Responses of the Oregon Solar Energy Industries Association (OSEIA) to Oregon Public Utility Commission Staff's Part B Questions.

B. How Should Capacity Be Valued?

Capacity Value as a Function of Resource Type

6. Does capacity value compensation require a capacity resource to be available to meet all reliability needs in all time frames?

No, the compensation for capacity value should not require the capacity resource to be available to meet all types of reliability needs in all timeframes. Reliability needs are varied, and the mix of resources that are used to meet reliability needs is also varied. It would not make sense to require every type of capacity resource to be able to meet every type of reliability need, in all time frames, in order to have a non-zero capacity value. The compensation for capacity value should include all of the costs of meeting system reliability needs that a particular generation capacity resource allows its purchasing utility to avoid.

Various types of system reliability needs include (1) peaking capacity to meet system peak demand, (2) flexible capacity to ensure that some amount of generation will be able to ramp up (or down) quickly enough to meet changes in system load, and (3) the ancillary services that are used for balancing the system in real-time (i.e. regulation up, regulation down, spinning reserves, and non-spinning reserves). A "peaking capacity" resource does not have zero peaking capacity value if it cannot meet all other types reliability needs in all time frames as well. Similarly, a unit that provides flexible capacity should not be deemed to have zero peak capacity value; if the unit can both meet the ramping need and provide peaking capacity, then it should be compensated for both products.

In particular, staff should not assume that a solar photovoltaic (PV) resource will have a reduced or zero capacity value simply because it is not dispatchable. The capacity valuation of solar should consider the amount of solar output in the peak hours when capacity resources are used to provide energy. Also, to the extent solar PV is paired with battery storage, it is important to recognize that the combined capacity resource will in fact be dispatchable to a significant extent. Solar energy can be stored during daytime hours and dispatched from storage by the customer during other selected hours. Thus, the types of reliability needs and time frames solar PV can address may be greatly expanded with the addition of battery storage. Recent research indicates rapidly increasing levels of solar PV projects that include storage.[1]

[1] See page 17 of the LBNL 2019 report on utility scale solar, at https://eta-publications.lbl.gov/sites/default/files/lbnl_utility_scale_solar_2019_edition_final.pdf. We also note the report includes, in Table 3, a summary of the Wheatridge, Oregon PV hybrid project of NextEra/Portland General Electric in 2019/2020 that will include 300 MW of wind capacity, 50 MW of solar PV capacity,

a. Can a dedicated physical asset qualify to meet all reliability needs, or does it need to be supplemented with other resources?

A physical asset cannot meet all reliability needs. There are reliability risks for every type of resource, even for those, like natural gas-fired combustion turbines (CTs) that can provide multiple types of reliability needs. Gas-fired CTs are at risk for fuel-supply disruptions, and can experience forced or planned outages. Thus, there is always some probability that a particular physical asset will be unable to operate at some point in time, and will need to be supplemented or replaced with other resources.
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Even when a resource can operate with sufficient reliability, how the resource is actually used may determine what particular reliability needs it is deemed to serve. For example, a resource cannot simultaneously be utilized (i.e. dispatched at full capacity) and also reserved or "unloaded" for meeting potential real-time load increases. Or, if a resource is assumed to provide upward ramping flexible capacity (e.g. +10 MW per hour over a 3-hour period), it is essentially providing 30 MW of peaking capacity that has simply been defined as "flexible" capacity.

Thus, resources may need to be supplemented, either due to reliability issues of specific resources, or due to how particular resources are used to meet system reliability needs. Generally, the marginal capacity value for meeting a particular reliability need should consider the mix of resources that are used to meet that need, including any relevant reliability constraints for those resources.

We note that storage is an important increasingly common way for solar PV to be supplemented with another resource. Battery storage will improve the ability of solar PV assets to meet all reliability needs, as well as improve grid and supply resiliency.

b. Can a portfolio of resources that meet the availability requirement qualify for the same or better compensation than a dedicated physical asset?

A portfolio of resources is likely be more reliable than a single dedicated resource, by reducing the risk of an outage compared to a single dedicated asset. For example, if a single CT is the dedicated physical asset, and has an outage rate of 5%, then one would expect the CT will be unable to provide any capacity in about 5% of hours. On the other hand, multiple (and independent) CTs would be less likely to experience a simultaneous outage. Combining capacity resources across different technology types also may provide an increased level of reliability, by limiting the impact of factors that impact only some types of resources.

