BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 21-10-002 (Filed October 7, 2021)

JOINT DER PARTIES REPLY COMMENTS

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I. Introduction

Pursuant to the December 2, 2021 *Assigned Commissioner's Scoping Memo and Ruling*,[1] the Joint Distributed Energy Resource (DER) Parties[2] offer these reply comments to both respond to specific contentions made by several parties, and to revise portions of our original Proposal.[3] Certain critiques of the Proposal raised by parties are either incorrect, take aspects of the Proposal out of context, or argue for a lengthy, expensive, and circuitous process for which there is no venue. These contentions can generally be categorized as relating to: process, use case, or proposal-specific issues. These reply comments address these issues in this order. In addition, redline revisions providing further clarifications and updates to the Proposal are appended to these comments as Attachment A.

Seven parties actively support the Joint DER Parties' Proposal and recommend its adoption by the California Public Utilities Commission (Commission): Advanced Energy Economy (AEE),[4] Solar Energy Industries Association (SEIA),[5] and Center for Energy

[1] R.21-10-002, *Assigned Commissioner's Scoping Memo and Ruling* (December 2, 2021).
[2] The Joint DER Parties, for purposes of this filing, are: California Solar & Storage Association (CALSSA), California Energy Storage Alliance (CESA), Enel X North America, Inc. (Enel), and Sunrun Inc. (Sunrun). The Joint DER Parties have authorized Sunrun to file these reply comments on their behalf.
[3] R.21-10-002, *Joint DER Parties Implementation Track – Phase 2 Proposal* (January 21, 2022) ("Proposal").
[4] R.21-10-002, *Opening Comments of Advanced Energy Economy on Joint DER Parties Implementation Track – Phase 2 Proposal* (February 14, 2022) ("AEE Comments").
[5] R.21-10-002, *Comments of the Solar Energy Industries Association on Phase 2 Issues Related to the Resource Adequacy Program* (February 14, 2022) ("SEIA Comments").

Efficiency and Renewable Technologies (CEERT),[6] in addition to the four original proponents, CALSSA, CESA, Enel, and Sunrun. As SEIA points out, behind-the-meter (BTM) clean resources represent a "major" and valuable new resource "that could be tapped to increase the dispatchable capacity available to the RA program over the next decade."[7] Establishing a Qualifying Capacity (QC) value for these resources is an important and urgent issue to resolve within this proceeding, and subsequent implementation issues can be appropriately scoped and addressed in related venues after a QC value is determined by the Commission.[8]

At various points during the facilitated working group sessions and as evidenced in opening comments, some parties such as Southern California Edison Company (SCE) have raised questions about the export capacity potential that could be realized through this proposal, attempting to cast doubt on whether this process is worthwhile. In light of the state's near- and mid-term system capacity shortfalls in both normal and extreme weather conditions, as well as challenges in meeting local capacity needs with clean and preferred resources, BTM hybrid and energy storage resources play a vital role in addressing these needs by leveraging the built environment. Yet, the capacity potential of these resources is limited under current constructs focused on load reductions, where BTM hybrid and energy storage resources are not valued for the additional capacity potential that could be provided—but is not—when customer load is minimal or zero.

To illustrate in a very simple example and in terms of order of magnitude, there is currently 715 MW of installed BTM energy storage capacity today, according to Rule 21 interconnection data, and we estimate that up to 96.4 MW of capacity potential is stranded by load limitations from existing deployments alone.[9] Going forward, the 2021 Integrated Energy

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[6] R.21-10-002, *Opening Comments of Center for Energy Efficiency and Renewable Technologies on Phase 2 Proposals* (February 14, 2022) ("CEERT Comments").
[7] SEIA Comments, p. 2.
[8] *Id*., p. 3; AEE Comments, p. 6.
[9] *California Distributed Generation Statistics*, *available at* https://www.californiadgstats.ca.gov. *See also Gigawatt-Scale Customer-Sited Potential: Achieving California Energy Policy Goals, Grid Reliability and Local Resilience*, Station A, Sunrun, and Stem (March 2019), https://files.stationa.com/docs/Gigawatt-Scale%20Customer-Sited%20Potential.pdf. With an average duration of two hours and calculating a four-hour QC equivalent of 357 MW, Station A estimates that 27% of capacity is stranded because of export restrictions, which was calculated based on load modeling. The study assumes that the average person would use 73% of their storage capacity to serve onsite load in PDR events. However, 27% would be unused due to lack of onsite load, which would be the additional average amount enabled by exports. On average, the 715 MW of BTM energy storage installed today under Rule 21 has an average duration of two hours, translating to 357 MW of equivalent four-hour

Policy Report (IEPR) forecasts up to 42,900 MW of BTM energy storage will be installed by 2035 in the "Medium Storage Adoption/Medium Electric Demand" case,[10] which could translate to 6,507 MW of additional capacity provided by exports if resource adequacy (RA) constructs were developed to recognize and value exports.[11] While more robust estimates could be developed and produced, it should be clear and obvious from this back-of-the-envelope math alone that the stranded potential or missed opportunity from not enabling exports through a capacity valuation is significant. In fact, such basic estimates may be *undervaluing* the additional capacity potential via exports because a forward QC methodology would inform smart decisions around designing BTM hybrid and energy storage resources to co-optimize around exports and customer load reductions, not just load reductions alone. That is, rather than sizing the energy storage system in either hybrid or standalone configuration in line with minimum customer load to determine a reliable and consistent level of load-reducing RA that could be provided under a Proxy Demand Resource (PDR) model, sizing and design of storage devices could be co-optimized for grid needs as well as a result of the recognition, valuation, and compensation of export capacity.

