Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

April 26, 2021

Via Electronic Filing

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

Re: UM 2011 PGE Report of Concentric Energy Advisors

Dear Filing Center:

In addition to its participation in the Joint Utility Comments, Portland General Electric Company (PGE) submits the attached Report of Concentric Energy Advisors (Concentric), which addresses the valuation of capacity as it applies to the development of avoided cost pricing for power purchase agreements (PPAs) for qualifying facilities (QFs) under the Public Utility Regulatory Policy Act (PURPA). While PGE acknowledges that this docket is taking a broad approach to its evaluation of capacity value, there remains a great deal of uncertainty around the ultimate outcome of this investigation, particularly because Staff has suggested that any capacity valuation principles adopted here may ultimately be applied to QF avoided cost pricing. Given the complexities inherent in valuing capacity, and the specific legal and policy constraints imposed by PURPA, PGE retained Concentric to help assess the pros and cons of available approaches to valuing capacity in the context of QF avoided cost pricing and consistent with PURPA's unique legal and regulatory requirements. PGE selected Concentric based on that firm's deep understanding of energy markets, project finance and regulatory policy.

To frame the relevant subject matter for the report, PGE asked Concentric to respond to the following five questions:

1. What methodology should the OPUC use to determine the per unit compensation that QFs receive for providing capacity?
2. How should a utility's opportunity to procure capacity at a cost less than the Cost of New Entry (CONE) be considered within a capacity compensation framework?
3. Should QF capacity be paid for in time periods when the utility has met its capacity requirements?
4. If the utility separately pays for capacity and energy for a QF resource, is it ever appropriate for those payments to exceed the underlying avoided cost?
5. What risks should be considered when forecasting capacity contribution performance across a long time period?

Concentric's report explores each of these issues, including relevant analysis and summary conclusions.

PGE appreciates the opportunity to comment and engage in this docket.

Sincerely,

/s/ Robert Macfarlane

Robert Macfarlane
Manager Pricing & Tariffs

AN ASSESSMENT OF UM 2011 POLICY MATTERS

PREPARED FOR: PORTLAND GENERAL ELECTRIC

APRIL 26, 2021

CEADVISORS.COM

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SECTION 1:
INTRODUCTION

Concentric Energy Advisors (Concentric) has been asked by Portland General Electric (PGE) to review the comments filed in Oregon Public Utility Commission (OPUC or Commission) Docket UM 2011, including the report by Energy + Environmental Economics (E3) on December 15, 2020 entitled Principles of Capacity Valuation (E3 Report), and to address several specific questions related to capacity pricing specifically as it applies to contracts with Qualifying Facilities (QFs) under the Public Utility Regulatory Policy Act (PURPA). The questions posed by PGE are as follows:

1. What methodology should the OPUC use to determine the per unit compensation that QFs receive for providing capacity?

2. How should a utility's opportunity to procure capacity at a cost less than the Cost of New Entry (CONE) be considered within a capacity compensation framework?

3. Should QF capacity be paid for in time periods when the utility has met its capacity planning requirement?

4. If the utility separately pays for capacity and energy for a QF resource, is it ever appropriate for those payments to exceed the underlying avoided cost?

5. What risks should be considered when forecasting capacity contribution performance across a long time period?

Prior to addressing these questions, this report provides a brief summary of the observed relationship between certain administratively determined QF rates and contract rates set in the competitive market. Summary responses to the PGE questions are as follows:

TABLE 1
Summary Responses to PGE Questions

PGE Question	Concentric Summary Response
1	Market-based indicators are important in ensuring that QF rates do not exceed avoided costs. However, in cases where there is a lack of sufficient market observations, such as in Oregon, we recommend setting avoided capacity costs through a combination of data obtained from competitive processes such as major all-source solicitations and administrative avoided costs analysis. The use of market-based data supplemented by administratively determined costs is consistent with the imperfect and illiquid capacity market that exists in the Northwest.
2	Net Cost of New Entry (Net CONE) calculations should represent a maximum avoided capacity price recognizing that Net CONE is subject to significant inaccuracies in estimating market revenues and generation-specific costs. When available, competitive outcomes represent far better indicators of actual market capacity prices at which arms-length buyers and sellers will transact for capacity. In cases where such competitive transactions are not widely available, a combination of all-source competitive solicitations and administratively determined capacity values would represent an appropriate approach to setting avoided capacity costs.
3	The determination of a utility's need for capacity should be based on the outcome of the utility's Integrated Resource Plan (IRP) and resulting requirements for new resources to meet reliability targets. If a utility system has sufficient capacity resources available to achieve its adequacy metric, such as a target Loss of Load Probability (LOLP), purchasing additional capacity would result in duplicate payments of capacity and excess and unnecessary ratepayer costs.
4	Ratepayers should not be exposed to the risk of overpayment for QF output. A basic tenet of PURPA is that ratepayers are held harmless from purchases of QF power. If the cost of capacity and energy is higher than the utility's net avoided cost, or if the contract term length is unreasonably long—thus requiring ratepayers to buy capacity and energy that may not be needed in the future—the ratepayer indifference tenet is not met. To prevent these outcomes, the Commission may seek to retain some level of flexibility in setting avoided capacity and energy values and setting an appropriate contract term to ensure the objectives of PURPA are achieved.
5	Ratepayers do face the risk that the Effective Load Carrying Capacity (ELCC) of intermittent and energy-limited resources will decline as more of these resources are added to the system and region. The result of such a decline in ELCC can be an effective increase in the unit cost of usable capacity. To mitigate this risk, the Commission may seek to evaluate shorter duration capacity contracts.

