ORDER NO. 26-021

ENTERED 01/23/2026

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2000

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into PURPA Implementation.	ORDER

DISPOSITION: PACIFICORP, PGE, AND IDAHO POWER TO FILE STANDARDIZED WORKBOOK AND AVOIDED COST RATES

I. BACKGROUND

The Commission opened this docket, an Investigation into Public Utility Regulatory Policy Act (PURPA) Implementation, at the February 14, 2019 Regular Public Meeting. This investigation subsequently led to the opening of multiple dockets, including several rulemakings. Through this effort the Commission has modernized the rules governing PURPA, implemented alternative dispute resolution procedures, substantially updated and standardized the standard contract available to small generators, established a solar+storage PURPA rate and addressed a range of interconnection issues, such as transparency and standard interconnection technical requirements. In additional preparation for addressing PURPA avoided cost, the Commission has also undertaken extensive work establishing a common approach to crediting capacity. In this contested case phase, Staff and intervenors explored improvements to the methodology for establishing standard avoided cost prices in light of this prior work and have brought a variety of proposals before us for decision.

Numerous parties intervened in this proceeding. In the contested case phase, parties filed five rounds of testimony and then, on August 12, 2025, the Commission conducted an evidentiary hearing. The Oregon Solar + Storage Industries Association (OSSIA), the Qualifying Facility Trade Groups (QFTGs),[1] PacifiCorp, dba Pacific Power, Idaho Power Company, NewSun Energy LLC, Portland General Electric, and Staff of the Public Utility Commission of Oregon filed opening and reply briefs.

[1] Consisting of the Renewable Energy Coalition (the Coalition), Community Renewable Energy Association (CREA), OSSIA, and Northwest & Intermountain Power Producers Coalition (NIPPC).

II. LEGAL BACKGROUND

In 1978, PURPA created a new class of electric generators called "Qualifying Facilities" (QFs). These QFs—small power developers and cogeneration facilities—have certain rights under PURPA, including the right to sell electricity to utilities at a fair price. PURPA specifies that the rates paid by utilities for electric energy purchased from QFs may not exceed "the incremental cost to the electric utility of alternative electric energy."[2] PURPA defines incremental costs as "the cost to the electric utility of the electric energy which, but for the purchases from such [QF], such utility would generate or purchase from another source."[3] This is referred to as the "avoided cost," a term not used in the statute. PURPA also requires electric utilities to purchase power from QFs at rates that are just and reasonable to the utility's customers and in the public interest and that do not discriminate against QFs but are not more than avoided costs.[4] This is sometimes called the customer indifference standard. That is, customers are indifferent to whether generators are PURPA facilities or utility selected facilities because the costs, benefits and risks customers experience are relatively similar between the two providers.

PURPA also requires states to implement the promulgated Federal Energy Regulatory Commission (FERC) rules for investor-owned electric utilities.[5] Indeed, PURPA and FERC regulations delegate calculation of appropriate QF contract rates to individual state agencies. Oregon adopted parallel state legislation (ORS 758.505, *et seq.*) in 1983. The Commission first began developing rules implementing the federal and state requirements in 1980.[6]

III. DISCUSSION

A. Standard Price Streams

1. Price Streams

a. Existing Practice

Utilities subject to Oregon's Renewable Portfolio Standard (RPS), PacifiCorp and PGE, are required to offer two avoided cost price streams: one based on avoided costs of an RPS-compliant resource ("renewable" avoided cost rates) and the other based on the

[2] 16 USC § 824a-3(b).
[3] 16 USC.§ 824a-3(d).
[4] 16 USC § 824a-3(b)(1) and (2).
[5] *Federal Energy Regulatory Commission v. American Electric Power Service Corporation*, 76 L Ed 2d 22, 34 (May 16, 1983).
[6] *See* OAR 860-029-0001 *et seq*.

avoided costs of a combined-cycle combustion turbine and simple-cycle combustion turbine (SCCT) ("non-renewable" avoided cost rates). RPS-compliant QFs are allowed to choose between the two price streams. To be eligible for the renewable price stream, the QF must transfer renewable energy certificates (RECs) generated by the QF during the power purchase agreement (PPA) "deficiency period" to the utility, even during the last five years of the contract when the QF is receiving market prices.

Both the renewable and non-renewable avoided cost price streams are subject to adjustment to account for differing contributions to peak (CTP) capacity of different resource types. PGE and Idaho Power perform the capacity contribution adjustment using four resource types: baseload, solar, wind, and "hybrid," which currently is solar+storage. PacifiCorp uses these four categories as well, but has two separate categories for solar QFs, "fixed" solar and "tracking" solar.

b. Positions of the Parties

Staff recommends eliminating separate price streams for RPS-compliant and non-RPS compliant resources and instead supports a single price stream that it says better aligns with changing resource procurement practices by accounting for utilities' costs to comply with the requirements of House Bill (HB) 2021 and the RPS.[7] No party opposes moving away from the division between RPS-compliant and non-RPS compliant price streams, subject to price adjustments being calculated accurately.

NewSun stated in its position statement that there should be an option for an energy-only fixed price stream based on projected avoided costs at the time the legal obligation to purchase energy is incurred but did not pursue that proposal in its briefs.

c. Resolution

We agree with the elimination of separate price streams for RPS-compliant and non-RPS compliant resources, and support the adoption of a single price stream, with the refinements discussed below. We find that it will result in avoided cost rates that are just and reasonable and not unduly discriminatory. We do not address NewSun's proposal, raised only in its position statement, as it has not provided sufficient detail or support for us to do so.

[7] Staff Opening Brief at 3-4 (recommending "eliminating separate price streams for RPS-compliant and non-RPS compliant resources offered by PacifiCorp and [PGE] and adopting a methodology for a single price stream" and referring to applying RPS and deliverability adders to Idaho Power's "avoided cost price stream.").

2. Size Eligibility

a. Existing Practice

Currently, as set forth in OAR 860-029-0045, solar QFs with a nameplate capacity of no more than 3 MW, and all other QFs with a nameplate capacity of no more than 10 MW are eligible for standard avoided cost prices. All QFs regardless of resource type with a nameplate capacity rating of 10 MW or less are eligible for standard contract terms other than prices.

b. Positions of the Parties

Staff notes that HB 3863 requires the Commission to set the cap for standard avoided cost rates at no less than 10 MW. Staff recommends the Commission adopt a 10 MW cap for standard contract and price eligibility for all three utilities. Idaho Power, PacifiCorp, PGE, and the QFTGs recognize that Staff's proposal is consistent with HB 3863. NewSun argues on brief, but did not submit testimony in support of its position, that the size cap for standard avoided cost rate availability should be set at 80 MW, stating that doing so "could unlock additional resources to help meet [HB 2021's] emissions reductions targets."[8]

c. Resolution

We set the cap for standard avoided cost rates at 10 MW. This is consistent with HB 3863. It is also consistent with our long-standing policy and FERC's long-standing policy that the standard contract option is intended to eliminate barriers to entry for smaller QFs.[9] There is no evidence in the record that QFs as large as 80 MW face barriers to executing negotiated contracts that warrant administratively set prices and terms. Nor did any party submit evidence in the record to support revising our previous determination:[10]

> With standard contracts, project characteristics that cause the utility's cost savings to differ from its actual avoided costs are ignored. * * * [T]he risk customers face because avoided costs in the future may be different from

[8] NewSun Reply Brief at 4.
[9] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (1980); *In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 05-584, at 13-14 May 13, 2005.
[10] *Id.* at 16.

> the prices paid under a standard contract * * * is greater for a large QF than a small one.

In other words, there is a risk that prices under a standard PPA will deviate from actual costs avoided by the utility, eroding customer indifference; this risk is mitigated by negotiated prices that may account for the actual characteristics of the contracting QF, and we continue to find that mitigation to be appropriate for larger QFs. There is no evidence in the record that would justify diverging from our previous determinations on this issue.

3. Standard Pricing Term

a. Existing Practice

Standard PPAs have a 15-year fixed price term and a 20-year total term. Purchases in the final five years of the 20-year PPA are at variable market rates. This contract length and overall pricing structure was revisited and affirmed in light of other contract terms during contract modernization efforts in 2023 through docket AR 631.

b. Positions of the Parties

Staff recommends no change to the current term of the standard PPA—a 15-year fixed price term with an additional five years of market prices—arguing that the factors underlying the Commission's 2005 and 2014 decisions to require that utilities offer standard contracts with this term have not materially changed, and that as the Commission has previously determined, a 15-year fixed price term with five years of market prices best balances the risk to customers of PPA prices varying from the market against QF developers' need to acquire financing for development. The QFTGs argue for fixed prices for the entire 20-year period, while NewSun states in its position statement that "[c]ontracts should be for up to 30 years fixed at the seller's choice unless the utility is acquiring resources for longer periods." NewSun does not put forth a proposal for the situation in which the utility is acquiring resources for longer periods. NewSun asserts in its reply brief that adopting a 30-year contract term could help meet emissions targets[11] and that we have "sufficient grounds upon which to support adopting * * * 30-year contracts."[12] The utilities oppose extending the current 15-year fixed price term.

[11] NewSun Reply Brief at 4.
[12] *Id.* at 6.

c. Resolution

We again affirm our prior policy. The standard PPA will have a 15-year fixed price term with an additional five years of market prices. We find the factors underlying our 2005 and 2014 decisions still stand. As we explained in 2016:

> We recognize the benefits and risks associated with longer QF contract terms. Longer term contracts help align the financing period with an asset's useful life, making the investment less risky and likelier to obtain far more reasonable financing terms. On the other hand, longer term contracts increase the likelihood of forecasting errors in developing QF avoided prices, thus potentially subjecting ratepayers to costs that exceed the utility's actual avoided costs.[13]

While the QFTGs point to evidence in the record that they characterize as demonstrating "very limited development under PURPA in recent years,"[14] no party has demonstrated that QF development is being limited by 15-year fixed-price terms; and as other parties note, recent years have also been subject to unusual disruptions including the COVID-19 pandemic and high inflation.[15] Indeed, the QFTGs' witness testified that "[w]hile the new Oregon standard contract [resulting from AR 631] increases costs and risks on the QF, it still is a financeable contract for many (but not all) QF business models."[16] We do not find any evidence to indicate that most QFs are unable to obtain financing on competitive terms under our existing policy. Therefore, we find that a 15-year fixed price term continues to adequately balance the competing goals of facilitating QF financing while minimizing, to the extent possible, customer exposure to overestimates of future avoided costs.[17]

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[13] *In the Matter of Idaho Power Company, Application to Lower Standard Contract Eligibility Cap and to Reduce Standard Contract Term, for Approval of Solar Integration Charge and Change in Resource Sufficiency Determination*, Docket No. UM 1725, Order No. 16-129 at 8 (Mar. 29, 2016).
[14] QFTGs Reply Brief at 11 n 37 (citing Idaho Power's Opening Brief at 16 (citing Idaho Power/200, Valdepeña-Delgado/4).).
[15] PGE Reply Brief at 6-7, Idaho Power Reply Brief at 5.
[16] QFTG/100, Lowe/6.
[17] *See* Staff/500, Bain/11.