In short, there should be no doubt about the urgency and importance of addressing the eight barriers enumerated in Commission Decision (D.) 21-06-029 and adopting the Proposal submitted by the Joint DER Parties. The export capacity potential is significant and aligns with the Commission's urgent need for clean and flexible resources at both the system and local levels. Continued deferral of these issues can and should be avoided.

II. Process-Related Issues

Some parties assert that specific threshold matters must be addressed prior to the adoption of a QC value, such as deliverability, incrementality, visibility, measurement and verification, performance requirements and penalties, and jurisdictional issues around energy settlements.[12] While many of these issues are addressed in our Proposal with clear

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capacity. We understand that the translation of a two-hour duration to a four-hour duration is not 1-to-1 for QC purposes since there are retail uses and because the actual capacity delivered would be subject to customer load profiles and onsite customer needs, but this estimation is merely intended to demonstrate an order of magnitude of the potential.

[10] *2021 Integrated Energy Policy Report Volume IV*, p. 25 (February 17, 2022), *available at* https://www.energy.ca.gov/publications/2021/2021-integrated-energy-policy-report.

[11] *See supra* n. 9 for explanation of estimation methodology used.

[12] R.21-10-002, *Comments of Pacific Gas and Electric Company on Phase 2 Proposals and Workshop*, pp. 3-4 (February 14, 2022) ("PG&E Comments"); R.21-10-002, *Opening Comments of Southern*

recommendations, the RA proceeding is not the appropriate venue to scope and resolve all relevant barriers to operationalizing BTM DERs in the RA framework. In fact, several issues are within the jurisdiction of other agencies and cannot be solved by the Commission.

As AEE correctly observes, "there exists an element of circular reasoning among the agencies that *must* be broken to catalyze meaningful progress on exporting BTM DER barriers to RA."[13] Issues must be sufficiently and directionally addressed to allow the Commission to adopt a QC value and/or methodology. The Joint DER Parties' Proposal does that, and offers a path forward. It is not necessary, as Pacific Gas and Electric Company (PG&E) claims, to fully evaluate each participation model; the Commission has given clear direction in the 2020 and 2021 RA decisions, D.20-06-031 and D.21-06-029, that:

> [A] capacity value should be determined after the underlying issues are addressed and after the Commission has determined that BTM resources will be providing incremental, reliable capacity benefits[14]; and
>
> The Commission reiterates that a viable proposal must address the eight issues previously enumerated in D.20-06-031.[15]

Nowhere in D.21-06-029 or D.20-06-031 did the Commission require or direct that the issues enumerated in D.20-06-031 be *fully resolved* before a QC value for BTM hybrid or storage resources can be considered. Many of the issues listed by the Commission in both decisions, and consequently addressed in our Proposal, are outside of the scope of the RA docket, and even outside the jurisdiction of the Commission. There is absolutely no good reason to engage other Commission dockets or agencies to conduct the work necessary to realize the recommendations relating to these issues, *unless* and *until* a QC value, incrementality rules, and must-offer obligation (MOO) are adopted by the Commission. Each of these three items is within the direct jurisdiction and scope of this proceeding.

By the same token, establishing a QC valuation methodology is a necessary preliminary step to prompt action in other fora to fully resolve several issues identified by the Commission. The Joint DER Parties seek forward movement in this docket as a way to avoid the chicken-and-

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California Edison Company on Phase 2 Proposals and Workshop, pp. 7-8 (February 14, 2022) ("SCE Comments").

[13] AEE Comments, p. 10.

[14] D.21-06-029, p. 54.

[15] *Id*., p. 55.

egg problem that has continually impeded the ability of these resources to contribute to state capacity needs.

The Joint DER Parties thus urge the Commission to break this cycle and adopt a QC methodology, MOO, and incrementality guidance specific to exporting BTM DERs' participation in RA, in this docket. The specific proposals for each of these items were originally submitted by the Joint DER Parties on January 21, 2022, and some have been revised as reflected in Attachment A hereto.

