BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2011

In the Matter of **PUBLIC UTILITY COMMISSION OF OREGON,** **General Capacity Investigation.**	**Staff's Opening Comments**

Introduction

Background

The scope of General Capacity Investigation UM 2011 was designed to answer three central questions:

- What is capacity?
- How is capacity acquired?
- How should capacity be valued?

The docket was divided into three phases to address these questions serially.[1] In Phase 1, stakeholders met at a workshop in May 2019 to define capacity. Based on Staff's research and stakeholder feedback, Staff defines capacity for the purposes of this investigation as: given the absence of any transmission or distribution constraint, the ability to reliably and predictably deliver energy of a certain amount to an identified load, delivered at a certain time, for a certain duration, allowing the Loss of Load Probability (LOLP) to remain below a specified threshold.[2]

In Phase 2, Staff and stakeholders convened at a workshop in October 2019 where Portland General Electric (PGE), PacifiCorp (PAC), Idaho Power Company (IPCo), and Northwest Natural each presented their current approach to acquiring capacity. Understanding how the utilities currently acquire capacity informed Phase 3.

Phase 1 was completed in mid-2019. Phase 2 was completed in late-2019. The Commission hired Energy and Environmental Economics, Inc. (E3) to help inform and provide recommendations for Phase 3, capacity valuation.

For Phase 3, Staff contracted with E3 to identify and make recommendations regarding capacity valuation methodologies. In July 2020, Staff and stakeholders met at a workshop where E3 presented a framework for capacity valuation to stakeholders. In August 2020, Staff and stakeholders met again to

[1] UM 2011 Staff Report for the April 23, 2019 Public Meeting, pp. 3-4. Available at: https://edocs.puc.state.or.us/efdocs/HAA/um2011haa105618.pdf.

[2] Page 2 of E3's Report states that, "…many systems are planned to a target loss-of-load expectation ("LOLE", i.e., the number of days per year with expected loss of load) standard of one day in ten years or 0.1 days per year."

further scope capacity valuation methodology issues to address in this docket and later shared written comments. In October and November of 2020, PAC and PGE led technical workshops for stakeholders on their integrated resource plan (IRP) capacity contribution methodologies. These technical workshops provided stakeholders an opportunity to ask questions about the mathematical models currently used to value capacity. They also helped Staff understand the extent to which proposed methodologies aligned with or differed from current practices. Subsequently, E3 produced a report titled "Principles of Capacity Valuation, UM 2011 Capacity Investigation" (Report). Staff conveyed the issues discussed at the workshops to inform E3's Report, which presented an appropriate valuation methodology for capacity. Staff also analyzed the approach presented in the Report in the context of the issues discussed with stakeholders and current capacity contribution methodologies employed by PAC, PGE, IPCo and the Energy Trust of Oregon (ETO). These Staff Comments outline and respond to E3's Report.

Summary of E3's Report and Staff's responses

E3 proposes a Capacity Valuation Framework that that relies on LOLP and avoided cost principles. In its report, E3 provides guidance on the application of the Capacity Valuation Framework, including overarching recommendations, as well as resource specific applications. E3 identifies different methods for compensating resources for capacity value that are designed with the characteristics of the resources in mind.

Staff largely supports E3's recommended Capacity Valuation Framework, except for E3's proposal for distinguishing between a utility's resource sufficiency and deficiency periods and E3's proposal that all utilities on the same electricity system use the same ELCC model. In these comments, Staff describes E3's Capacity Valuation Framework, its overarching recommendations and guidance on the application of the Framework to different resource types, and provides Staff recommendations on these topics. Staff also describes E3's ideas related to compensation frameworks, such as for PURPA and Energy Efficiency. Staff recognizes E3's recommendations on compensation frameworks are beyond the scope of this docket. However, they are informative and help to illustrate the potential application of the Capacity Valuation Mechanism and Staff includes the ideas in these comments.

Capacity Valuation Framework Key Questions

Per E3's Report, capacity valuation can be determined by answering two key questions: (1) How much capacity can a resource provide?, and (2) what is the value of capacity? Table 1 below is a summary of E3's proposed approach, based on these questions, and Staff's responses.

Table 1: Capacity Valuation Framework - Key Questions & Recommendations

Key Questions	*E3 Recommendation*	*Staff Response*
How much capacity can a resource provide?	• Generally, use each resource's marginal contribution to reducing loss-of-load events as capacity contribution.	• Loss-of-load probability principles are current practice to compute capacity contribution in IRPs and Staff supports their continued use.
What is the value of capacity?	• Resource sufficiency/deficiency demarcated at the expected year of load plus planning reserve margin exceeding capacity supply. • Value of capacity in deficiency period is equal to lowest net cost of capacity resource. • Value of capacity in sufficiency period is equal to the fixed operations and maintenance cost of the lowest net cost resource. • In the resource sufficiency period ramp up to full capacity value.	• Use standard sufficiency period assumption (three years) to distinguish between sufficiency/deficiency period values. • Value of capacity in deficiency period is equal to lowest net cost of capacity resource. • Value of capacity in sufficiency period is equal to the fixed operations and maintenance cost of the lowest net cost resource. • Ramp up capacity value over three years of sufficiency period to full deficiency period capacity value in year four.

Capacity Valuation Framework

Key Question 1: How much capacity can a resource provide?

Differentiating between capacity and energy can be difficult. Several approaches exist to determine the capacity contribution of different resources. For example, an early measure used in some parts of the country was to look at generation coincidence with peak load.[3] Generally, recent practice is to look at net load and whether energy demand will be met by resource supply. E3's Capacity Valuation Framework is based on loss-of-load probability (LOLP) principles and employs what E3 describes as the "gold standard" for measuring capacity, the Effective Load Carrying Capability (ELCC).

ELCC is a technology-neutral measurement of equivalent "perfect" capacity of any resource using LOLP principles. ELCC is calculated by 1) calculating system reliability, 2) adding the desired resource to the resource portfolio, and then 3) removing perfect capacity until the original level of reliability is restored.

[3] *See* Table 1 in Cynthia Bothwell and Benjamin F. Hobbs, 2017. "Crediting Wind and Solar Renewables in Electricity Capacity Markets: The Effects of Alternative Definitions upon Market Efficiency," *The Energy Journal*, International Association for Energy Economics, vol. 0(KAPSARC S).