B. Capacity

1. Capacity Contribution Methodology

a. Existing Practice

The current methodology for fixed-price term avoided cost prices distinguishes between the capacity contribution of QFs during periods of overall resource sufficiency and deficiency. The purchasing utility's periods of resource sufficiency and deficiency are updated when avoided cost prices are updated and therefore are known at the time of contract execution. During the utility's periods of resource sufficiency, avoided cost prices are based on the utility's most recent forward market price forecast. During the utility's periods of resource deficiency that fall within the fixed-price term, avoided cost prices are based on costs of an avoided proxy resource and are subject to a capacity contribution adjustment to account for the differing contribution to peak capacity of different QF resource types as compared to the avoided proxy resource. For the last five years of the contract, prices are at current market rates.

A utility is considered resource sufficient from contract execution until the year of its next planned acquisition of a "major" resource in its most recently acknowledged Integrated Resource Plan (IRP). A major resource is defined for purposes of the competitive bidding guidelines and PURPA as one with nameplate capacity of at least 80 MW with a duration of five years.

A natural gas fired SCCT is used as the proxy resource to determine deficiency period capacity prices for the "non-renewable price stream." Cost data for calculating the prices is sourced from modeling done in the purchasing utility's most recently acknowledged IRP. For the "renewable" rate, avoided cost prices are based on costs of the least-cost RPS-compliant resource modelled in the company's most recently acknowledged IRP.

b. Positions of the Parties

Staff recommends the Commission require utilities to calculate the four different resource types' contribution to peak at the time avoided cost prices are updated based on Staff's Capacity Contribution Best Practices adopted by the Commission in docket UM 2011. Staff states that the best measure of capacity contribution is the "tuned," "last-in" Effective Load Carrying Capability (ELCC) of the resource type, where "tuned" refers to adjusting the modeled system to meet a specific reliability metric by adding or subtracting capacity. According to the Energy+Environmental Economics (E3) Report submitted by Staff, "Last-In ELCC is a measurement of the marginal ELCC of a resource

after all other intermittent or energy-limited resources have been added to the system."[18] This is contrasted with the "first-in" ELCC methodology, which E3 describes as "a measurement of ELCC as if it were the *first* and *only* intermittent or energy-limited resource on the system."[19] Staff argues that the last-in approach "captures a resource type's synergistic and antagonistic effects or interactions with all resources in the resource mix, and results in ELCC values that characterize how new resources will contribute to system capacity needs."[20] According to Staff, to determine the tuned, last-in ELCC, the utility should calculate system reliability; add or subtract expected resources or perfect capacity to achieve the target reliability metric based on a specific reliability standard; add the desired resource to the portfolio; and then remove perfect capacity until the target reliability is restored. This operation would be performed for four modelled years spread throughout a 15-year term, with intervening years interpolated using a reasonable method. The projected ELCCs should reflect the best estimates of resource retirements at the time of the study, the IRP preferred portfolio, specific resource additions that are contractually committed to come online and reasonably expected to produce power, and a QF renewal rate based on the 10-year historical renewal rate of QF projects at the time of IRP filing.

Idaho Power supports Staff's proposal, stating that "the last-in ELCC approach identifies the marginal value that each resource provides to the [c]ompany's system, accounting for the interactions with other resources in the [c]ompany's portfolio over time."[21] PGE supports Staff's proposal to use the last-in ELCC value, modeled in years 1, 5, 10, and 15, but proposes to use an *untuned* ELCC methodology, meaning that the desired resource is added to the portfolio without first adding or subtracting capacity to achieve a target reliability metric. PGE states that it uses an untuned last-in ELCC approach in its IRP modeling. PacifiCorp supports Staff's proposed last-in approach but would use the Loss of Load Probability (LOLP) method instead of the ELCC method for PacifiCorp's system. Staff does not oppose PacifiCorp's proposal to use LOLP instead of ELCC, noting PacifiCorp's testimony that an LOLP methodology inherently produces a last-in capacity contribution. PacifiCorp advocates for a 2.4 hours per year loss-of-load reliability metric, which is PacifiCorp's interpretation of the traditional 1-in-10-years loss of load expectation metric.

The QFTGs advocate for what they term a "first-in" ELCC method, which they describe as one in which the ELCC is based on the utility's committed portfolio of resources at the time of original QF contract execution, or an alternative approach that they refer to as "first-in tuned" in which the ELCC is based on the utility's portfolio at the time of QF

[18] Staff/103, Bain/7-8.
[19] Staff/103, Bain/7 (emphasis in original).
[20] Staff Opening Brief at 13.
[21] Idaho Power Reply Brief at 8.

contract execution but reflects expected changes to load over time.[22] According to the QFTGs, these approaches are consistent with PURPA because they compensate the QF based upon "the tranche of resource additions the QF enables the utility to avoid."[23] As another alternative, the QFTGs support use of the Western Resource Adequacy Program (WRAP) ELCCs. NewSun states in its position statement that ELCC values should not be less than WRAP resource ELCC values but does not address this issue further in its briefs.

c. Resolution

We determine that a last-in, tuned ELCC is the appropriate method for establishing avoided costs and will result in avoided cost rates that are just and reasonable and not unduly discriminatory. We also find that it is consistent with the best practices we adopted in docket UM 2011.[24] Additionally, we find that the last-in, tuned ELCC most accurately measures the capacity contribution of the resource over the course of the contract life, with four modelled years spread throughout a 15-year term and interpolating years between using a reasonable method.[25] Additionally, we agree with Idaho Power that a tuned, last-in ELCC method properly accounts for expected resource retirements and additions and the marginal value to the system provided by the QF.[26] It does this by accounting for both changing loads and resource portfolios in future years, rather than reflecting a snapshot year, as the QFTGs' "first-in" approach would.[27]

We also agree that using the methodology in the E3 Report, which served as the basis for Staff's recommendation in docket UM 2011, will apply a "consistent set of principles in valuing capacity across all resources and use cases to ensure that one technology, customer, or ownership type is not favored over another."[28]

Conversely, we find that using the QFTGs' "first-in" method would, over the course of the contract life, ignore additional resources that are anticipated to be added to the system and the antagonistic and synergistic effects between them.[29] Nor do we accept PGE's "untuned" approach. We find, as we did in docket UM 2011, that tuning is important

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[22] QFTGs Opening Brief at 18 (In contrast to other parties' definitions of "first-in" ELCC, the [QFTGs] state that their "'first-in' methodology is not a recommendation to treat the QF as the only resource on the utility's system, but instead it would require the utility to evaluate the QF resource's ELCC based on utility's committed generation portfolio at the time of the QF enters into its original contract.")
[23] *Id.*
[24] Staff/100, Bain/40-45; s*ee In the Matter of Public Utility Commission of Oregon, General Capacity Investigation.*, Docket No. UM 2011, Order No. 22- 468, Appendix A at 16-20 (Dec. 1, 2022).
[25] Staff Brief Opening at 11; Staff/100, Bain/41.
[26] Idaho Power Opening Brief at 20 (citing Staff/100, Bain/40-41).
[27] Staff/300 Bain/19; *see also* Order No. 22-468, Appendix A at 8.
[28] Order No. 22-468, Appendix A at 2.
[29] Staff/103, Bain/7; *see* Staff/103, Bain/6.

because "[e]valuating future portfolios which are tuned to the reliability metric ensures marginal [or last-in] ELCC is calculated as opposed to a mixture of marginal, average, and first-in ELCC."[30]

Finally, we allow PacifiCorp to use its LOLP approach, finding that it has the same general advantages as a last-in, tuned ELCC while being easier for PacifiCorp to administer on its system. Additionally, this approach is consistent with the best practices we adopted in docket UM 2011.

2. Avoided Capacity Resource Selection

a. Existing Practice

For the "non-renewable rate," avoided capacity costs and resource characteristics are based on a gas-fired SCCT as modeled in the utility's most recently acknowledged IRP. For the "renewable" rate, capacity costs and resource characteristics are based the next avoidable major renewable resource in the utility's IRP, plus integration costs.

b. Positions of the Parties

Staff proposes that in place of the default use of a gas-fired SCCT modeled in the utilities' IRPs, the avoided capacity resource be the least-cost capacity resource acquired in the utility's most recent RFP, or the preceding RFP if no capacity resources were concluded in the utility's most recent RFP.[31] If the utility has not conducted an RFP in the preceding 24 months, Staff states that the proxy resource should be the lowest $/MW-yr major resource the utility is capable of acquiring and using to deliver electricity to Oregon customers.[32] In either case, for utilities subject to HB 2021, the avoided capacity resource must be non-emitting. PGE agrees with Staff's position regarding the use of RFP data to determine the avoided capacity resource but proposes to use data from the past two RFPs to help address confidentiality concerns.

Idaho Power advocates for using the lowest net-cost capacity resource in the most recently acknowledged IRP. PacifiCorp recommends that avoided capacity costs reflect a utility's reasonably available resource with the lowest net cost of capacity, and states that to calculate this value, utilities should prepare and file calculations of the net cost of capacity for resources in the IRP. Unlike Idaho Power, PacifiCorp recommends that

[30] Order No. 22-468, Appendix A at 8.
[31] Staff Reply Brief at 8.
[32] Staff Opening Brief at 14.

consideration of updated resource costs begin upon filing of the IRP, rather than after acknowledgement is complete.

The QFTGs state that for utilities subject to HB 2021, the avoided capacity resource should be the lowest cost non-emitting resource that the utility is capable of acquiring and delivering to Oregon customers based on third-party pricing information from the National Renewable Energy Laboratories (NREL)[33] or a similar source; they do not support basing the determination on RFP data.

The QFTGs argue that a battery energy storage system (BESS), standing alone without any cost for charging energy, should not be the avoided capacity resource. Idaho Power questions whether a battery energy storage resource, which is not fully dispatchable, can properly be considered a capacity resource for purposes of the calculation, but does not oppose using a battery storage resource for valuing avoided capacity if the resource has a lower net cost than an SCCT.

NewSun argues that if multiple resources are selected in the RFP, it is the most expensive resource that would be avoided or deferred, not the least expensive. NewSun states in addition that if the resource used as the proxy avoided capacity resource would not actually fill the need, then it is not an accurate reflection of what costs might actually be avoided. NewSun recommends that we defer consideration of the proxy avoided capacity resource until an expected E3 analysis[34] has been completed and can be reviewed within this docket.

c. Resolution

We will use the least-cost capacity resource acquired in the utility's most recent RFP, or the preceding RFP if no capacity resources were included in the utility's most recent RFP. If no RFP has been concluded in the preceding 24 months, the proxy resource should be the lowest $/MW-yr major resource the utility is capable of acquiring and using to deliver electricity to Oregon customers, which may be determined by reference to third-party NREL or comparable data. We find that this will result in avoided costs that are just and reasonable and not unduly discriminatory. For utilities subject to HB 2021, the major resource must be non-emitting. We agree with Staff that RFP data is the most appropriate to use. As Staff notes, IRP data is likely to be stale by the time the IRP is acknowledged,[35] and third-party data lacks the specificity to the particular utility that

[33] Recently redesignated as the "National Laboratory of the Rockies."
[34] NewSun Opening Brief at 4; *see also*, NewSun Opening Brief Attachment A at 2 ("Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results," Energy+Environmental Economics (commissioned by "regional utilities and generation owners,").)
[35] Staff Opening Brief at 15.