However, OSEIA does not expect capacity resources that meet an availability requirement to see "better" compensation due to being part of a portfolio. For example,

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and 30 MW of four-hour storage. We also note LBNL's summary slides for the report include a bar chart showing paired projects starting in 2018. (See the "hatched" portions of the 2014-2018 bar chart at slide #40 of eta-publications.lbl.gov/sites/default/files/lbnl_utility-scale_solar_2019_edition_slides_final.pdf).

if compensation is based on the cost of the utility's marginal source of capacity, it is not clear that there should be any impact on this compensation due to portfolio benefits.

c. Can a financial contract qualify for the same or better compensation than a physical asset?

A financial contract might qualify for better compensation than an individual physical asset if there is assurance of a deep portfolio of resources standing behind the financial contract. Financial contracts and forward markets require a deep and liquid spot market, to provide confidence that the physical asset can be delivered. For example, the Henry Hub, Louisiana, market for physical gas supply is the foundation for the natural gas forward (physical and financial) markets. To the extent a financial contract allows the purchasing utility to be assured it will receive its contracted supply, because the supplier promises to absorb any risk that the supply cannot be delivered, such a contract may qualify for better compensation than a physical asset that does not include any such assurance. Note, however, the expected costs to the supplier would also increase if it absorbs such risks.

7. Regarding the capabilities listed in question 4 above, what should be the qualification criteria for determining if a resource can meet these needs, assuming the information, communications and control systems are in place to support development of qualification criteria?

Question 4 asked whether capacity that is available to meet Resource Adequacy (RA), flexible, temporal, or locational capacity needs should be considered distinctly. Criteria for different types of RA capacity may depend on the market and regulatory structure for the particular RA program, more than on the basic nature of the capacity resource.

Some regions of the U.S. have established forward capacity markets, such as in the ISO New England and PJM markets. However, capacity markets are not yet a common supplement to the regional energy markets, and the existing capacity markets are controversial. More widespread than formal capacity markets are resource adequacy programs or planning reserve margin requirements. For example, the California ISO (CAISO) analyzes Resource Adequacy (RA) requirements, not just in California but also in other western states, as one of the requirements for participating in the western Energy Imbalance Market (EIM).

For nuclear and thermal generating units, the CAISO's net qualifying capacity (NQC) calculation for RA is based on NERC's net dependable capacity definition. Thus, the RA qualification criteria for certain resources makes use of traditional standardized capacity calculations.

On the other hand, criteria for determining how solar PV, or solar PV paired with battery storage, qualify for RA requires statistical analysis of how such resources contribute to those needs. Qualification criteria should agree with the methodology adopted by the OPUC for valuation of solar PV or solar PV plus battery storage. For example, our initial comments described both capacity factor and ELCC methods for evaluating solar PV capacity.

8. **Should supply-side and demand-side resources that demonstrate the capability to satisfy the qualification criteria for that type of capacity be valued in the same way?**

Yes, supply and demand side resources with similar demonstrated capabilities should be evaluated similarly. For example, demand response (DR) resources should be valued in a similar fashion to supply-side peaking resources, because either type of resource addresses peak load conditions. Although these resources may have somewhat different risks and capabilities, such differences should be captured through analysis of the quantity of capacity they are able to provide in practice. Once an apples-to-apples amount of capacity is determined, the value applied to that capacity should be the same.

We note that solar PV or solar PV plus storage that is installed behind the customer meter, despite being a source of generation, is a source of load reduction from the utility's perspective. If a customer serves some of their own load from on-site solar generation, it will purchase less electricity delivered from the utility. Thus, it may be desirable for any qualification criteria to be symmetric with respect to supply-side and demand-side resources, in order for there to be consistent treatment of customer (e.g. rooftop) solar PV and utility scale projects. Also, storage can be sited on the grid at utility-scale or behind the meter at the customer level, and therefore consistent RA qualification criteria would be desirable.

<u>Capacity Value as a Function of Temporal, Durational, Locational and Size Attributes of Resources</u>

9. **How should the value of each type of capacity be calculated and how should its temporal availability (e.g. short vs. long-term capacity) affect the valuation? *In response to stakeholder requests for clarification, this question refers to the time period and duration for which a resource is committed by contract, ownership by a utility, or other arrangement.***

Resources may be forecast to have greater value in future years than in the present, particularly if there are adequate resources in the short-term. Thus, a resource's capacity value will depend on the term of its presence on the system. For a utility-owned resource, this will be the economic life of the resource. For a third-party-owned resource, it is at least for the term of the contract with the utility. However, even then, the regional electric system as a whole safely can be assumed to have access to third-party-owned resources for their entire economic life, even if not all years are under contract. This is because resources with remaining economic life and value would not be expected simply to retire at the end of their initial contract term.