These calculations can be done using any system reliability model that adheres to LOLP principles by calculating reliability over a wide range of system conditions.[4]

E3 explains that calculating ELCC in LOLP models is computationally intensive and requires a significant quantity of data. This is because the model should capture load and resource performance under a wide array of system conditions that could possibly result in loss of load, which should happen, at most, infrequently.[5] Accordingly, E3 identifies simplified alternatives or heuristics, and discusses their advantages, limitations, and appropriateness for different use cases. Ultimately, E3 recommends using each resource's marginal contribution to reducing loss-of-load events – last-in ELCC – as its capacity contribution.

Staff supports determining the capacity contribution of resources based on LOLP principles described in E3's Report. Ratepayers are best off when the electricity system is reliable, safe, and affordable, with sufficient resources to meet load and reserve margins. Accurately computing the capacity contribution of a new resource allows the utility to value additional capacity investments appropriately and send clear market signals. Further, this methodology puts different resource types onto a comparable basis, which facilitates equitable valuation of capacity.

Additionally, E3's LOLP principles capture synergies or dis-synergies associated with additional resources and load, such as decreasing capacity values for solar over time as peak net load is pushed into the evening hours. As solar resources are added to a system, the solar generation, absent battery installations, will change the utility's load profile. Staff believes the ability to capture these changes is necessary so that resource decisions reflect the current economics of alternative resources. These issues are important because when the load profile is sufficiently affected, the capacity needs will change and could significantly reduce the capacity contribution of resources. That does not mean the performance of the resource is less, but rather, the output of the resource is not needed as much to ensure loads are met.

Loss-of-load probability principles are already the current practice to compute capacity contribution in IRPs.[6] The utilities have developed models to forecast the probability, under a wide range of scenarios, that electric demand will exceed electricity supply, causing a loss of load event. The data requirements described by E3 for an ELCC approach, including many years of weather and generation data, are an important consideration in adopting E3's LOLP approach. Staff welcomes stakeholder feedback on the tradeoff of ELCC model accuracy versus complexity and resource requirements.

Key Question 2: What is the value of capacity?

E3's methodology for determining the value of capacity turns on two considerations: "(1) does the utility need new capacity, and (2) how much does capacity cost."[7] Like the Commission's current avoided cost approach, E3's Framework distinguishes between the value of capacity depending on whether a utility is

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[4] E3 Report, p. 2.
[5] E3 Report, p. 4.
[6] *See In the Matter of Public Utility Commission of Oregon Investigation to Explore Issues Related to a Renewable Generators' Contribution to Capacity* (Docket No. UM 1719), Order No. 16-326, August 26, 2016.
[7] E3 Report, p. 9.

resource sufficient or deficient. For periods of resource deficiency, E3 recommends basing the value of capacity on the net resource cost of the lowest net cost resource available to the utility. For periods of resource sufficiency, E3 recommends basing the capacity value on the fixed operations and maintenance costs of the lowest net cost resource. E3 recommends basing the determination of a utility's need for capacity (demarcating between resource sufficiency and deficiency) on the utility's need for new resources to meet reliability requirements.

Staff agrees with E3's proposed methodologies to value capacity during resource sufficiency and deficiency periods but disagrees with E3's recommendation as to how to determine a utility's need for capacity.

Does the utility need new capacity?

Defining the Resource Sufficiency/Deficiency Periods

Currently, the resource deficiency periods for "non-renewable" avoided cost prices for PURPA, energy efficiency, and demand response cost effectiveness calculations start the year of the utility's next planned major resource acquisitions in the utility's most recently-acknowledged IRP.[8] For PURPA "renewable" avoided cost prices, which are prices available to QFs that are renewable portfolio standard (RPS) compliant and that are based on avoided costs of an RPS compliant resource, the deficiency period starts the year of the utility's next planned utility-scale RPS-compliant resource in the utility's most recently acknowledged IRP.[9]

The current sufficiency/deficiency demarcation methodology rests on the assumption that only IRP-identified need – whether by load growth or legislation – drives utility resource acquisitions. The foundation for this assumption has been challenged recently. Utilities continue to acquire major resources for the economic opportunity to support other organizational goals. These acquisitions have been, outside of the various types of need, identified in their IRPs.[10] While this development is understandable given the drop in renewable resource costs over the past decade ***and*** the strengthening policy drive to decarbonize electricity generation, it nevertheless creates an imbalance in how capacity value is currently formed and ultimately used for avoided cost price formation.

E3 proposes to identify when a utility needs capacity based on consideration of the following:

- Utility's Planning Reserve Margin (PRM),
- The appropriate amount of excess capacity to hold above the PRM,
- The utilities' load, including peak load, and
- Resource availability.

[8] Order No. 10-488 (December 22, 2010).
[9] Order No. 11-505 (December 11, 2011).
[10] *See*, for example, Order No. 20-171 (May 26, 2020) in PGE's UM 1728 changing the renewable deficiency date from 2030 to 2025, Order No. 18-273 (July 18, 2018) in PAC's UM 1729 changing the renewable deficiency date from 2029 to 2021, or Order No. 19-430 in UM 1893 (December 6, 2019) changing PAC's energy efficiency cost effectiveness computation deficiency date from 2026 to 2021.

Utilities have argued that the start of a deficiency period for avoided cost prices should continue to turn on need for capacity or RPS-compliant resources, not the planned acquisition of a resource. QFs have objected, noting that this interpretation allows the utility acquisition of significant amounts of resources to constantly forestall any meaningful deficiency-period pricing.

Staff finds the E3 recommendation for distinguishing between resource sufficiency and deficiency for capacity valuation does not fully account for recent trends in Oregon. Staff proposes that the Commission adopt a more standardized method that builds on observed trends in utility planning and avoids artificially suppressing the value of resources from other market actors. Specifically, Staff proposes that the Commission rely on previous trends in IRP resource need identification and acquisition. Staff requests to create a standard for determining resource sufficiency/deficiency. The standard would be a rolling three-year period of resource sufficiency for purposes of valuing capacity.

Under Staff's proposal, the utility will be resource sufficient in year one of a PPA or the period for which cost effectiveness is being determined and will be resource deficient starting in year four of the PPA or evaluation period. The value of capacity will ramp up during years two and three of the utility's sufficiency period so that a capacity adder equal to 1/3 of the deficiency period capacity value applies in year two and a capacity adder equal to 2/3 of the deficiency period value applies in year three.