SCE[16] recommends an impartial process to resolve issues while San Diego Gas and Electric Company (SDG&E)[17] offers recommendations for "further examination." Practically speaking, it is unclear what exact process(es) these two utilities would seek to further examine these issues. The Joint DER Parties note that, apart from a joint agency workshop in November 2020, the Commission has not elected to take on these issues, nor have its sister agencies. The task has been left entirely to parties to develop.[18] The Joint DER Parties have duly taken on the task to identify recommendations to the agencies' barriers and issues. In the course of this work in this proceeding—spanning approximately seven months and including four workshops to date—the Joint DER Parties have addressed the issues as impartially as possible, engaged a diverse set of stakeholders in workshops, provided notes and informal comment opportunities, incorporated productive feedback, and now compiled a comprehensive Proposal reflecting this work. In particular, the workshops we have held to date have enjoyed participation by California Energy Commission (CEC) and California Independent System Operator (CAISO) staff regarding issues in their respective jurisdictions, as well as engagement from the Commission's Energy Division. The Joint DER Parties appreciate, and encourage, engagement by the agencies. We do not recommend, at this stage, an entirely new agency-led process that would reinvent the work and discussions to date. Instead, it is now time for the Commission to recognize the significant work done to address the underlying issues previously identified, and adopt the Proposal recommendations to make incremental progress on the BTM resource barriers that are within its jurisdiction.

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[16] SCE Comments, p. 7.

[17] R.21-10-002, *San Diego Gas & Electric Company Comments on Implementation Track – Phase 2 Proposals*, pp. 2-3 (February 14, 2022) ("SDG&E Comments").

[18] *See* D.21-06-029, p. 55 ("Parties may undertake a working group to develop a proposal that addresses the concerns raised by the Commission here.").

III. Use Case Clarification

The Joint DER Parties' Proposal is focused on the CAISO's Distributed Energy Resource Provider (DERP) model, as it is an available market participation model that accounts for BTM resource exports. We remain open to a PDR model that accounts for exports, but unless and until PDR is modified to account for capacity contribution beyond load reduction only, it is not the subject of this Proposal. Furthermore, representatives from the CAISO clarified during the stakeholder-led working group process that revising the PDR model to account for exports would be a significant effort.

With that said, many of the issues that we cover in the Proposal, including submetering, deliverability, and incrementality, are relevant to exporting BTM resources regardless of whether they participate through the DERP model or through a revised PDR model. Thus, there is no reason to identify one model as the most viable, as the barriers and recommendations remain the same.

PG&E's recommendation[19] that the BTM working group process include a full exploration of BTM projects realizing proxy RA value through load reductions and reducing a load serving entity's (LSE) future RA obligation, *prior* to the Commission undertaking further efforts on this issue, should be rejected. The Joint DER Parties have addressed this issue multiple times in working group meetings, individual meetings with the investor-owned utilities (IOUs), and in our Proposal. We also note that the Commission recognized the shortcomings of this pathway in D.21-06-029.[20] To be considered a load modifying resource, DER aggregations must have a predictable load profile and consistently operate during monthly system coincident peak load days from 4-9 PM. These resources may not be dispatched to respond to system events. This is not similar, as PG&E suggests, "to how the resources would be dispatched as part of the RA program."[21]

First, the Commission's prior "bifurcation" decisions (*e.g.*, D.15-11-042) must be revisited to develop a load-modifying pathway that enables the types of DER operations that respond to "market-informed" events. The "bifurcation" policy originated in the Demand Response (DR) proceeding, so it is not appropriate for an RA proposal or decision and is out of

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[19] PG&E Comments, pp. 3-4.
[20] D.21-06-029, pp. 52-53.
[21] PG&E Comments, p. 3.

scope. Second, the Joint DER Parties' Proposal is responsive to D.21-06-029, which identified barriers applicable to DERs participating as supply-side RA resources. Third, the CAISO has repeatedly expressed that any capacity value for BTM resources must be supply-side and market-integrated.[22]

IV. Proposal-Specific Issues

A. Forward Qualifying Capacity Determination

The Joint DER Parties originally recommended that the QC methodology for BTM hybrids and storage be set equivalent to their in-front-of-the-meter (IFM) counterparts initially. That QC would then be modified based on incrementality considerations and deliverability, for a net qualifying capacity (NQC) value, akin to other resources. While the Joint DER Parties believe that a resource's contribution to reliability does not fundamentally change based on its point of interconnection—*i.e.*, whether or not the resource is co-located with a customer's load—we reframe our Proposal here to address concerns with IFM and BTM equivalence.

In lieu of an ex ante calculation of RA capacity, as is done today for IFM hybrids and storage or DR resources using the Load Impact Protocols (LIP), the Joint DER Parties recommend that a resource's QC be accepted based on its contracted capacity, reflective of the resource's capabilities and inclusive of penalties for any shortfall for non-performance. In offering a resource into capacity procurements, a provider is inherently motivated to ensure that any predetermined amount of battery capacity reserved for customer resiliency, along with any incremental battery activity during the dispatch period, is properly accounted for, as described below. A provider is also on the hook for delivering the amount of capacity it is contracted for, and it will thus seek to include a margin of excess above the overall obligation of the aggregation to ensure that its capacity obligations are always met. Contracts for resource capacity would also cover the availability requirement for the resources, whether it is at least four hours of duration, as is the case today, or for a subset of hours or "slice" under a future "slice of day" (SOD) framework.[23]