10. **How should temporal and durational attributes of capacity be calculated? *In response to stakeholder requests for clarification, this question refers 'temporal***

availability' in a different sense: when and how a resource is capable of serving load, regardless of its ownership structure or contractual arrangements.

a. **How could temporal and durational availability affect the valuation?**
    i. **How could availability of a system peak capacity product at critical times affect its valuation?**
    ii. **How could availability and sustained duration of ramping capability affect valuation of a capacity product?**
    iii. **How could seasonal availability affect valuation for a capacity product?**
    iv. **How could ability to provide ancillary services at times of system stress affect valuation?**

The issue of how resource availability affects valuation depends on the power production characteristics of the resource or the resource portfolio. For solar resources, the quantity of capacity to value will depend on the timing and duration of the critical hours that have a positive capacity value. Output during the hours that are considered to be the critical times would thus directly impact valuation.

It is not reasonable to assume that solar generation is inflexible. Many solar integration studies appear to be based on the assumption that future solar resources will be procured under must-take contracts that do not allow the utility any flexibility in dispatching future solar resources and that assume that solar projects will be unable to provide ancillary services such as load following. This is not necessarily a reasonable assumption. Utility-scale solar projects have demonstrated the technical capability to provide a broad range of ancillary services, including upward regulation and load following, provided the necessary control systems are in place to operate the plant to provide those services.[2] Recent modeling of a southeastern U.S. utility under scenarios with high penetrations of solar have demonstrated that solar's value is maximized if it is operated in the most flexible manner possible, including allowing the solar resources the headroom to provide upwardly flexible ancillary services.[3]

Solar will also be paired increasingly with storage. The pairing allows the storage to qualify for the solar investment tax credit, reducing the cost of storage significantly, and substantially increasing the value of the combined resource to the system compared to solar alone. The use of storage will reduce substantially the variability of solar output, because storage either can be dispatched by the utility or can be pre-programmed to discharge at a specific rate in certain peak hours. The storage that is paired with solar can become a firm source for a variety of ancillary services, including load following,

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[2] CAISO / First Solar / NREL, *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant* (March 2017). Available at https://www.nrel.gov/docs/fy17osti/67799.pdf.

[3] Energy and Environmental Economics, *Investigating the Economic Value of Flexible Solar Power Plant Operation* (October 2018), at pp 4, 33-35. Available at https://www.ethree.com/wpcontent/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

regulation, and fast frequency response. This will substantially reduce or eliminate integration costs, and may provide important ancillary services to the grid for which the solar plus storage project should be compensated.

11. If locational capacity is something that should be compensated, which factors should be used to inform the locational value of capacity?

a. **Avoided transmission costs (or needed upgrades),**
b. **Avoided distribution costs (or needed upgrades),**
c. **Impact of new capacity in a "load pocket," if applicable, or**
d. **Other factors**

If capacity is needed in a particular location, its value should be determined based on an estimate of the marginal cost of capacity in that location. If there is no readily identifiable marginal source of capacity in a particular location, for example on the distribution grid where the energy from most traditional capacity resources is imported using transmission and distribution capacity, a local capacity resource displaces remote capacity plus the T&D capacity needed to deliver that capacity to the specific location. Therefore, T&D value is a component of the locational value of capacity value, for example in load pockets.

For example, when the CAISO evaluates locational capacity adequacy, it considers a range of possible transmission outage events that could occur. In this way, it can plan for a level of local reliability that is not dependent on all transmission remaining in service at all times. The CAISO makes use of the standard NERC categorization of outage events for its analysis. The label "(N-0)" to refers to normal operating conditions; an "(N-1)" event is when there is an outage of a single transmission line on CAISO system; an "(N-1-1)" event represents two outages in sequence. To ensure reliability, the CAISO performs analyses to determine whether adequate locational capacity exists, in the event of N-1 or N-1-1 contingencies.[4] CAISO's analysis indicates which areas, if any, do not have sufficient generation capacity.