RFP data has. We trust stakeholders to resolve confidentiality through appropriate use of protective orders, and we note that a review and update of our rule on protective orders and of the use of protective orders in our proceedings is pending in docket AR 672. That rulemaking is intended to:

> [P]rovide Staff, the utilities, and other interested parties an opportunity to work together on developing processes to facilitate parties' participation in our proceedings while appropriately safeguarding sensitive information.[36]

As discussed below, we also find that avoided capacity costs should be calculated using RFP data. Accordingly, we believe it is important not to create an unnecessary mismatch by using IRP data or NREL data (unless there is no recent RFP) for resource selection. We also believe the RFP data will be most reflective of the options actually available to the individual utility whose avoided costs are at issue.

We reject NewSun's proposal to use the most expensive resource if multiple resources are selected in an RFP—the avoided cost resource is what the utility could otherwise acquire but for the QF; utilities are expected to obtain least-cost resources as part of our prudent planning processes. We also decline to defer consideration of the avoided capacity resource until E3 has performed a supplemental analysis on behalf of regional utilities and generation owners; we have performed a long, stakeholder-informed process in this docket, and decline to extend this process further given the substantial evidence on the record.

3. Avoided Capacity Resource Valuation

a. Existing Practice

"Non-renewable" avoided capacity costs are based on the costs of a SCCT modeled in the utility's most recently acknowledged IRP (*i.e.*, modeled for resource portfolio comparisons) and renewable capacity costs are based on the estimated costs of the utility's next avoidable "major" renewable resource in the utility's IRP, plus integration costs.

b. Positions of the Parties

Staff believes cost information taken from a utility's IRP is too stale and instead recommends that the costs of the avoided capacity resource be the average price of major

[36] *In the Matter of PacifiCorp, dba Pacific Power, 2026 Transition Adjustment Mechanism*, Docket No. UE 450, Order No. 25-195 at 7 (May 23, 2025).

resources selected to the utility's short lists in all RFPs concluded by the utility in the preceding 24 months, with data taken from the Independent Evaluator's (IE) Final Report for each RFP. If there has not been a qualifying resource procurement within the last 24 months, Staff states that avoided cost prices should be based on the lowest $/MW-yr resource the utility is capable of acquiring and using to deliver energy to Oregon customers and that meets the criteria set forth above with respect to avoided capacity resource selection, with cost data based on third-party pricing information. Staff believes that using data from the IE's Final Report addresses confidentiality concerns and should not impair the utility's negotiations with the winning bidder(s). PGE generally agrees with Staff's position but recommends using the data from PGE's publicly available Final Short List Report rather than waiting for the post-contract-execution IE Report, which PGE states may result in stale data.

Idaho Power argues that the IRP should serve as the basis for avoided energy cost calculations because the proxy resource costs included in the IRP are informed by data from recent RFPs, other developer data, the IRP public process, and industry data from NREL, and therefore encompass a large sample size of data sources that is updated every two years. Idaho Power states that relying solely on RFP data presents confidentiality concerns and complications that would result from publicizing averaged RFP data during active negotiations with developers and notes moreover that RFP data can be unreliable when bids for certain resource types are lacking. PacifiCorp shares Idaho Power's confidentiality concerns, and highlights in addition the likelihood that individual circumstances will vary, making a prescribed calculation inappropriate.

The QFTGs oppose using either RFP or IRP data, which they characterize as subject to manipulation, and argue that capacity resource valuation should instead be based on third-party pricing information.

NewSun states in its reply brief that "Oregon statute mandates that 'at the option of the [QF]' the prices may be based on either '[t]he avoided costs calculated at the time of delivery, or [t]he projected avoided costs calculated at the time the legal obligation to purchase the energy or energy and capacity is incurred.'" According to NewSun, it is therefore impermissible to base avoided costs on the costs of past resource acquisition with no adjustment for what those costs are projected to be in the future, because such an approach fails to give the QF a right to elect to have its avoided cost based on a projection into the future.[37]

Staff and the utilities support making capacity payments net of benefits associated with the avoided resource. Staff notes that this approach is supported by the E3 Report

[37] NewSun Reply Brief at 7 (quoting ORS 758.525(2).

underlying Staff's Best Practices, which states that "[t]he value of capacity in a deficiency period is equal to the net resource cost of the lowest cost capacity resource."[38] According to Idaho Power, "[w]ithout netting these non-capacity benefits, avoided cost capacity prices would overcompensate a QF for non-capacity benefits."[39] Among the values that these parties would net out of the fixed costs of the avoided capacity resource are "energy benefits, the savings from avoiding market purchases or reducing fuel consumption, operating reserve benefits, and freeing up flexible capacity on existing resources"[40] and "revenue excess of the cost to charge in the case of battery capacity resources."[41] Staff states in its reply brief, however, that "its proposal to use[] forecasts of hourly avoided cost prices over the course of the fixed-price term of the PPA should smooth out the impact of the arbitrage that the [QFTGs] identify and eliminate the need to net out the battery benefits of pursuing arbitrage opportunities."[42] PacifiCorp suggests that "[d]isputes regarding the proper implementation of the net cost principle can be addressed at a later stage of this docket. But the basic premise that benefits should be accounted for is well-accepted and should be adopted for use in calculating avoided capacity."[43]

The QFTGs oppose the net capacity method. They argue that the capacity netting proposal "ignores that the elevated peak energy prices used to reduce the BESS's capacity cost, through forecasted energy arbitrage transactions, are in fact the hourly realization of the cost of capacity."[44] They object to the practice in addition as overly complex, and emphasize that it can lead to negative capacity payments,[45] which they point out "leads to arbitrary results, including that the lower the capacity contribution of the BESS, *the more negative and thus lower* the capacity rates become during any year with negative net capacity costs" because "when the numerator for this proposed netting calculation is negative, the proxy BESS's lower capacity contribution *decreases* the avoided costs offered to QFs."[46]

The QFTGs also argue that batteries are not equivalent to baseload capacity and thus, if batteries are allowed for use as the capacity resource, the Commission should require a baseload capacity adder to QFs that provide baseload capacity.

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[38] Staff Reply Brief at 13 (quoting Staff/103, Bain/16 ("Principles of Capacity Valuation," by (Energy+Environmental Economics) (December 2020).).
[39] Idaho Power Opening Brief at 28; *see also*, *e.g.*, PGE Reply Brief at 15 (failing to net out non-capacity benefits would "artificially inflate the cost of capacity used to calculate avoided costs by disregarding values that bring the cost of installing capacity down.").
[40] Idaho Power Opening Brief at 28.
[41] Staff Opening Brief at 19.
[42] Staff Reply Brief at 14.
[43] PacifiCorp Opening Brief at 23.
[44] QFTGs Opening Brief at 27.
[45] *Id.*; *see also* QFTGs Reply Brief at 26, 28.
[46] *Id.* at 29-30 (emphasis in original).

Staff responds that "the Commission could impose a floor on the cost of capacity of $0.00, meaning the capacity value could not go negative."[47] PacifiCorp similarly notes that:

> [U]tilities, the Commission, and stakeholders must use judgement to select the reasonably available resource with the lowest net cost of capacity. And where the calculation leads to counterintuitive result, the Commission has and should retain the authority to accept alternatives to the IRP supply-side table in annual updates if it will result in more accurate avoided costs.[48]

PacifiCorp adds that:

> [P]utting aside the 'reasonably available' tenet, the [QFTGs'] argument [that net capacity cost could be negative] actually supports the Commission's use of a net cost of capacity. * * * [W]here a capacity resource has a negative net cost, using it to serve customers should lower customer rates, *i.e.* its benefits would offset its costs. If a QF is displacing capacity resources that would otherwise have saved customers money, it is appropriate for QF pricing to reflect both the cost savings and the lost benefits associated with the capacity resources.[49]

According to Staff, "netting the costs and benefits of a capacity resource also means adding costs to the resource when appropriate. For example, it is necessary to ensure the costs of a capacity resource are included for purpose of the netting, which would include the cost to charge a four-hour battery."[50]

Staff adds:

> The [QFTGs'] argument the capacity value of a BESS must be increased for baseload QFs' contribution to capacity is without merit. The value of a baseload QF is captured by the higher ELCC value in the capacity contribution adjustment and compensated appropriately. Any additional compensation would be undue, and duplicative to the value received due to a baseload resource's higher ELCC value. As discussed above in the arguments regarding netting, the cost to charge a battery is included in the

[47] Staff Reply Brief at 14.
[48] PacifiCorp Reply Brief at 8 (internal citations and quotations omitted).
[49] *Id.* at 9.
[50] Staff Reply Brief at 14.

costs of capacity netted against the benefits, so it is not necessary to add this cost in a separate adjustment.[51]

c. Resolution

We find that using the RFP data is the best method for determining each utility's incremental cost to acquire a resource from an alternate source and that it will result in rates that are just and reasonable and not unduly discriminatory. While third-party data is an appropriate substitute when recent RFP data is not available, it is not likely to be as reflective of the utility's incremental costs as information from that utility's recently concluded RFPs. We agree that IRP data is likely to be stale by the time an IRP is acknowledged—as Staff notes, a utility spends months preparing an IRP and the Commission and stakeholders spend months reviewing it.[52] We find that the RFP costs are recent and in line with what avoided resources would cost at the time of contracting—or the time the legal obligation would be incurred. If a QF chooses to elect the avoided costs calculated at the time of delivery, it can negotiate non-standard avoided costs. By necessity, these standard costs must use a particular method. We conclude that neither PURPA nor ORS 758.525 requires the projected costs to be offered in a standard contract.

As discussed above, we find that IRP costs would likely be stale by the time of contracting, so decline Idaho Power's suggestion to use IRP costs instead. And we also find that the NREL costs are less representative than the utility-specific RFP costs, and therefore that, while they are a suitable substitute if there has been no recent RFP, they are not the first costs that should be used. We therefore accept Staff's proposal.

We also find that avoided costs should be based on the net cost of capacity, with a floor of zero so that capacity costs cannot go negative. This is consistent with the best practices we adopted in docket UM 2011. It is also logical: the basic cost of net capacity is to account for both the contributions and the costs of a resource; accounting for only the costs gives a less accurate picture of what customers receive when they forgo the avoided capacity resources in favor of the QF.[53] However, we agree with the QFTGs that it would be unduly burdensome and confusing for avoided costs to fall below zero, and therefore impose a floor of $0.00 as Staff suggests.[54]

We decline to order a baseload capacity adder at this time. For the purposes of this docket, we agree with Staff that the value of a baseload QF is captured by the higher

[51] *Id.*at 15.
[52] *Id.*
[53] PAC/200, MacNeil/30-31.
[54] Staff Reply Brief at 14.