Providers have a strong disincentive to exhaust their customers' battery capacity, or to allow customers to adjust their event participation or battery operations on their own, as

[22] *See* R.21-10-002, *Opening Comments on Workshop and Proposals of the California Independent System Operator Corporation*, p. 2 (February 14, 2022) ("CAISO Comments").
[23] PG&E Comments, p. 4.

cautioned by PG&E.[24] Allowing for either to occur will result in very unhappy customers. Control over daily battery dispatch, including event response for customers enrolled in capacity programs, is a key feature of the optimization that vendors provide to their customers. Battery customers are not simply left to manage California's complex rate structure, and unit dispatch on their own—this is done for them. The variability and unpredictability of customer behavior for a BTM storage device, as a physically backed asset separate from direct customer load, is far less than for traditional forms of DR. The Joint DER Parties have addressed this issue, extensively, in working group meetings with parties.

The contract-based approach recommended here is consistent with the approach established in other organized markets such as PJM and New York Independent System Operator (NYISO), and in the Commission's Demand Response Auction Mechanism (DRAM). It is also one of the "interim" DR QC approaches recommended by the CEC's Supply-Side DR working group.[25] Similarly, contract capacity can be used for IFM hybrid and energy storage systems that either commit resources for capacity deliveries less than the QC-based counting methodology or facilitate multiple-use applications (MUAs).[26] To the same ends, other resource types, such as imports, recognize the use of contract capacity.[27] Taken together, the Joint DER Parties believe that contract capacity should not be a foreign concept in the RA Program, and it can be readily adopted to BTM hybrid and energy storage resources. We detail our recommendations for ex post retail capacity settlement in the next section.

B. Wholesale Market Participation: Metering, Dispatch Control, and Communication

The Joint DER Parties continue to recommend the elimination of this issue from the Commission's list of barriers. Instead, the Commission should focus on the topics of requiring

[24] PG&E Comments, p. 5.
[25] R.21-10-002, *Administrative Law Judge's Ruling on Loss of Load Expectation Study and Supply-Side Demand Response Report, and Setting Comment Schedule*, Appendix B: Incentive-Based "PJM/NYISO" Approach, PDF pp. 36-40 (February 18, 2022).
[26] *See, e.g.*, D.21-06-029, p. 26 ("although net qualifying capacity (NQC) values are based on four-hour dispatch, we note that a 4-hour storage resource may be shown in Category 2 on RA filings for half of its NQC value."). This demonstrates how contract capacity can be used for compliance purposes for the RA Program, which could be similarly extended for BTM hybrid and energy storage resources that account for incrementality, deliverability, and MUAs. *See also* D.18-01-003, Appendix A (Rules 6 and 8 specify how MUAs can be enabled and realized through contracts for services as well as the enforcement of rules).
[27] *See, e.g.*, D.20-06-028, Ordering Paragraph 3.

submetering for retail capacity settlement, as well as enhanced protocols for deliverability at the transmission and distribution interface in the future. The CAISO's opening comments do not change our recommendation. The Joint DER Parties recognize that the Federal Energy Regulatory Commission (FERC) has not yet approved the CAISO's Order No. 2222 compliance filing, as the CAISO points out.[28] However, the Joint DER Parties' intent in including the CAISO's quotes from their Order 2222 filing was to reflect the current provisions of the CAISO's tariff, which also apply to customer resources providing RA under the PDR model. The cited language was not included, nor ever characterized, as a "broad statement"[29] of all that the CAISO may desire in the future. Whether the CAISO desires greater visibility or protocols for DER Aggregation (DERA) resources providing RA or not, it has not yet, to the Joint DER Parties' knowledge, sought those tariff modifications in its Order No. 2222 compliance filing or otherwise. Thus, the Joint DER Parties did not misstate the CAISO's current requirements nor its public statements about those requirements. If the CAISO wishes to have more visibility into customer resources providing RA, it may seek that visibility through its stakeholder initiative process, or otherwise in modifications to its tariff or business practice manuals.

We turn to the topic of retail capacity measurement and settlement. The Joint DER Parties had originally recommended that the IOUs employ the same submetering protocol and processes as are developed for the Emergency Load Reduction Program (ELRP) per D.21-12-015.[30] Since the submission of our Proposal, the IOUs have submitted their joint advice letter for implementation of the ELRP,[31] which does not specify a submetering protocol or other relevant requirements for ELRP. Thus, we modify our recommendation for retail capacity settlement to mirror the method of measurement and settlement already in place in the CAISO tariff for storage-backed DR resources in the CAISO wholesale market, the meter generator output (MGO) methodology.[32]

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[28] CAISO Comments, pp. 6-7.
[29] *Id.*, p. 6.
[30] *See* D.21-12-015, Attachment 2, pp. 14-15.
[31] PG&E Advice Letter 6485-E, *et al.*, Attachment A, p. 15 (January 31, 2022) (PG&E proposes that "[t]he baseline method may be used with submetering once the CPUC has approved submetering protocols.").
[32] *CAISO Business Practice Manual for Demand Response*, Section 5.1 (April 1, 2020), https://bpmcm.caiso.com/BPM%20Document%20Library/Demand%20Response/BPM_for_Demand_Response_V3_clean.pdf.