SECTION 2:
BACKGROUND

Congress passed PURPA in 1978 and required the Federal Energy Regulatory Commission (FERC) to establish regulations to implement the law. Under PURPA, Public Utility Commissions (PUCs) are required to adopt rules that comply with FERC regulations when implementing PURPA within their state. PURPA generally requires all electric utilities to purchase electricity from QFs at "avoided cost", which can take the form of "cogeneration facilities" and "small power production facilities that are 80 MW or smaller."[1] FERC regulations define avoided cost as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[2]

The OPUC has long held that its goal in implementing PURPA is to "encourage the economically efficient development of these qualifying facilities, while protecting ratepayers by ensuring that utilities pay rates equal to that which they would have incurred in lieu of purchasing QF power."[3] However, setting QF contract rates administratively without regard to current market conditions can result in inefficient levels of investment and unintended outcomes.

Ensuring that ratepayers incur costs for energy and capacity from QFs that do not exceed the utility's avoided cost can be challenging in situations in which limited competitive market price indicators exist, as is the case in the Northwest. While we recognize the desire to address this situation by creating administratively determined benchmarks, we urge caution in doing so given that such approaches could potentially result in utility customers paying more for energy and capacity than necessary, contrary to the PURPA customer indifference principle.[4] Furthermore, the challenge of

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1 Congress amended PURPA, once, through the Energy Policy Act of 2005 (EPAct 2005) to allow FERC to terminate the mandatory purchase obligation if FERC finds that specific criteria are met. In implementing EPAct 2005, FERC found that QFs of 20 MW or less are not presumed to have access to wholesale markets. Robust competitive electricity markets largely did not exist when PURPA was enacted in 1978, so with FERC's guidance, state PUCs used administrative methods as the only available mechanism to estimate a utility's avoided cost. However, as recognized in EPAct 2005, competitive electricity markets have developed throughout the United States in the past 40 years and now provide a means to estimate a competitive benchmark for a utility's avoided cost for energy and capacity.

2 *See* 18 C.F.R. § 292.101(b)(6). Under PURPA, the rates electric utilities pay QFs must be: 1) just and reasonable to the electric utility's customers and in the public interest; 2) non-discriminatory toward QFs and cogenerators; and 3) not exceed "the incremental cost to the electric utility of alternative electric energy." *See* 16 U.S.C. § 824a-3(b) and 3(d).

3 *See In the Matter of the Investigation into Electric Utility Tariffs for Cogeneration and Small Power Production Facilities*, Docket No. R-58, Order No. 81-319 at 3 (May 6, 1981)

4 *See e.g.*, *In the Matter of Portland Gen. Elec. Co.*, Docket UM 1894, Order No. 18-025 at 7 (Jan 25, 2018) ("[O]ne critical feature of our implementation of PURPA, including (but not limited to) the terms and

adhering to PURPA avoided cost principles becomes magnified when energy and capacity are subject to distinct fixed compensation mechanisms reliant on long-term avoided cost forecasts, particularly when these mechanisms are developed in isolation. This challenge is particularly notable in times when load patterns and supply costs are undergoing significant change, as is currently the case.[5]

As the Commission develops and refines its capacity valuation mechanism, it is important to recognize and consider past experiences in which unintended outcomes have resulted in excessive ratepayer costs. Such outcomes ultimately reduce the quantity of renewables that can be procured on behalf of consumers at any given level of expenditure, which undermines, rather than advances, policy goals encouraging the reduction of carbon emissions.

