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Sunrun comments filed separately

Additional submitted attachment is included below.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Oversee the
Resource Adequacy Program, Consider
Program Refinements, and Establish Annual
Local and Flexible Procurement Obligations
for the 2019 and 2020 Compliance Years.

Rulemaking 17-09-020
(Filed September 28, 2017)

TRACK 3 PROPOSAL OF SUNRUN INC.

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TRACK 3 PROPOSAL OF SUNRUN INC.

Pursuant to Commissioner Randolph’s January 29, 2019 *Amended Scoping Memo and Ruling*, Sunrun, Inc. (“Sunrun”) hereby submits the following Track 3 Proposal (“Proposal”) addressing further refinements to the Resource Adequacy (“RA”) program.¹ On February 22, 2019, Administrative Law Judge Debbie Chiv issued an e-mail ruling pursuant to Rule 11.6 of the Commission’s Rules of Practice and Procedure extending the filing deadline for Track 3 proposals to March 4, 2019. Sunrun is the largest dedicated residential rooftop solar company in the United States. Products like Sunrun’s Brightbox combine onsite solar power generation with smart inverter technology and home battery storage. Sunrun’s Proposal takes aim at program rule changes and clarifications necessary to allow meaningful participation of behind-the-meter (“BTM”) solar and battery storage customers in the California Independent System Operator (“CAISO”) and Commission’s RA program.

Sunrun recently gained national media attention for winning an ISO-New England bid to provide wholesale capacity similar to RA capacity by aggregating 20 MW of Brightbox distributed energy resource (“DER”) systems on approximately 5,000 homes.² The project will

¹ R.17-09-020, *Amended Scoping Memo and Ruling of Assigned Commissioner*, p. 3 (Jan. 29, 2019) (“Amended Scoping Ruling”).

² See, e.g., *Utility Dive*, *Residential solar + storage breaks new ground as Sunrun wins ISO-NE capacity contract* (Feb. 8, 2019) (available at: <https://www.utilitydive.com/news/residential-solarstorage-breaks-new-ground-as-sunrun-wins-iso-ne-capacity/547966/>).

be online in 2022, and, besides securing capacity at competitive prices, Sunrun's storage component provides direct backup power to customers, increasing grid resiliency. In California, Sunrun has entered into the Demand Response Auction Mechanism in 2018-2019, which, via the CAISO's Proxy Demand Response ("PDR") program, is currently the only programmatic mechanism for DERs to provide RA capacity.

To demonstrate the relevance of enabling BTM solar and battery storage to provide grid reliability to California's policy goals, Sunrun has participated in an analysis to show the potential for hundreds or even thousands of megawatts of RA potential in specific local and sub-local areas on the California grid. The current RA program's narrow focus on PDR, and the limitations thereof, severely limits the potential for residential BTM solar and battery storage DER aggregations to provide reliability services throughout distribution and transmission-constrained load pockets. The purpose of the instant Proposal is to unlock these resources' potential here in California and bring the State up to par with the other parts of the country leading the way on leveraging these resources for generation capacity.

I. Summary of Sunrun's Proposal

The current RA rules prevent a large fraction, and potentially the majority, of the potential capacity that individual residential BTM storage systems can provide to the RA market without any sound reliability or economic justification. Sunrun's Proposal addresses this shortcoming via Commission action in four areas:

- 1) Allow all dischargeable capacity, including exported energy, to receive RA credit, thereby recognizing the firm capacity BTM storage resources can provide beyond current limitations that are based on the simultaneous host load requirements of PDR;
- 2) Provide clear direction on incrementality for resources providing RA capacity;

- 3) Clarify the way the current load forecasting methodology for load-serving entities (“LSEs”) counts BTM DERs, *i.e.*, as load modifications during certain periods, toward one that more accurately reflects the impact of these resources; and
- 4) Establish reasonable Effective Load Carrying Capacity (“ELCC”) values for combinations of BTM solar and battery storage and clarify application of those values.

Without these adjustments to the RA program, BTM resources, particularly in the residential sector, will be impeded in the market, unnecessarily increasing costs for all customers and inhibiting the achievement of important energy policy goals.

II. Residential Solar and Battery Storage Can Meaningfully Contribute to Grid Reliability.

Sunrun has worked with Station A, a software company whose platform allows users to explore the feasibility of customer-sited clean energy on a building-by-building basis, along with Stem, Inc., a provider of commercial and industrial storage, to quantify the potential for customer-sited solar and battery storage to provide grid reliability capacity in key geographies across the state. The resulting white paper is attached.

The white paper examines building stock across the investor-owned utilities’ (“IOUs”) service territories based on parcel-level data sets, to identify the potential for solar and storage development in geographies including Local Areas and Sub-Local Areas where RA capacity can have particular value for grid reliability. The results show that based on techno-economic potential, defined as those customers who can realize energy cost savings by adopting solar and/or storage as of today, there is upwards of 9 GW of 4-hour duration RA capacity potential from customer-sited solar and storage across the IOU territories. This includes hundreds or even thousands of megawatts of RA potential in Local Areas and Sub-Local Areas.³

³ Station A, Stem, and Sunrun, *Gigawatt-Scale Customer-Sited Potential: Achieving California Energy Policy Goals, Grid Reliability and Local Resilience* (February 2019) (Attachment A).

Local Resource Adequacy Potential - Selected Local and Sub-Local Areas

Local Area	Solar Potential (MWdc)	Energy Storage Potential (MWh)	Resource Adequacy Potential (MW @ 4hr Duration, Limited by Load)	Resource Adequacy Potential (MW @ 4hr Duration, Full ESS Utilization)
LA Basin	14,391	12,886	2,149	2,723
San Diego	4,455	5,570	928	1,194
Greater Bay Area	10,476	8,169	1,294	1,855
San Jose / Moss Landing Sub- Local Area	3,607	2,176	338	498
Pittsburg Sub- Local Area	1,343	1,132	175	261
Oakland Sub- Local Area	348	336	56	67
Greater Fresno	1,687	1,384	241	333
Stockton	1,694	1,357	224	300
Kern	977	754	129	168

Customer-Sited Potential by Utility Territory

Utility Service Territory	Solar Potential (MWdc)	Energy Storage Potential (MWh)	Resource Adequacy Potential (MW @ 4hr Duration, Limited by Load)	Resource Adequacy Potential (MW @ 4hr Duration, Full ESS Utilization)
IOU Service Territories	47,781	42,392	6,730	9,245
PG&E	23,347	19,039	2,870	4,086
SDG&E*	4,455	5,570	928	1,194
SCE	19,979	17,782	2,931	3,965

* San Diego Local Area coincides with SDG&E service territory and is reflected in both tables.

The participation of customer-sited solar and storage in delivering RA can be of key importance to achieving grid reliability goals because the scale potential is meaningful in relation to overall capacity needs. The study also illustrates the scale impact of failing to value battery exports for capacity value, *i.e.*, eliminating gigawatts of potential customer-sited RA.

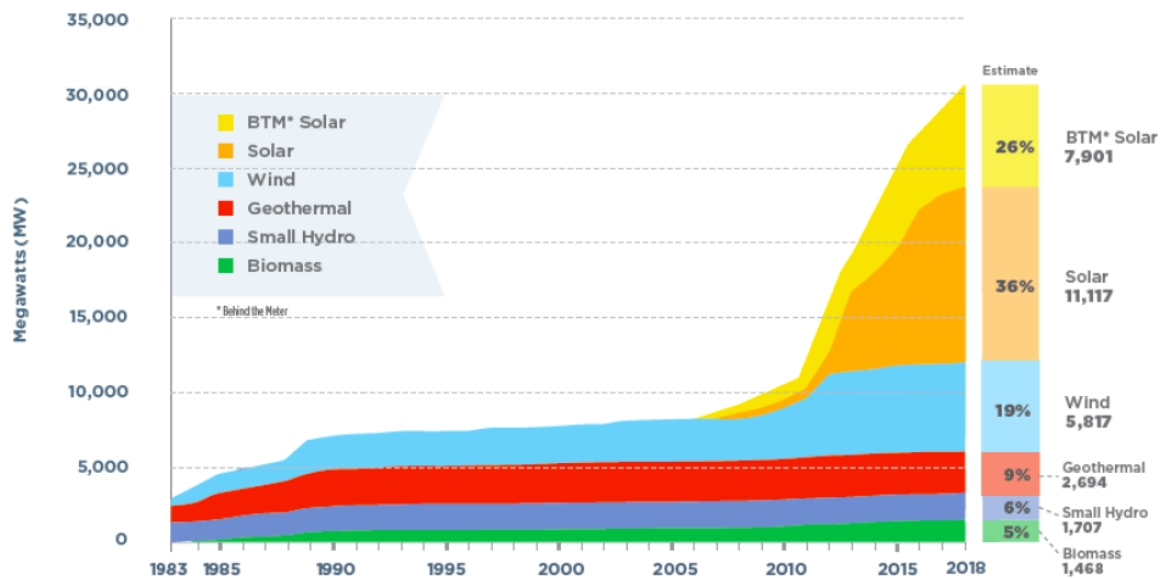
III. The Current Rules Unnecessarily Restrict the Market for RA Supply, Leading to Deficiencies in LSE Procurement and the Need for Backstop.

Per Commissioner Picker's comments at the Commission's February 21, 2019 business meeting, ten energy service providers and San Diego Gas & Electric filed for RA waivers in 2018 because they were unable to find sufficient, reasonably priced local capacity in the market.⁴ Addressing this capacity shortfall requires the Commission to use all of the tools and resources at its disposal. The current rules restrict the ability of DERs to provide RA capacity to PDR, limiting the size of a market where local RA capacity, in particular, is in need. With the continued growth in residential solar adoption and the large and increasing proportion of solar customers that pair their solar systems with battery storage, the aggregate capacity lost to the market is significant and growing.

The chart below shows the annual installed capacity of renewable energy in California since 1983. As of December 2018, BTM solar resources account 7,901 MW, or 26% of total renewable energy capacity in the State.

⁴ See also Commission's List of Local Waiver Letters, available at: <http://www.cpuc.ca.gov/General.aspx?id=6311>.

Figure ES-4: Annual Cumulative Installed Renewable Capacity Since 1983 (Including Behind-the-Meter Solar)



Source: California Energy Commission, Tracking Progress, Renewable Energy, updated December 2018

Pairing batteries with solar greatly increases the potential value to customers and the system and can be done far more cost-effectively than installing solar on its own and separately solving for capacity and other grid needs. However, in order to create a virtuous cycle of customers adding batteries to solar installations, the path to monetization of grid value streams must be clear, possible to operationalize, and a reliable source of long-term value for long-term assets. Limiting the ability of BTM solar and battery DERs to provide RA capacity via the CAISO PDR program effectively eliminates large swathes of this capacity as a potential source of dynamic RA resources and stymies this virtuous cycle.

BTM solar and battery storage systems are deployed across California's diverse sublaps and, with appropriate market signals, aggregators can commit to provide capacity in focused locations of need, including those specified in the attached white paper. Much of the RA reforms discussed in this docket have been motivated by the concern of increased reliance on backstop procurement in light of LSE proliferation, curbing market power, increased retail customer

migration among LSEs, and ensuring the opportunity for and investment in procurement of local preferred resources.⁵ DERs provide an opportunity to mitigate market power possessed by certain generators that are needed for local RA and reduce the need for backstop procurement. Including DERs with storage as a central component of the Commission’s RA strategy will diminish current supply constraints, where LSEs are having trouble procuring local RA, and improve the flexibility of the State’s fleet of resources.

More broadly, actively encouraging DER aggregations to utilize their multiple-use applications (“MUAs”) to provide the widest range and highest value of grid services possible is also consistent with the vision articulated in the Commission’s DER Action Plan.⁶ That plan calls for “wholesale DER market integration and interconnection” allowing DERs to “participate robustly as grid resources through progressively greater visibility, dispatchability, and profitability in wholesale (and local) grid operations and markets.”⁷ Noting DERs’ “stacking value,” the Commission calls for rules and procedures to be put in place “governing how DERs may participate in the wholesale market while providing distribution capacity and other services to distribution utilities, including clear prioritization of services in case of reliability events.”⁸

The problem has been sequencing and synthesizing the various venues in which the Commission addresses these issues. The attached report from the California Solar & Storage Association (“CALSSA Report”) highlights the existing barriers to leveraging BTM resources for generation capacity, distribution system capacity, and the provision of other grid services. Fully untangling these regulatory barriers requires coordination between the Commission and CAISO and likely requires evaluation of a range of topics such as interconnection, the

⁵ See, e.g. D.19-02-022, p. 18 and Ordering Paragraphs 3 and 16 (Feb. 21, 2019).