Two modifications that the Joint DER Parties recommend to the MGO methodology and baseline adopted by the CAISO are 1) to *not* zero out exports (*i.e.*, storage discharge that exceeds host-site load), and 2) to *not* zero out lookback intervals when the storage device is charging. Given that this methodology will be used for exporting BTM storage and hybrids using the DERP model, or PDR model if amended in the future to allow for exports, any exported energy *must* be included in settlement. And, while storage charging during peak-time hours on non-event days may be more expensive than charging during off-peak hours, this does not justify artificially reducing a storage device's event performance by only recognizing storage stand-by or discharging in the baseline.

The MGO baseline on battery output adopted by the CAISO evaluates event performance based on a selection of prior non-event days in comparison to battery performance in the same hours as the event dispatch, which captures storage discharge for routine usage such as demand charge management. Contrary to PG&E's assertion,[33] no comparison to customer load or subtractive billing is necessary with this approach. The BTM storage or hybrid system generates and/or discharges power to serve the customer's load first. It therefore follows that any BTM DER *output* displaces an equivalent amount of energy served by the grid, which in turn creates a commensurate reduction in customer demand at the utility meter. In other words, the onsite storage still offsets a customer's load to the benefit of the grid, even if that customer needed to purchase additional incremental energy from the grid. This includes scenarios where the site load (as measured at the retail meter) increases relative to non-event days: the grid would be tasked with serving any portion of the site load that the on-site battery does not cover, but this does not diminish the event-day performance of the battery itself.

The only Commission requirement for IFM generating and storage facilities is settlement quality meter data based on actual measurement. We recommend the same for BTM resources. Submetering standards can be specified (accuracy, applicable testing and certification standard) in implementation.[34] Metering data management and settlement issues do not need to be fully addressed in this docket, beyond acceptance of a reasonable measurement method consistent with that used for the wholesale market.[35] Data management and settlement can be addressed as

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[33] PG&E Comments, p. 7.
[34] SDG&E Comments, p. 6.
[35] PG&E Comments, p. 7.

an implementation matter, with the Commission providing guidance and making determinations as a policy matter.

C. Incrementality

Given our proposed modifications to the QC methodology and measurement, the Joint DER Parties make one modification to our incrementality proposal, which is to remove changes to the QC methodology based on whether or not a customer takes NEM. This revision is reflected in Attachment A. Even with this modification, the Joint DER Parties maintain that in order for NEM systems to participate in a DERA, the Commission must approve a NEM tariff that may be used for wholesale market transactions; further, we note that our Proposal did, in fact, address NEM compensation incrementality,[36] despite claims to the contrary.[37] We respond here to critiques of aspects of our incrementality proposal.

SDG&E correctly asserts that Self-Generation Incentive Program (SGIP) and NEM system incrementality hinges on "dispatch requirements" and "material enhancement[s]."[38] However, these requirements essentially consist of commitment to a supply-side RA contract, wholesale market participation, and, in the case of NEM systems, storage-coupling in order to enable dispatchability. Each of these would always be true in the context of our Proposal.

Second, PG&E disagrees that double compensation concerns associated with the SGIP, Solar on Multifamily Affordable Housing (SOMAH) Program, and Multifamily Affordable Solar Housing (MASH) Program should be eliminated outright, and recommends that these issues be explored once there is a near-final framework to confirm that double-compensation issues do not exist.[39] The Proposal specifies that these programs do not present double compensation concerns *insofar as* they do not require dispatch in accordance with system needs.[40] This is consistent with prior Commission decisions and is precedential. While we support review of program requirements to avoid double counting, PG&E should not attempt to relitigate matters previously settled by the Commission here.

Third, with regard to load forecasting, PG&E incorrectly argues that the Joint DER Parties conflate load forecasting incrementality and double compensation.[41] This is not true: the

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36 Proposal, pp. 41-43.
37 PG&E Comments, p. 7; SDG&E Comments, p. 3.
38 SDG&E Comments, pp. 7-8.
39 PG&E Comments, p. 7.
40 Proposal, pp. 41-42.
41 PG&E Comments, p. 4.

issues are handled separately in the Proposal and are not conflated. Several parties assert that the Proposal does not sufficiently address double counting concerns in supply and load forecast.[42] The Joint DER Parties have recommended that forecasts be adjusted for actual DER supply-side contracting, and have had positive discussions with the CEC to address data needs in the forecasting process. As a practical matter, this topic is out of scope for the Commission and this docket, and must be addressed by the CEC in the next IEPR cycle. Further, and importantly, there is no reason for the CEC and parties to engage in the process of determining data requirements and process for identifying supply-side BTM resources used in a wholesale market aggregation, in the absence of a QC methodology from the Commission. Thus, we reiterate our recommendation that the Commission set the QC methodology first, and then work with parties and the CEC to alleviate any concerns regarding double counting in the CEC's forecast.