The challenge of correctly establishing avoided cost capacity rates is not new. In fact, there is substantial evidence that utilities, including utilities in Oregon, have been required to execute QF Power Purchase Agreements (PPAs) at rates that are above rates that may be commercially available in the competitive market. This conclusion is based on a comparison between recent competitive market prices for utility-scale solar PPAs compiled by Berkeley Labs and recent PGE levelized renewable avoided cost prices approved by the OPUC. The Berkeley Labs' data represents PPA rates applicable to utility-scale projects that sell energy, capacity, and environmental attributes in the wholesale market through a long-term, bundled PPA.[6] The PGE average rate represents 15-year levelized prices stated in 2019 dollars.[7] This rate comparison is shown in Figure 1.

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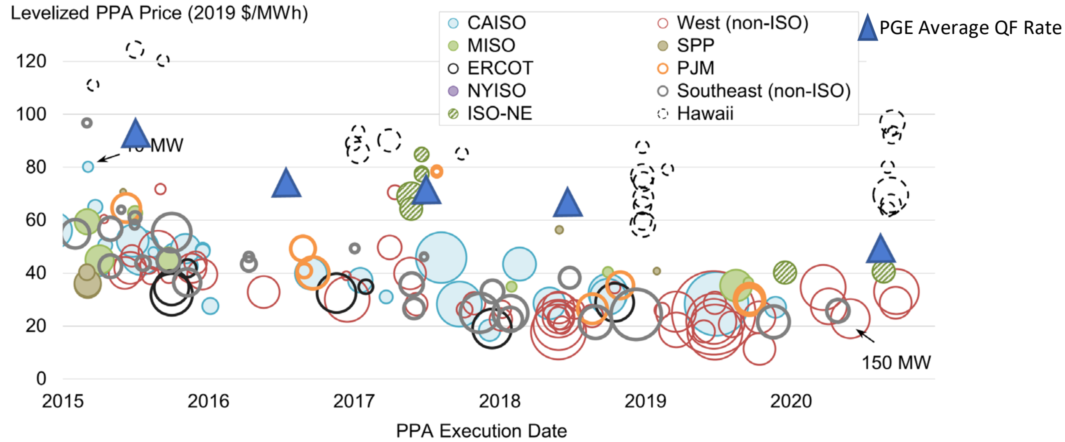
conditions of our regulated PURPA contracts, is the need to ensure that ratepayers remain financially indifferent to QF development.").

5 Concentric Energy Advisors, *An Empirical Analysis of Avoided Costs Rates for Solar and Wind QFs Under PURPA* (2019).

6 *See e.g.*, M. Bolinger, J. Seel, D. Robson, & C. Warner, *Utility-Scale Solar Data: Update 2020 Edition* 30 (Lawrence Berkeley National Laboratory, Nov. 2020).

7 Docket No. UM 1728. Portland General Electric Levelized Renewable Avoided Costs - Solar QFs ($2019).

FIGURE 1: Levelized Utility Scale PV PPA Prices



Furthermore, there is evidence that the observed price differential between a large set of QF contract rates from across the country and competitive PPAs rates have expanded over time as the installed cost of renewable generation has declined more rapidly than administratively determined avoided cost rates. This relationship is shown in Figure 2.[8]

[8] Concentric Energy Advisors, *An Empirical Analysis of Avoided Costs Rates for Solar and Wind QFs Under PURPA* (2019). In that report, Concentric Energy Advisors found that the decline in solar Levelized Cost of Energy (LCOE) of 73.1% over the 2009-2018 period was significantly higher than the 45.5% decline observed in the MW-weighted average QF solar contract rate over the same period. The Concentric Energy Advisor LCOE estimates are roughly in line with Lazard's November 2019 LCOE estimates for solar PV, which Lazard estimates declined by 89% over the 2009-2019 period, or 20% per year on average (gray line in Figure 2). To calculate the LCOE declines, Concentric used the National Renewable Energy Laboratory's CREST model and solar installation benchmark cost data between 2010 and 2018 to calculate the LCOE of a generic fixed-tilt utility-scale solar system in each state that a solar QF in our sample was located. Concentric then plotted the MW-weighted average of these state-level solar LCOEs for purposes of comparison with the MW-weighted average solar QF contract price each year. For this comparison, Concentric assumed that the 2009 MW-weighted average QF contract rate changes throughout the sample at the same year-over-year change as the generic photovoltaic LCOEs estimated in CREST (green line in Figure 2).

FIGURE 2: MW-Weighted Average Solar QF and Generic Solar LCOE Trend Comparison[9]

The data depicted in Figures 1 and 2 demonstrate that administratively established price forecasts can be poor substitutes for market-based outcomes and can result in significant differences between the payments made to QFs and rates available in competitive markets.