⁶ CPUC, *California’s Distributed Energy Resources Action Plan: Aligning Vision and Action*, (May 3, 2017).

⁷ *Id.* §§ 3.A.-3.C.

⁸ *Id.* §§ 3.A.-3.C.

Commission’s net energy metering (“NEM”) and other DER tariff program rules, the Commission’s MUA policy, and various CAISO programs and tariffs.

In Sunrun’s experience, the restriction on exports in demand response (“DR”) programs remains one proximate issue preventing aggregations of residential BTM solar and battery storage customers from providing RA to a degree that drives greater adoption and a long-term path of market integration of these resources and urgently needs resolution. With realization of its full capacity value, BTM solar and battery storage cost per kilowatt of RA will decline and more scale will be realized. Behind this, pathways to deliver RA from aggregated BTM resources at scale can be fully developed, solving operational details of market participation by PDR resources in CAISO and/or fully enabling load modification pathways as described below.

Numerous parties identified the exclusion of exports as a key barrier for DR resource participation in the CAISO market in R.13-09-011 and as an issue that should be prioritized for resolution by PG&E.⁹ However, the Commission did not address the item at all in its decision, D.17-10-017, and it did not include it within the scope of the Supply Side Working Group created as part of that decision.¹⁰ The decision did state, however, that “all resource adequacy-related issues will be determined in the resource adequacy proceeding.”¹¹ In R.15-03-011, the MUA working group helped frame the detailed sub-issues that would need resolution on this topic and provided a current discussion of areas of disagreement between the utility participants and the industry participants.¹² Unfortunately, that proceeding is closed and there is no clear

⁹ R.13-09-011, Comments of Tesla (July 6, 2017); R.13-09-011, Comments of CESA (July 6, 2017); and R.13-09-011, Comments of CalSEIA (July 6, 2017). *See also* R.13-09-011, Tesla Reply Comments (July 17, 2017).

¹⁰ D.17-10-017 at 71-76.

¹¹ *Id.* at 73.

¹² *See, e.g.,* R.15-03-011, *Compliance Report of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39 E), and San Diego Gas & Electric Company (U 902-E) on Behalf of the Multiple-Use Application Working Group*, Appendix A, pp. 1-2 (Aug. 9, 2018).

procedural vehicle for the Commission to provide a focused venue to drive this issue to resolution without delay.

In addition to counting exports, we believe that the approach to valuing load modification in the manner described below has significant value in enabling LSEs to more proactively engage diverse DERs for firm, flexible and long-term load modification. While a path for market integration via PDR may be appropriate, this approach assumes DER aggregators are operating independently to deliver RA to an LSE. Load modification provides a path for LSEs to integrate a strategy for DERs for capacity value with DER programs with complementary goals such as decarbonization that extend to how DERs are managed on a 24-hour basis, not simply for system or local capacity. It may also provide a path for more straightforward integration of multiple devices on an individual customer meter (such as solar, battery, smart water heater and EV charger). While integration of a range of DERs behind individual meters is possible within a single PDR, this otherwise attractive outcome requires a level of sophistication that could prove prohibitive to near-term realization. To support such integration goals, as well as account for the need to update load forecasts for new DER realities, load modification approaches can complement all other efforts to derive capacity benefit from growing solar and battery storage.

While all of the barriers to DERs participating in wholesale markets cannot be resolved in this proceeding, much needed progress can be made. Reliability is this proceeding's responsibility, and rules to govern DERs should be taken up here and now to address the most significant near-term barriers for solar and battery storage DERs to serve this critical procurement market. As many have pointed out in earlier phases, and recently recognized with the January 29th Scoping Ruling, RA counting for combinations of storage and other resources is one of the key RA refinement areas the Commission has determined is needed for resolution in

Track 3, in addition to modifying the load forecasting methodology.¹³ Both issues are the source of current limitations on DERs, along with a need for the Commission to set clear participation and incrementality terms for less traditional resources.

A. Allow all dischargeable capacity to receive RA credit and recognize the firm capacity BTM storage resources can provide.

Currently, the only path for RA recognition for customer-sited assets is through a qualifying supply-side demand response program. The Commission has clarified that the only RA capacity recognized from DR is that which is integrated into the CAISO market.¹⁴ The only existing programs that meet these conditions are the CAISO's PDR, Reliability Demand Response Resource ("RDRR"), and certain utility-run demand response programs.¹⁵ "When PDR and RDRR were under development, they were designed to fit the traditional demand response model of load curtailment. No provision for potential export of energy was envisioned."¹⁶ As such, CAISO ignores any exported energy despite its equal benefit to system reliability, and its tariffs do not recognize the potential capacity value of energy exports from BTM resources.¹⁷

The omission of exports mainly reduces residential customers' ability to assist with LSEs' RA shortfalls and does not impact traditional DR providers who are simply curtailing their

¹³ Amended Scoping Ruling at 2-3.

<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M262/K405/262405974.PDF>

¹⁴ D.15-11-042 at Ordering Paragraph 1 (stating "Effective January 1, 2018 Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall only attribute capacity value to demand response programs that are integrated into the California Independent System Operators wholesale market or embedded in the California Energy Commission's unmanaged/base case load forecast.").

¹⁵ California Solar & Storage Association, *Barriers to Maximizing the Value of Behind-the-Meter Distributed Energy Resources*, p. 8 (Jan. 2019) (Attachment B).

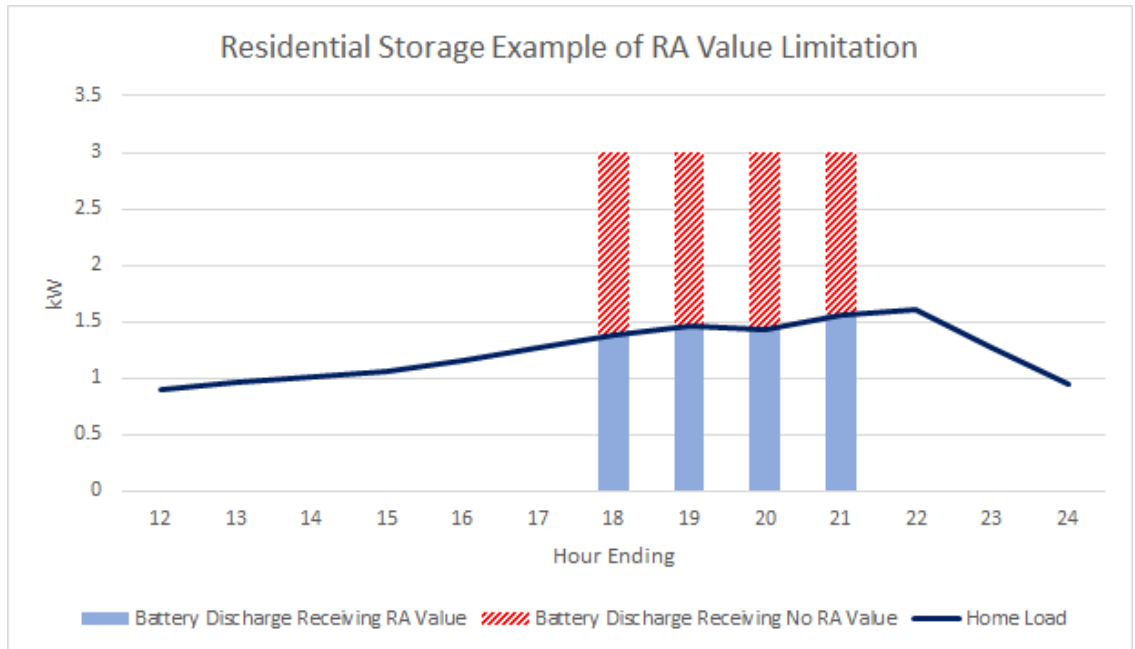
¹⁶ *Id.*

¹⁷ CAISO has put in place a non-generator resource ("NGR") aggregator program. However, the NGR addresses energy and ancillary services (not capacity), requires wholesale energy settlement regardless of whether a bid is submitted (meaning resources pay twice for charging energy), and largely requires interconnection via the WDAT process.

loads. Commercial and industrial customers with BTM storage are also less affected because they rarely size their battery systems above the loads intended to be managed for demand charges and because solar potential is usually more constrained relative to load than for a residential system (although some customers such as schools may have discharge capacity that far exceeds simultaneous loads during anticipated peak periods in the summer and can be significantly impacted).

However, for residential customers, the rated discharge capacity of their storage systems often exceeds minimum load during peak periods when most valuable to the grid. Battery sizing for residential solar systems is in the 9-14 kilowatt hour (“kWh”) range typically today, but sizing to maximize the optimization of solar production under TOU tariffs and maximize resiliency value means that sizing will likely increase to 15-25 kWh in coming years. As the graph below illustrates, for a typical residential customer with an illustrative solar and battery storage system (5 kW solar / 12 kWh usable battery capacity), restricting capacity to the discharge that offsets simultaneous load would remove more than half of potential capacity.¹⁸

¹⁸ Residential battery sizing typically is a function of (a) the value to the customer from backup power, which reasonably runs to 10-20 kWh and (b) maximizing the value of collocated solar. Solar must be sized to annual usage, meaning the 10-20 kWh is a rational assumption for homes with a coincident load of 1-2 kW.



Example shows typical residential load in August for the Los Angeles region (OpenEI TMY2 residential load data) with a battery delivering 12 kWh of load shift via the Meter Generator Output baseline methodology

When combined with forecasted adoption of over 5,000 MWh of residential storage in California cumulatively through 2023, according to the Wood Mackenzie Q4 2018 Energy Storage Monitor, the current RA restrictions may unnecessarily remove hundreds of MW of local, flexible, customer-driven residential capacity from the RA market and run counter to the Commission's DER integration goals.

Resolution around the load forecasting process and counting the exportable capacity of BTM storage are critical pieces to this puzzle and are addressed below. Before addressing those questions, however, Sunrun specifically requests the Commission make a clear determination of its intent to make the full capacity potential of BTM storage available to the market. Such a determination should include an official recommendation that the CAISO modify its PDR and RDRR tariffs to remove the restrictions that limit RA capacity eligibility to load curtailment.

B. Provide clear direction on incrementality for resources providing RA capacity.

In addition, Sunrun proposes the Commission make clear determinations on the question of incrementality within this proceeding for purposes of providing RA capacity. In Resolution E-4889, the CPUC indirectly addressed the issue of programmatic prohibitions on DERs providing value in more than one domain from the (1) customer, (2) distribution, (3) transmission, (4) wholesale market and (5) RA domains included in the Commission's MUA framework.¹⁹ That Resolution addressed incrementality in the context of the distribution domain, specifically the ability of existing resources to provide distribution capacity within the Integrated Distributed Energy Resource ("IDER") distribution investment deferral pilot projects.

The Resolution found that participation in another program, such as the Self-Generation Incentive Program ("SGIP"), DR, or NEM should not preclude participation in a distribution services solicitation, provided that the resource was operated in a way that would provide incremental service.²⁰ A subsequent ruling in the Distribution Resource Planning ("DRP") proceeding, acknowledging that further development of the Competitive Solicitation Framework governing IDER and DRP solicitations could not be completed until sometime in 2019, extended the guidance from Resolution E-4889 to cover the first round of Distribution Investment Deferral Framework solicitations.²¹

Sunrun proposes the Commission address potential categorical exclusions for the RA "domain" here as well. Both DR and SGIP-funded resources can already provide RA. However, recent solicitations for local capacity, including SCE's Preferred Resources Pilot, SCE's

¹⁹ See, e.g., D.18-01-003 at 10.

²⁰ Resolution E-4889, pp. 25-29 and Finding 8 (Dec. 14, 2017).