Given that capacity resources must be built ahead of load growth, so as to ensure no constraints in meeting demand, it is often the case that there is no present need for incremental generation capacity or additional T&D capacity, even though planning requires future capacity expansions. For this reason, it is useful to consider long-run marginal T&D costs.

The "NERA method" is a standard approach to the analysis of long-term avoided T&D investment costs. It is based on a linear regression to estimate of a utility's cumulative transmission (or distribution) system investments as a function of peak transmission (or distribution) system demand or capacity over a 15-year period, including historical (i.e. 10 years) and forecast (i.e. 5 year) data. The slope of the regression calculation provides an estimate of the annual investment that is associated with an increment of load. By annualizing the regression slope, and adjusting for variable O&M and general plant costs,

[4] See http://www.caiso.com/Documents/Final2020LocalCapacityTechnicalReport.pdf at pages 10-12.

the NERA method results in a $/kW-year capacity value that estimates the long-term value of T&D capacity that could inform local capacity valuation.

We acknowledge that the RVOS orders (19-021, 19-022, and 19-022) in UM 1910, adopted the use of a Marginal Cost of Service Study (MCOSS) as the most reasonable method for estimating T&D capacity at the time. However, in those decisions, the Commission agreed with OSEIA that "ultimately T&D capacity value is best expressed according to granular needs, both with respect to time and location" and also stated that "(u)ltimately, we believe the T&D capacity value could be a very important price signal that indicates system need and is actively used to encourage project siting in line with system needs, leading to more efficient and beneficial development."[5]

12. How does the scale of a given resource affect its value?

- **a. Is there a threshold size of a project, above or below which its value to the system as a whole changes categorically, or out of proportion to an increase or decrease the number of MWs of power it can produce?**
- **b. Could a threshold size in a specific location sometimes affect valuation?**
- **c. Could a threshold size affect whether MW-year or MWh compensation is appropriate.**

In order to make economically efficient decisions, the value of a given resource should reflect its incremental value to the utility, where the size of the increment reflects the scale of the given resource addition. In this way, suppliers can decide whether to construct a resource based upon considerations of whether the incremental value the resource brings to the utility will exceed their costs for building the resource. This results in the socially desirable outcome that resources with costs above a utility's incremental cost will not be built, while those with costs equal to or less than incremental cost will be built.

It is important to recognize that a portfolio of resources functions similarly to a single large resource. And, as implied in question 6c above, many small projects may provide portfolio benefits that avoid risks associated with a single larger project. Given that a portfolio may have more value than a single larger project, it would not make sense to adopt a size threshold, below which capacity value is decreased.

Examples of distributed generation (DG) or distributed energy resources (DERs) that aggregate to the value and size of larger single projects abound. As noted in the RAP's December 2, 2019 workshop presentation in UM 2011, a combination of DERs are being used to replace the 165 MW Dynegy gas peaker plus 115 and 230 kV transmission; a combination of energy efficiency, demand reduction, solar PV, battery storage allow for the replacement of a single larger project.

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[5] e.g. see Order 19-021 at pp. 15-16.

Supply and demand conditions together determine value. Thus, without knowing demand conditions, it is difficult to say how large of a supply increment might be needed before there is a definite change in value. For example, when an economic constraint is completely eliminated, the shadow price associated with that value goes to zero. For example, consider a two stair-step supply curve, and a certain fixed quantity of demand. Marginal cost will drop from the higher stair-step to the lower stair-step by adding a sufficient quantity of generation capacity with costs at (or below) the lower stair-step in order to completely eliminate taking any of the more expensive supply at the higher stair-step price. This quantity, however, is based on both supply and demand conditions, so there is no simple answer based on supply alone.

Another aspect of the scale of resources is the matter of information tracking & management. System operators may have a limit on the size of resources that they can track cost-effectively (such as 0.5 or 1.0 MW). Also, smaller behind-the-meter resources that serve onsite customer demand and only export some of their production to the distribution grid may not be possible to track except after-the-fact, through billing data.

The CAISO limits bids for aggregated distributed energy resources (DERs) to no more than 0.5 MW. It also has size limits for participating demand response (DR) resources. Thus, in terms of ISO participation, there are practical size limits that may apply for determining when resources can participate in ISO markets and resource-specific scheduling activities.

<u>Benchmarking and Other Valuation Techniques for Capacity</u>

13. Currently, simple-cycle gas plant costs are generally used to value capacity. Is this method still appropriate for some types or categories of capacity?