ELCC value in the capacity contribution adjustment and compensated appropriately.[55] We are, however, interested in the resiliency benefits that baseload capacity provides to the grid, and expect to explore ways to compensate these benefits outside of PURPA in future dockets.

4. Capacity Sufficiency and Deficiency Periods

a. Existing Practice

The current avoided cost price methodology distinguishes between a utility's periods of resource sufficiency and deficiency. The QF is paid based on the avoided cost of market energy until the period of resource deficiency, which is the year of the utility's next planned major resource acquisition in its most recently acknowledged IRP. During periods of resource deficiency during the fixed-price term of the PPA, avoided cost prices are based on the avoided costs of energy and capacity resources.

b. Positions of the Parties

In place of the existing methodology's distinction between a utility's periods of resource sufficiency and deficiency, Staff recommends a capacity-value ramp-in during the initial years of the standard PPA for new QFs, beginning on the QF's scheduled commercial operation date (COD) as set in the QF's PPA. The duration of the ramp-in period would be based on the utility's actual procurement behavior and its procurement strategy as communicated in IRPs and would be subject to review at least once every three years; Staff suggests that this review occur during the utility's post-IRP acknowledgment avoided cost update. Staff recommends, based on review of the utilities' actual procurement behavior and strategies, that the Commission start with a capacity ramp-in period of three years for PGE and PacifiCorp and a period of five years for Idaho Power. This means QFs selling to PGE and PacifiCorp would receive no payment for capacity in year one of their contract, one-third value in the second year, two-thirds in the third year, and full capacity value starting year four of the contract. According to Staff:

> [T]he ramp-in methodology is not based on the assumption the utility will be resource sufficient for the first four years after contract execution, one-third resource deficient during year five, and so on. Instead, the three-year ramp in is intended to better match the utilities' current capacity acquisition practices to the fixed-price term of the PPA.[56]

[55] Staff/500, Bain/33.
[56] Staff Reply Brief at 7.

The QFTGs state that they do not object to the concept of a capacity ramp-in period, but that the period should begin on the contract execution date rather than the scheduled COD, because beginning the ramp-in on the scheduled COD effectively adds three years (a typical development timeline) to the ramp-in period. The QFTGs argue in addition that Idaho Power's initial ramp in period should be three years rather than five. And they suggest that for purposes of the ramp-in period review, the major resource definition should be a 40 MW resource with a minimum term of five years.

Staff notes in response that the QFTGs' proposal to begin the ramp-in on the date of contract execution would effectively eliminate the ramp-in of capacity value, or make it a ramp-in of one year starting at 66 percent, which Staff states is not an accurate reflection of the utilities' current resource acquisition practices with respect to major resources. Staff states that we have previously concluded that the planned acquisition of a resource that is at least 80 MW is an appropriate indicator of the utility's need for capacity, and Staff believes that there has not been sufficient exploration in this docket to question the continuing validity of this assumption for the purpose of designing avoided cost prices.

PacifiCorp, PGE, and Idaho Power support Staff's ramp-in proposal, but argue that the ramp-in period should begin when the QF enters commercial operation. PacifiCorp recommends that the size of the capacity payments and the percentage discounts applicable during each year of the ramp-in period be calculated through an annual percentage discount applicable during peak hours, stating as an example that because capacity payments make up approximately 16 percent of high load hour (HLH) pricing for baseload QFs in 2028, a 0 percent capacity payment could be applied as a 16 percent reduction in HLH pricing, and a 50 percent capacity payment would be applied as an 8 percent reduction in HLH pricing. PacifiCorp argues that its proposed approach will significantly increase administrability.

Staff does not object to PacifiCorp's proposed implementation of the ramp-in, provided the utilities provide sufficient detail in avoided cost filings for Staff and stakeholders to see the data underlying the calculation of avoided cost prices. Staff does, however, object to the utilities' proposal to start the ramp-in on the actual COD, arguing that starting the ramp-in with the start of the fixed-price term on the scheduled COD, which can be extended upon agreement between utility and QF, protects customers, because to the extent a QF may fail to come on-line by the scheduled COD, the QF will be subject to damages based on the contract price, and if a QF's delay extends into the ramp-in period, any damages the QF must pay would account for the ramped-in value of capacity. Under the method proposed by the utilities, Staff states, damages would presumably always be just the value of energy, offering less protection to customers.

For existing QFs that choose to renew an expiring PPA, Staff recommends no ramp-in provided that the QF gave at least two years' notice to the utility of its intent to renew, subject to a financial penalty if the QF gives notice but does not renew. Staff recommends the Commission allow parties to address the minimum requirements of the renewal notice in Phase III of this proceeding.

Idaho Power supports the two-year notice exception for renewing QFs, which Idaho Power says must evidence a firm commitment, because non-binding notice would not allow the utility to avoid procuring alternative capacity resources to meet reliability standards.

PacifiCorp recommends that the Commission require renewing QFs to either execute the renewal contract or otherwise establish a legally enforceable obligation at least two years in advance of renewal to retain full capacity compensation for the full contract term. PacifiCorp argues that if a renewing QF fails to provide promised capacity and as a result causes the utility to incur a WRAP forward showing deficiency charge, the WRAP deficiency charge should be charged to the QF to the extent the QF contributed to the shortfall. When the ramp-in applies to renewing QFs (because the QF did not enter into a replacement contract at least two years prior to expiration), PacifiCorp recommends that a two-year ramp-in period begin upon execution of the replacement contract, so that there is a 0 percent capacity payment during the first year following contract execution, followed by 50 percent capacity payments during the second year, with full capacity payments beginning after the end of the second year.[57]

The QFTGs argue that there should be no ramp-in period for renewing QFs, and no requirement to provide notice of intent to renew; they state that utilities must already plan for QF renewals in their IRPs because existing QFs have a high renewal rate, and that a requirement to provide binding notice will result in renewing QFs losing payment for full capacity value because they forget to provide notice or are unaware of the requirement. Staff responds that it agrees that it is necessary to ensure QFs are properly informed of the need to provide notice of renewal and recommends that how this should occur can be addressed in Phase III. Idaho Power argues that IRP assumptions, alone, are not a basis to risk a capacity shortfall by forgoing procurement in reliance on the assumption that a QF will choose to renew. Idaho Power claims that the QFTGs' proposal to allow QFs to access capacity payment without binding notice of intent to renew leaves customers at risk of paying for both the capacity payments to the QF and the alternate capacity resource that the utility procured before it knew that the QF would renew its contract, violating the customer indifference standard.

[57] PacifiCorp Opening Brief at 24-25.

c. Resolution

We find that it is reasonable for the capacity ramp-in to be three years for PacifiCorp and PGE and five years for Idaho Power as an initial matter. Idaho Power does not need to acquire capacity at the same pace as an HB 2021-subject utility,[58] so the longer initial ramp-in is reasonable. However, we agree that these ramp-in rates should be reviewed every three years in the post-IRP acknowledgment period.

We find that the capacity ramp-in period should, as Staff proposes, begin on the scheduled COD. Utilities plan other resource procurement based on that scheduled COD, and it is also the date of the start of the fixed-price term. Additionally, as Staff points out, under the current methodology, the demarcation between the resource sufficiency and deficiency pricing in the fixed price term does not change if the QF does not meet its scheduled COD.[59] Finally, our rules, as updated in AR 631, align the QF's and utility's financial incentives to meet the scheduled COD. Each faces a loss in value if it is the source of delay. Aligning the ramp-in period with the same date retains the balanced incentive structure.

We also find that it is reasonable for renewing QFs to provide binding notice to avoid the capacity ramp-in, but we limit that period to one year. We find that this notice is important to ensure that utilities are able to plan for contract renewal but find that a year's notice is sufficient to allow that planning time. We defer the remaining details of this renewal notice for further development in Phase III of this proceeding.

We find that PacifiCorp's proposal for a two-year ramp-in period for QFs that do not provide a binding notice of renewal is reasonable given that utilities can assume certain renewal rates based on historical data.[60]

Finally, we find that the threshold for a major resource should be 80 MW, as we have found in the competitive bidding context. We agree with Staff that the record in this proceeding does not justify a departure from that standard.

[58] Staff/100, Bain/32.
[59] Staff Reply Brief at 6.
[60] PAC/100, MacNeil/72-73.

5. Capacity Payment Structure

a. Existing Practice

In an earlier phase of this docket, we adopted interim capacity rates for solar plus storage projects, up to a 50 MW availability tranche: capacity payments are paid under a volumetric payment for capacity provided during "premium peak hours," paid in addition to the energy price. Premium peak hours are the four hours of highest expectation for loss of load in a given month, identified in the utility's IRP.[61] For other QF resources, the payment for capacity is embedded into the levelized on-peak energy price, based on capacity contribution in HLH.

b. Positions of the Parties

Staff seeks to move to a monthly pricing definition, where 24-hour by 12-month pricing is developed and capacity payments are baked into the pricing of hours of capacity need. Staff argues that this would provide improved signaling of system capacity need, allowing for more efficient resource optimization and maintenance scheduling, and avoiding the phenomenon of some capacity value being apportioned to off-peak, or light load hours (LLH) as currently occurs.

The QFTGs oppose moving to a 12 x 24 schedule, stating that it is far too voluminous and presumes a degree of accuracy that might exceed actual precision.

PGE supports the existing HLH and LLH framework for QF capacity payments. It believes Staff's proposal to move to a 24-hour by 12-month pricing schedule would add administrative complexity and may create confusion for QFs. It also argues that administratively determined prices over a 20-year term are unlikely to be accurate for a specific hour and month years after the prices are set.

PacifiCorp states that it supported a single on-peak and off-peak pricing definition for capacity, but does not oppose more granular pricing definitions provided that they give actionable incentives. However, it does recommend a change to pricing schedules that reflect monthly avoided costs. PacifiCorp argues that resource needs and resource output vary significantly throughout the year, resulting in significant fluctuations in value. It also argues that monthly pricing encourages QFs to schedule maintenance outside of the highest value periods.

[61] Order No. 23-179 (May 18, 2023).