Staff's proposed standard finds this to be a better fit than E3's recommendation and Oregon's current method for distinguishing between periods of resource sufficiency and deficiency. As noted above, utilities acquire non-RPS-compliant resources for reasons other than reliability (i.e., for economic reasons).[11] Utilities have sought to acquire a resource before it is needed for resource adequacy, breaking the theoretical link between high capacity value and capacity need. Similarly, utilities continue to acquire RPS-compliant resources for reasons other than RPS compliance. Thus, utilities have procured renewable resources before there is need for renewable energy certificates (RECs), voiding the link between the need for renewable resource with the start of a deficiency period for the renewable avoided cost price stream.

A utility's need for resources would typically be identified in a utility's Integrated Resource Plan (IRP), as would the utility's planned resource acquisitions. IRPs are filed and acknowledged in two-year cycles. However, utilities' resource portfolios and loads change during the two-year cycles, changing the date of a utility's "capacity need,"[12] and the dates of planned acquisitions. Accordingly, even if the Commission wanted to tie deficiency-period pricing directly to a utility's need to acquire resources for reliability or even to a utility's planned acquisitions, it is not necessarily possible, or at least administratively simple, to do so.

Furthermore, tying the value of capacity directly to the utility's resource/load balance or the utility's planned acquisitions may not be equitable if the utility acquires new resources in advance of need or in advance of planned acquisitions. In such a circumstance, the utility would be allowed to earn full return

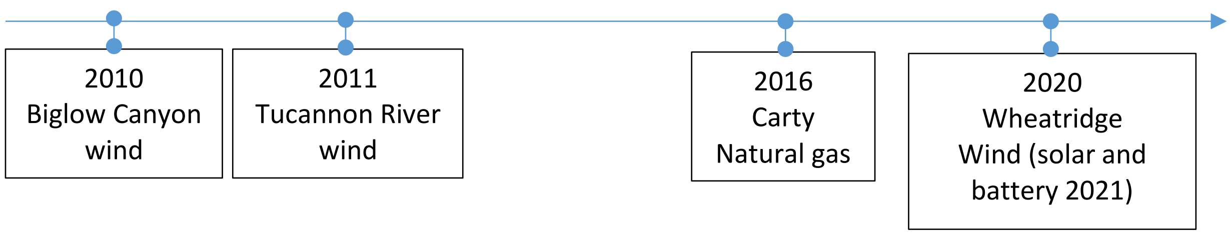
[11] *See* Order No. 20-186 (June 8, 2020) in LC 70, p. 11: "PacifiCorp makes off-system sales that reduce customer costs… the incremental resources in the preferred portfolio contribute to significant economic balancing sales."
[12] For example, Idaho Power changed its preferred Valmy Coal Plant exit date between IRPs.

on generation assets it puts into rate base while it is resource sufficient, but QFs would not receive payments that reflect this reality.

In addition, the value of a resource's capacity does not neatly fit into a binary determination of resource sufficiency and deficiency. Instead, the value of capacity to utilities may increase gradually in advance of an acquisition need for reliability, rather than simply change overnight as the current methodology contemplates.

The combination of all these factors leaves the Commission and stakeholders in proceedings to determine utilities' resource sufficiency/deficiency periods that are often contentious and difficult. Staff found after reviewing historical data that a three-year sufficiency period starting in year one of the pertinent period (i.e., PPA or installation of EE or DR) reasonably represents the amount of time between utility resource acquisitions. Consider for example that PGE had about four large resource acquisitions in the past decade, which if spread evenly would be approximately one acquisition every three years:[13]

Figure 1: PGE LC 73 IRP, timeline of recent large, acknowledged resource acquisitions



Staff's proposed general standard has the benefit of being administratively simple and avoids continuous disputes about resource deficiency start dates. When the current pattern of resource retirements changes, or **if there are** other unanticipated changes that substantially affect the effective load/resource balance, the standard resource deficiency period or ramp-up should be paused or revisited.

Capacity value during the resource sufficiency period

Currently, the Commission bases avoided cost prices for resource sufficiency periods on market prices in forward market price curves, reasoning that the cost of capacity is embedded in such prices.[14] E3's approach to determining the cost of capacity during sufficiency periods differs from the Commission's current approach. E3 proposes an approach in which the value of capacity in a sufficiency period is equal to the fixed operations and maintenance (O&M) cost of the lowest cost resource, ramping up to the full net resource cost as the deficiency period approaches. This value would be added to the cost of energy if it is not shown as a separate capacity adder.

[13] *See* PGE LC 73 IRP, pp. 275 – 278.
[14] Order No. 05-584 (May 13, 2005).

Staff supports the switch from using forward market prices for avoided cost prices during the resource sufficiency period to using the fixed O&M cost of the lowest cost resource because market prices might not reflect the utilities' avoided costs. Forward market prices are an alternative to building a new resource. However, the financial penalties of not delivering to the forward market are likely lower than the per-unit cost of a new resource, so the prices might not represent the full cost of capacity.

In practice, forward market prices do not necessarily increase as the resource deficiency period approaches, for example, the August 2021 avoided cost prices exceed the August 2023 avoided cost prices in PGE's most recent avoided cost update which had resource deficiency dates of 2025.[15]

Moving away from forward market prices is also convenient because it allows the utilities to specify separate energy and capacity price streams, which means the energy avoided cost price stream can be valued identically during both the resource sufficiency and deficiency periods. Whereas in the current approach, the capacity versus the energy component of forward market prices cannot be differentiated.

E3 proposes to determine the capacity value in the sufficiency period using the O&M cost of the avoided resource and to ramp up the capacity value to the fixed costs of that resource in the years before the resource deficiency date. Staff supports ramping up because additional resources will always increase reliability, even during the sufficiency period. Versus current prices, E3's two-part recommendation, to pay the fixed O&M cost of the lowest cost resource during the resource sufficiency period and to ramp that value up to the full net resource cost, can result in higher or lower aggregate avoided cost compensation to QFs during the resource sufficiency period depending on forward market prices.