- **a. If yes, for which types?**
- **b. If no, for which types?**
    - **i. Further, is a new or different benchmark or proxy more appropriate? If so, for which types/categories of capacity?**

It is not clear that gas plant costs remain relevant to the determination of capacity value. For example, there has been recent debate in California about whether battery storage should become the marginal capacity resource instead of CTs.[6] Gas-fired CTs are only the benchmark for capacity value if they still are being built, or could be built in the future. Given the general agreement that it is highly unlikely that new gas-fired generation will be built in California, parties tend to support assuming battery storage is the marginal generation capacity resource that will be built in the future. Modeling in California's IRP docket indicates that solar plus storage is likely to be constructed for future capacity needs, with no new gas resources selected. If it is also the case in Oregon that no new natural gas-fired generation is expected to be built in the future, then energy storage rather than a gas-fired CT likewise should be used to value capacity.

[6] CPUC Staff's proposed 2020 avoided cost calculator update discusses this issue, at page 4 of http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M319/K898/319898332.PDF.

Battery storage capacity may need to be augmented with generation capacity such as from solar PV, in order to provide a "pure" capacity resource (i.e. generating incremental capacity for the system rather than simply providing capacity to move generation from one point in time to another).

14. Should capacity compensation for Distributed Energy Resources (DER) be based solely upon contribution to meeting an identified system need, or should it be supplemented with other factors considered in DER valuation? How relevant are the following factors for capacity valuation, and which are missing?

- **a. Avoided environmental costs**
- **b. Avoided fuel costs**
- **c. Avoided plant O & M costs**
- **d. Avoided generation capacity costs (capex)**
- **e. Avoided cost of transmission upgrade**
- **f. Avoided distribution capacity costs**
- **g. New costs for new distribution system technologies**
- **h. Costs associated with forecasting (variable renewables)**
- **i. Ability to dispatch (i.e. small turbines, gen sets, storage) vs. lack of ability to dispatch (i.e. variable renewables)**
- **j. Avoided (or differently calculated) costs of reserve capacity**

DER capacity compensation can be based solely on contribution to meeting system need, but the definition of system need should not be unnecessarily limited or narrow.

For example, the Resource Balance Year (RBY) concept, which has been used in the Pacific Northwest and for a time in California, assumes that the marginal cost of generation capacity will only equal the (annualized) cost of new generation capacity once there is an identified system need for new system capacity. The method assumes that capacity value will be lower than the cost of new generation during the years when there is excess generation capacity relative to demand.

In 2016, the CPUC decided against the use of the RBY concept, noting that the use of a combination of short-run and long-run costs is unfair to DERs.[7] Short-term pricing based on the cost of Resource Adequacy (RA) contracts with existing resources ignores factors such as: (1) the actions taken by the California commission to implement clean energy policies, (2) the state's preferred loading order (in which fossil resources should be procured last after "preferred" resources such as energy efficiency, clean distributed generation, or renewables), and (3) the grid planning processes. Thus, the CPUC has moved away from assuming that the timing of gas-fired generation procurement should determine generation capacity value.

We note that use of the RBY can result in a "missing money" problem. It is unreasonable to assume there is no value, or need, for new capacity resources until far into the future,

[7] See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K338/163338441.PDF at pp. 12-17.

when capacity actually is being added for other reasons in the near term. Undervaluation of avoided capacity costs occurs when it is assumed there will always be a capacity oversupply at any moment in time, even though capacity resources are being added to the system over time in order to ensure sufficient future capacity supply. The fact that electricity supply planning requires advance planning should not lead to a disconnect in which marginal capacity costs today are always assumed reflect capacity oversupply and reflect prices that are much less than the actual capacity procurement costs incurred by utilities. Economic theory argues for marginal costs below average costs when supply capacity is more than adequate to serve demand, but in the energy industry with advance procurement needed to avoid future shortage risks, and with procurement required to meet different (e.g. clean energy or renewables) objectives, it is overly simplistic to argue that a system is only briefly in a RBY when there is the next big lumpy system addition of generating capacity. Given that marginal cost should swing above and below average cost as capacity is short or long, respectively, it makes no sense to utilize a methodology that captures only the downside (i.e. excess supply) value.