D. Cost for Energy

There was limited comment on this aspect of the Joint DER Parties' Proposal, which discussed some of the complexities of wholesale versus retail differentiation regarding the cost for energy and recommended an interim approach to assess all charged energy at retail until accounting mechanisms can be developed in the future to enable such differentiation. Only the CAISO responded with two points, and based on our review, these comments can be readily addressed and thus did not result in any revisions to our Proposal on this topic.

First, CAISO argues that retail rates and incentives may derate the expected QC value for BTM hybrid and energy storage resources.[43] The Joint DER Parties agree and have never argued to the contrary since our original Proposal recommended the use of contract capacity to account for retail uses. Even with the QC being based on the equivalent methodology for its IFM counterparts as a starting point, the Joint DER Parties explained that the actual capacity count for these resources would be "derated" based on contracted capacity to account for dedicated onsite customer needs (*e.g.*, resiliency) and to reflect any incrementality or deliverability determinations. In other words, given that these resources would be subject to RA incentives and penalties, the aggregator or DER provider would already derate their capacity when contracting with LSEs, only contracting for an amount that they can reliably and consistently

[42] *See* R.21-10-002, *Comments of Calpine Corporation on Phase 2 Proposals and Workshop*, p. 1 (February 14, 2022) ("Calpine Comments"); SCE Comments, p. 11.
[43] CAISO Comments, p. 4.

deliver in accordance with MOOs and in co-optimizing against retail rates and incentives. It is incumbent on the aggregator or provider to determine the right contract capacity amount, and as a result, the Joint DER Parties do not see an issue as we understand the CAISO's concerns. As discussed in Section IV.B above and in our revised Proposal on QC methodology, the net QC value incremental to any retail or typical usage would be reflected in the direct storage output metering and baselining approach.

Second, the CAISO argues that economic dispatch based on market and grid conditions is needed to avoid undue preference per the Federal Power Act and California law.[44] The Joint DER Parties agree and proposed a contractual means to achieve these ends.[45] Even though we propose maintaining retail rate treatment for all charging energy, BTM hybrid and energy storage resources would be exposed to wholesale price signals, with the RA contract netting out any energy settlements to avoid double charging or compensation of retail and wholesale rates. However, it is unclear how our Proposal would proffer BTM hybrid and energy storage resources with undue preference, especially when we consider storage-backed PDRs that do not face wholesale prices on the charge side. DERPs, by contrast, are capable of both charging and injection and would still face wholesale price signals for both charge and discharge, in addition to being subject to RA MOOs and requirements, which ensures that they are responsive to market and grid conditions.

E. Deliverability Determination

The Joint DER Parties identified current barriers to the deliverability determination of BTM hybrid and energy storage, and recommended clarifications on the applicability of the current distributed generation deliverability (DGD) study criteria and modifications to the current deliverability study and allocation process to accommodate BTM aggregations. Comments on the Proposal related to deliverability determination generally suggest that existing study criteria and processes, with some modifications or clarifications, can readily apply to BTM hybrid and energy storage resources, although these specific modifications or clarifications will need to be taken up in other initiatives or proceedings. These comments demonstrate that the issue of deliverability determination is a surmountable barrier that can be further developed and

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[44] *Id*.

[45] *E.g.*, PG&E's Long-Term RA Agreement with Energy Settlement (LTRAA-ES) contract. *See* Proposal, pp. 38-40.

refined in the appropriate CAISO and Commission venues upon the Commission adopting our proposed QC methodology for BTM hybrid and energy storage resources.

First, the CAISO explains that the existing process already allows for BTM DERs to be studied for deliverability and that the issue is a matter of coordination with utility distribution companies (UDCs) on how much deliverability should be reserved for DERAs.[46] This is a welcome insight on which the Joint DER Parties sought clarification in our original Proposal; it is now reflected in our revised Proposal. Specifically, the Joint DER Parties understand the CAISO's clarifications as affirming that the aggregations of BTM resources "behind" the DGD node will be studied for deliverability as an aggregated total, similar to how multiple IFM generation and storage projects would be studied. As a result, although parties pointed to the lack of a deliverability study methodology for BTM aggregations in the past in workshop and working group processes in Rulemaking 15-03-011, the CAISO has affirmed that nothing would need to be changed within the DGD deliverability study methodology.