In Order No. 872, FERC recognized the ratepayer impacts of such long-term contacts, finding that "long-term forecasts of avoided energy costs are inherently less accurate, and that states should be given the flexibility to rely on a more accurate variable avoided cost energy rate approach."[10] While FERC's findings are focused on a lack of accuracy of long-term energy price forecasts, a similar concern should also exist regarding long term capacity price forecasting generally, and specifically, in the Northwest due to the lack of transparency regarding the cost of capacity in the region. Given the strong evidence that existing QF contract rates may exceed rates available in competitive markets, any use of administratively determined forecasted rates should be applied with caution to ensure that the resulting avoided cost rates are consistent with the requirements of PURPA.

Separately, regulatory policies should not require utilities to procure capacity that is not needed as part of the utility's obligation to provide reliable electric service to ratepayers at just and reasonable rates. The concern regarding the purchase of excess capacity is particularly important for utilities in Oregon, as excess QF capacity cannot be sold into a liquid market as is the case with entities operating in organized competitive markets.

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9 *Ibid.*

10 *See* Docket Nos. RM19-15-000 and AD16-16-000, FERC Order No. 872 at 150 (July 16, 2020).

To address the risk of the procurement of QF capacity that is ultimately not needed to reliably serve ratepayers, we encourage the consideration of shorter-term capacity contracts which may reduce the magnitude of the differential between contract rates and the utility's actual avoided capacity cost, thus limiting the potential that ratepayers pay for excess capacity in violation of PURPA's customer indifference principle.[11]

11 In a commercial market context, reducing contract duration is a common strategy taken by managers of load obligations to address uncertainty regarding future load levels and market prices.

SECTION 3:

RESPONSES TO QUESTIONS POSED BY PGE

1. What methodology should the OPUC use to determine the per unit compensation that QFs receive for providing capacity?

QF Market-Based Capacity Values

The value of capacity provided by a QF resource should be equal to the lowest net resource cost (defined as the installed cost of the facility minus energy, ancillary and renewable attribute revenues earned by the resource) available to the utility to meet its capacity requirement. Ideally, a recognized capacity market clearing price for capacity, when available, can be used to determine capacity compensation for QFs. In the absence of such consistent and visible market prices, a set of competitive market value indicators such as utility all-source procurements, structured contracts and bilateral agreements should be applied whenever possible in setting avoided cost rates[12]

While such observable competitive mechanisms represent the most direct means to assess actual avoided costs that a utility would incur to meet its capacity requirement, it is likely that these competitive solicitations may be limited in scope and may need to be supplemented with administratively determined capacity value indicators in Oregon in setting avoided cost rates. This blended approach may be particularly important in situations in which there is a lack of observable market data across time. An approach to establishing avoided capacity rates that takes into account the attributes of the capacity market, including the availability of competitive transactions, is shown in Figure 3. Given the potential for a limited set of utility and commercial contracts applicable in Oregon, it is likely that the most accurate indicator of capacity value may include a blend of market transactions and administratively determined capacity rates.

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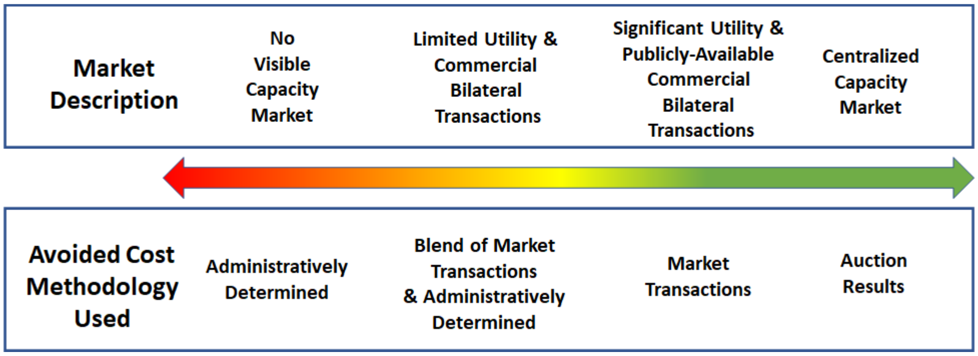
[12] All-source procurements represent a rigorous review of capacity options available to utilities. FERC Order No. 872 now expressly permits utilities to set avoided costs rates through solicitations that meet specific transparency requirements. *See* Docket Nos. RM19-15-000 and AD16-16-000, FERC Order No. 872, at 232-236 (July 16, 2020).