²¹ R.14-08-013, *Administrative Law Judge's Ruling on the Application of the Competitive Solicitation Framework for Distribution Investment Deferrals in the Distributed Resources Planning Proceeding* (Nov. 19, 2018).

Moorpark-Goleta solicitation, and PG&E's South Bay-Moss Landing energy storage solicitation, have included categorical exclusions for SGIP, NEM and other BTM DERs, limiting the pool of resources that can respond.²² To remain consistent with prior incrementality guidance for distribution system capacity, the Commission should extend the same guidance for generation capacity, including a clear prohibition on categorical exclusions for aggregated resources from providing RA capacity that participate in another program, such as SGIP, DR, or NEM. This clarity will provide a foundation for aggregated DERs to provide generation capacity beyond the limited avenues available under the *status quo*.

Admittedly, Resolution E-4889's incrementality framework did not resolve the opaque methods the utilities then used to ensure incrementality within their IDER solicitations.²³ For this reason, Sunrun supports the CALSSA Report's recommendation for close coordination between the IDER and RA proceedings to develop clear incrementality methodologies.²⁴ In the meantime, while Sunrun would prefer clear and consistent incrementality methodologies, we agree with CALSSA that incrementality for RA purposes should be determined, as an interim measure, on an *ad hoc* basis using the conceptual frameworks developed in the IDER proceeding and pilots.

What the Commission need not decide here are issues surrounding compensation for RA capacity from resources, such as NEM facilities, already participating in other programs. Parties have argued, for example, that customers receiving a retail credit via the NEM program are

²² CALSSA Report at 5.

²³ See *id.* at pp. 5-7 (summarizing the lack of clarity between the IOUs regarding what is and is not an incremental service and the difficulties for bidders to understand the details of the utilities' methodologies).

²⁴ *Id.* at 8.

already compensated for the capacity value they provide.²⁵ Those questions should remain outside the purview of Track 3 and be resolved elsewhere once a firm policy and methodology regarding incrementality is established. An incrementality methodology (and a related counting methodology for BTM solar and battery storage resources, discussed below) will help to establish the foundation for what RA capacity services are being provided above and beyond those from existing programs and, therefore, the amount of capacity that deserves further compensation.

Another reason to avoid consideration of the compensation issue here is that LSEs largely procure RA resources via bilateral contracting. Each LSE, whether the price it pays for RA procurement is CPUC-jurisdictional or otherwise, should be able to determine the amount of compensation they wish to provide local, aggregated DER resources. The key, preliminary issues the Commission should address at this time is to establish a qualifying capacity counting methodology, a clear incrementality methodology for generation capacity, and a prohibition on excluding BTM DER resources from LSE solicitations.

²⁵ Sunrun disagrees with this assertion for a number of reasons, including, but not limited to: (1) customers earning NEM credits for exports from storage discharge are not receiving a net increase in compensation because they are losing the opportunity to earn retail value for solar that had been used to charge their systems or the retail value of offsetting future load; (2) the Commission has recognized the higher value of load reduction and exported energy during limited event windows in establishing the retail rates in its DR programs such as Peak Day Pricing; (3) the combined compensation for an aggregation of exporting NEM customers with storage would not be structurally different than what is provided to aggregations of load curtailment customers whose onsite load is so large that combinations of onsite generation and storage discharge would never export to the grid; and (4) the incremental revenue that a customer or aggregator earns from providing wholesale capacity services is by no means a windfall profit margin but rather needed to offset the incremental cost and risk involved in committing to aggregate and offer sufficient capacity subject to performance requirements (the situation is analogous to the way Lyft and AirBNB incur risks and costs in order to provide a platform for aggregating the supply of shared rides and short-term rentals).

C. Clarify the current methodology for counting BTM DERs within load forecasts towards counting more responsive RA value.

DER providers, particularly those with firm, controllable and directly measurable technologies such as battery storage, can modify their customers' aggregate load profile in ways to reduce the market's need for local, system, and flexible RA. This is an important component of the procurement choice that LSEs, such as community choice aggregators, are actively pursuing to most cost-effectively encourage clean, local, community-driven resources. To fully realize the load modification opportunity for both LSEs and DER providers, the Commission needs to revisit the methodology used for establishing LSE load forecasts used for RA obligation assignment and make the adjustments, in particular those assumed for forecasted adoption of BTM solar and battery storage, transparent and open to review.

In comments to the Track 2 Proposed Decision and in various *ex parte* communications, several parties expressed the importance of encouraging LSEs to work with DER providers to provide beneficial load modifications. Sunrun reiterates the importance of cost recovery approaches that preserve individual LSE incentives. However, we also seek to point out the fundamental circularities and ambiguities embedded in the entire process for establishing the load forecasts for setting RA obligations. Without establishing clarity in load forecasts between RA needs and "autonomously procured" DERs, it becomes difficult to procure RA from DERs of *any* type whose "autonomous" adoption is in the load forecasts that determine RA needs.

Currently, the California Energy Commission ("CEC") is largely responsible for collecting and validating LSE load forecasts that the CPUC adopts for the purpose of setting LSE RA responsibility. Ensuring fair, consistent forecasts is a complex task that requires accounting for factors such as weather sensitivity, load migration, and customer adoption of demand-modifying technology. The Commission last provided detailed guidance on its load forecasting

protocol and adjustments in 2016, but that document clarifies that the methodology for adjustments for projected adoption of “distributed generation” (“DG”) follows direction last provided *in 2005*.²⁶ That 2005 decision essentially concluded that given the limited penetration of DG at that time (“a few hundred megawatts”), the IOUs would provide forecasted penetration and “stereotypical” generation profiles to Energy Division and the CEC for purposes of modifying the load forecasts.²⁷ As the current load forecast templates demonstrate, this informal and undocumented approach is still in effect, whereby only the IOUs provide forecasted monthly MW peak impacts of adoption for DERs with limited, if any, stakeholder involvement.²⁸ The 2005 decision clarified that if “DG” adoption were to substantially increase, this determination could be revisited and more sophisticated methodologies employed.²⁹

First, not only has “DG” adoption substantially increased, it has evolved technologically, and the scale introduction of flexible battery storage within DER systems calls into question the methodology and design of load forecasts inclusive of DERs. For example, electricity usage and certain DER behavior can be forecast, but, within residential TOU windows, battery storage (and by extension EV charging) has no inherent predictable load shape. A wide range of battery discharge patterns can be equally economically rational within a TOU pricing period. Despite this fact, an Integrated Energy Policy Report (“IEPR”) forecast with an unknown accounting for

²⁶ Cerutti, M. and Brooks, D., California Public Utilities Commission, *Resource Adequacy 2016 Load Forecast Adjustment Methodology - Revised*, p. 6 (2016) (stating with regard to load forecasting that “[a]fter the coincidence adjustments and plausibility adjustments are applied, CEC staff allocates credit for energy efficiency (EE), demand response (DR), and distributed generation (DG) programs in each of the three IOU service areas. The allocation accounts for the proportion of the load impacts accruing to each LSE due to a portion of the distribution charge paid by their customers. CEC staff allocates the impacts of the programs to LSEs proportionate to their share of load and so the decrease to their loads equals to the sum of the EE, DR, and DG credits. Consistent with the direction in D.05-10-042, impacts are either allocated to each LSE based on its share of total load or to only the IOUs depending on whether all customers or only bundled customers participate in the program.”) (“Load Forecast Report”).

²⁷ D.05-10-042 at 41.

²⁸ Load Forecast Report at 6.

²⁹ D.05-10-042 at 41.

battery behavior is being used as the basis for opaque incrementality determinations for solar and battery storage for local capacity (and distribution deferral) procurements.

Considering the order of magnitude increase in DER adoption in the past 15 years, the increased pairing of solar with storage, future DER adoption with flexible load profiles, the need for clarity on battery load shape, and the growing diversity of LSEs, it is time to revisit these adjustments. At a minimum, there should be transparency on the forecasted quantity of adoption and the forecasted aggregate profile adjustments that are attributed to the most common BTM DER technologies. While there is considerable variation in different solar technologies and azimuth orientations, standardized aggregate profiles are likely acceptable as long as the assumptions and sources are transparent. To be clear, the aggregate load modification would include the impacts of both generation that reduces individual customer load as well as generation that is exported to the grid.

Storage load modifications, however, likely follow a myriad of different adjustments depending on the customer-specific objectives and whether the storage is incorporated in an aggregation to meet other grid service needs. As an owner and operator of a BTM storage fleet, it is unclear to Sunrun how a load forecast *could* be done fairly for battery storage except if extrapolated on an empirical basis under an agreed-upon methodology. Even in this case, the result would be from arbitrary battery settings for existing customers and might not be appropriate on which to gauge the behavior of future customers. A NEM battery with export ability can discharge in any number of patterns that are equally economically rational during TOU peak periods lasting several hours. While the incrementality of particular battery charge / discharge patterns is of key importance for determining whether batteries are valued for RA according to utility viewpoints expressed in the MUA working group, *no particular* battery

operating pattern can be said to be a single rational baseline against which incremental battery operation should be measured.

For that reason, when setting an LSE's base forecast, it would be most appropriate to initially omit any assumed modification from batteries or similarly flexible DERs to the aggregate load profile. If this is not done, an LSE that seeks to avoid crediting BTM storage could simply suggest that battery discharge done specifically for RA from an individual battery is already assumed in the aggregate load forecast, thereby completely ignoring the incremental value the addition of batteries provides, with no way for an aggregator to disprove the assertion.

Perhaps even more fundamental than providing an accurate *prediction* of load modifying impacts of flexible DERs, the Commission should clearly establish guidelines for what baseline level of adoption and load modification LSEs should be permitted to "claim" in their forecast that establishes their RA obligations. Without transparent and fair guidelines, LSEs may be precluded from valuing RA at the system or local level delivered by DERs because there is no established methodology for how such capacity would relate with the load forecast.

For example, this issue could be acute in the case of a Local RA need including midday and afternoon hours, such as the Goleta / Moorpark sub-local area, which was the subject of a local capacity procurement beginning in 2018. BTM solar would deliver benefit towards this Local RA need even without load shift from storage because the targeted hours included peak solar production times. The forecast used to determine the Local RA requirement includes *some* DERs. This means it is impossible to determine if a given contracted procurement of BTM solar is the "same" DERs expected to be "autonomously" adopted in the forecast. This precludes the procurement of a resource that may be ideally suited to deliver Local RA need. (Equally, LSEs might also benefit from reduced obligations without appropriately compensating the DERs that

enabled those reduced obligations - indeed, if Local RA has elevated value, it seems likely that they would.)

At the same time, LSEs should benefit from the level of historical or contracted adoption or load adjustment where assignment of those benefits has been clearly established by the Commission. For simplicity, the Commission should consider straightforward limits to the forecast starting in the 2020-21 compliance year to remove any incremental forecasted DER adoption that is not supported by an explicit RA transfer agreement. These forecasting modifications are necessary at both the system and local area. This approach will allow a DER provider to commit to providing its product, on a contractual basis, in exchange for RA value, rather than precluding such commitment for performance by deferring to a forecast that cannot precisely predict how, when or where a DER resource will show up on the system.

Stated another way, DER providers should be able to seek compensation from an LSE for either providing beneficial load modification above a reasonable “baseline” forecast, or for providing a supply-side RA resource that an LSE can procure to meet its RA obligations. Fair and transparent protocols need to be established to prevent double counting of resources so that the market truly benefits from incremental contribution of capacity and that capacity is not unreasonably withheld from the market based on overly conservative or opportunistic disqualification. The risk otherwise is that we are not accurately forecasting and procuring for RA, which risks negative reliability impacts for ratepayers.

D. Establish reasonable ELCC values for combinations of BTM solar and battery storage and clarify application of those values.

Developing reasonable ELCC values for combinations of BTM solar and battery storage and establishing a clear, reasonable method for allowing those resources to earn RA credit for those values is essential to integrating BTM DERs into the capacity markets. ELCC modeling

should find a synergistic benefit of matching solar with storage. Specifically, the contribution to reliability of solar and battery storage combinations is likely higher than the sum of the ELCC of solar-only combined with the nameplate kW of battery due to the increased diversity benefits.