Idaho Power states that it generally agrees with Staff's recommendation to move towards a monthly pricing schedule, provided that the Commission also removes the existing seasonality factors included in the QF PPA.

c. Resolution

We agree with PacifiCorp and Idaho Power that having a pricing schedule that is not static from month to month captures the fact that resource needs and resource output vary throughout the year and find that it better aligns incentives with actual costs. The current HLH/LLH construct has the virtue of simplicity, but it does not align compensation with the hours when energy is most needed. A 12 x 24 pricing schedule, on the other hand, would more accurately compensate generators for the value they bring to the system: in this construct (regardless of the number of pricing blocks per day or per year) the shaping of payments across the pricing blocks would not affect the total compensation received by a resource that generates at full capacity in every hour of the year. Compensation would be weighted toward higher-value time periods so that the resource would receive more compensation for generating at those times, and correspondingly less for low-value time periods. To the extent that a generator with less than 100 percent availability is able to target production in higher-value time periods, the generator would receive greater compensation, corresponding to its greater value to the system. This is a desirable result. However, as the QFTGs note, a 12 x 24 pricing schedule would require that each contract include "a different set of 24 different hourly rates for each of the 12 months in each of the years of the contract." We agree with the QFTGs that "[t]his is * * * an unmanageable level of contractual complexity for a standard contract,"[62] at least at this time. The intent is in part to send appropriate price signals to QFs; a pricing structure that is too complex to reasonably inform QF investment and operational decisions would undermine that purpose. Similarly, while PacifiCorp's suggestion of additional shaping based on weather has conceptual appeal, such an approach would introduce excessive complexity.

Accordingly, we find that a six by six pricing schedule—*i.e.*, six four-hour blocks per day, for each of six pairs of consecutive months per year, with prices projected for the 15-year fixed-price term—is sufficient to introduce the needed granularity while limiting the administrative complexity involved to a manageable level. In addition, while we recognize that no projection is perfectly accurate, we find that prices projected for a 15-year period, accounting for reasonably expected changes to the system over time, will be a substantial improvement over the accuracy of the current HLH/LLH approach. As noted in section A.3 above, the fixed-price term is limited to 15 years to mitigate the impact on ratepayers of inevitable forecast errors.

[62] QFTGs Reply Brief at 39.

While we agree with Staff that more granular pricing definition is important, we find that a six by six pricing schedule—*i.e.*, six four-hour blocks per day, with a different shape for each set of two consecutive months—is sufficient to introduce more granularity in pricing while limiting the administrative complexity involved to a manageable level. We agree with PacifiCorp and Idaho Power that having a pricing schedule that is not static throughout the year captures the fact that resource needs vary throughout the year and find that such a pricing schedule better aligns incentives with actual avoided capacity costs. This approach will better compensate those generators that are available when their capacity is most needed and incentivize the addition of more such resources. This shape should be drawn from the analysis of hours of need in the ELCC analysis. In their compliance filings, the parties should submit a six by six pricing schedule in accordance with this order.

6. Source for Purchasing of Characteristic Assumptions

a. Existing practice

Currently, QF characteristic assumptions, which underpin the development of technology specific prices, are developed from IRP supply side resource data.

b. Positions of the Parties

Staff proposes to continue using the IRP supply side resource data to develop QF characteristic assumptions, so that the QF resource is appropriately modelled in the IRP. For resources that are not well captured in the IRP supply side resource data, such as solar and storage QFs or other novel resources, Staff recommends use of independent public data sources for these QF characteristic assumptions.

The QFTGs prefer use of public sources of information, such as from NREL. Alternatively, they argue, if Staff's proposal for use of the utility's IRP supply-side tables is approved, only information from acknowledged IRPs that are consistent with Commission orders should be utilized.

PacifiCorp supports using IRP supply side data as the starting point for QF modeling characteristics but recommends allowing utilities the ability to deviate from those assumptions if there are material changed circumstances or if doing so will result in a more accurate avoided cost. For solar and storage resources, PacifiCorp recommends the Commission allow PacifiCorp to continue basing QF modeling characteristics on spreadsheet analysis of charging and discharging opportunities.

PGE and Idaho Power are supportive of Staff's proposal.

c. Resolution

We will use IRP supply side resource data to develop purchasing QF characteristic assumptions, with the caveat that we will consider deviations from those assumptions if there are material changed circumstances or doing so will result in a more accurate avoided cost. We find that this will balance the need for predictability in the development community with concerns that the information may become stale. We also find that the benefits of using utility-specific data outweigh the potential harms related to manipulation of data raised by the QFTGs, and decline their suggestion to use publicly-available data, such as that from NREL. Using the same data as underpins modeling in the utility RFP process supports customer indifference and a more level playing field between ownership models.

C. Energy

1. Avoided Energy Resource Selection and Valuation

a. Existing Practice

Currently, for sufficiency period pricing, avoided energy costs are based on the purchasing utility's forecasted market prices for energy, using the HLH / LLH framework. For deficiency period pricing, the avoided energy resource is assumed to be the portion of a combined-cycle combustion turbine (CCCT) gas plant that does not serve capacity needs. This has traditionally been determined by considering the full cost to operate a CCCT—which has a higher capital cost and lower fuel cost, and can be used to meet baseload energy needs as well as peak capacity needs and subtracting the cost to operate an SCCT—which generally have lower capital costs but higher fuel costs, and are used primarily to meet peak capacity needs. The difference in costs is assumed to be the portion of the CCCT that goes towards meeting energy needs and is treated as the avoided energy cost.

b. Positions of the Parties

Staff recommends discontinuing the distinction between sufficiency period and deficiency period energy values and instead using one method to determine avoided energy value for the fixed term of the standard PPA. Staff's proposed method is similar to the current netting methodology for determining energy value during the utility's

deficiency period. However, Staff no longer relies on netting costs of a gas fired CCCT and SCCT for utilities subject to HB 2021.

In place of the SCCT, Staff proposes using the avoided capacity resource, with costs represented by the average cost of non-emitting capacity resources that appear on the utility's shortlists for RFPs concluded in the last 24 months, or from an independent third-party source if no competitive solicitations have concluded in the last 24 months.

In place of the CCCT, Staff proposes to use the average costs of major non-emitting energy resources shortlisted in a utility's RFPs concluded in the last 24 months. As with capacity valuation, Staff recommends relying on data from the IE's Final Report to determine the value. If the utility has not concluded an RFP within the preceding months, Staff recommends using data from an independent third-party source. For the characteristics of the avoided energy resource, Staff recommends using the least-cost energy resource most recently selected in an RFP conducted by the utility.

To account for the intermittent value of renewable generation and the energy-limited nature of some capacity resources when finding the avoided energy resource value, Staff recommends scaling the capacity cost from the proxy resource by the avoided energy resource's ELCC from the utility's most recent acknowledged IRP prior to performing the netting exercise. This should ensure that when netting the capacity value from the avoided energy resource, the portion of the renewable generator being used to serve energy is not being overstated.

Staff notes that for Idaho Power, which is not subject to HB 2021, the proxy resources to determine avoided energy value need not be HB 2021 compliant.

The QFTGs generally agree with Staff's conceptual framework that the avoided energy resource used to calculate avoided costs should be the lowest cost energy resource that the utility is capable of acquiring and delivering to Oregon customers; and for HB 2021 utilities, that resource should be non-emitting. However, it disagrees that with Staff's proposal to use RFP data to cap avoided energy prices, stating, as it did with the avoided capacity resource, *supra*, that imposing a cap on the avoided cost rates with data from an RFP is entirely unreasonable, given the lack of transparency of RFP data, the opportunity for manipulation of such RFP data by utilities, and the risk that RFP data may not reflect the costs of future resources deferred by the QF. The QFTGs would use third party NREL data instead.

The QFTGs also disagree with Staff's proposal for energy valuation during the sufficiency period. Instead, they argue, the Commission should continue to use market

prices for sufficiency period energy valuation but revise the current method to include a premium for non-emitting energy, such as the cost of greenhouse gas allowances priced through the Western Energy Imbalance Market (WEIM).

Idaho Power argues that the avoided energy resource should be the lowest-cost energy resource in the company's most recently acknowledged IRP, for the same reason as discussed in the avoided capacity section, *supra*. Idaho Power also argues that the valuation of avoided energy should be based on the least-cost energy resource identified in the company's most recently acknowledged IRP, calculated using the same netting approach that has historically been used to isolate the cost of energy.

As it does with capacity resources, PGE supports averaging the cost of energy resources shortlisted in the company's two most recently concluded RFPs. PGE does not oppose Staff's proposal to eliminate the sufficiency period pricing at this time, but argues that the deficiency or sufficiency status of each utility should be reevaluated after each acknowledged IRP or CEP because requiring customers to make capacity payments and basing avoided costs on the value of an avoided resource would be inconsistent with PURPA if PGE is not actively procuring resources to meet capacity needs.

PacifiCorp proposes a market-based approach to valuing energy until its clean proxy resource comes online in 2028, at which point PacifiCorp proposes to adjust the avoided cost rate to account for the value of avoided energy and capacity associated with the proxy resource as compared to projected market value of energy. To select the energy proxy resource used in calculating the adjustment, PacifiCorp proposes to use a similar approach to its recommendation with respect to capacity—to select the lowest-cost energy resource based on data from the company's most recent IRP along with a consideration of supply, demand, and marginal resource options.

PacifiCorp proposes to value energy through the use of forecasted hourly market prices. The values would be structured on a 12-month by 24-hour profile that incorporates weighted average prices derived from historical WEIM data. The profile would account for historical weather, load, and market conditions, and it would capture the daily and hourly variation in prices during periods when solar and wind resources are generating. Beginning in 2028—consistent with PacifiCorp's currently approved standard avoided cost rates and the online date of its clean energy proxy resource—PacifiCorp proposes an adjustment to avoided costs based upon the forecasted contributions of its clean energy proxy. The adjustment would take into account the forecasted net value of the capacity and energy contributions of the proxy resource, and it would compare those contributions to the forecasted market value of energy, measured through reference weighted 12-month by 24-hour profile.

Finally, NewSun views Staff's proposal as too complicated and recommends that the methodology be vastly simplified to avoid tying the avoided energy value to the avoided capacity value in this way to more accurately reflect the simple intuitive outcome that as capacity resources become more expensive, the total avoided cost payment also increases. To do otherwise, it argues, is an inaccurate reflection of the costs that are being avoided and does not fairly compensate the QF for the value they provide in deferring more expensive capacity resources.

c. Resolution

We find that netting the average costs of shortlisted capacity versus energy resources from the utility's RFPs concluded in the preceding 24 months, after scaling the capacity cost from the proxy resource by the avoided energy resource's ELCC from the utility's most recent acknowledged IRP, will yield more accurate results than the current approach. As such, we find that it will result in rates that are just and reasonable and not unduly discriminatory. The characteristics of the avoided energy resource should be based on the least-cost energy resource most recently selected in an RFP conducted by the utility. For the reasons discussed above in the context of avoided capacity valuation, we believe that RFP data is best suited for this purpose, with independent third-party data to be used when RFP data from the prior 24 months is not available.

We decline to consider NewSun's proposal to simplify avoided costs because (a) it was not supported by evidence either of the counterintuitive results NewSun alleges or of how a simplified calculation could fix avoided cost rates, and (b) it is not sufficiently specific for us to accurately evaluate.