Figure 3: Market Design and Appropriate Avoided Cost Approach



<u>Administratively Determined Capacity Values</u>

A determination of capacity value based *solely* on an administrative process can represent a second-best indicator of avoided costs when valid market market-based capacity value transactions exist. Capacity costs set through an administrative process are subject to significant potential error given the uncertainty that exists regarding both future energy revenues and proxy project costs. To the extent that the Net CONE[13] is the administratively determined cost indicator used to set capacity rates, the resulting capacity rate may be significantly impacted by forecasted energy and other potential revenues streams (*e.g.*, ancillary service and environmental benefit). These forecasted revenues are subject to considerable uncertainty, resulting in capacity value uncertainty that becomes magnified as the forecasted time horizon expands.

By comparison, in organized markets Net CONE plays a far less important role than in markets such as Oregon because Net CONE generally does not set capacity values in these organized markets; rather, Net CONE is used to set a capacity auction starting price. Competition then generally drives the market clearing price for capacity far below Net CONE.

In these markets, Net CONE is designed to represent the fixed cost compensation that a hypothetical generating unit would likely need to enter the market when capacity is needed and is not intended to represent the actual compensation that a generating resource will receive for providing capacity, which is ultimately subject to competitive market forces. As auction results clearly show, actual capacity prices paid to generators operating in organized markets are generally far below administratively determined Net CONE values. This fact is highlighted in Figure 4 below.

[13] Net CONE is defined as the installed cost of the unit and operating expenses, including capital investment, minus the energy, ancillary services and renewable attribute revenues over the estimated economic life of the facility. *See* American Public Power Association, *Missing Money Revisited: Evolution of PJM's RPM Capacity Construct* 3 (September 2016).

Furthermore, a proxy method that sets an administratively determined value based on a designated generating resource technology of the expected new entrant introduces a degree of uncertainty regarding the likely new entrant generation technology, which can potentially result in capacity costs that may be in excess of the true avoided costs of the actual new entrant. For example, while a simple cycle combustion turbine may often be the lowest cost resource, QF avoided cost determinations should consider all potential capacity resources including solar and hydroelectric resources.

In cases in which both capacity and energy avoided cost rates are independently set using purely administratively determined methods, significant risk exists that these rates may together magnify the potential for energy and capacity rates to exceed actual avoided costs. To address this risk, it is important to consider direct market-based indicators in setting energy rates thereby reducing the overall risk that the combination of avoided energy and capacity rates do not exceed the utility's actual avoided costs.

<u>Summary</u>

Market-based indicators are important in ensuring that QF rates do not exceed avoided costs. However, in cases where there is a lack of sufficient market observations such as in Oregon, we recommend setting avoided capacity costs through a combination of data obtained from competitive processes, such as major all-source solicitations, and administrative avoided costs analysis. The use of market-based data supplemented by administratively determined costs is consistent with the imperfect and illiquid capacity market that exists in the Northwest.

2. How should a utility's opportunity to procure capacity at a cost less than CONE be considered within a capacity compensation framework?

<u>Review of Net CONE Results</u>

Across various organized markets, there is strong evidence that merchant power plant developers and owners are often willing to construct, maintain and offer generating capacity into the market at rates far below what would have been estimated through a Net CONE analysis. This situation is not surprising given that the key function of power plant asset managers and developers is to maximize profits through a combination of efforts that increase revenues and decrease project costs. Asset managers and developers do so by seeking to obtain the highest possible revenues through various origination efforts and identifying the lowest cost combination of inputs through numerous competitive solicitations and support from various advisors (*e.g.,* financial advisors) regarding ways in which overall project costs can be reduced. Several of the "levers" likely used by developers to reduce project cost are described below:

- ***Access to lower-cost financing.*** Developers are often able to lower their overall cost of capital versus what is typically assumed in a Net CONE calculation which is generally based on a merchant entrant using project financing. Strategies to lower capital costs include use of capital available through a financially strong parent company, use of tax equity, specialized debt instruments and greater use of leverage than may be included in the more simplistic financing assumptions within a Net CONE calculation.

- ***Favorable tax policy. (i.e., accelerated depreciation).*** The Net CONE calculations may not fully reflect the use of bonus depreciation, which allows developers to decrease near term tax obligations.