Commission efforts to specifically study and confirm this expected phenomenon and develop a set of generic ELCC factors that vendors and LSEs can reference for RA compliance are critical to animating these resources to provide RA capacity. While Energy Division's proposal shows a synergistic benefit of introducing storage into a solar-heavy resource mix, Energy Division suggests spreading the extra benefit of storage to "all" solar resources, but then only to "supply side solar", regardless of whether those specific solar resources had paired storage with their solar generation.³⁰ The Commission should ensure that ELCC modeling allows developers (or customers) that directly combine solar with storage, whether in front of or behind the meter, to directly benefit from that pairing and not dilute the benefit of storage pairing by socializing the benefits across all solar resources.

Energy Division's analysis also only focuses on utility-scale resource profiles, though modeling of aggregated distributed resources may require additional adjustments. For example, due to increased diversity, aggregated profiles will likely have less intermittency and be less prone to large outages than single large projects. In addition, the contribution from customer-sited resources should be adjusted for reduced line losses and transmission constraints. In any case, ELCC analyses should demonstrate that the reliability contribution from BTM solar and battery storage combinations are not limited to load reductions, but also include the exportable capacity.

Once reasonable ELCC values are established for BTM solar and battery storage combinations, the Commission needs to establish appropriate ways for DER providers and LSEs

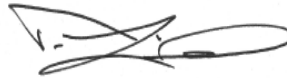
³⁰ Energy Division, *Revised Staff Proposal*, Slides 10, 14 and 17 (Feb. 13, 2019).

to apply those values. As recognized by some parties, *e.g.*, PG&E and Calpine, establishing ELCC values for BTM resources may require re-adjusting the current load modification impacts of DG adoption currently embedded in the forecasts used for setting LSE RA obligations. Subsequently, incremental contribution from BTM solar and battery storage combinations could be procured by LSEs at their ELCC value to either modify their specific RA obligations or to provide RA supply.

IV. Conclusion

Sunrun appreciates the Commission's consideration of this proposal and looks forward to working with Staff and other parties on the issues addressed herein.

Respectfully submitted,

A handwritten signature in black ink, appearing to read 'Tim Lindl', with a stylized, looping flourish at the end.

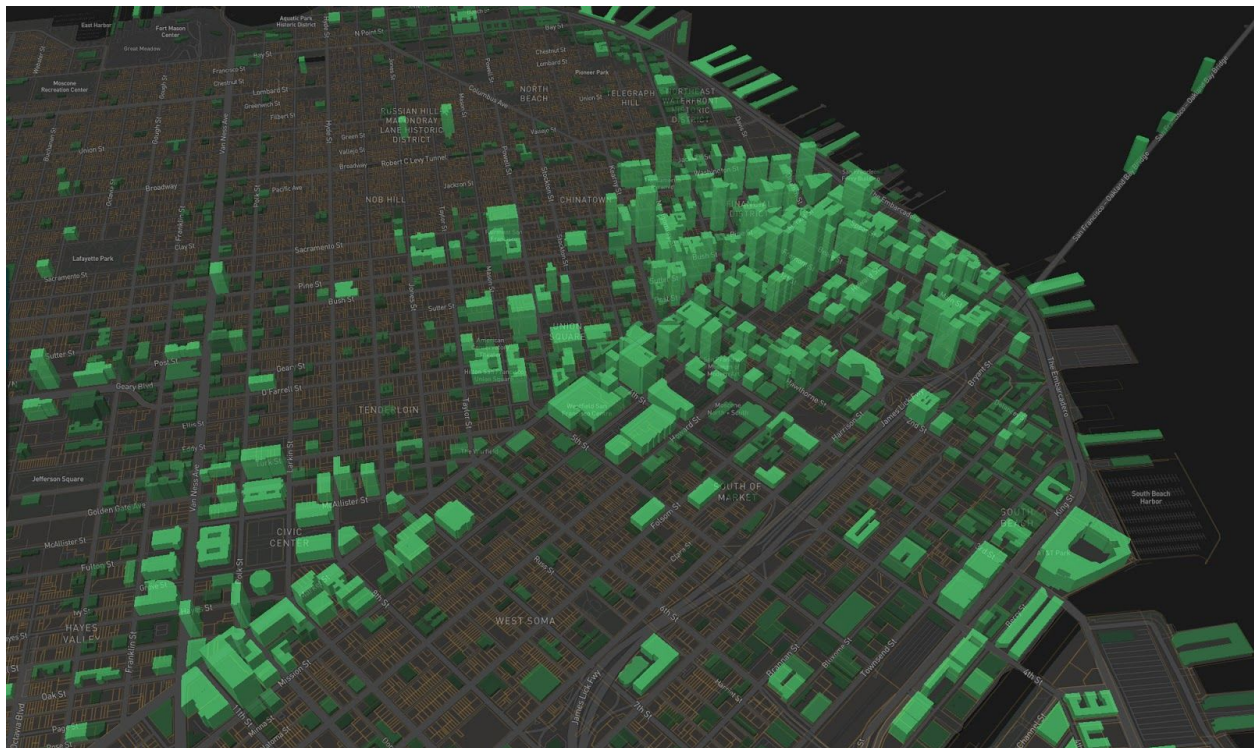
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Gigawatt-Scale Customer-Sited Potential: Achieving California Energy Policy Goals, Grid Reliability and Local Resilience

February 2019



Gigawatt-Scale Customer-Sited Potential: Achieving California Energy Policy Goals, Grid Reliability and Local Resilience

California has chosen the groundbreaking path of achieving 100% clean energy by 2045,¹ driving transformation in how the grid will be powered and managed. Simultaneously, California must tackle the challenge of adapting the grid for a changing climate, fire risk and increasing need for resilience. Even as a transformation unfolds, the grid must remain stable and reliable. To achieve this will require innovation that draws on all of the solutions that the state can bring to bear.

Station A, a software company whose platform allows users to explore the feasibility of customer-sited clean energy on a building-by-building basis, has worked with Sunrun and Stem, as market leaders in the deployment of distributed energy resources in California, to quantify the potential for customer-sited solar and battery storage to provide grid reliability capacity in key geographies across the state. This includes areas where local grid reliability has been or may become a concern in relation to the retirement of existing generation resources. By quantifying the aggregate potential, our goal is to bring focus to the enormous resource that California has across cities, suburbs and even rural areas to bolster grid reliability while driving clean energy uptake and increasing grid resilience.

This analysis identifies techno-economic potential for 48 gigawatts of rooftop solar and 42 gigawatt-hours of battery storage which together would provide approximately **9 gigawatts** of Resource Adequacy across the IOU service territories. Key geographies have Local RA potential of hundreds to thousands of megawatts. This potential was evaluated without grid reliability revenue; the addition of this revenue could increase scale potential even further.

As the CPUC, CAISO, and utilities identify approaches to maintain reliability while increasing resilience and clean energy, and the CEC identifies paths to achieve California's energy policy goals, customer-sited solar and battery storage resource potential can be a key pillar and should be at the forefront for consideration. The results of our analysis show that the scale of customer-sited potential is far greater, relative to the scale of local reliability needs, than has been observed in recent relevant procurements. The scale of resource potential should inform existing and future procurement and sourcing approaches from IOUs and CCAs that will more successfully drive the maximum deployment of customer-sited solar and battery storage to be cost-effectively drawn on for local and flexible capacity needs.

Specifically, Current Resource Adequacy frameworks undervalue the capability of behind the meter resources to deliver cost-effective capacity – especially at the local level. Our analysis illustrates that fully 2.5 GW of aggregate RA potential would be “stranded,” even after being developed, based on current rules limiting batteries participating as Proxy Demand Resources.

¹ Senate Bill 100, September 10, 2018

Customer-Sited Resources are Inherently Well-Suited for Local Reliability and Resilience

Enabling a transition to a cleaner energy mix includes ensuring reliability in local and sub-local areas, meaning clean resources must be found in *every* local area or there is a risk that reliability-based revenue streams will run counter to California policy goals, if they have the effect of delaying the retirement of thermal generation. Load is driven by businesses and homes, which are also the sites for customer-sited solutions. This means that, as our analysis shows, there is substantial potential for customer-sited solutions in every local area that makes major demands on the grid.

Importantly, customer-sited solar and battery storage not only supports local reliability, it is inherently aligned with increasing resilience. The more resources that exist *within* communities on a customer-sited basis - especially solar-paired storage resources that can operate indefinitely regardless of grid availability - the lower the impact or risk posed by de-energization, transmission contingencies, or other disruptions to the grid. Finally, resources that are sited on the distribution grid are inherently situated to provide distribution deferral value related to reliability.

Nature and Purpose of this Analysis

To inform the processes driving California's approach to reliability, resilience and clean energy, Station A, Sunrun and Stem have sought to highlight on a broad basis the clean energy grid reliability potential that exists in California's single family home and C&I segments specifically. As leading developers of such resources, Sunrun and Stem operate competitively but see on a daily basis potential that may be opaque to observers outside of industry. Working with the aid of Station A's independent analysis, we have sought to illuminate this potential in a format that can inform all interested parties.

Our estimates for customer-sited solar and battery storage potential in local areas should be considered *techno-economic potential*, relating to the expected viability of solar and battery storage to create positive economics for customers based on factors such as building stock, energy usage expectations and current costs for solar, storage and retail electricity in today's underlying customer tariff environment. The potential for Resource Adequacy (RA) value from these resources is estimated based on the expected usage of this storage to deliver RA via Proxy Demand Resource in CAISO, as described below, and takes into account seasonal variation due to variation in solar production. Estimates reflect the annual *average* of RA capacity across the year, with potential for higher values in summer when California's peak demand and thus maximum need for RA actually occurs.

It should be noted that this techno-economic potential does *not* factor in capacity revenue of any kind. This underscores two facts: first, that customer-sited resources will

emerge independently of capacity revenue and second, that the cost to utilize these assets for grid reliability can be cost effective because customer value covers a portion of the cost of deployment. By adding potential revenue from services that enhance grid reliability, deployment can be accelerated, the overall market opportunity expanded, and these resources will be fully utilized for reliability value above and beyond their use for customer value.

Estimates represent the potential if *all* customers that are prime candidates for solar and battery storage today were to adopt this technology instantaneously. This analysis does not suggest the rate at which such adoption can be expected to occur. Rather, these numbers are intended to spur discussion of the approaches that will *maximize* the realization of this potential. Such approaches should include eliminating regulatory impediments to market potential that exist today and structuring procurement approaches to incorporate a resource type that is deployed in a modular form over years based on customer demand rather than in “lumpy” large-scale investments solely based on utility contracts.

If the potential exists and customer-sited resources have unique and inherent value towards multiple key policy goals while delivering grid reliability on a cost-effective basis, then approaches to local reliability should begin with this question. A criterion for procurement processes, as well as planning, tariffs and programmatic initiatives, should be their success against this potential. The objective should be speeding the achievement of California policy goals, including clean energy and resilience, in ways that bring the maximum benefits to all of California’s citizens.

Represent Customer-Sited Resources in Key Grid Modeling Efforts

Station A, Sunrun and Stem are forthright in acknowledging that this analysis is indicative as compared to the highly sophisticated models that inform California grid and resource planning. We challenge those determining the modeling approaches for such processes to improve on these numbers through approaches with greater economic sophistication that will yield greater detail, and then to consider how the load flexibility and reliability resources they create can interact with local reliability requirements in nuanced ways. Relevant processes include Integrated Resource Planning (IRP), the CAISO Transmission Planning Process (TPP), and potentially others including the Integrated Energy Policy Report (IEPR). The general methodologies we use can be translated to other datasets to enable such approaches.

It should be noted that this analysis reflects *today’s* techno-economic viability. Given decreasing solar and battery storage costs, our estimates should be considered floors that will increase over time as more homes and businesses become prime candidates for adopting these technologies. This lends further importance to creating nuanced models that are integrated into California’s planning processes and update over time to reflect increasing potential.