Capacity value during the resource deficiency period

E3 recommends the starting point for valuing capacity during the resource deficiency period is the net resource cost of the lowest net cost resource available to the utility. Net resource cost is equal to the gross cost of the capacity resource less the value of the system benefits it provides and can be compensated for. E3's Report describes that, "traditionally, combustion turbines have been the lowest net cost of capacity resource in the electricity system."[16] E3 cautions that another resource should not be used to determine capacity value unless it is lower cost or if there is a restriction that requires selection of another type of resource.[17]

At this time, for Oregon, the lowest net cost capacity-providing resource likely continues to be a natural-gas-fired combustion turbine. Stakeholders at UM 2011 workshops have been greatly interested in whether natural gas-fired combustion turbines should be the avoided resource given that utilities are increasingly looking to procure storage for capacity. At this time, purchasing combustion turbines is likely a lower-cost method to ensure system reliability than purchasing storage. The rationale for using the lowest net-cost capacity resource is to accurately reflect the resource that otherwise would have been purchased. It should be closely monitored whether gas is indeed the resource that otherwise would be purchased. For example, as summarized in Renewable Northwest's Phase 2 Comments, PAC is

[15] PGE, UM 1728, May 19, 2020 compliance filing, available at https://edocs.puc.state.or.us/efdocs/HAD/um1728had164712.pdf.
[16] E3 Report, p. 10.
[17] E3 Report, p. 10.

analyzing whether non-emitting resources can meet future capacity needs.[18] As a second example, PGE believes it can meet its capacity needs "without acquiring or contracting for new natural gas fired generation."[19]

In prior workshops, parties have commented that the determination of the cost of the capacity resource should include the benefits that a resource can provide, such as the resilience value of distributed resources during natural disasters. While such benefits are out of scope for the generation capacity valuation in this docket, Staff agrees with those comments raised by parties in workshops that storage can have benefits not offered by combustion turbines. Staff believes the value of resource attributes other than generation capacity could be explored in a future docket.

General cross-cutting principles recommendations for capacity valuation

E3 recommends determining a resource's capacity contribution based on "Last-in" ELCC. E3 notes that Last-in ELCC is consistent with the marginal value that each resource provides and is consistent with the utility's avoided cost of capacity. E3 explains that the ELCC of a resource can be measured in several different ways. For example, Portfolio ELCC is a measurement of the combined ELCC of all intermittent and energy-limited resources. First-in ELCC is a measurement of ELCC as if it were the first and only intermittent or energy-limited resource on the system. E3 describes that First-In ELCC ignores the interactive effects of resources. 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. In contrast to First-in ELCC, Last-in ELCC captures all of the interactive effects with other resources.[20]

E3 notes that the Last-in ELCC of a resource can either be higher or lower than its First-in ELCC. If higher, this indicates that there are positive or synergistic interactive effects with the other resources in the system, yielding a diversity benefit. If Last-in ELCC is lower than First-in ELCC, this indicates there are antagonistic interactive effects because the resource has similar characteristics to other resources on the system, yielding a "diversity penalty."[21] Staff agrees that using Last-in ELCC is the most appropriate measurement for procurement decisions for the reasons stated by E3.

E3 recommends that LOLP periods should differ year-by-year to reflect expected changes in capacity supply and demand. Staff believes using yearly LOLP periods will be an improvement over utilities' current practice in IRPs of using values from a single year.

E3 recommends that all resources on the same electricity system should be modeled using the same ELCC model for consistency. This implies using uniform ELCC values across utilities if the utilities can easily trade energy. Instead, Staff recommends using distinct capacity models for each utility until a capacity market is developed in the Northwest, but encourages stakeholder feedback on this issue.

The Northwest Power Pool's (NWPP's) Resource Adequacy process under development is also expected to have uniform ELCC values across participating utilities. Currently, utility-specific capacity contribution

[18] Renewable Northwest Comments in UM 2011, January 13, 2019, pp. 5-7.
[19] Ernst, Steve, "PGE Targets Net-Zero Emissions by 2040, Clean Energy for Capacity Gaps," November 20, 2020, *Clearing Up*.
[20] E3 Report, pp. 3-4.
[21] E3 Report, p. 4.

values are computed in each IRP. There is merit to the argument that extremely different capacity contributions are odd if the utilities can easily trade energy.[22] However, PURPA pricing may legally require the use of utility-specific values. PURPA standard is to have prices reflect the costs the utility would avoid but for the purchase of power from the PURPA resource.[23] In addition, the Pacific Northwest does not have a structured market at this time. The Oregon PUC and the utilities have yet to agree to coordinating planning values across utilities or the region and moving elements of regulatory control to a region-wide body. Therefore, it seems premature to have region-wide uniformity in LOLP and capacity valuations.

Capacity Compensation Frameworks

How to compensate resources for capacity is not at issue in this docket. However, E3's Report includes a discussion of capacity compensation frameworks that is helpful for understanding real-world applications of E3's proposed Capacity Valuation Framework. E3's Report notes that the capacity compensation framework should ideally reflect both the quantity of capacity (MW) each resource provides and the monetary value ($/MW) of that capacity, and that it is difficult to construct a single compensation framework for all energy resource types. E3 provides an overview of two general capacity compensation frameworks: a "fixed payment" method and "pay-as-you go" method.[24]

In a fixed payment structure, resources are compensated based on a fixed annual value ($/yr) that aligns with their capacity credit (MW) and the value of capacity ($/MW-yr). The value of capacity is established using net resource cost and a sufficiency/deficiency determination (as described in the previous section), while the capacity credit can be determined either through ELCC calculations or a heuristic method such as hourly LOLP-based approximations of ELCC. E3 finds fixed payment structures work well for dispatchable resources where capacity is tied to operational decisions.[25] E3 contemplates that locking in capacity values over the economic life of the resource, and setting contract lengths equal to the economic life of the resource, offers opportunities to third-party resource developers that are comparable to the opportunities offered to the utilities.

In a Pay-as-you-Go compensation structure, resources are compensated based on energy production during hours of expected capacity scarcity. These hours can either be based on real-time dynamic system need or on pre-determined periods with expectation of high capacity needs (e.g., informed by high LOLP hours).[26]

In order to align compensation with the characteristics of resources, E3 discusses grouping resources into 'libraries' of similar characteristics and recommends groupings such that "the Last-In ELCC assigned from the library to each individual renewable resource is within 5 [percent] of its true Last-In ELCC."[27]

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[22] Such as 51.30 percent for solar in IPCo's UM 1730 and 15.78 percent for solar in PGE's UM 1729.
[23] *See* OAR 860-029-0010(1).
[24] E3 Report, p. 12.
[25] E3 Report, pp. 12-13.
[26] E3 Report, p. 13.
[27] E3 Report, p. 19.