2. Granularity of Payment Method

a. Existing Practice

The current method for determining avoided energy costs during the sufficiency period uses the purchasing utility's forecasted market prices for energy and the HLH/LLH framework.

b. Positions of the Parties

Staff recommends replacing the current HLH and LLH pricing methodology with a 12 by 24-hour monthly pricing methodology. Staff argues that this would improve energy pricing granularity, better align pricing with hours of heaviest use, and align PURPA

avoided cost pricing with the Energy Efficiency avoided cost pricing methodology developed for UM 1893.

The QFTGs recommend against more granularity than HLH/LLH monthly prices for standard rates. In particular, they argue that a 12 by 24 price schedule for each month of the contract is far too voluminous and presumes "a degree of accuracy in avoided cost price forecasting that may exceed the actual precision."[63] The QFTGs argue that it is highly unlikely that the forecasted hourly price shapes in 10 or 15 years will actually reflect the forecasted prices.

Idaho Power generally supports Staff's recommendation, but with the clarification that the seasonality factors in the existing avoided cost pricing be removed as unnecessary.

PacifiCorp supports discontinuing the demarcation between sufficiency period and deficiency period energy prices and instead using its own weather-adjusted 12-month by 24-hour price profile described *supra.*

c. Resolution

As we decided above regarding the granularity of capacity payments, we agree with Staff that more granular pricing definition is important, but we find that a six by six pricing schedule—*i.e.*, six four-hour blocks per day, with a different daily shape for each set of two consecutive months—is sufficient to introduce more granularity in pricing while limiting the administrative complexity involved to a manageable level.

We agree with PacifiCorp and Idaho Power that a pricing schedule that is not static throughout the year captures the fact that the value of energy, and in this case specifically the energy displaced by a (must-take, by definition) PURPA contract, varies throughout the year. We appreciate PacifiCorp's forward-looking approach, which proposed using shaping energy values based on the actual pricing results of the WEIM. This energy is specifically the energy that a must-take PURPA contract displaces for utility customers in the optimized EIM dispatch. As PacifiCorp highlights, the EIM often shows very low energy prices during the HLH period, because the regional market is saturated with energy. However, introducing a new source of data to shape energy values as compared to capacity values increases the level of complexity and the opportunity for disputes. We believe that utilizing the ELCC modeling to demonstrate hours of energy saturation and hours of high energy value, consistent with our directive above in the context of capacity value, is sufficient to arrive at a fair price.

[63] QFTGs/200, Kaufman/14.

D. Policy Compliance Values

1. Renewable Portfolio Standard Adder

a. Existing Practice

Currently, RPS compliant QFs that select the "renewable rate" must transfer the RECs associated with the QF output to the utility during the deficiency period of the PPA, including the final five years of the PPA when the QF is receiving market-based prices. QFs selecting the renewable rate do not transfer RECs to the utility during the sufficiency period of the PPA. QFs selecting the "non-renewable" rate need not transfer RECs to the utility.

b. Positions of the Parties

As discussed above, Staff recommends eliminating separate "renewable" and "non- renewable" avoided cost price streams in favor of one adjustable rate. However, because the RPS still exists, Staff believes it is appropriate to ensure the avoided cost price stream accounts for the RPS compliance value when the QF is acquired in place of a resource that would generate RPS-eligible RECs. Staff's proposal regarding RPS-eligible RECs is as follows:

- If the avoided energy resource and the QF both produce RPS-eligible RECs, the QF's RECs transfer to the utility and no REC adder is added to or subtracted from the avoided cost price.

- If the avoided energy resource produces RPS-eligible RECs but the QF resource does not, the QF's avoided cost price is reduced by the amount of the REC adder.

- If the avoided energy resource does not produce RPS-eligible RECs but the QF resource does, the QF transfers RECs to the utility when the utility is RPS deficient and receives the REC adder. When the utility is RPS sufficient, the QF retains the RECs (and, we infer, does not receive the REC adder).

- If neither the avoided energy resource nor the QF produce RPS-eligible RECs, no RECs transfer and no REC value is added to or subtracted from the avoided cost price.

Staff recommends valuing RECs using a market rate, or implied market rate, based on values contained in PacifiCorp and PGE's bundled REC product programs known as

Blue Sky and Green Futures. Whether the avoided proxy utility resource is RPS compliant will be determined by the proportion of forecasted energy produced by projects used to calculate the avoided resource's cost. If more than 50 percent of the energy produced by projects used to calculate the avoided resource cost comes from RPS eligible resources, then the utility's avoided resource will be assumed to be RPS eligible.

The QFTGs generally support Staff's proposal, with certain clarifications. First, they state that the RPS adder should be paid whenever the avoided *energy or capacity* resource does not produce RPS-eligible RECs but the QF's RECs are surrendered to the utility. Second, they argue that the RPS adder should be based on the incremental bundled value of RECs and not the unbundled value. Third, the QFTGs urge the Commission to unambiguously repeal its current policy on REC ownership in the last five years of a 20-year contract so that the QF does not need to cede RECs to the utilities when being paid market-based rates.

PGE agrees that QFs should remit their RECs to the purchasing utility when the avoided energy resource produces RECs. However, PGE proposes that when the avoided energy resource does not produce RPS-eligible RECs, the QF should retain any RECs it produces and be allowed to engage in unbundled sales outside of the context of PURPA. It argues that under FERC Order 872, avoided cost rates "are not intended to compensate the QF for more than capacity and energy" and may not be set higher to account for non-energy benefits, such as "environmental benefits."[64] RECs, it says, reflect eligible generators' environmental, social, and economic benefits. Second, PGE argues that administratively determining and updating the prevailing market rate for RPS-eligible RECs would be an imprecise and difficult task. PGE also disagrees with the QFTGs' clarifications, arguing that RECs should be remitted for the full term of the PPA, as they currently are, and that the avoided energy resource, not the avoided capacity resource, is the appropriate reference point for RPS compliance. Idaho Power and PacifiCorp concur with PGE.

On reply and in support of its position, Staff argues that the Ninth Circuit Court of Appeals has found that

> [W]hen a state has a requirement that utilities source energy from a particular type of generator, 'generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement.' Thus, where a state has an RPS and the utility is using a QF's energy to meet the RPS, the utility

[64] FERC Order at P 123 (2005).

> cannot calculate avoided costs based on energy sources that would not also meet the RPS.[65]

Staff states that it proposed using the value of RECs as a substitute for a standard avoided cost price stream based only on RPS-compliant resources. In the alternative, the Commission could require the utility to calculate two avoided cost price streams when the avoided energy resource is classified as non-RPS compliant using Staff's methodology.

In reply to the QFTGs, Staff clarifies that it is recommending that the Commission not require the QF to transmit RECs to the utility in the last five years of a contract when the QF is receiving market prices.

c. Resolution

We find that Staff's proposal is in accordance with PURPA and approve it. In doing so, we are informed by the Ninth Circuit's decision that "where a state has an RPS and the utility is using a QF's energy to meet the RPS, the utility cannot calculate avoided costs based on energy sources that would not also meet the RPS."[66] FERC's mandate, as interpreted by the Ninth Circuit, is that a state take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy.[67] We find that Staff's construct here does so as well, and thus we find that Staff's construct satisfies FERC's mandate.[68] We include in our decision Staff's clarification that the Commission not require the QF to transmit RECs to the utility in the last five years of a contract.

2. Small Scale Renewables Adder

a. Existing Practice

ORS 469A.210 provides that by 2030, at least 10 percent of the electrical capacity of PGE and PacifiCorp must be composed of electricity generated by one or both of the

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[65] *Californians for Renewable Energy v. California Pub. Utilities Comm'n*, 922 F3d 929, 937 (9th Cir 2019), quoting *Cal. Pub. Util. Comm'n*, 133 FERC par. 61059, 61,265 2010 WL 4144227 (2010).
[66] *Californians for Renewable Energy v. California Pub. Utilities Comm'n*, 922 F3d 929, 937 (9th Cir 2019).
[67] *CPUC,* 133 FERC P 61,059 (2010).
[68] We note that the 9th Circuit also stated in *CARE v. CPUC* that "RECs are not covered under PURPA; rather they are considered state programs and do not factor into the avoided cost determination." *CARE,* 922 F2d at 940. However, in doing so, the 9th Circuit was ruling that a program that required QFs to remit RECs did not reduce costs to QFs below avoided costs. Here, the QFs are being fully compensated for the RECs they remit, so we hold their transfer to be a permissible exercise of our authority.

following sources: (a) small-scale renewable energy projects with a generating capacity of 20 MW or less that generate electricity utilizing a type of energy described in ORS 469A.025; or (b) facilities that generate electricity using a biomass that also generate thermal energy for a secondary purpose. The current methodology does not specifically account for the value of standard QFs with respect to this Small-Scale Renewable (SSR) Standard.

b. Positions of the Parties

Staff supports a flat 8 percent adder to the avoided capacity resource's monthly modelled avoided costs as a monthly fixed addition to compensation for QFs that satisfy the criteria of the standard. PGE calculated this 8 percent number, based upon research performed by Lawrence Berkeley National Laboratory (LBNL), but opposes the adder.

The QFTGs support Staff's proposal but offer some clarifications. First, they argue that the SSR adder should be applied as a fixed payment, paid as a $/MW amount, based on the QF's nameplate capacity. Given this, since prices are in $/MWh, there would need to be a conversion from monthly prices into nameplate capacity, such as by multiplying the $/MWh price by monthly generation capacity factor of the modeled resource. Third, they argue, the SSR adder should be the same $/MW price paid regardless of the resource type of the SSR QF (*e.g.*, solar, wind, RPS-qualified hydro, etc.). Fourth, the QFTGs argue that a resource should be paid the SSR adder even in months where it does not generate any energy.

PacifiCorp proposes accounting for the factors that contribute to SSR compliance by basing the size of the SSR adder according to four categories, which each depend on whether the QF is SSR-compliant and firm:

- SSR compliant and firm: QFs receive an SSR adder based on 100 percent of the QF's nameplate capacity (although eligibility would need to be adjusted for certain non-standard biomass-based QFs that exceed 20 MW);

- Non-SSR compliant and firm: QFs do not receive an SSR adder or a deduction because the SSR compliance requirement is expected to be offset by avoided utility-scale capacity and/or clean energy resources;

- SSR compliant and non-firm: QFs receive net SSR adder based on 90 percent of nameplate capacity; and

- Non-SSR compliant and non-firm: QF receives an SSR deduction based on 10 percent of nameplate capacity.

To calculate the size of the SSR adder, PacifiCorp proposes to measure the incremental cost of small-scale resources relative to the utility-scale proxy energy resource identified by the Commission.

PGE opposes any SSR adder, stating that it is inconsistent with PURPA. Specifically, it states that Staff's proposed adder would violate PURPA by incorporating speculative future costs into PGE's avoided cost rates and by compensating QFs for non-energy or capacity benefits. PGE argues that it has several avenues through which the SSR mandate may be satisfied apart from acquiring additional resources, so it may be unnecessary to spend the equivalent of an 8 percent premium on the SSR adder for QFs. PGE argues in addition that the 8 percent value is not supported by substantial evidence because Staff based it on PGE's quick approximation, which was developed based on an LBNL study to satisfy Staff's request that utilities model Staff's straw proposal, and was not based on PGE's actual avoided costs.