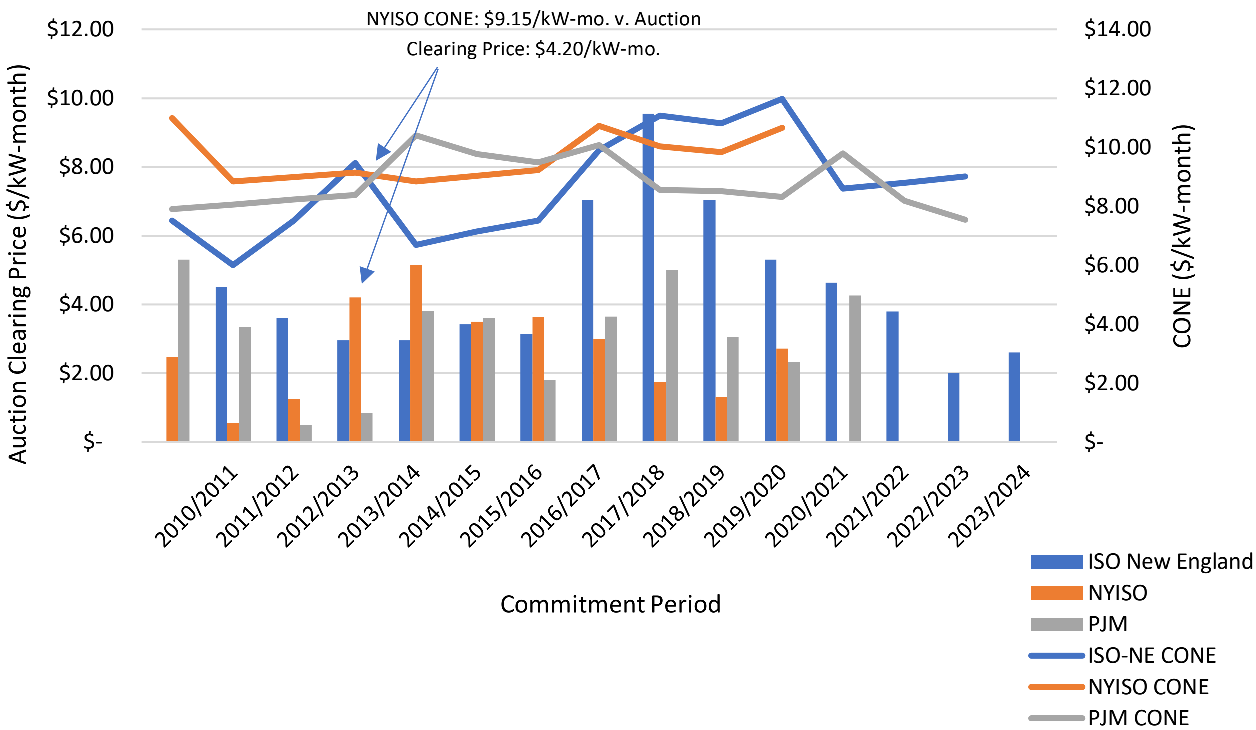
- ***Lower fixed and variable operating costs.*** While the Net CONE calculation assumes typical and expected fixed and variable operating costs for a "hypothetical" new entrant, developers are generally very experienced with generating resource operations, and are able to leverage that experience to lower operating costs below net CONE calculation inputs.

- ***Siting conditions.*** Because the Net CONE calculation reflects a hypothetical new entrant whose costs should be high enough to incent new entry when needed, but not so high that unnecessary costs are incurred, the costs related to interconnection, fuel, and property values are generic in nature and designed to represent a midpoint in a range of reasonable costs. In reality, developers will choose to site a resource such that interconnection (and fuel) costs are minimized and may negotiate property tax rates that are lower than publicly available tax rates.

- ***Higher energy and ancillary service revenues.*** The Net CONE calculation uses energy and ancillary services revenues based on either historical market prices or projected future prices that reflect subjective assumptions about supply/demand balance, natural gas prices, load levels, etc. The assumptions about the future state of the market used in the Net CONE calculation are deliberately set at a level sufficient to incent new entry.

The ability of new and existing generation to consistently offer capacity at rates below Net CONE can be observed in three of the regional transmission organizations (RTOs) with capacity markets – ISO New England, the New York Independent System Operator, and the PJM Interconnection. As can be seen in Figure 4, the past 10 capacity auctions in each of these RTOs have cleared well below the administratively set Net CONE values.

Figure 4: New England, New York and PJM CONE and Clearing Prices 2010/2011 through 2023/2024 Commitment Periods



Summary

Net CONE calculations should represent a maximum avoided capacity price recognizing that Net CONE is subject to significant inaccuracies in estimating market revenues and generation-specific costs. When available, competitive outcomes represent far better indicators of actual market capacity prices at which arms-length buyers and sellers will transact capacity. In cases where such competitive transactions are not widely available, a combination of all-source competitive solicitations and administratively determined capacity values would represent an appropriate approach to setting avoided capacity costs.