Staff supports the use of library groupings. Staff notes that it would be important to address the concern raised by Oregon Solar Energy Industry Association (OSEIA) that very different resources should not be grouped together because, for example, "the production from photovoltaic generators varies greatly within Oregon (from 1.03 kWh/watt DC per year in Astoria to 1.47 kWh/watt DC in Klamath Falls) depending on the solar resource at the array location."[28] Applying E3's methodology could result in separate library entries for photovoltaic generators in Astoria versus Klamath Falls if a single value has differences of at least 5 percent.

As additional examples of potential changes from using library groupings, run-of-the-river hydro is currently classified as baseload and whether its characteristics are similar to a baseload resource needs to be investigated. Currently for PURPA QFs, "QFs with storage are treated the same as other QFs" unless negotiating nonstandard rates.[29] Staff believes that if library groupings are introduced, a new "library" entry for hybrid resources will be needed. Grouping similar resources into "libraries" would ensure that compensation for specific individual resources does not stray too far from the compensation that would be suggested if a full-ELCC model were run (the full ELCC model is not run for all resources because it is a time-consuming process).

E3's Application of Capacity Valuation Framework

E3 applies its capacity valuation methodology to five resource types: renewable generation, storage, demand response, hybrid resources (renewables + storage), and energy efficiency. For each resource type, the capacity contribution is computed using LOLP principles and the compensation framework is designed to incentivize system benefits. Although implementing capacity compensation is out of the scope of this docket, E3's applications demonstrate that using LOLP principles to value capacity succeeds in valuing each resource type. Staff excerpted summaries that capture the key application components described in E3's Report.

Renewable Generation

E3 states that:

> Compensating non-dispatchable renewable via a pay-as-you-go structure can provide appropriate compensation that balances accuracy and simplicity. Non-dispatchable renewable generation includes solar, wind, run-of-river hydro, and any other resource that is not directly controllable by the resource owner due to weather-dependency. This capacity compensation framework can be applied to either utility-scale or behind-the-meter resources. The $/MWh hourly payment values can be set equal to adjusted hourly LOLP values multiplied by the monetary value of capacity. The adjustment to the hourly LOLP values can be based on the ratio of Last-In ELCC to LOLP-generation coincidence.

[28] OSEIA August 14, 2020 comments in UM 2011, available at: https://edocs.puc.state.or.us/efdocs/HAC/um2011hac134611.pdf.
[29] PGE's response to stakeholders in UM 2000 https://edocs.puc.state.or.us/efdocs/HAC/um2000hac16523.pdf.

> The end result of this compensation structure is that a resource that generates as expected will be compensated equivalently to its Last-In ELCC.[30]

E3 notes further that:

> Compensating renewable generation resources through a pay-as-you-go structure can be a compelling option because unlike dispatchable resources, the generation of non-dispatchable renewable resources is dictated solely by weather conditions (i.e., the wind and the sun). It is therefore more difficult to compensate these resources through fixed payments with performance requirements when a lack of performance is difficult to attribute to weather variability that is already captured in the ELCC value or some other reason. A pay-as-you-go structure provides an appropriate incentive for owners of these resources to ensure their generators are well-maintained and available to generate when weather conditions permit.
>
> The Last-In ELCC value that could be used for each resource would reflect the specific characteristics of that renewable resource (e.g., fixed axis vs. tracking solar generators) and could be calculated for each year of the resource's life. Calculating the ELCC value upfront for each year of the contract requires projected LOLP values in future years to accurately reflect the expected capacity contribution over time. The utility must make these projections available for 10 – 20 years (or longer) depending on contract length. While calculating Last-In ELCC values for individual renewable projects can be a computationally intensive exercise, one simplification is to use a "library" approach described above.[31]

Storage

Regarding Storage, E3 notes that:

> Compensating storage resources through fixed annual payments with performance requirements can provide appropriate compensation that balances accuracy efficiency, and fairness. The fixed payment can be based on the product of the storage resource's Last-in ELCC and the monetary value of capacity. E3 notes that storage assets are dispatchable and primarily provide capacity to the system based on operator decisions as opposed to weather decisions. E3 notes that computing the capacity contribution of storage using ELCC and compensating storage with a fixed payment with performance requirements to avoid unnecessarily cycling during times without capacity need.[32]

Staff notes that multiple storage applications in Oregon already follow the methodologies in E3's Report, including calculating the quantity of capacity using ELCC, compensation per kW, and assuming that the storage optimizes its use for operational benefits, such as via utility control of a battery. As an example of calculating the quantity of capacity using ELCC, PGE describes in its draft storage potential evaluation

[30] E3 Report, p. 17.
[31] E3 Report, p. 19.
[32] E3 Report, pp. 19-20.

examples that, "to determine generation capacity value to incorporate into StorageVET, PGE will use the Renewable Energy Capacity Planning ("RECAP") model… to determine the effective load carrying capability ("ELCC")."[33] As an example of compensation per kW, UM 1751 describes capacity payments in $/kW per year valued at the "incremental slice of next best alternative adjusted for incremental capacity equivalent of energy storage in relation to next-best alternative (e.g., combustion turbine)."[34] As an example of assuming that the storage is optimally dispatched for operational benefits, PAC's UM 2059 RFP discusses battery storage operation, performance guarantees, and verification.[35]

Having performance requirements can protect customers by ensuring that the resources are reasonably reliable and performing as needed. For comparability purposes, when a utility adds a resource such as generation, it goes into rate base, and the utility recovers the cost of its plant over time through depreciation as well as earns a return on the remaining net plant balance, independent of whether the plant generates or is used. Just as utilities have prudence reviews in the original investment decision, as well there should be performance requirements for storage to ensure it operates as expected.

Demand response

E3's demand response application states that:

> The fixed payment would be based on the product of the demand response resource's Last-in ELCC and the monetary value of capacity. The performance requirements would be based on the inherent capabilities of the demand response resource and would be the identical to limitations used in calculating its ELCC.[36]

Staff notes the capacity contribution of demand response is computed in IRPs, which matches E3's application of using last-in ELCC to value demand response. The capacity contribution of demand response and other resources are computed in the same model, meeting E3's principle of like compensation for like capacity.