Idaho Power notes that it is not subject to HB 2021 and therefore the SSR adder does not apply to it.

c. Resolution

We adopt Staff's proposed flat 8 percent adder, calculated as a percentage of the SSR-compliant QF's total monthly payment. We find that an adder is appropriate because, as with the RPS, the SSR standard is a resource procurement requirement. We agree with Staff that under the Ninth Circuit Court of Appeal's opinion in *Californians for Renewable Energy*, SSR-compliant QFs should be eligible to receive an avoided cost rate based on costs of resources eligible to meet the SSR standard.[69] We also agree with Staff that calculating a separate avoided cost price stream at this time would be difficult and impractical.[70] While the 8 percent value based on an LBNL study is an imperfect approximation, this is true of all standardized avoided cost inputs, and no more accurate value has been proposed. Accordingly, we adopt the 8 percent proposed by Staff, with the note that this adder can be revisited if evidence demonstrates that it should be lower or higher in the future.

We do not agree that the adder should only apply after 2030, which is the first year that utilities must demonstrate compliance with the SSR requirement. Utilities need to be

[69] Staff Reply Brief at 26.
[70] *Id.* at 27.

procuring small-scale renewables now in order to be able to demonstrate compliance beginning in 2030. Further, we do not agree that the value of the adder should depend on the QF's firmness. PacifiCorp's approach does attempt to address the complex dynamics of the capacity-based small-scale renewable requirement. However, other adjustments to the QF proxy rate will account for the QF's firmness and there is value in the administrative simplicity of the 8 percent adder.[71] We also do not find that, as the QFTGs argue, the adder should be paid in months where the QF does not operate. While it is true that QFs contribute to the SSR requirement in all months, the adder was calculated assuming that it would be paid as 8 percent of the total monthly payment. Accordingly, we do not agree that it should be paid in months where the QF does not generate.

3. Deliverability Adder

a. Existing Practice

Our existing approach to avoided transmission in the case of an off-system proxy resource is laid out in Order No. 14-058: "if the proxy resource used to calculate a utility's avoided costs is an off-system resource, the costs of the third-party transmission are avoided, and are therefore included in the calculation of avoided cost prices." As to an on-system proxy resource, Order No. 16-174 sets out "a rebuttable presumption that there are no avoided transmission costs, and thus the costs of third-party transmission are not included in the calculation of avoided cost prices." We found that to rebut the presumption, evidence "must demonstrate that a renewable proxy resource has incremental transmission costs that can actually be avoided by the purchase of QF energy."

b. Positions of the Parties

Staff recommends no change to the current rebuttable presumption with respect to the cost of transmitting an on-system QF's output to load, as compared to the same type of cost for the proxy resource. However, Staff recommends a deliverability adder to avoided cost prices for on-system QFs to account for avoided off-system transmission infrastructure development. Staff's recommended methodology borrows from work done in docket UM 1893. In docket UM 1893, PGE calculated the Transmission Expansion Credit (TEC) by measuring the Levelized Cost of Energy (LCOE) of the preferred portfolio in the IRP both with and without transmission constraints. The TEC is expressed in the $/MWh difference between the LCOE in these two scenarios. PacifiCorp initially provided two methodologies in docket UM 1893 that produced similar results. One method (Alternative 1) incorporated QF interconnection costs on an energy basis (in

[71] *Id.* at 28.

$/MWh) and capacity basis (in 5 $/kW-yr). Here, Staff proposes an approach that aligns with PacifiCorp's Alternative 1 proposal in UM 1893. Staff submitted in this proceeding a UM 1893 Staff Report laying out Staff's explanation of and support for a TEC.[72] While Staff cites the TECs calculated by PacifiCorp and PGE under their respective methodologies in answer to the question "[i]f the TEC were used, what would the avoided deliverability cost be for an on-system QF in PacifiCorp's or PGE's territory,"[73] it appears that Staff is recommending in this proceeding that all three utilities use the first of two alternative approaches proposed by PacifiCorp in docket UM 1893, although Staff would also accept PacifiCorp's second alternative approach.[74]

Staff does not recommend adding the TEC to avoided cost prices for off-system QFs. It argues that purchases from off-system QFs would exacerbate the need for off-system transmission infrastructure rather than avoid it. It also states that if the utility is using an on-system resource as its proxy avoided resource, the on-system QF will receive the TEC minus avoided transmission set at the wheeling rate.

The QFTGs support Staff's conceptual proposal to ensure that avoided deliverability costs are included in avoided cost prices in general, and Staff's proposal to use values from the utilities' TEC calculation in docket UM 1893 to calculate the adder. However, they argue that Staff's proposal to constrain the availability of the TEC deliverability adder to the circumstance where the utility's proxy avoided resource is an off-system resource and the QF is on system is unjustified. Instead, they argue, the TEC deliverability adder should apply to all QFs, on-system and off-system, and it should apply in full regardless of whether the utility proposes an on-system or off-system proxy resource. The QFTGs argue that off-system QFs allow the utility to avoid the same transmission expansion costs as on-system QFs because off-system QFs must compensate the utility for transmission costs necessitated to deliver their power from the point of delivery to the utility's system to the utility's load. The QFTGs also argue that it is arbitrary to reduce the TEC deliverability adder for a wheeling rate in any scenario; if the TEC is the avoided deliverability cost tied to the utility's avoided generation, then it should apply regardless of whether the utility labels the proxy resource as "off-system" or "on-system."

The utilities oppose any deliverability adder. First, PGE argues that it would be fundamentally unfair to adopt a proposal made by Staff in the last round of testimony. Second, PGE argues that the record in this case does not provide "compelling" and "factual and not anecdotal" evidence of incremental transmission costs that can actually

[72] Staff/601 (Order No. 25-017, Appendix A at 11).
[73] Staff/600, Drennan/5.
[74] Staff Opening Brief at 40; Staff Reply Brief at 29-30.

be avoided by QF purchases, which the Commission has previously stated would be required to include on-system transmission costs in avoided costs.[75] Third, PGE argues that the Commission's decision must be supported by substantial evidence in the record in this case, and the Commission cannot rely on its order from UM 1893 as evidentiary support for its decision in this case.[76]

Additionally, PGE argues that the adder is unlawful under PURPA because FERC has made clear that an adder based on avoided transmission system costs must be based on "an actual determination of the expected costs of upgrades . . . that the QFs will permit the purchasing utility to avoid."[77] Here, PGE argues, a single QF will not permit PGE to avoid additional transmission investment, so customers would be required to pay twice for the same transmission investments—once to the QF and again for the actual construction. Finally, PGE argues that the current construct adequately and accurately captures PGE's current avoided deliverability costs and should be retained without modification.

c. Resolution

We find that Staff's proposal will result in just and reasonable rates and approve it. We do not accept the QFTG's proposal that the deliverability adder always apply. We see value in incentivizing on-system resources that are not using regional transmission capacity that is already heavily constrained. Further, incentivizing additional projects connected to the distribution system supports local resilience goals. As Staff states, a purchase from an on-system QF allows a utility to avoid the need for a resource in a more distant geographic area, which could require significant transmission infrastructure development—anticipated by both PGE and PacifiCorp in their testimony and IRPs.[78] We disagree with PGE's argument that the record in this case does not provide compelling and non-anecdotal examples of transmission that can be avoided. It is logical that if sufficient QFs were connected on-system, that certain regional transmission expansions could be avoided entirely. It is true that any one 10 MW project cannot avoid a transmission expansion; but likewise, any one 10 MW QF purchase cannot avoid acquisition of a major resource, and yet it would be unjust and unreasonable to set avoided cost prices at zero. Therefore, we accept Staff's deliverability adder.

We agree with Staff that PacifiCorp's alternative 1 from UM 1893 should be used for calculation of the deliverability adder. We disagree with PGE that the Commission

[75] *In the Matter of Public Utility Commission of Oregon, Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 16-174 at 8 (May 13, 2016).
[76] *Calpine Energy Sols. LLC v. Pub. Util. Comm'n of Or.*, 298 Or App 143, 162-163, 445 P3d 308 (2019).
[77] *CPUC*, 133 FERC ¶ 61,059 at P 31 (Oct. 21, 2010).
[78] Staff Reply Brief at 29.

cannot rely on its order from UM 1893 as evidentiary support for its decision in this case. Staff submitted with its reply testimony the Staff Report from UM 1893 showing the calculation of the deliverability adder. That is sufficient evidence to support its calculations and we accept it.

E. Other System Values

1. Ancillary Services

a. Existing Practice

Currently, QFs are not compensated separately for any ancillary services they may provide.

b. Positions of the Parties

Staff and the utilities argue for maintenance of the Commission's existing policy. Staff states that the record does not show that the QFs that will execute the standard PPA will provide ancillary services and that, accordingly, the standard PPA is not the place to incorporate value for ancillary services. PacifiCorp and PGE argue that QFs are currently compensated for ancillary services through the proxy methodology and that adding separate compensation in the form of an adder would effectively compensate them twice. Idaho Power argues that solar and wind resources are intermittent and therefore cannot be held in reserve and dispatched when needed; QFs should not be compensated for services that they cannot provide. Idaho Power also argues that most ancillary services are encompassed by the interconnection requirements outlined in Institute of Electrical and Electronics Engineers (IEEE) 1547 and IEEE 2800, which apply to all generators interconnecting to Idaho Power's system; it is unclear, it says, what additional ancillary services could be sold by a QF to a third party.

The QFTGs argue that first, to the extent that the proxy resources have had flexibility and reserve values removed (see capacity netting, *supra*), they do not reflect the value of those services. Second, to the extent that the proxy resources are non-spinning resources, such as batteries and solar, the proxy resources do not reflect the production of reactive power. Third, they argue that to the extent that QF rates do not reflect 100 percent capacity value (due to the net capacity valuation method), the QF will not be compensated for capacity. The QFTGs argue that as a result, in years where the capacity payment is equal to or less than 50 percent, the QF be allowed to provide power on a non-firm basis, and if the capacity value is greater than 50 percent the QF be required to provide power on a firm basis (*i.e.*, not market capacity to third parties).

PGE responds to the QFTGs' proposal in its reply brief that the QFTGs' proposal is based on faulty assumptions and needlessly introduces complexity when QFs already have the option to sell on an as-available basis.

c. Resolution

The ancillary services that a particular QF can and does provide are more variable than can be accounted for in a standardized contract. We note that pursuant to the FERC's pro forma Small Generator Interconnection Agreement, to the extent that a utility requests an interconnecting generator—including a QF—to provide reactive power "outside the deadband" (the range of 0.95 leading to 0.95 lagging), the utility must compensate the generator in accordance with the applicable rate schedule then in effect.[79] We do not adopt additional compensation in this proceeding.

2. Resource or Portfolio Community Benefits Adder

a. Existing Practice.

