14 OAR 860-038-0250(2)(a) (emphasis added).
15 PacifiCorp's Nov. 2nd Proposal, p. 4.

direct access programs is not substantial, there would appear to be little potential impact with an early return to utility service. Additionally, at this time, enrollment is nowhere near the cap levels in PacifiCorp's NLDA or LTDA programs, so simply authorizing the caps to be raised is not any indication that enhanced risk would be realized. Thus, a better trigger for implementation of such an advance POLR charge, if one could ever be justified, may be the actual level of enrollment in the programs and not simply the level of the program cap. At this time, the Commission could commit to revisit the issue of developing an appropriate advance POLR charge if the enrollment caps are ever raised *and* enrollment rises above the current level of the caps.

Another alternative is that the Commission could create vintages of customers with those in the vintage of enrollment up to the current cap levels, e.g., 175 aMW of LTDA load for PacifiCorp and 300 aMW of LTDA load for PGE, would be subject to the POLR charges itemized above upon early return to utility service but no advance POLR charge. Customers enrolling in the next vintage, if any, would be subject to an advance POLR charge to be filed by the utility for Commission adjudication and decision if the utility still believes such advanced POLR charge is warranted at the time enrollment reaches the first enrollment vintage's cap level. There is precedent in Oregon for applying different terms and conditions to different vintages of LTDA enrollment. For example, PGE's LTDA customers enrolled before 2015, must provide only two years notice to return to cost-of-service, whereas customers enrolled after that time must provide three years notice.[16] Thus, the use of vintages may be a useful mechanism to

[16] *E.g.*, PGE's Schedule 485, p. 5; Docket No. UE , 262, Order No. 13-459, App. B, p. 2 ¶ 3a (stipulation amending notice period).

avoid, or at least limit, the need to procure excess capacity or assess duplicative capacity charges to any customers.

Other Mitigating Measures: PacifiCorp discusses certain other potential mitigation measures being considered in California and recommends adoption of two in Oregon. First, PacifiCorp proposes adoption of a financial reporting requirement for ESSs to ensure the utility receives advance notice of impending failure.[17] Second, PacifiCorp proposes defining POLR service as "temporary, market-cost service that utilities provide to the returning customers for as long as necessary to plan for the return of those customer's to the utility's service."[18] PacifiCorp appears to assert that it does not believe a financial security requirement (e.g., bond) is necessary if its other recommendations are adopted.[19]

With respect to the financial reporting requirement, Calpine Solutions does not object to including a reasonable reporting requirement to alert utilities to adverse financial circumstances of an ESS, subject to review of the details for reasonableness. Notably, however, PacifiCorp and PGE already have extensive credit requirements, including requirements to inform the utility of material adverse changes, in their Rule 21 and Rule K, respectively.[20] It is not clear what further information PacifiCorp proposes here.

With respect to PacifiCorp's proposed definition of POLR service, Calpine Solutions agrees that PacifiCorp's proposed definition is appropriate.

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17 PacifiCorp's Nov. 2nd Proposal, p. 4.
18 PacifiCorp's Nov. 2nd Proposal, p. 4.
19 PacifiCorp's Nov. 2nd Proposal, p. 4.
20 PacifiCorp's Rule 21, pp. 16-22; PGE's Rule K, pp. 2-9.

DATED: November 18, 2022.

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