Staff believes the utilities IRP modeling is detailed enough to capture the unique features of demand response, for example, in PAC's 2019 LC 70 IRP: "for resources which are energy limited, such as energy storage or demand response programs, the LOLP values in each iteration must be examined independently, to ensure that the available storage or control hours are sufficient."[37]

Hybrid resources (renewable + storage)

E3 notes that:

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[33] PGE UM 1856 (draft storage potential evaluation) October 25, 2018 compliance filing https://edocs.puc.state.or.us/efdocs/HAD/um1856had13262.pdf.

[34] Appendix A of Order No. 17-118 in UM 1751 (HB 2193 implementing an energy storage program guidelines) https://apps.puc.state.or.us/orders/2017ords/17-118.pdf.

[35] UM 2059 (PAC RFP) BTA and PPA storage specifications https://www.pacificorp.com/suppliers/rfps/all-source-rfp/2020-all-source-rfp-docs.html.

[36] E3 Report, p. 20.

[37] PAC LC 70 IRP, p. 400, Appendix N.

> …[h]ybrid resources share characteristics of two distinct individual resources: renewables and storage. This presents the option of compensating such resources for their capacity contribution based on the generating resource (i.e., renewable portion), or separately compensating the components based on their individual characteristics. …If electing to compensate the hybrid resource based solely on the pay-as-you-go structure, this would be implemented identically as with renewable generators. The potential downside of this compensation structure is that it creates a large burden on storage to cycle on a daily basis which may not be necessary to realize full capacity value. Alternatively, if electing to compensate the resource separately based on the renewable and storage components separately, the renewable portion would receive compensation through a pay-as-you-go construct, while the storage portion would receive a fixed payment in conjunction with performance dispatch requirements, identical to the structure described above for standalone storage resources... Note that compensating hybrid resources entirely on a fixed price basis is likely not a practical option given that the generation portion of the resource remains dependent on variable weather conditions, and therefore developing performance requirements is very difficult as discussed in the renewable generation section.[38]

In E3's application for renewable plus storage (hybrid resources), the level of fixed payment depends on both the MW rating of the battery as well as the battery duration. Staff notes that giving generators compensation options for storage resources could support technological innovation because generators might experiment with non-standard hybrid resource pairings. Battery duration in hybrid resources has been a topic of interest during UM 2011 stakeholder workshops. To describe the topic, in PAC's 2019 IRP "combined storage is modeled with a maximum output equal to 25 percent of the renewable resource nameplate and a four-hour storage duration."[39] Whereas, stakeholders have expressed interest in experimenting with optimization strategies involving larger or longer duration storage.

Energy efficiency

E3 states that:

> Given that energy efficiency is not typically metered, a valuation based on expected (assumed) performance is a reasonable approach for these resources. The value of energy efficiency resources can therefore be determined by taking the net present value of the product of a) the forecasted annual Last-In ELCCs, and b) the forecasted annual capacity values. This approach considers the expected Last-In ELCC contribution of the energy efficiency resource as well as the expected value of capacity in each year, including expected resource sufficiency and deficiency.[40]

[38] E3 Report, pp. 21-22.
[39] PAC LC 70 IRP, p. 402.
[40] E3 Report, p. 22.

Currently, energy efficiency avoided cost prices are set with a methodology involving peak periods to compute the capacity contribution of energy efficiency measures. Peak periods do not necessarily capture all of the times that capacity is needed to prevent loss of load events. E3's Report recommends that "capacity contribution of energy efficiency resources should be determined using an industry standard LOLP model to calculate Last-In ELCC."[41] Implementing this recommendation would involve the utilities running their ELCC models for Energy Trust's energy efficiency measures. During the December 17, 2020 UM 2011 Workshop, E3 described that it recommends using the full ELCC model because the LOLP heuristic is unlikely to provide an accurate approximation of capacity value for energy efficiency because, as E3 describes, "days with actual lost load, however, may be correlated with conditions that also produce higher or lower than average resource production."[42] Staff worked with staff at Energy Trust and reached a similar conclusion that the LOLP heuristic did not capture key correlations between weather and energy efficiency.

Staff worked with staff at Energy Trust to understand the potential implications of using ELCC as the capacity contribution of energy efficiency measures. The avoided costs of air conditioning energy efficiency measures are likely to decrease because the seasonal capacity split in the current methodology differs from the seasonality of the LOLP hours. By similar rationale, the capacity contribution of residential heating energy efficiency is likely to increase under E3's methodology. Staff notes that using ELCC would make energy efficiency evaluation consistent with other current applications that use ELCC.

E3 recommends using annual ELCC values for energy efficiency. This is important in order to capture load changes over time. In reviewing past PGE IRPs, one of the trends typically identified is an increasing level of air-conditioning loads contributing to summer peaks to the extent that they could be driving the need for additional capacity. Energy Trust currently captures load changes over time by using a long-term analysis that forecasts the emergence of a summer peaking load driver.

Computing the ELCC for each energy efficiency measure, as mentioned above, could align energy efficiency capacity contributions with LOLP principles so that all five resource types (renewable generation, storage, demand response, hybrid resources, and energy efficiency) follow the same methodology of capacity valuations based on contribution to increased system reliability.

Staff Example of compensation proportional to hourly LOLP

Below Staff presents an example of how capacity compensation might change through application of E3's method for renewable resources. Currently PURPA pricing is set based on the ELCC of the IRP proxy resources. The ELCC model also outputs hourly LOLP values, so for example, for the IRP proxy solar resource, the PURPA QF non-renewable price stream capacity adder payments can be equivalently computed as:

[41] E3 Report, p. 22.

[42] E3 Report, p. 7.

