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

California Solar & Storage Association

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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

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[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.

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[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

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[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.docx

[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 that 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

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[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

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[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.

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