3. Should QF capacity be paid for in time periods when the utility has met its capacity planning requirement?

Capacity Sufficiency

The capacity contribution that an incremental resource provides to a given utility system is determined by the resource's ability to reduce the quantity of capacity needed to achieve the established target reliability level (*e.g.,* 1-day-in-10-year LOLP) less the cost of the resource. If a utility system has already achieved its target reliability level, the system does not require additional capacity and an incremental resource's contribution to system's planned reliability target approaches zero. If a utility in such a capacity sufficiency state was required to pay for additional unnecessary capacity, it would incur both existing capacity costs and additional unnecessary capacity resource costs, resulting in overpayment by ratepayers. Therefore, surplus QF capacity should not receive capacity-based compensation.

The Oregon IRP Process

The IRP process in Oregon is designed to rigorously and transparently determine the need for additional generating capacity. Each Oregon utility prepares its IRP by considering all-available resources to determine the combination of resources that best balances customer costs and risks while meeting identified capacity needs. This process involves significant engagement with OPUC Staff and other stakeholders and a deep and comprehensive review by the Commission itself. Only if the utility meets all of the requirements set forth by the OPUC and the preferred portfolio reasonably reflects the least-cost, least-risk portfolio, will the OPUC acknowledge the IRP. Given the comprehensive nature of each utility's IRP process, the IRP process should continue to be used to determine capacity sufficiency and deficiency.[14]

E3's Fixed Operating and Maintenance Cost Proposal

E3 recommends that during the sufficiency period compensation for surplus QF capacity is set equal to an amount reflecting Fixed Operating and Maintenance (FOM) costs of the lowest cost resource and this avoided cost rate would escalate in some way as the deficiency period approaches. The rationale for the E3 proposal to compensate surplus QF capacity at an FOM rate during sufficiency appears to be based on a desire to ensure that these surplus resources are available to serve load:

> In periods of sufficiency, a common approach to valuing capacity is to use the fixed operations and maintenance cost of the net resource cost resource. This approach is based on the cost to maintain existing capacity resources such that they are available to ensure system reliability, while also recognizing that the full cost of new capacity resources is an excessive measure of capacity value in times where sufficient resources are available.[15]

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14 It has been suggested in this proceeding that the utility IRP process is somehow subject to "gaming" by the utilities and, therefore, not an appropriate mechanism to determine capacity sufficiency and deficiency. *See* Renewable Energy Coalition Initial Comments, at 8-10 (Mar. 8, 2021). Given the review and oversight a utility IRP is subject to, it is unreasonable to suggest that the IRP process is used to justify excess utility capacity as a means of reducing opportunities for QF contracting.

15 E3 Report to OPUC Staff, at 10-11 (Dec. 15, 2020).

While the compensation approach proffered by E3 is designed to support existing resources by providing some level of revenue, the E3 approach is not consistent with fundamental PURPA avoided cost principles and, if implemented, would lead to excess costs for ratepayers.[16]

Summary

The determination of a utility's need for capacity should be based on the outcome of the utility's IRP and resulting requirements for new resources to meet reliability targets. If a utility system has sufficient capacity resources available to achieve its adequacy metric, such as a target LOLP, purchasing additional capacity would result in duplicate payments of capacity and excess and unnecessary ratepayer costs.

4. If the utility separately pays for capacity and energy for a QF resource, is it ever appropriate for those payments to exceed the underlying avoided cost?

When QF capacity and energy are valued and purchased separately, a situation can arise in which total compensation for these two products exceeds the utility's full avoided cost in violation of PURPA. Thus, care must be taken when pricing QF capacity and energy separately that the customer-indifference standard is met.

Furthermore, when capacity and energy QF rates are both fixed and set through an administratively determined mechanism, there is a strong possibility that total fixed QF payments will exceed the utility's avoided costs, contrary to the customer indifference principle. Setting the QF energy rate equal to an observable liquid market price would significantly reduce this risk.

However, there are certain circumstances in which total QF payments may exceed underlying avoided costs, such as when the QF receives a floating energy market price. In such a circumstance, market conditions may be such that the floating energy market prices may increase above the assumed proxy energy cost. For example, in Oregon, under a standard avoided cost contract a seller receives market payments after 15 years of fixed payments. In such a contract, the seller accepts the benefits and risks associated with an uncertain market price and should be entitled to resulting high energy market prices should they occur.