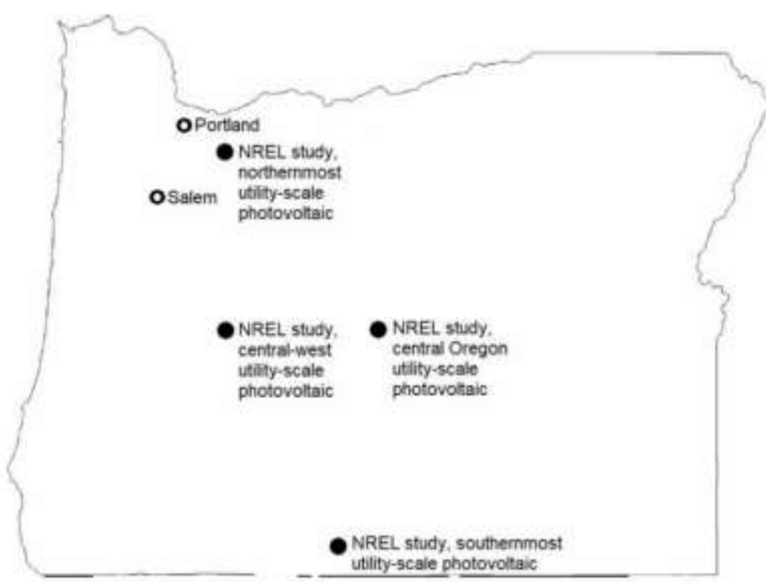
Equation #1		Equation #2
The levelized capital cost of the SCCT multiplied by the solar ELCC	or	The hourly solar generation multiplied by the hourly capacity adder component of the avoided cost price

For example, the equations for PAC's PURPA QF avoided costs for the solar proxy resource in the year 2026 are shown below:

Equation #1		Equation #2
\$100,007 per MW multiplied by 14.8% = \$14,807 per MW annually	or	2,109 hours of on-peak generation multiplied by \$7.02 = \$14,807 per MW annually

Without running the ELCC model for each resource, the ELCC of solar resources other than the proxy resource are not known. Thus, Equation #2 above is the only option, and it is used to pay non-renewable QFs approximately according to their ELCC. The quality of the approximation depends on how similar the QF's hourly production is to the proxy resource. The approximation can be a major shortcoming. For example, mathematically it is possible for a solar resource with a higher (unmeasured) ELCC than the proxy resource to receive lower payments than the proxy resource. This results if the PURPA peak periods do not align well with the high-need LOLP hours. E3 describes a method to compensate QFs according to their production coincidence with high-need LOLP hours. E3's method is a different price for each hour. Directly compensating QFs according to their production in high-need LOLP hours resolves the issue of potential misalignment between the high-need LOLP hours and peak periods. E3 describes this approach for PURPA renewables: "The \$/MWh hourly payment values would be set equal to adjusted hourly LOLP values multiplied by the monetary value of capacity."[43]

Figure 2: NREL Utility-Scale Solar Sample Approximate Locations



[43] E3 Report, p. 17.

As an example of how capacity compensation might change, Staff simulated compensation for PURPA QFs under the current methodology versus a rough approximation of E3's methodology. Due to data availability, Staff's approximation of E3's method used a single year of LOLP values rather than values by year as E3 recommends. Due to confidentiality of the proxy resource's hourly generation, Staff modeled a two-part range of ELCC to LOLP coincidence values rather than the actual value.

Staff looked at four geographically-diverse utility-scale solar generators using the National Renewable Energy Lab's (NREL) hypothetical hourly solar generation profiles ranging in size from 20 to 34MW. [44] **Error! Reference source not found.** shows the utility-scale solar sample approximate locations.

The example in Table 2 uses an assumed value of 111 percent to match E3's illustrative example of a ratio of ELCC to LOLP-generation coincidence adjustment factor.[45] An adjustment factor is needed when a resource's output is correlated with peak needs. For example, summer peak loads tend to be clear and therefore have higher solar output levels.[46] If the ELCC to LOLP-generation coincidence adjustment factor is 111 percent, then for the NREL study solar generators in Table 2, E3's proposed method does not drastically change the capacity adder payments per kW. This is because the on-peak capacity factor is highly correlated with the LOLP coincidence, since on-peak hours end at 10pm when the sun is down.

Table 2: Current versus E3 proposed capacity adder compensation

	Current PAC avoided cost capacity adder per MW	E3 proposal: hourly payments based on LOLP – approximate	On-peak capacity factor	LOLP coincidence – assumed value for proxy solar
Proxy solar	~$14,807	~$14,807	43%	~14%
NREL - Central (C)	$11,400	$12,900	33%	12%
NREL - Central-west (CW)	$10,500	$13,500	30%	12%
NREL - Northernmost (N)	$8,600	$10,800	25%	10%
NREL - Southernmost (S)	$9,100	$8,300	26%	7%

Table 2 shows that the southernmost solar generator is "overpaid" under current PURPA pricing. Although the southernmost solar generator generates during many of the daytime hours, versus other solar locations, it has a lower proportion of its generation during the high-need July and August evening

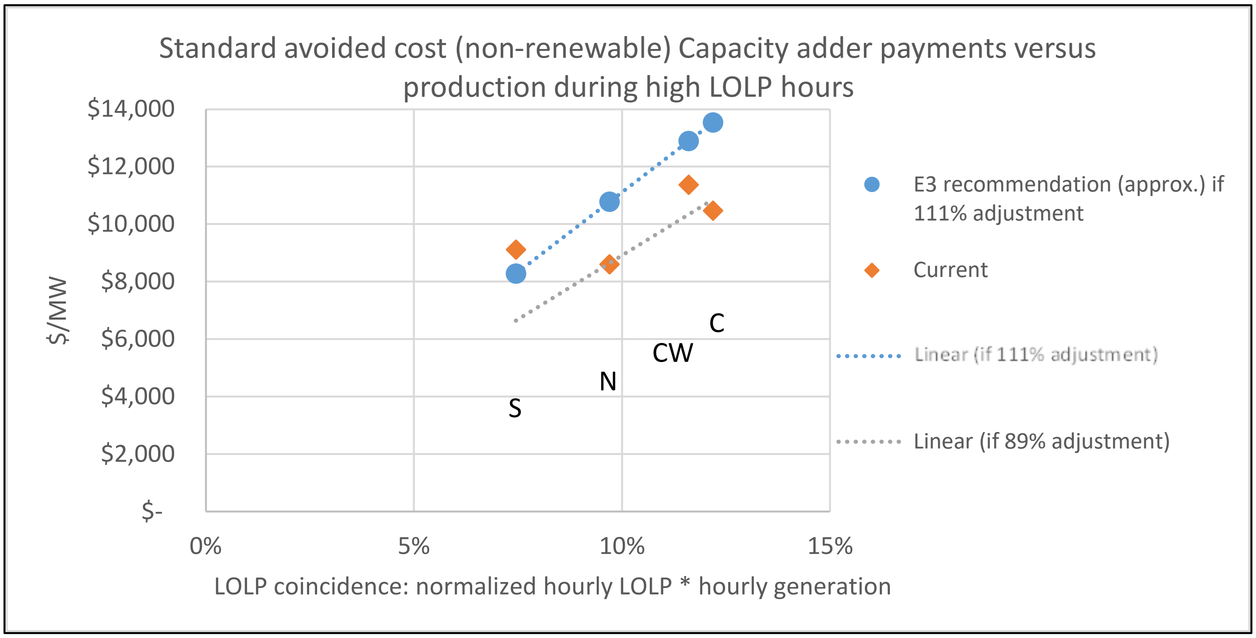
[44] National Renewable Energy Laboratory NREL (2006), "Solar Power Data for Integration Studies," Accessed November 23, 2020 at https://www.nrel.gov/grid/solar-power-data.html

[45] The 111 percent adjustment factor is not based on actual data, but rather is an illustrative example.