Second, along the same lines that this barrier is a matter of coordination among the resource procurement and transmission and distribution planning processes, SDG&E commented that the DGD process focuses on allocation for existing deliverability (not new upgrades)[47] and that LSE interest to guide policy-driven deliverability assessments does not provide the locational certainty needed.[48] The Joint DER Parties agree but do not find the issues to represent insurmountable barriers to realizing deliverable export capacity from BTM hybrid and energy storage resources. As discussed in our initial Proposal, leveraging the existing DGD process can only go so far in adapting the deliverability allocation process if such capacity exists on the transmission grid. For this reason, it will be important to foster a process that enables the identification and allocation of proactive deliverability upgrades via policy-driven deliverability assessments. On the transmission side, such location granularity, however, is unlikely necessary,[49] whereas on the distribution side, this issue is something that should be addressed in

[46] CAISO Comments, pp. 5-6.
[47] SDG&E Comments, p. 10.
[48] *Id*., pp. 11-12.
[49] SDG&E's proposed use of the distribution planning process (DPP) is unclear since the DPP utilizes the disaggregated CEC IEPR forecast, such that any distribution upgrades are identified and built based on load or DERs embedded in the forecast. By contrast, this Proposal focuses on supply-side DERs that seek deliverability and upgrades if incremental to this forecast, or after adjusting this forecast. As such, the proposed use of the DPP is unclear and not sufficiently explained or specified.

the relevant interconnection-related docket at the Commission—a point that SCE discusses as well.[50] Overall, these comments point to the need for follow-up work at the Commission and CAISO to refine these proposals, but we stress again that the resolution of these issues does not need to occur as a threshold matter prior to the Commission's adoption of a QC methodology. If the Commission followed SCE's process, the circular logic would apply, and the question of "whether developing a deliverability assessment methodology and process for DERAs is worthwhile" would again be raised in the absence of a Commission-established QC methodology.

Third, SCE asserts that the Wholesale Distribution Access Tariff (WDAT) is still applicable for distribution service, even if Rule 21 can apply for interconnection.[51] The Joint DER Parties disagree since our Proposal does not involve any net FERC-jurisdictional sale of energy through the proposed energy settlement structure, but notwithstanding these jurisdictional questions, we emphasize how our broader Proposal still holds merit regardless of whether WDAT or Rule 21 applies in one case or the other. All in all, our analysis in developing the deliverability-related proposal, combined with the comments submitted by CAISO and others, underscores how existing processes can be refined or modified to accommodate the unique deliverability considerations of BTM hybrid and energy storage resources. Considering the utilities have previously expressed how the WDAT and Rule 21 studies and processes are designed in ways to largely mirror each other, any proposals developed related to deliverability determination could be adapted and applied to either the WDAT or Rule 21 contexts. In other words, whether WDAT or Rule 21 applies is important, but this question should not deter the Commission from making key policy determinations in this proceeding, and then subsequently addressing this issue in more detail in the relevant forum at FERC or the Commission.

Finally, in response to the Joint DER Parties' conceptual proposal around decoupling System and Local RA for BTM hybrid and energy storage resources, SDG&E commented that Local RA requirements are a result of constraints on the CAISO transmission system, making the Proposal unworkable.[52] We clarify that our main proposal does not hinge on the decoupling of System and Local RA for the purposes of deliverability, but future discussions should be held on

[50] SCE Comments, pp. 9-10.
[51] *Id*., p. 10.
[52] SDG&E Comments, p. 13.

whether this concept could be developed further, recognizing that BTM hybrid and energy storage resources will likely be developed to meet an LSE's local reliability requirements. From a power flow perspective as well, the exports from a DERA are likely to be consumed by local load rather than being exported to the bulk electric system. This may not always be the case, but in locations for DER aggregations where there is excess hosting capacity, the exports will likely be consumed locally such that a system deliverability study and allocation process could lead to upgrades that are not necessary and would lead to excessive costs to procure these resources. We thus do not dispute the nature of local capacity requirements but instead highlight the potential for local DERs to serve local load where excess hosting capacity is available, which could support more timely and less expensive deployment of BTM hybrid and energy storage resources. In developing this approach, the Joint DER Parties do not view local or system reliability to be impacted, though it could impact the fungibility of BTM hybrid and energy storage as RA resources and therefore the ability to substitute for this capacity if required by the LSE. In sum, we still strongly advocate for this approach as a high-potential follow-up consideration in the Commission's RA proceeding, in coordination with the CAISO's initiatives.

V. Conclusion

For the foregoing reasons, the Joint DER Parties urge the Commission to adopt the recommendations in the revised Proposal attached hereto as Attachment A.

Respectfully submitted,

/s/ Rachel McMahon
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Dated: February 24, 2022

Attachment A

Revised Proposal of the Joint DER Parties

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 21-10-002 (Filed October 7, 2021)

JOINT DER PARTIES REVISED IMPLEMENTATION TRACK – PHASE 2 PROPOSAL

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Dated: ~~January 21~~February 24, 2022