Using Customer-Sited Solar and Battery Storage for Local Resource Adequacy and Flexible Resource Adequacy

Customer-sited solar and battery storage are able to deliver grid reliability via existing mechanisms in CAISO to provide Resource Adequacy (RA) alongside traditional resources. The primary mechanism for this is participation as a Proxy Demand Resource (PDR). In the context of PDR, solar and battery storage are joined by other load flexibility technologies, the potential for which should not be minimized. However, solar and battery storage are well suited to provide long-duration capacity that has particular salience for Local RA requirements that may extend beyond the requirements of System RA. In addition, solar and battery storage can provide Flexible RA, a growing need as renewable energy penetration creates variability in supply and new ramping requirements.

To focus attention on the specific value of customer-sited solar and battery storage, we have expressed potential in megawatts of RA from solar and battery storage organized as PDR. While Local RA requirements will vary in terms of duration and timing, we have used System RA as a generic starting point and proxy. In general, the amount of Local RA available for a given need should relate to System RA potential according to the ratio of the duration of Local RA need to the 4-hour duration of System RA. This is to say, 150 MW of System RA potential at 4-hour duration could be expected to translate to roughly 100 MW of Local RA potential of 6-hour duration. This could vary based on the time of day of this need in relation to solar production.

Key Issues and Considerations for Local RA from Customer-Sited Solar and Battery Storage

Significant barriers still exist to fully realizing the value of solar and battery storage as Proxy Demand Resources. Specifically, the RA that customer-sited storage can provide is limited to the coincident load on the associated customer meter in a given hour. While a customer-sited energy storage system may have additional capacity available at times of system or local need above the load on a given customer's meter, any injections back onto the grid are valued at zero and therefore would not be provided. To highlight the impact that this has on aggregate potential, which is dramatic, we identify two different sets of RA potential: one under current RA accounting, and one that allows the system to benefit from batteries discharging fully during hours of need. If this issue is not addressed, no matter how much of the techno-economic potential is realized, a material portion of the RA potential from customer-sited solar and battery storage will be unutilized.

Second, we necessarily worked from today's identified Local Areas and Sub-Local Areas and the mapping resources available publicly for the selected areas. As grid conditions evolve, Local Area definitions will change. This underscores further the need for the sophisticated modeling efforts that drive grid and resource planning to incorporate customer-sited resource

potential from the bottom up, so that for any given geographic boundary an updated view of potential can be identified and incorporated at the very front end of conceptualization of options for addressing local needs.

Customer-Sited Solar and Battery Storage Capacity in Select Local Areas and Sub-Local Areas

The results of Sunrun and Stem's analysis can be seen below, for a selection of Local and Sub-Local Areas. These have been chosen to represent a cross-section of geographies across California with widely varying building stock and climate characteristics, demonstrating that customer-sited solar and battery storage can serve as a key resource across the entirety of California's grid. For reference, we identify the aggregate solar *techno-economic* potential identified across the CA IOU's as being 47.8 GW. Notably, researchers at NREL have estimated purely technical rooftop solar potential in California at 128.9 GW.² Against this total potential, the techno-economic potential for the residential and C&I segments in the IOU territories is broadly reasonable. Our approach for determining solar techno-economic viability and then building on this to identify storage sizing and Resource Adequacy potential is described in the Methodology section.

Local Resource Adequacy Potential - Selected Local and Sub-Local Areas

Local Area	Solar Potential (MWdc)	Energy Storage Potential (MWh)	Resource Adequacy Potential (MW @ 4hr Duration, Limited by Load)	Resource Adequacy Potential (MW @ 4hr Duration, Full ESS Utilization)
LA Basin	14,391	12,886	2,149	2,723
San Diego	4,455	5,570	928	1,194
Greater Bay Area	10,476	8,169	1,294	1,855
San Jose / Moss Landing Sub-Local Area	3,607	2,176	338	498
Pittsburg Sub-Local Area	1,343	1,132	175	261
Oakland Sub-Local Area	348	336	56	67
Greater Fresno	1,687	1,384	241	333
Stockton	1,694	1,357	224	300
Kern	977	754	129	168

² "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment." Pieter Gagnon, Robert Margolis, Jennifer Melius, Caleb Phillips, Ryan Elmore. National Renewable Energy Laboratory, January 2016.

Because the boundaries of local areas change over time, we include for reference the overall resource potential we find in each of the IOUs, indicating the full scale of additional potential that exists should new local reliability needs be identified. A comprehensive modeling approach used for grid planning would incorporate underlying potential across all IOU territory to be used in analysis of evolving local reliability needs.

Customer-Sited Potential by Utility Territory

Utility Service Territory	Solar Potential (MWdc)	Energy Storage Potential (MWh)	Resource Adequacy Potential (MW @ 4hr Duration, Limited by Load)	Resource Adequacy Potential (MW @ 4hr Duration, Full ESS Utilization)
IOU Service Territories	47,781	42,392	6,730	9,245
PG&E	23,347	19,039	2,870	4,086
SDG&E*	4,455	5,570	928	1,194
SCE	19,979	17,782	2,931	3,965

* San Diego Local Area coincides with SDG&E service territory and is reflected in both tables.

Conclusion: Gigawatt Potential to Support Policy and Grid Planning Goals

Customer-sited solar and battery storage across residential and C&I segments can provide upwards of 9,200 MW of Resource Adequacy across California, including 2,515 MW that are enabled by improvements to the CAISO PDR structure to enable RA value for the full capacity of customer-sited batteries. This includes hundreds of megawatts in areas where recent procurements have or are expected to focus on front-of-meter solutions with more limited resilience and customer benefits and that do not necessarily increase the clean energy mix on California's grid.

The mix of resources that will provide reliability on California's grid is too important to ignore a key potential clean resource that can be found at scale in every part of the state. This is especially the case when the *status quo* trajectory suggests that - even as solar and battery storage deployments grow day-by-day through autonomous customer adoption - only a fraction of this potential will be utilized as local reliability through LSE procurement.

Customer-sited resource potential should be evaluated on its ability to serve identified grid needs and should not be discounted in the ability to fully serve local reliability because these resources take a different form than traditional resources. Customer-sited resources and resulting load flexibility must be fully reflected in grid reliability modeling in order to accurately

identify the best path towards a clean, reliable grid for California. And equally importantly, procurement approaches must continually be evaluated on their success in sourcing from the broadest pool of resources to deliver grid reliability in a manner that most cost effectively supports California's broader policy goals. If these steps are taken, the continued growth of customer-sited resources will be properly valued and prioritized, and the role that they can play to support an energy transformation will be more fully realized.

METHODOLOGY STATEMENT

To identify techno-economic potential for customer-sited solar and storage, we sought to identify from building stock databases the sites likely to have energy usage and related characteristics enabling customers to realize savings on their energy costs relative to retail electricity rates given current tariffs and current solar and storage costs. The potential for C&I solar and storage was based on a bottom-up analysis of individual buildings in the Station A platform, and the potential for residential solar and storage was evaluated based on a methodology informed by Station A and applied to a residential building stock and demographic datasets provided by Sunrun.

Given trends towards lower solar and storage costs, it can be assumed that techno-economic potential will increase. In the future, a greater number of the sites that can physically accommodate solar and storage will also see an economic benefit from adopting them.

Building Stock Selection

We started by identifying building stock with the physical characteristics to support solar and storage.

For the C&I segment, we built our analysis on Station A's geospatial dataset, which includes all buildings with a footprint over 10,000 ft² in California, as well as all land parcels in the state.

For the residential segment, we identified building stock potential based on home size by square footage, which was used to estimate energy usage. A minimum square footage threshold was used as a cutoff, below which it was estimated that attractive year one savings from solar and/or solar paired with storage could not generally be achieved. This is based on comparing the levelized cost of solar and storage to the utility retail rates, accounting for minimum bill charges.

Solar Potential per Building

Based on the selected building stock, we applied further restrictions based on the amount of solar that could be installed as well as the potential that physical characteristics would prevent successful solar installation.

At each C&I site, we estimated the maximum technical potential for rooftop solar using industry-standard metrics for perimeter setbacks, roof coverage, and PV energy density. We disallowed solar on sites over 6 stories. We applied a limit to the solar potential based on net energy metering rules, disallowing system sizes that would generate more than 100% of the building's estimated energy usage in a typical year.

We then applied an economic filter. First, we estimated a power purchase agreement (PPA) price for the system based on its estimated cost to build, accounting for policy incentives including the Investment Tax Credit (ITC), its expected annual production, and a rate of return required by the project developer. We then used the building's likely tariff and estimated energy usage to calculate the avoided cost of energy for the building. We only included sites at which the avoided cost of energy was greater than the estimated PPA price for the solar array.

For the residential segment, economic viability of roofs for solar depends on factors such as (a) angling of roof planes for sufficient insolation, primarily based on azimuth (b) roof materials and quality and (c) shading from trees or other structures. Estimates for the percentage of homes of sufficient square footage that meet these criteria of roof suitability were derived for each local area from data in Sunrun's prior evaluation of tens of thousands of homes across California for solar. Sizing for solar was based on observed average solar installations in California of approximately 6.5 kW per home.

Energy Storage Potential per Building

We evaluated energy storage based on the expected electricity bill savings it could provide to customers. This ignores energy storages's resilience value, which may lead customers to adopt energy storage even when it is not economically optimal or to adopt larger energy storage systems than are justified on a pure cost basis. Our energy storage sizing is therefore conservative, especially in the residential segment. Differences in sizing between residential and C&I segments results from the differing tariff structures (Time of Use versus Demand Charges) under which each segment generally receives electricity service.

To calculate energy storage potential in the C&I segment, we assumed that energy storage systems (ESS) could be installed indoors or outdoors. We calculated the technical potential for energy storage indoors and outdoors using industry-standard metrics for ESS energy density, minimum and maximum size limitations, and property line and building setbacks. At each site, we chose either indoor or outdoor installation for energy storage based on potential system size and cost to build.

From the maximum technical potential, we limited the ESS power capacity to 100% of the customer's peak load when paired with solar, and 50% of the customer's peak load when not paired with solar. We assumed all ESS to have a 2:1 ratio of MWh to MW.

We filtered potential ESS sites based on economic criteria. We determined the likely tariff at each building and used it to estimate the electricity bill savings provided by an ESS, modeling savings due to reduced demand charges and due to "energy arbitrage," the process of shifting energy consumption from more expensive time of use periods to cheaper ones. We calculated system cost to build based on system size and whether it was located indoors or outdoors, accounting for policy incentives including the Self-Generation Incentive Program (SGIP). We

filtered out systems that didn't provided sufficient bill savings to meet an ESS developer's required internal rate of return.

Every C&I property was modeled with stand-alone solar, stand-alone storage, and solar paired with storage, and we selected the product combination with the highest savings for the customer. Where solar and storage were sited together, we modeled cost savings from both the ITC and SGIP.

For the residential segment, storage capacity was modeled based on an assumed single ESS size for each home set at 8.8 kWh usable ESS capacity, in line with existing product availability for the residential market. The added levelized cost of an ESS was incorporated into estimates of customer savings, which is diminished in certain cases and leads to storage attachment of less than 100%.

The vast majority of solar systems sized to annual energy usage in California, averaging approximately 6.5 kW, can utilize an ESS of larger size and can be expected to do so in the future. Customers adopting batteries for resilience value might also choose to adopt large batteries. This would have the effect of increasing the Resource Adequacy potential, potentially dramatically so under rules enabling the full capacity of the battery to provide RA value.

Resource Adequacy Potential

Resource Adequacy potential was estimated by modeling a 4-hour discharge of the ESS during CAISO's current Must Offer Obligation period. Local Resource Adequacy will vary, but this measure is used as a starting point.

For the C&I segment, RA capacity was de-rated relative to a 4-hour discharge from installed ESS capacity to account for the expected state-of-charge of the ESS given multiple operating parameters, including demand charge mitigation, energy arbitrage, and solar charging constraints.

For the residential segment, Resource Adequacy potential was estimated by modeling daily discharging of the ESS for 4 hour duration during CAISO's current Must Offer Obligation period, and subsequent recharging of the ESS on the subsequent day via solar. 100% of ESS charging is assumed to come from the paired solar system. Solar insolation was modeled for each hour of the year based on TMY3 data, varying by region of California. The result is a seasonal variation in RA per unit per month that is lowest in winter and highest in summer. The estimate shared reflects the average of all months of the year, underestimating the RA available during California's annual peak in summer. For estimates of RA based on current Proxy Demand Resource rules that limit utilization of storage for RA purposes to coincident hourly load, household load was estimated based on climate zone and the approximate portion of a given Local Area or Sub-Local Area falling into each climate zone.