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16 Electric utilities are not required to pay for QF capacity in cases in which the utility's need for capacity is zero. *See* Hydrodynamics Inc., 146 FERC ¶ 61,193, at P 35 (2014) (Hydrodynamics) (referencing City of Ketchikan, Alaska, 94 FERC ¶ 61,293, at 62,061 (2001) ("[A]voided cost rates need not include the cost for capacity in the event that the utility's demand (or need) for capacity is zero. That is, when the demand for capacity is zero, the cost for capacity may also be zero."); Entergy Servs., Inc., 137 FERC ¶ 61,199, at P. 56 (2011).

Summary

Ratepayers should not be exposed to the risk of overpayment for QF output. A basic tenet of PURPA is that ratepayers are to be held harmless from purchases of QF power. If the cost of capacity and energy is higher than the utility's net avoided cost, or if the contract term length is unreasonably long—thus requiring ratepayers to buy capacity and energy that may not be needed in the future—the ratepayer indifference tenet is not met. To prevent these outcomes, the Commission may seek to retain some level of flexibility in setting avoided capacity and energy values and setting an appropriate contract term to ensure the objectives of PURPA are achieved.

5. What risks should be considered when forecasting capacity contribution performance across a long time period?

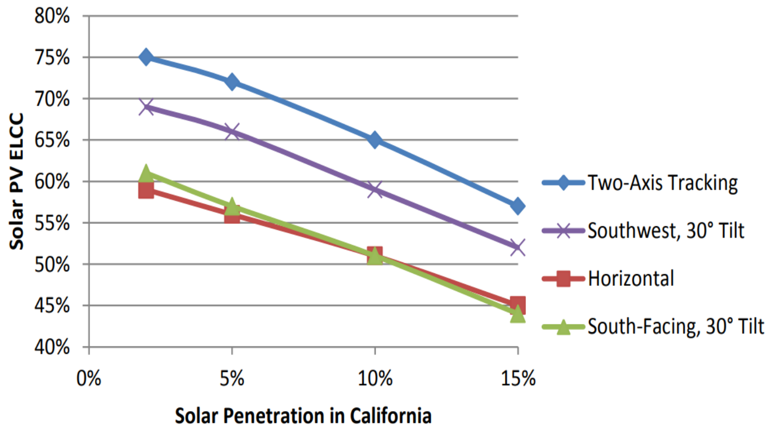
LOLP and ELCC

A resource's contribution to reliability is measured by its ability to achieve an established capacity adequacy standard, typically a one day in ten-year reliability standard. To the extent that there is an increased risk that the resource will not be available to provide capacity and contribute to meeting the established reliability standard, the capacity has a lower value to the system. Similarly, resources with higher reliability levels during times of potential loss of load are relatively more valuable. Given that the ELCC of an intermittent resource will change as additional intermittent resources are added to the system, we support the use of methodologies consistent with a last-in ELCC measure.

Addressing ELCC Forecasting Risk

The ELCC of a specific resource over time is dependent on various factors including changes in net load and changes in the composition of the resource portfolio. Generally, variable output resources like solar and wind have an ELCC that decreases as the number of variable output resources increases. In the case of solar generation, ELCC declines as solar penetration increases, because the risk of losing load compresses into a small number of hours and shifts to later in the day. As shown in Figure 5, increasing quantities of solar generation on the system will generally reduce the ELCC of existing and new solar generation due to the coincidence of solar generation output.

FIGURE 5: Impact of Increasing Solar PV Penetration on ELCC Values in California[17]



Over time, solar resources, and renewable resources in general, are expected to represent an increasing proportion of generating capacity in Oregon. Therefore, forecasting the ELCC of resources over long time periods will be subject to significant uncertainty.[18] This is particularly true in situations in which utility net load profiles are anticipated to change significantly in coming years such as is the case in the Northwest. To mitigate the risk that the actual ELCC of resources may decline over longer time periods, the Commission may seek to evaluate the risk of changing ELCC values and use this information to inform the potential for shorter duration capacity contracts. Such an evaluation may be particularly appropriate for non-dispatchable and energy-limited resources.

Summary

Ratepayers do face the risk that the ELCC of intermittent and energy-limited resources will decline as more of these resources are added in the region. The result of such a decline in ELCC can be an effective increase in the unit cost of usable capacity. To mitigate the risk, the Commission may seek to evaluate shorter duration capacity contracts.

17 California Public Utilities Commission – Energy Division, Resource Adequacy Proceeding R.11-10-023, Staff Proposal, *Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources* at 12 (Jan.16, 2014). Representative of a portfolio of new and existing resources.

18 E3 has proposed that future capacity quantities for non-dispatchable resources should be based on a forecast of ELCC that accounts for forecasted resource additions, retirements, and changes in load. The inherent uncertainty of such forecasts must be included in any application of such a forecast.