[46] E3 also recommended this adjustment factor in RVOS UM 1716: "The hourly capacity allocators (net CONE, allocated using LOLP) are scaled to ensure that the final generation capacity value of solar results are consistent with the utility-estimated solar contribution to peak" (*See* UM 1716 Staff/200, Olson/30-31).

hours. E3's proposal corrects this overpayment by compensating solar according to its likelihood of availability during high-need LOLP hours. As another example, Figure 3 displays how the results would change with an 89 percent adjustment factor. The linear best-fit lines in Figure 3 show that E3's proposal results in compensation proportional to LOLP coincidence.

Figure 3: Capacity adder payments versus production during high LOLP hours



As described previously, the precise ratio of ELCC to LOLP-generation coincidence adjustment factor is not shown in the figure above due to confidentiality of the proxy resource's hourly generation data and instead a range is shown (89 – 111 percent). At an 89 percent adjustment, each of the capacity adder payments would be about 20 percent lower than at a 111 percent adjustment. The actual adjustment factor could be higher than 111 percent or lower than 89 percent. Applying the adjustment factor to LOLP approximations of the ELCC value is important to ensure that the approximation does not differ significantly from the value that a more computationally-intensive full-ELCC model would output.

To gain additional insight into the difference between the aggregate payments under E3's recommendation versus current compensation methodology, the 12 month x 24 hour diagrams below display the hourly payments. For simplicity, the weekday versus weekend payments are not differentiated.

Using the same hypothetical ELCC to LOLP-generation coincidence adjustment factor of 111 percent, we can show the hourly avoided cost prices that led to the aggregate compensation amounts in Table 2 and Figure 3. Table 3 displays PAC's 2019 IRP LOLP hours and shows that the greatest capacity need is in July and August evenings:

Table 3: PAC's LC 70 IRP LOLP hours

Hr Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.08	0.00	0.00	0.00	0.00
19	0.01	0.00	0.00	0.00	0.00	0.01	0.05	0.17	0.00	0.00	0.00	0.01
20	0.01	0.00	0.00	0.00	0.00	0.01	0.09	0.17	0.00	0.00	0.00	0.01
21	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.11	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 4 shows that current PAC solar non-renewable PURPA avoided cost capacity adders are $7 for each on-peak hour – weekdays from 6am to 10pm:

*Table 4: Current PURPA Avoided Cost Capacity Adder**

Hr Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
8	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
9	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
10	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
11	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
12	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
13	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
14	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
15	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
16	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
17	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
18	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
19	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
20	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
21	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5
22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

*approximate average capacity adder: $5 = $7.02 weekdays and $0 weekends/holidays.

Table 5 shows that, with an ELCC to LOLP-generation coincidence adjustment factor of 111 percent, using E3's method of pay-for-performance capacity payments in proportion to the LOLP hours, for most hours, generators would receive less than $7 for providing capacity – including all of February to May and November. However, for July and August evenings, generators would receive capacity adder payments of about $600 for a single MWh. For comparison, energy payments for solar generators are about $30 per MWh in 2026.

*Table 5: E3 Example: capacity adder proportional to LOLP***

Hr Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0
5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0
7	$3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
8	$29	$0	$0	$0	$1	$0	$0	$1	$0	$14	$1	$6
9	$10	$0	$1	$1	$0	$0	$1	$0	$0	$9	$0	$1
10	$6	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	$15	$0	$1	$0	$0	$0	$1	$1	$0	$5	$4	$0
12	$7	$0	$0	$0	$0	$0	$5	$4	$0	$3	$0	$0
13	$1	$1	$0	$0	$0	$0	$15	$15	$0	$0	$0	$0
14	$0	$0	$0	$0	$0	$0	$36	$42	$0	$0	$0	$0
15	$4	$0	$0	$0	$0	$0	$33	$101	$0	$0	$1	$0
16	$0	$0	$0	$1	$0	$0	$39	$52	$0	$0	$0	$0
17	$0	$0	$0	$0	$0	$0	$3	$49	$0	$0	$0	$2
18	$1	$0	$0	$0	$0	$1	$42	$296	$11	$0	$0	$17
19	$37	$0	$1	$0	$0	$22	$187	$612	$16	$0	$0	$23
20	$29	$1	$4	$0	$0	$29	$336	$609	$17	$0	$0	$21
21	$12	$0	$0	$0	$0	$17	$232	$389	$0	$1	$0	$11
22	$0	$0	$0	$0	$0	$14	$60	$12	$0	$0	$0	$0
23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

**approximate average capacity adder: weekdays have higher LOLP values than weekends

Current capacity adder payments differ by resource, for instance, PAC non-renewable wind capacity adder payments in 2026 are $29.91 versus the $7.02 for solar above. Under E3's recommendation, the hourly payments for wind and other resources would match that of solar, except for the ratio of ELCC to LOLP-generation coincidence adjustment factor. If instead of a 12x24 LOLP matrix, the full 8760 LOLP values are used and mapped with output generation of a renewable resource, the extent to which an adjustment factor is needed may change depending on whether output data for renewable resources are allowed to vary based on weather conditions. This is an open question that needs to be investigated further.

E3's proposal is an improvement because paying generators based on their likelihood of availability during high-need LOLP hours could incentivize new generators that can generate during those hours.

Next Steps

Staff recommends a non-contested case process for this docket. Staff emphasizes that a non-contested case will allow for more stakeholder participation and engagement. Staff appreciates the robust stakeholder engagement thus far in UM 2011 and stresses the importance of allowing a wide range of stakeholders participation in this docket to develop methodology.

This concludes Staff's opening comments.

Dated at Salem, Oregon, this 14th of January, 2021

/s/ Max St. Brown

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Max St. Brown

Senior Utility Analyst

Energy Resources and Planning Division