Regarding the specific elements listed above, OSEIA responds as follows:

- **a.** Possibly. If not valued elsewhere, the costs due to emissions of GHGs and criteria pollutants from the avoided capacity resource should be valued. If natural gas is the fuel for the marginal capacity resource (e.g. a CT), then the additional GHG costs from methane leakage on the gas system upstream from power plants should be valued.
- **b.** No, except in calculating energy rents for the marginal capacity resource.
- **c.** Avoided fixed O&M at existing plants is used as a short-term metric for avoided capacity (absent a visible RA market or formal capacity market) in years with no capacity need. However, see the RBY discussion above for caveats on using O&M costs to value short-term capacity.
- **d.** Yes – annualized capex (plus fixed O&M, less energy and A/S rents) for the marginal capacity resource is the long-term value of capacity. Generally, the 30-year levelized cost of capacity that is used to value long-term capacity on the system should include all capital and fixed O&M costs for the plant over its lifetime.
- **e.** DERs also should be compensated for unspecified avoided T&D costs. See the response to question 11 above, regarding why T&D avoided costs are an element of locational avoided costs, and regarding the NERA method for estimating T&D value.
- **f.** See [e].
- **g.** DERs typically have to pay for system upgrades as part of interconnection costs. Upgrades may be driven by more new loads, such as EVs, than by DERs. New distribution system technologies (grid modernization) may have other benefits (better reliability, shorter outages) than just integrating DERs.
- **h.** Generally, costs for improved forecasting are much lower than the benefits of reducing integration costs, and have other benefits for utility operations.
- **i.** Dispatchability has value.

j. Behind the meter resources that reduce the peak load served from the grid also allow reductions in the reserve margin, to the extent that the reserve margin is based on a percent of peak demand.

In terms of factors that are missing from the list that may impact DER valuation, resiliency is an important emerging value of distributed energy resources that are paired with storage, such that the DER provides backup capacity to serve a customer's or a micro-grid's essential loads when the grid is down for either a momentary interruption or a prolonged "black sky" event such as wildfires or earthquakes.

We note that RAP's December 2, 2019 workshop presentation provided an example of using solar PV plus battery storage on a micro-grid to achieve resiliency at the Los Alamitos Joint Forces Training Base (JFTB).

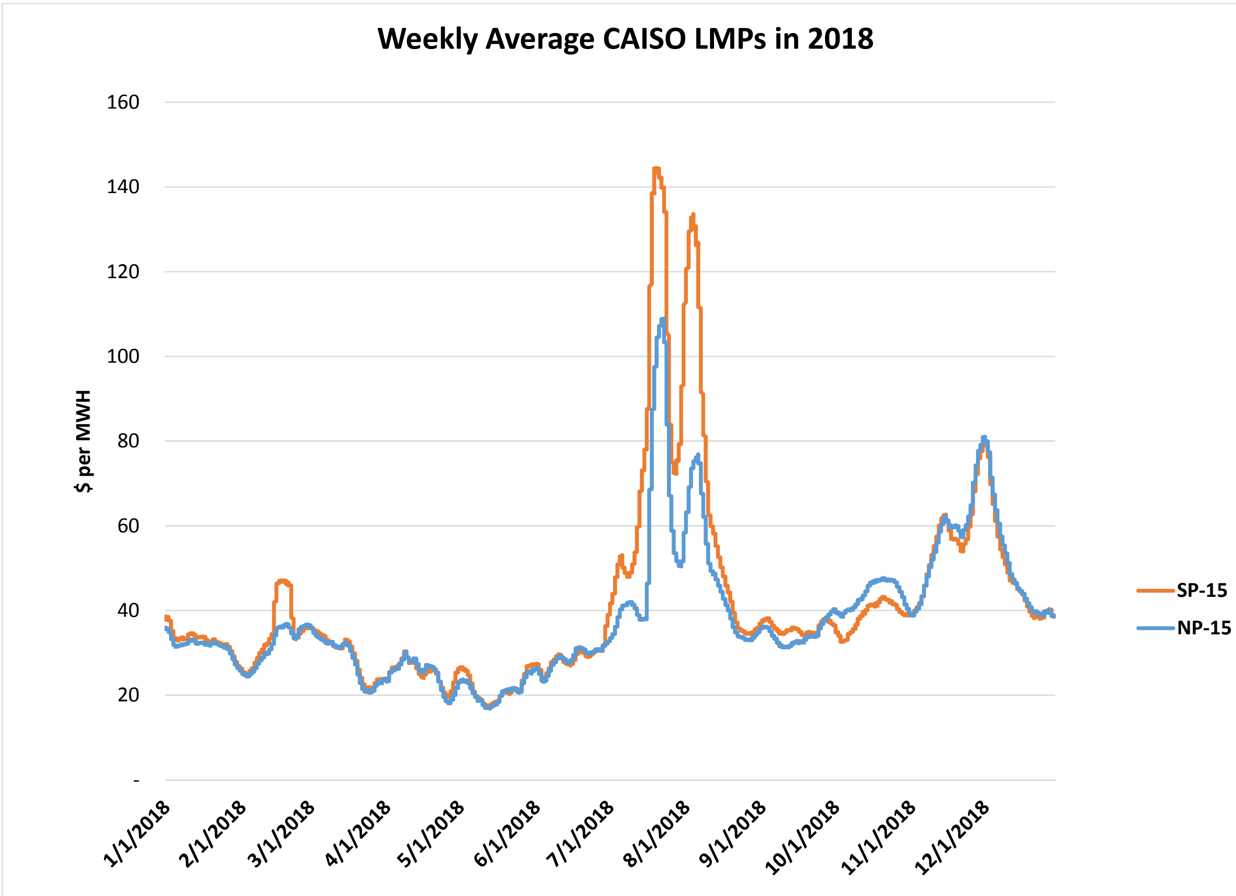
15. How can proper calculation of RA capacity help to cost effectively address the region's RA issues?