ABOUT THE AUTHORS

Station A

Station A is a software company offering a platform that provides the insights needed to take any building to zero carbon emissions. The platform connects clean energy developers with building owners and enables them to plan and execute projects. Station A's mission is to enable a carbon-neutral future by scaling and automating the clean energy development process. Station A's customers include the country's leading clean energy developers and technology providers. Users can join the platform today at www.stationa.com.

Sunrun

Sunrun is the nation's largest residential solar, battery storage and energy services company. With a mission to create a planet run by the sun, Sunrun has led the industry since 2007 with its solar-as-a-service model, which provides clean energy to households with little to no upfront cost and at a saving compared to traditional electricity. Sunrun offers a home solar battery service, Sunrun Brightbox, that manages household solar energy, storage and utility power with smart inverter technology. For more information, please visit: www.sunrun.com.

Stem

Stem creates innovative technology services that transform the way energy is distributed and consumed. Athena™ by Stem is the first AI for energy storage and virtual power plants. It optimizes the timing of energy use and facilitates consumers' participation in energy markets, yielding economic and societal benefits while decarbonizing the grid. The company's mission is to build and operate the smartest and largest digitally-connected energy storage network for our customers. Visit www.stem.com for more information.



Barriers to Maximizing the Value of Behind-the-Meter Distributed Energy Resources

California Solar & Storage Association

Scott Murtishaw

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January 2019



Barriers to Maximizing the Value of Behind-the-Meter Distributed Energy Resources

1. Introduction

The California Public Utilities Commission (CPUC) and the California Independent System Operator (CAISO) have developed various programs that allow distributed energy resources (DERs) to compete with traditional generation, transmission, and distribution infrastructure to provide capacity and ancillary services. Customer-sited, or behind-the-meter (BTM), resources can provide multiple grid services at the distribution and transmission levels,¹ but numerous barriers have hindered the efforts of the CPUC and CAISO to enable BTM resources to provide these services. This report builds on several documents that industry stakeholders have produced for staff in the CPUC's Energy Division describing these barriers.²

In this whitepaper, we organize the barriers into five categories:

1. Program Participation Exclusions in Utility Solicitations
2. Lack of Clarity in Demonstrating Incrementality vis-à-vis DER Adoption Forecasts
3. Dual Participation Limits in Demand Response Programs
4. Capacity Credit Limitations and Availability Requirements in Demand Response Programs
5. Prohibitions on Participating in Multiple Utility Programs

This whitepaper provides specific examples within each of the five types, assesses the current regulatory status of each barrier, and suggests options to resolve them.

2. History of DER Participation in Utility Solicitations

Energy efficiency, demand response, and renewable energy have enjoyed favored status at the CPUC since the "loading order" adopted by the CPUC in the wake of the electricity crisis.³ More recently, energy storage has also been added to this list of preferred resources. These resources were usually procured through siloed, resource-specific solicitations and customer incentive programs. The electric

¹ Fitzgerald, Garrett, James Mandel, Jesse Morris, and Hervé Touati. The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid. Rocky Mountain Institute, September 2015. http://www.rmi.org/electricity_battery_value

² "Systematic Barriers to BTM Resources in Local Capacity, DRP, and IDER Procurements." Sunrun, Stem, Engie, AMS and Swell.

Letter to Ed Randolph re NEM, SGIP and Dual Participation exclusions, May 2, 2018. Sunrun, Stem, Engie, AMS and Swell.

Letter to Ed Randolph re need for workshops on RA value of BTM resources and cross-cutting issues, May 2, 2018. Sunrun, Stem, Engie, AMS and Swell.

"ADR Memo." AMS.

"Multiple-Use Applications MEMO." AMS.

³ See <http://www.cpuc.ca.gov/eaps/> for related documents.



utilities were required to procure any remaining new capacity needed to ensure reliability via competitive solicitations. Although some solicitations were nominally open to all new sources, new gas-fired generators met the residual capacity needs in practice.

The era of preferred resources competing head-to-head against gas-fired facilities to provide new capacity began in 2013 with D.13-02-015, which, for the first time, required a utility to procure a minimum amount of storage and other preferred resources to meet a local reliability need. All solicitations following this decision have either been all-source or limited to preferred resources.

In D.13-02-015 the CPUC ordered Southern California Edison (SCE) to procure between 1,400 and 1,800 MW of capacity in the West Los Angeles area to mitigate the expected retirement of several once-through-cooling generation units. Of the required capacity, the CPUC ordered SCE to procure at least 50 MW of storage and 150 MW of other preferred resources, and up to 600 additional MW of either. Due to lack of experience with using storage and other DERs for reliability purposes, the decision required a minimum of 1000 MW of gas-fired resources. A subsequent decision (D.14-03-004) required an additional 500 – 700 MW of capacity to compensate for the closure of the San Onofre Nuclear Generating Station, with at least 400 MW from preferred resources, yielding a combined minimum of 600 MW of preferred resources. In response to these decisions, SCE issued a Request for Offers (RFO) and in late 2014, filed an application for approval of nearly 1,900 MW of capacity. SCE selected a little over 500 MW of storage and preferred resources, of which 400 MW were BTM.⁴

In addition to solicitations for reliability capacity, emerging small-scale solicitation opportunities are occurring as a result of the CPUC's Distribution Resources Plan (DRP) and Integration of Distributed Energy Resources (IDER) initiatives. These proceedings are focused on the use of distributed resources to provide location-specific values such as avoided transmission and distribution capacity. Because the use of the DERs to provide capacity services is still a nascent area, these solicitations have been limited to pilots. A decision from February of 2018 (D.18-02-004) established an ongoing annual process, referred to as the Distribution Investment Deferral Framework, in which the utilities identify specific distribution grid needs over a a ten-year planning horizon and propose solicitations for third-party owned DERs to fulfill those needs where feasible. This decision created the potential for procurement of sizeable amounts of DERs every year, but progress will be substantially hindered if the numerous barriers developers have encountered to date are not resolved.

3. Types of Barriers, Current Regulatory Activity, and Proposed Solutions

Although the CPUC has supported for DERs via several policies and programs, BTM resources have encountered barriers to operationalizing and monetizing their potential value. These barriers can be grouped into the five broad categories listed above. The following sections provide information on individual barriers in each category, discuss the current regulatory status of the barriers, and offer possible solutions.

⁴ The CPUC disqualified 70 MW of demand response since it would have been provided by behind-the-meter gas-fired generation.



3.1 Program Participation Exclusions in Utility Solicitations

Overview

This type of barrier refers to categorical prohibitions on resources participating in utility solicitations if they also receive incentive payments from, or otherwise participate in, one or more other utility programs. These are sometimes referred to in solicitations as “double dipping” provisions.

Some solicitations include general exclusions such as SCE’s Moorpark solicitation, which prohibits receipt of any “Double Incentive.” The solicitation materials define “Double Incentive” as any “rebates, discounts, incentives, low interest loans, or services from any other programs funded or administered by SCE or the CPUC for the same Generating Facility installed at the End-Use Customer’s Site.”⁵ Solicitation materials often contain more specific prohibitions, usually related to the Self-Generation Incentive Program (SGIP) and/or net energy metering (NEM). For example, Pacific Gas and Electric Company’s (PG&E) solicitation for storage capacity in the South Bay-Moss Landing sub-area includes the following language:

At all times during the Delivery Term, the Project must include Units that were installed without using financial incentives under the Self-Generation Incentive Program (“SGIP”) with an aggregate rated capacity of no less than the capacity associated with the Operational Characteristics. The Project may include Units that were installed using financial incentives under SGIP in excess of the capacity associated with the Operational Characteristics, provided that Seller complies with all rules and requirements under SGIP.⁶

Some solicitations prohibit demand response projects from receiving any incentives from the Automated Demand Response (ADR) program. For example, ADR is excluded in SCE’s preferred resources pilot, which also excludes SGIP and NEM.⁷ This is particularly puzzling since ADR is intended to increase the effectiveness of demand response.

The utilities give two different rationales for the prohibition on resources receiving compensation from these programs in addition to any payment for providing distinct services such as generation or distribution capacity. First, exclusions are often predicated on the notion that participating host customers will be overcompensated. This may be expressed as a more general concern, particularly for systems that receive NEM, or may be described as overcompensation for the same service or unduly

⁵ 2018 Moorpark/Goleta RFP Pro Forma Distributed Generation with Energy Storage Purchase and Sale Agreement. pp. 3, 46, A-5.

⁶ PG&E Protocol for the Local Sub-Area Energy Storage RFO: Appendix F2 – Behind-the-Retail Meter Capacity Storage Agreement.” p. 7

https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2018%20Local%20Sub-Area%20Energy%20Storage%20RFO/Appendix%20F2_%20PGE%20Form%20BTM%20CSA%20FINAL%20022718.doc

x

⁷ Second Preferred Resources Pilot RFO Pro Forma: Demand Response Energy Storage Agreement, p. 51



large incentives for a device.⁸ BTM stakeholders broadly agree that developers and customers should not receive overcompensation for the same service, but the utilities' broad interpretation of double dipping fails to distinguish upfront incentives designed to encourage technology adoption and market transformation from payments for specific services. Receipt of an incentive should not preclude DERs from being compensated for providing additional value by committing to certain operational requirements that benefit the grid.

The second rationale is that services from systems receiving compensation from NEM, SGIP and/or other incentive programs have already been incorporated into the utilities' forecasts and are therefore not incremental. This issue is discussed in more detail in the subsequent section on incrementality.

Current Regulatory Status

In Resolution (Res) E-4889, the CPUC indirectly addressed the issue of programmatic prohibitions, in the context of discussing the incrementality of existing resources to provide distribution services. The CPUC stated that it agrees with arguments put forward by Tesla, OhmConnect, and CESA that participation in another program, such as SGIP, demand response, or NEM should not preclude participation in a distribution services solicitation, as long as the bidder can show that the system will be operated in a way that provides an incremental service.⁹ However, the language in the resolution limits the impact of the CPUC's guidance in terms of both the scope and duration of the relief. The pertinent ordering paragraph states only that "*existing* [emphasis added] resources that offer services that do not conflict with the incrementality principles in Decision 16-12-036, should be considered incremental *for the purposes of this pilot* [emphasis added]."¹⁰ A subsequent ruling in the DRP proceeding, acknowledging that further development of the Competitive Solicitation Framework (CSF) governing IDER and DRP solicitations could not be completed until sometime in 2019, extended the guidance from the Res E-4889 to cover the first round of Distribution Investment Deferral Framework solicitations.¹¹

Following the guidance provided in Res E-4889, the utilities did not categorically exclude bids from projects participating in other programs in the IDER pilot solicitations. Instead, they created three categories of incrementality: wholly, partially, or non-incremental. Offers providing DER resources that receive no compensation from any other tariff or program were considered wholly incremental. The utilities categorized projects that already receive compensation under SGIP as "partially incremental" to the extent they can demonstrate additional output during the hours of identified need, but the solicitation materials provided little guidance about how partial incrementality would be determined or quantified.

While the CPUC has begun to address categorical exclusions for distribution capacity purposes, it has yet to apply similar guidance in the Resource Adequacy (RA) program. Despite Res E-4889 and the inclusion

⁸ See for example comments of SDG&E in the MUA WG Draft Report, pp. 46 – 47.

⁹ Resolution E-4889, issued December 19, 2017, pp. 26 – 27.

<http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K961/201961781.PDF>

¹⁰ Resolution E-4889, p. 57.

¹¹ Administrative Law Judge's Ruling on the Application of the Competitive Solicitation Framework for Distribution Investment Deferrals in the Distributed Resources Planning Proceeding, issued November 19, 2018.

<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M240/K044/240044803.PDF>



of terms in the IDER solicitations that allow for participation in SGIP and NEM, solicitations for local capacity continue to include categorical exclusions. Examples include SCE’s Preferred Resources Pilot, SCE’s Moorpark-Goleta solicitation, and PG&E’s South Bay-Moss Landing energy storage solicitation.