There is not currently a resource or portfolio community benefits adder.

b. Positions of the Parties

OSSIA advocates for a community benefits adder because HB 2021 mandates resource planning that delivers local community benefits.[80] OSSIA suggests calculating the proposed adder by using values for Resource Community Benefits Indicators (rCBIs) and Portfolio Community Benefits Indicators (pCBIs) as a starting point for calculating the proposed adder. OSSIA further suggests looking to projects that verifiably improve LOLP or provide local workforce benefits to reduce costs that would otherwise be borne by utilities and their ratepayers. The QFTGs support OSSIA's proposed adder.

Staff and the utilities oppose the proposed adder. Staff states that Section 2(2) of HB 2021 is a policy, rather than an enforceable standard and that avoided cost rates can only account for costs that are incurred by the utilities. PGE and PacifiCorp cite to a FERC order where FERC stated that PURPA prohibits the incorporation of non-energy benefits, such as economic development benefits, into avoided cost rates.[81] PacifiCorp also states that there is not evidence in the record demonstrating that utilities pay an

[79] *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023-A, 186 FERC ¶ 61,199, Appendix F Small Generator Interconnection Agreement, §§ 1.8.1-1.8.3.
[80] ORS 469A.405(2).
[81] FERC Order 872 at P 123.

incrementally higher cost to procure resources that possess the requisite community benefits. Idaho Power notes that it is not subject to HB 2021 and therefore should not be subject to this adder.

c. Resolution

We find that a community benefits adder is not appropriate and reject it. FERC, in the order cited by PGE and PacifiCorp was clear: "Because the Commission already requires states to set QF rates at full avoided costs, it is barred from requiring QF rates set higher than that based on the non-energy benefits that QFs may also provide."[82] Here, unlike with the RPS requirements discussed *supra*, HB 2021 utilities are not incurring specific costs to comply with HB 2021's mandates on local community benefits, and therefore it is not appropriate to create a tiered rate in PURPA. The utilities may compensate specific, distinguishable projects through traditional contracting if community benefits are present, under our traditional cost recovery constructs.

3. Distribution Deferral Credit Adder

a. Existing Practice

There is not currently a distribution deferral credit adder.

b. Positions of the Parties

OSSIA argues for a distribution deferral credit adder because distribution-level avoided costs are distinct from transmission-level avoided costs and traditional avoided transmission cost calculations do not account for distribution-level avoided costs. It argues that modern solar-plus-storage projects can defer or eliminate costly substation and feeder upgrades by providing balancing and voltage support services. The QFTGs support OSSIA's proposed adder.

Staff and the utilities oppose the proposed adder. Staff argues that, first, the record does not show that a typical QF that qualifies for a standard PPA will have the technical or practical ability to provide the benefits described by OSSIA. Second, it argues, if the QF were to provide these benefits, the QF and utility would have to negotiate the circumstances in which the benefits would be provided, so an adder to the standard PPA is inappropriate. PacifiCorp argues that QFs produce non-curtailable generation, increasing strain on the transmission and distribution system. Idaho Power argues that this would be a fact specific inquiry and not appropriate for standardization. And PGE

[82] *Id.*

notes that QF dispatch is controlled by the QF operator and QGs cannot be curtailed, so given this, there is insufficient evidence that QGs can defer distribution investments.

c. Resolution

We reject the proposed adder. While we believe there may be some situations in which a QF may enable the avoidance of distribution costs—and while we encourage the interconnection of QFs that enable the avoidance of distribution costs—we agree with Idaho Power that these avoided costs would be fact specific and not amenable to standardization in the form of an adder. We further find that the record in this proceeding does not demonstrate standardizable distribution costs that can be deferred as a result of the interconnection of QFs which, as PGE points out, cannot be curtailed.

4. WRAP ELCC Adder

a. Existing Practice

There is not currently a WRAP ELCC adder.

b. Positions of the Parties

OSSIA argues in favor of a WRAP ELCC adder, which would represent the difference between the utilities' internal ELCC and WRAP ELCC values. OSSIA states that participation in WRAP requires utilities to demonstrate sufficient capacity based on WRAP's ELCC methodology; without the QF, the utility would need to procure incremental capacity to satisfy WRAP. Therefore, it argues, a standardized QF adder would ensure QFs are fairly compensated for the regional adequacy contributions utilities rely upon. The QFTGs support OSSIA's WRAP ELCC adder.

Staff and utilities oppose the proposed adder. Idaho Power argues and Staff agrees—that the proposal is substantively flawed because it would use two different methodologies for determining the ELCC—the utility's ELCC would be used for the avoided resource, while the WRAP ELCC would be used for the QF. Consistency, Idaho Power argues, requires the same calculation for both, otherwise one cannot determine what is avoided by the QF. PacifiCorp and PGE concur that it is an apples to oranges comparison, and also add that utilities do not necessarily incur costs simply to meet WRAP requirements.

c. Resolution

We reject the proposed adder. Utilities plan primarily to serve their load—using utility-specific ELCC values—not to meet WRAP requirements.[83] In addition, as Staff notes, the proposed adder is inappropriately premised on comparing WRAP portfolio modelled ELCCs with utility modelled marginal ELCCs.[84]

And while a WRAP ELCC adder may be higher currently, we cannot say based on the record in front of us that it would always be higher. Theoretically, sharing through WRAP could produce lower ELCC requirements by drawing on the diversity of loads and resources represented and we choose not to decrement avoided costs where the WRAP ELCC value is lower than the avoided cost calculated ELCC.

5. Wildfire Mitigation Adder

a. Existing Practice

There is not currently a wildfire mitigation adder.

b. Positions of the Parties

The QFTGs argue that a QF should be compensated for avoided utility cost and risk associated with practices that reduce wildfire risks or reduce the costs a utility needs to spend on wildfire mitigation. For instance, they argue, wood waste combusted at a biomass facility can include clearings from transmission rights-of-way, slash piles left over from logging, mill waste, used pallet waste, agricultural waste, and more. By using the wood waste for electricity generation, they assert, risk of wildfire decreases because of the decrease in potential fuel sources for those wildfires.

Staff and utilities oppose the proposed adder. Staff states that an adder is only appropriate in specific circumstances, and that QFs like the biomass QFs described by the QFTGs have the option to negotiate a non-standard PPA. PacifiCorp argues that the adder is foreclosed by PURPA. In particular, it argues, PURPA does not allow increases to avoided costs to account for non-energy benefits. As examples, it says, FERC has cited, in Order 872, "environmental benefits, waste reduction benefits, and economic development benefits" as the kinds of value that may not be accounted for in avoided costs.[85] Biomass removal is both environmental benefits and waste reduction benefits,

[83] *See* PGE/200, Mead/11.
[84] Staff/300, Bain/45.
[85] FERC Order 872 at ¶ 123.

PacifiCorp argues, and cannot be included in avoided costs. Idaho Power and PGE echo this concern and add that the QFTGs have not provided evidence showing how the alleged wildfire mitigation effects of biomass facilities will allow a utility to avoid spending on its own wildfire mitigation efforts.

On reply, the QFTGs argue that FERC Order 872 does not apply because biomass facilities contribute to the reduction of wildfire mitigation costs that would otherwise be passed onto consumers in electric utility rates. They also point to their testimony which provides evidence of the wildfire mitigation reduction value that biomass facilities can provide.

c. Resolution

We reject the proposed adder. In doing so, we are not dismissing the contribution that biomass facilities can provide in the state of Oregon. But we are conscious of FERC's order that environmental benefits, waste reduction benefits, and economic benefits are not compensable through PURPA.[86] And while we agree that biomass facilities may enable utilities to defer wildfire mitigation costs, the record before us does not demonstrate how and what those costs are in a way we can standardize into an adder. Therefore, the proposed adder is not appropriate.

6. QF Forecasting Practices for Use in IRP and Other PURPA Capacity Contribution Methods

a. Existing Practice

There is not currently an existing policy or practice.

b. Positions of the Parties

Staff states that QF renewal and success rates are important in the context of avoided cost modelling, as they have a material impact on the capacity needs of the future system, which is the basis of modelled ELCC values, and thus avoided cost rates. Accordingly, Staff would have utilities use their 10-year historical renewal and success rates of QF projects as of the time of IRP filing. Should 10 years of data not be available, Staff states that utilities should use an assumed rate of 75 percent for both renewal and success.

PGE and the QFTGs support Staff's proposal. PacifiCorp does not oppose using 10 years of historical data and, if that is lacking, a 75 percent assumed success rate. However, it

[86] *Id.*

suggests that the 10-year historical rates be established during the IRP process rather than at the time of the filing so that it does not have to rerun its models based on a relatively small data point. Idaho Power argues that the IRP is the better forum for establishing both renewal and success rates because establishing a renewal rate that does not align with the IRP could create contradictory assumptions for avoided cost pricing and resource planning.

c. Resolution

We find that 10 years of historical data and, lacking that, a 75 percent assumed success rate is reasonable. We also find that it is appropriate for 10-year historical rates to be established during the IRP process rather than at the time of filing and allow utilities to do so.

7. Avoided Cost Workbooks

a. Existing Practice

Currently utilities are required to submit workbooks satisfying certain filing requirements when filing avoided cost updates. Each utility's filing is uniquely structured and may include multiple workbooks.

b. Positions of the Parties

Staff recommends that the Commission direct Staff and parties to work on developing a standardized workbook that utilities must file with every avoided cost update. That work would be done in a third phase of this proceeding. The QFTGs go beyond Staff's recommendation and argue that the Commission should adopt as much standardization as possible. Specifically, in addition to a common cost model, as Staff proposes, the QFTGs argue for the use of common inputs where practical, such as common price forecasts, and the use of common methodologies for inputs where practical, such as common methods of calculating capacity contribution. They also state that it would be preferred for OPUC Staff to calculate the avoided cost prices using standardized models like is done in Idaho.

Staff takes no position on common inputs here, finding it premature. PacifiCorp, Idaho Power, and PGE oppose standardizing input values, arguing that market prices differ among resources within a utility's portfolio and among different utilities and that there is variation in market participation, load growth, and customer characteristics between utilities.

c. Resolution

We direct the three utilities to coordinate on a workbook and to submit it within 90 days of this decision. Given its numerous other priorities, we decline to burden Staff with either authoring the workbook or taking on "ownership" of the workbook on a yearly basis. Nonetheless, we see benefits to standardization and direct the utilities to work on it in Phase III of this proceeding.

IV. ORDER

IT IS ORDERED that:

1. Portland General Electric Company, PacifiCorp, dba Pacific Power, and Idaho Power Company are to coordinate on a standardized workbook and submit it within 90 days of this decision.

2. Portland General Electric Company, PacifiCorp, dba Pacific Power, and Idaho Power are to file revised avoided cost rates in accordance with the decisions made in this order within 120 days.

Made, entered, and effective Jan 23 2026.

Letha Tawney
Chair

Les Perkins
Commissioner

Karin Power
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001- 0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.