Accurate calculation of RA capacity is essential if the RA program and its metrics are to be depended on to meet peak demands. Too-stringent RA requirements risks overbuilding capacity. Existing solar & wind RA capacity valuation methods do not appear to have resulted in reliability issues in high-penetration markets such as California.

For example, recent reliability issues in California have revolved around gas system deliverability issues in southern California, not with the 25% penetration of wind and solar resources. The "duck curve," summarized in our prior set of comments in this docket, indicate the extent to which wind and solar resources have allowed for decreased mid-day energy prices in California (which is a significant benefit for ratepayers, enabling, for example, a greatly expanded set of hours for low-cost EV charging). The CAISO has not experienced serious reliability issues in meeting the higher ramping needs due to the duck curve. We also note that our December 16, 2019 comments provided reference to the NCSEA/SEIA analysis showing that significant wind and solar penetration in California in recent years has not resulted in increased CAISO ancillary service costs.

On the other hand, since the Aliso Canyon gas storage leak on the SoCalGas system in Southern California in October 2015, natural gas deliveries to electric generators in southern California have been at times problematic, leading to very high electricity market prices, as generators are forced to include the cost of gas imbalance penalties in market bids. In addition, in recent years, there have been other serious gas transmission outages on the SoCalGas system that have threatened reliable gas service to gas-fired power plants in southern California. The following figure shows how CAISO day-ahead market prices in 2018 were significantly higher in southern California than in northern California.

As solar PV paired with battery storage becomes more prevalent, it will be very important to adequately assess RA value for solar PV and solar PV plus storage. By doing so, the RA capacity from solar PV and from battery storage – and from both combined – can be properly recognized as an important element of RA capacity that is relied upon by the system.



16. Given your answers to all of the above questions, do you have recommendations about what types of capacity should be compensated, how to define those types of capacity, and do you have examples of calculations or methodology suggestions you would like to offer?

OSEIA refers to the answers to the questions above regarding the importance of including solar PV and solar PV plus storage in all of the types of capacity that may be considered for compensation. Analysis of the amount of capacity provided for each type of capability requires analysis. However, resources should not be excluded from compensation for certain types of capabilities simply because they are not contracted to provide that specific capability. For example, resources that provide energy during peak periods are utilizing their capacity, regardless of whether the resource has been contracted to provide peaking generation. Similarly, a baseload resource that earns most of its revenues based on energy market prices, plus a contractual payment for capacity, would have a capacity value even if it is not providing capacity through a formal capacity market or RA capacity agreement. Resources that ramp up during hours of rapidly increasing load may be providing de-facto flexible generation capacity (or, equivalently, reducing the remaining system need for obtaining flexible capacity resources), regardless of whether they are actually contracted by the system dispatcher to provide a flexible capacity product. Thus, to the extent the Commission defines a particular set of capabilities, resources should be analyzed and compensated in terms of the value they bring, not simply based on the set of capabilities they are explicitly providing under contract to the utility. For example, even facilities that are non-dispatchable provide capacity value based on the amount of energy that they provide during periods when capacity is needed.

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