An RA proceeding (R.17-09-020) is currently open to determine RA obligations and to consider revisions to RA program rules and capacity accounting methodologies. The proceeding has been divided into three tracks. Neither track 1 nor track 2 currently has refinements to programmatic barriers or incrementality within their scope, but the scoping ruling for the proceeding allows parties to propose program modifications in track 3, which has not yet begun.

Proposed Solutions

The CPUC should clarify in the IDER proceeding that receipt of an “incentive,” such as SGIP, NEM or ADR, does not automatically disqualify resources, whether new or existing, from consideration or selection in an RFO process or any other resource procurement mechanism, including tariffs, if the resource can provide additional services. The CPUC should clarify that the intent of Res E-4889 is to allow for participation in other programs and should explicitly extend this provision to cover new resources as well. Although the November 19 DRP ruling extended the guidance beyond the IDER pilots, a full CPUC decision would provide clearer, and more permanent, resolution of this issue. A similar policy is needed in the RA proceeding to provide equivalent treatment to BTM resources offering reliability capacity.

3.2 Lack of Clarity in Demonstrating Incrementality vis-à-vis DER Adoption Forecasts

Overview

The second type of barrier is the lack of clarity concerning the incrementality of BTM resources, which will likely be the barrier with the greatest long-term impact. Currently, the solicitation processes for generation reliability and distribution-level services fail to provide a detailed, explicit methodology that enables bidders to confidently establish the incrementality of their projects. Incrementality was a central concern in the IDER CSF Working Group and continued to be a controversial topic in the MUA Working Group that was formed in the storage procurement proceeding, R.15-03-011.

As D.16-12-036, which adopted the CSF, explains, the CSF Working Group could not come to consensus on a single incrementality methodology. Consequently, the WG put forward five different approaches for the CPUC’s consideration.¹² Rather than selecting a single approach, the CPUC allowed each utility, in consultation with the Distribution Planning Advisory Group, to select one or more of the approaches and include the proposal in its advice letter to conduct the pilot solicitation. As requested by the utilities in their respective advice letter filings, the CPUC approved the use of a hybrid of methods 4 and 5 for SCE and PG&E and the use of method 4 for SDG&E.¹³

Method 4 is referred to as a “tranche analysis” that examines whether, in light of expected baseline growth of the DERs in the project area, resources bid into the solicitation are already wholly or partially

¹² Decision 16-12-036, pp. 9 - 10.

¹³ See Resolution E-4889 and Resolution E-4956.



sourced through another channel. The method categorizes resources into three broad groups: DERs not already sourced, partially sourced (e.g., addition of new component or functionality to an existing resource), or wholly sourced through another channel. Resources in tranche 1 would generally be considered incremental. Those in tranche 2 may be considered incremental but only by the amount of the added functionality. Resources in tranche 3 would not be considered incremental. In effect, Method 4 is a “capacity incrementality” analysis that focuses on the forecast of the physical capacity of specific DER and whether a bid would induce additional capacity not embedded in the forecast. Method 5 extends the analysis by adding an element of “operational incrementality,” evaluating the specific attributes of DER operations to determine if the services may be incremental even if the DERs per se are not. For example, the operator of a storage system that is already installed may agree to make it available for dispatch during certain hours in which it would not normally be expected to discharge.¹⁴

While conceptually these approaches may seem reasonable, they require more detail to provide the certainty the market needs. In practice, bidders have contended with a large degree of subjectivity about the process for determining incrementality. For the IDER pilot solicitations, SCE included a one-page table, referred to as the Incrementality Matrix, that was the sole source of guidance to bidders for demonstrating the incrementality of their bids.¹⁵ While the matrix provides helpful examples of bid types that would fall into each of the three categories, it is far from exhaustive, and the none of the solicitation materials indicated the amount of partial credit that a partially incremental resource would receive.

Some progress has been made in terms of identifying the issues to be resolved and providing high level guidance about how to define and quantify incrementality, but the CPUC must adopt guidelines that require the utilities to disclose a greater level of detail. Bidders need detailed information regarding two aspects of the incrementality evaluation: 1) the utility’s planning assumptions for the anticipated business-as-usual adoption and utilization (e.g. timing of battery charging and discharging) of each type of DER and 2) the criteria by which utilities will judge whether bidders successfully demonstrate that their projects provide incremental services vis-à-vis the business-as-usual assumptions.

Methodologies must not only be more explicit, they should also be consistent across the utilities to facilitate market participation. While SCE has provided an incrementality matrix for its IDER solicitations, SDG&E disagrees in part and stresses that incrementality must be assessed on a case-by-case basis.¹⁶

In contrast to the limited progress on incrementality in IDER, there is currently no guidance regarding incrementality of BTM resources for generation capacity solicitations. Solicitation materials and stakeholder comments have referred to the incrementality guidelines adopted in IDER for distribution services, but they are not binding on generation capacity solicitations. For example, in a recent solicitation for storage to provide capacity in the Aliso Canyon area, SCE’s incrementality guidance

¹⁴ Competitive Solicitation Framework Working Group Report, pp. 26 - 30.

<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M166/K471/166471224.PDF>

¹⁵ SCE Advice Letter 3620-E-C Supplemental Filing. <https://www1.sce.com/NR/sc3/tm2/pdf/3620-E-C.pdf>

¹⁶ Multiple-Use Applications for Energy Storage: Final Working Group Report, p. 43.

<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M233/K836/233836260.PDF> (see Appendix A)



consisted of one page with a table taken from its IDER pilot incrementality matrix.¹⁷ The schedule for the solicitation provided no opportunity for bidders to receive feedback from SCE regarding its incrementality determination and provide additional information to address SCE's concerns.

Current Regulatory Status

As noted above, Res E-4889 discussed the implementation of incrementality principles and found that the utilities had to consider the incrementality of additional services offered by existing resources. The scoping ruling from September 1, 2016 describes that as part of the creation of the CSF for distribution services, two objectives of the proceeding are to develop "methodologies to count services provided, ensuring no duplication or double counting" and "solicitation rules or principles."¹⁸ It is not clear when the next opportunity will arise to revisit the incrementality methodology and solicitation disclosure requirements. The DRP decision on Growth Scenarios and the Distribution Investment Deferral Framework refers to an anticipated proposed decision in IDER in 2018 addressing these issues, but the CPUC has yet to issue a ruling soliciting input on these issues.¹⁹ Based on conversations with CPUC staff, this process may not begin until after the utilities file the first of their IDER pilot evaluation reports, which will focus on the solicitation process and which are due 90 days after the CPUC's approval of the pilot project contracts. SDG&E filed its report in November,²⁰ SCE's report is due in early 2019, and PGE's will not be due for several more months. Because the utilities submitted the first round of distribution deferral opportunities before the review of incrementality and other CSF issues could occur, the assigned administrative law judge in the DRP proceeding issued a ruling requiring the utilities to explain how the solicitations conform to the CSF guidance from D.16-12-036 and Resolution E-4889.²¹

The incrementality issue for generation capacity is not currently scoped into the RA proceeding, but the scoping ruling for the proceeding suggests that additional issues could be scoped into the proceeding in Track 3 at the suggestion of parties.

Incrementality has been a core issue in the MUA Working Group. However, the CPUC has closed the proceeding that established the Working Group, and it is not clear how the Working Group report will influence policy in either a successor storage proceeding or other proceedings. Moreover, the MUA Working Group's findings are focused exclusively on storage, not the full range of DERs.

Proposed Solutions

In order to extend consistent incrementality guidance to reliability capacity procurement, the CPUC should explicitly scope incrementality into Track 3 of the current RA proceeding. The RA and IDER

¹⁷ Aliso Canyon Energy Storage 2 Request for Offers: Participant Instructions Version 1 August 31, 2018, Attachment F. https://www.sce.com/sites/default/files/inline-files/2018ACESRFO_Instructions.pdf

¹⁸ Amended Scoping Ruling of Assigned Commissioner and Assigned Administrative Law Judge, issued September 1, 2016, p. 4.

¹⁹ Decision 18-02-004, p. 70.

²⁰ Report of San Diego Gas & Electric Company (U 902 E) Concerning Streamlined Competitive Solicitation Framework and Utility Regulatory Incentive Mechanism Pilot.

²¹ Administrative Law Judge's Ruling on the Application of the Competitive Solicitation Framework for Distribution Investment Deferrals in the Distribution Resource Planning Proceeding, issued November 19, 2019. <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M240/K044/240044803.PDF>



proceedings should coordinate closely, with a joint workshop to develop incrementality methodologies. Both proceedings should incorporate the IDER pilot solicitation reports of SCE and SDG&E and the MUA WG report into their records to draw from a common base of understanding. These materials could serve as the basis for party proposals regarding DER forecast transparency and the determination of incrementality, leading to a proposed decision in late 2019. It will be important to have a final decision out before the end of 2019 to inform procurement activities resulting from the utilities' next round of solicitations from the Distribution Investment Deferral Framework. While DER providers would prefer clear and consistent incrementality methodologies, as an interim measure incrementality for RA purposes should be determined on an ad hoc basis using the conceptual frameworks developed in the IDER proceeding.

3.3 Capacity Credit Limitations and Availability Requirements in Demand Response Programs

Overview

The third category of barriers relates to demand response program methodologies and restrictions that constrain BTM resources from receiving credit for the full amount of capacity they can provide. These limitations are a function of both CAISO and CPUC rules and the interconnection tariffs used for participation in DR programs. Four specific barriers fall under this rubric: restrictions on counting net exports in the calculation of the capacity delivered, the zeroing out of any net energy consumed by storage in the baseline methodology, a 24/7 availability requirement in one of the programs, and asymmetric compensation structures for electricity exported to the grid. We describe each of these barriers in greater detail below.

In order to receive explicit RA credit, BTM resources must participate in a qualifying supply-side demand response program, either CAISO's PDR or Reliability Demand Response Resource (RDRR). Participation in certain utility-run demand response programs that are integrated into PDR or RDRR also count for RA.²² However, the CAISO PDR and RDRR tariffs do not recognize for capacity purposes, and thus do not compensate, any energy exported to the grid from behind the retail meter.

When PDR and RDRR were under development, CAISO designed them to fit the traditional demand response model based on load curtailment. No provision for potential export of energy was envisioned. Moreover, no process existed for the distribution utility to confirm to the CAISO that exported energy would not be constrained by distribution-level congestion or outages. This is not problematic for traditional DR providers who are simply curtailing their loads. For commercial customers using only BTM storage, this constrains the potential size of an installation, limiting the capacity these resources can provide to the grid. For residential customers, however, the rated discharge capacity of standard storage

²² "Load-modifying" resources that do not participate in PDR may receive implicit RA credit once they are reflected in the Energy Commission's Integrated Energy Policy Report forecast, which forms the basis for RA obligations. If a load-serving entity were to devise a new program to incentivize the use of BTM DERs to reliably reduce load, it may not affect its RA obligation for three or four years.



systems often exceeds typical daytime instantaneous demand.²³ The constraint is exacerbated for customers with on-site solar because discharge of a battery for a demand-response event could occur during hours that the solar PV system is already exporting or could, in combination with solar generation, result in exported electricity. Any exports are ignored by CAISO, diminishing the capacity credited to the demand response provider.

In theory, DERs that export can participate in the wholesale market by interconnecting under the Wholesale Distribution Access Tariff (WDAT), which allows compensation for exports. WDAT, which is FERC-jurisdictional, typically involves longer, more complex, and more costly impact studies than the CPUC-jurisdictional Rule 21, which prohibits exports to the grid, with the exception of NEM generators. Nonetheless, even with WDAT interconnection, the PDR and RDRR tariffs must still be revised for CAISO to recognize exports from DR providers as part of the load response and compensate DR providers accordingly.

Another PDR and RDRR program barrier stems from CAISO's baseline methodology. CAISO uses a "10-in-10" baseline to measure the amount of load reduction in a given hour for which a DR provider receives credit. Under this methodology, the counterfactual, or expected, load that the actual load is compared to is based on average consumption during the previous 10 non-event days, with a day-of adjustment factor. CAISO rules currently allow PDR participants to measure load drop at either the retail meter or at a separate meter that can more accurately measure the change in output from a BTM resource. The second approach is referred to as Metered Generator Output (MGO). Many participants would prefer to use MGO in order to more accurately capture how BTM resources changed their operations in response to DR events.

Unfortunately, when CAISO approved the MGO methodology, it adopted an adjustment to the baseline that often narrows the difference between actual output and the baseline, generating less credit for the customer. The MGO adjustment does this by setting any hour during the baseline period in which the battery was charging to 0. The table below illustrates how this methodology can harm customers who charge during the baseline-setting non-event days. Recorded net discharges over the course of an hour are shown as positive numbers and charges are shown as negative numbers. For the sake of simplicity, the example assumes no "day-of" adjustment.

Baseline Setting for Customers with and without Charging During Previous 10 Non-Event Baseline (BL) Days

	BL 1	BL 2	BL 3	BL 4	BL 5	BL 6	BL 7	BL 8	BL 9	BL 10	AVG	EVENT	CREDIT
Customer 1	0.5	0.5	0.7	0.7	0.5	0.6	0.4	0.4	0.6	0.6	0.55	1	0.45
Customer 2	0.5	-0.5	0.7	0.7	0.5	-0.6	0.4	0.4	0.6	0.6	0.33	1	0.67
Customer 2, adj	0.5	0.0	0.7	0.7	0.5	0.0	0.4	0.4	0.6	0.6	0.44	1	0.56

In this example, Customer 1 and Customer 2 both have 1 MW storage systems. Customer 1 never charges during this interval in the previous 10 non-event days. The average discharge during the non-

²³ A typical household draws about 2 kW of electricity at any given time. By contrast, the Tesla Powerwall has a rated capacity of 5 kW. https://en.wikipedia.org/wiki/Domestic_energy_consumption



event days is 0.55 MWh. During the event day, the customer maximizes the discharge to 1 MWh and receives credit for the difference of 0.45 MWh. Customer 2's operational profile is very similar, except that on two of the 10 non-event days, the battery charged during this hour. The average discharge is 0.33 MWh. Like Customer 1, Customer 2 maximizes discharge during the event. Compared to the actual average usage of the battery, Customer 2 should receive credit for reducing load by 0.67 MWh. However, because the electricity used for charging on two of the baseline days was zeroed-out (as shown on the bottom row), Customer 2 only receives credit for a 0.56 MWh load reduction.

CAISO recently adopted a new load-shift product for BTM storage referred to as the Proxy Demand Response-Load Shift Resource (PDR-LSR).²⁴ This product, like the existing PDR program, enables storage resources to receive capacity credit and energy payments for dispatching when called by CAISO but adds the opportunity for storage to be paid for charging during negative pricing periods in the wholesale market. In developing this product, CAISO modified the 10-in-10 baseline used in PDR. In the PDR-LSR version, individual intervals in which charging occurs are not set to zero, but the if more charging than discharging occurs over the 10 intervals, the resulting negative average is set to zero. Although more analysis of real-world data is needed to understand the extent to which the revised baseline may still under-credit capacity, simply adopting the same approach for PDR would greatly improve the under-crediting of capacity in that program.

As an alternative to PDR and RDRR, DER aggregators can interconnect under WDAT and register with CAISO as a Non-Generator Resource (NGR). The NGR process allows storage systems or aggregations of storage systems (in front of or behind the meter) to participate in the energy and ancillary services markets. Under NGR, storage systems can export electricity to the grid, but the aggregated resources must receive a concurrence letter from the distribution utility stating that any potentially exported energy is deliverable. Despite wholesale market participation, NGR resources are currently ineligible to receive RA credit because the CPUC has not approved a process for that purpose. Moreover, resources registered as NGRs are "participating generators" that are subject to 24/7 availability, which precludes most prospective multiple uses from any given unit of storage capacity.

Another disincentive for BTM participation as an NGR is that exported energy is likely to result in financial losses for the customer. This happens because BTM storage devices pay twice for the energy used for charging, once at the retail rate and again at the wholesale rate. When batteries discharge to serve onsite load, the customer effectively receives both wholesale compensation, via a direct payment from CAISO, and retail compensation, via avoided purchases of retail energy. In contrast, exported energy does not receive any retail rate credit. Thus, participating NGRs lose money on any exported electricity.

Current Regulatory Status

In addition to the guidance on incrementality, Res E-4889 also stated that projects that export from BTM should not be a priori excluded.²⁵ However, the resolution noted that there may be "jurisdictional or

²⁴ See <http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=97C3E62B-ECDB-4CCC-AC3D-98263F57F5E4>.

²⁵ Resolution E-4889, pp. 36, 50, 58.



regulatory barriers” that could prevent the utilities from selecting such contracts. In order to ensure that exports from BTM resources are eligible to supply distribution or generation capacity, it would be simplest to integrate them into the existing DR construct. This would require CAISO to revise the no-export rule in PDR and RDRR and work with the distribution utilities on a process to verify deliverability of exported energy. CAISO has no active stakeholder process to consider revising the no export rule, to adopt the revised PDR-LSR baseline for PDR, or a use-limited resource exception to the 24/7 availability requirement for NGRs, nor does the CPUC have any active forum to consider retail rate credits for electricity exports from NGRs.

Proposed Solutions

CAISO should count exported electricity when measuring the total response in its DR tariffs. Participants who either interconnect under WDAT or who have NEM-paired storage devices and interconnect under Rule 21 should be eligible to export. This would require making a small change to the PDR and RDRR tariffs and submitting them for approval at FERC. Alternatively, the CPUC could explore whether jurisdictional or regulatory barriers could be avoided if the export from BTM is limited to providing energy, and the associated capacity, to the utility or other load-serving entity (i.e. not integrated in the CAISO market). This approach may require modifications to Rule 21 to allow for other forms of compensated exports other than NEM where the retail provider is the off-taker. The New York Public Service Commission has explicitly allowed this for distribution deferral “non-wires alternatives,” allowing export from BTM storage without crossing into federal jurisdiction. As another option, the CPUC could grant RA credit to BTM resources that participate in NGR, but without reforms to the availability and asymmetric compensation barriers, it would be of limited practical value.

The simplest barrier to resolve is the MGO baseline, which only requires CAISO to take comment on a proposed rule change and submit a revised tariff to FERC. CAISO has already established a precedent for an improved baseline methodology in the PDR-LSR program.

For multi-use applications and energy storage to be feasible, CAISO would need to create a carve-out for use-limited resources (as the PDR program allows) to exempt them from the 24/7 availability requirements that otherwise apply to participating generators. In order to eliminate the financial penalty associated with exports in NGR, the CPUC must also approve retail tariffs that ensure customers either only pay wholesale rates for the stored energy used for wholesale dispatch, by exempting them from paying the retail rate for the energy consumed by BTM battery systems to provide exports for wholesale dispatch, or receives a retail rate credit for energy exported by BTM battery systems.

3.4 Dual Participation Limits in Demand Response Programs

Overview

The fourth barrier concerns dual participation rules within the demand response program. These rules were established to prevent DR participants from receiving double compensation for the same load drop. At a high level, the relevant decision states that a single customer can enroll in only one energy program and one capacity program, and one day-of program and one day-ahead program. However, there have been disputes about exactly which programs are energy and which are capacity, and DR dual



participation rules have not been updated to take into consideration the Multiple Use Application (MUA) framework that was developed for energy storage resources. Existing dual participation rules were developed before DR resources were integrated into the wholesale market and before the DRP and IDER Proceedings were opened to enable DERs to provide distribution-level services as well as wholesale market services. Consequently, the DR Dual Participation Rules apply a blanket prohibition on a customer participating in two programs that are deemed incompatible even though storage allows for differentiation of the battery capacity to provide different services from different portions of the battery. Additionally, customers providing DR from both flexible loads and on-site storage could differentiate between those two sources of DR.

As one example, customers participating in CAISO's Proxy Demand Response (PDR) to supply capacity either through the Demand Response Auction Mechanism or a local capacity solicitation are prohibited from participating in any other DR program because this would run afoul of the dual participation rule prohibiting participation of the same capacity in two capacity-based programs. However, some storage providers would like to work with customers who are interested in, or might already be enrolled in, the reliability-driven Base Interruptible Program (BIP), which requires customers to reduce load to a predetermined Firm Service Level on thirty minutes notice. Participation in both PDR and BIP could be enabled by storage capacity differentiation or load/battery differentiation.

Current Regulatory Status

An amended scoping memo issued in May in the DR applications proceeding (A.17-01-012, et al.) identified dual participation as an important unresolved policy issue that should be addressed. In November, the CPUC, noting that the only option currently available for customers to participate in two DR programs is a combination of Critical Peak Pricing with one of a few different day-of capacity programs, indefinitely suspended the ability for new customers to dual participate, although existing customers may maintain the ability to dual participate only to the extent that they remain on their existing programs.²⁶

Proposed Solutions

The CPUC should consider opening a new proceeding to holistically address dual participation and other issues identified by the MUA Working Group and referenced above. As noted in D. 18-11-029, some aspects of the multiple-use of battery storage are beyond the scope of the current DR proceeding.²⁷

3.5 Prohibitions on Participating in Multiple Utility Programs

Overview

The third barrier is the prohibition on customers receiving related incentives from two different programs, primarily the ADR incentive program and SGIP. When the CPUC first established the ADR incentive, it was envisioned to support traditional demand response via load curtailment. Until recently, however, the CPUC had provided no guidance regarding whether customers could receive both ADR and

²⁶ Decision 18-11-029, pp. 13 – 23, 85 – 87, 96 – 97, 102.

²⁷ D.18-11-029, pp. 22, 87.



SGIP incentives, with SGIP supporting installation of basic battery hardware and battery management software and ADR funding enhancements to allow the energy storage systems to respond to ADR signals. While SCE and SDG&E included “double dipping” contract terms in the ADR program that forbade participating customers (or their agents) from having received, applied for, or ever applying for incentives for “the same product, equipment, or service” from SGIP “or any other similar program,” PG&E did not. Industry stakeholders agreed that SGIP and ADR incentives shouldn’t be used to pay for the same equipment, but SCE’s and SDG&E’s categorical exclusions on participation in both programs did not allow participants to demonstrate that the incentives for each program would be used for different equipment.

Current Regulatory Status

In a recent decision, the CPUC directed the Director of the Energy Division to establish a stakeholder process to address the issue of battery storage participation in ADR.²⁸ The utilities are ordered file a proposal that covers several questions related to the types of battery controls that should be eligible, including how to ensure that the same control equipment does not receive incentives from two different programs. The utilities’ proposals are due April 15, 2019. The decision stipulates that until the CPUC adopts final guidance in response to the proposals and stakeholder comments, utilities shall not provide ADR incentives for any battery storage controls, regardless of whether the storage system has participated in SGIP.

Proposed Solutions

The CPUC has established a process to resolve the SGIP and ADR dual participation issue. As a result of this process, the CPUC should move quickly to approve lists of ADR-eligible equipment types that are distinct from the energy storage system equipment covered by SGIP.

4. Conclusions

Behind-the-meter DERs have the potential to provide a wide array of services to customers and the grid, but numerous barriers impede the provision of their full value. In this whitepaper we have described a framework for categorizing these barriers into five types. Many of the barriers are cross-cutting, implicating multiple policy areas at the CPUC as well as the CAISO. Above, we identified the specific proceedings where these issues have been addressed in the past and suggested next steps to resolve the barriers.

As an alternative, the CPUC could open a new proceeding that would holistically consider each of these barriers (with the exception of the ADR exclusion on SGIP for which the CPUC has recently launched a stakeholder process) as well as interrelations among them. Consolidating these issues in one procedural venue may help the CPUC coordinate among the various policy areas touched on by these barriers, including SGIP, NEM, demand response, resource adequacy, IDER, and multiple-use applications for storage. To the extent this approach risks delaying further action on addressing incrementality in IDER, there will be a trade-off between holistic and piecemeal approaches.

²⁸ Decision 18-11-029, pp. 58 – 61, 93, 100, 107 – 108.