TABLE OF CONTENTS

GLOSSARY OF TERMS

AAHs	Availability Assessment Hours
ANOPR	Advanced Notice of Proposed Rulemaking
BPM	Business Practice Manual
BTM	Behind-the-Meter
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CCA	Community Choice Aggregator
CEC	California Energy Commission
CIP	Capital Investment Project
COD	Commercial Operation Date
Commission	California Public Utilities Commission
CPUC	California Public Utilities Commission
D.	Decision
DA	Day-Ahead
DAM	Day-Ahead Market
DER	Distributed Energy Resource
DERA	Distributed Energy Resource Aggregation
DERP	Distributed Energy Resource Provider
DERPA	Distributed Energy Resource Provider Agreement
DGD	Distributed Generation Deliverability
DPU	Massachusetts Department of Public Utilities
DR	Demand Response
DRAM	Demand Response Auction Mechanism
DRP	Demand Response Provider
DRP-A	Demand Response Provider Agreement
EDC	Electric Distribution Company
ELCC	Effective Load Carrying Capability
ELRP	Emergency Load Reduction Program
ES	Energy Storage
ESDER	Energy Storage and Distributed Energy Resource
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
ICA	Integrated Capacity Analysis
IDER	Integrated Distributed Energy Resources
IEPR	Integrated Energy Policy Report
IFM	Integrated Forward Market
IFOM	In-Front-of-the-Meter
ILR	Incremental Load Reduction
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
ISO	Independent System Operator

KW	Kilowatt
kWh	Kilowatt-Hour
LCR	Local Capacity Requirement
LIFO	Last-In First-Out
LIP	Load Impact Protocol
LRA	Local Regulatory Authority
LSE	Load-Serving Entity
LTRAA-ES	Long-Term Resource Adequacy Agreement with Energy Settlement
MASH	Multifamily Affordable Solar Housing
MGO	Meter Generator Output
MOO	Must-Offer Obligation
MUA	Multiple-Use Application
MW	Megawatt
NEM	Net Energy Metering
NGR	Non-Generator Resource
NQC	Net Qualifying Capacity
NRI	New Resource Implementation
O&M	Operations and Maintenance
PBI	Performance-Based Incentive
PDR	Proxy Demand Response
PG&E	Pacific Gas & Electric
PV	Photovoltaic
QC	Qualifying Capacity
R.	Rulemaking
RA	Resource Adequacy
RAAIM	Resource Adequacy Availability Incentive Mechanism
RMR	Reliability Must Run
RTM	Real-Time Market
RTO	Regional Transmission Operator
RTP	Real-Time Pricing
RUC	Residual Unit Commitment
SC	Scheduling Coordinator
SCE	Southern California Edison
SCME	Scheduling Coordinator Metered Entities
SGIP	Self-Generation Incentive Program
SOD	Slice-of-Day
SOMAH	Solar on Multifamily Affordable Housing
SQMD	Settlement Quality Meter Data
Sub-LAP	Sub-Load Aggregation Point
T&D	Transmission and Distribution
TAC	Transmission Access Charge
TPD	Transmission Plan Deliverability
UCAP	Unforced Capacity

UDC	Utility Distribution Company
V2G	Vehicle-to-Grid
VEE	Validation, Estimation, and Editing
VPP	Virtual Power Plant
WDAT	Wholesale Distribution Access Tariff

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

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 21-10-002 (Filed October 7, 2021)

JOINT DER PARTIES REVISED IMPLEMENTATION TRACK – PHASE 2 PROPOSAL

I. INTRODUCTION

Pursuant to the December 2, 2021 *Assigned Commissioner's Scoping Memo and Ruling*,[1] the Joint DER Parties[2] submit this Implementation Track – Phase 2 Proposal in Rulemaking 21-10-002.

A. Background

The Joint DER Parties[3] submitted proposals in September 2020 and January 2021, focused on establishing a methodology for dispatchable storage and storage hybrid resources located behind-the-meter (BTM) to qualify for resource adequacy.[4]

[1] R.21-10-002, *Assigned Commissioner's Scoping Memo and Ruling* (December 2, 2021). All acronyms in this report and proposal have the meaning set forth in the Glossary of Terms.
[2] The Joint DER Parties, for purposes of this filing, are: California Solar & Storage Association (CalSSA), California Energy Storage Alliance (CESA), Enel X North America, Inc. and Sunrun Inc. The Joint DER Parties have authorized Sunrun Inc. to file this Proposal on their behalf.
[3] The Joint DER Parties, for purposes of prior filings, have included the California Energy Storage Alliance, California Solar & Storage Association, EDF Renewable Energy, Enel X North America, Inc., SunPower, Sunrun Inc., and Tesla.
[4] R.19-11-009, *Resource Adequacy Track 3.A Proposal of the California Energy Storage Alliance, Sunrun, Inc., Enel X North America, Tesla, and Center for Energy Efficiency and Renewable Technologies Pursuant to the Assigned Commissioner's Amended Track 3.A and Track 3.B Scoping Memo and Ruling* (September 1, 2020) and *Track 4 Proposal of Sunrun Inc., California Energy Storage Alliance, California Solar & Storage Association, Tesla, Inc., Center for Energy Efficiency and Renewable Technologies, Vote Solar, and Enel X North America, Inc.* (January 28, 2021) ("Track 4 Proposal").

The driving force behind these proposals is the inadequacy of the currently prescribed process for calculating resource adequacy (RA) value for BTM resources, which is the load impact protocol (LIP). The LIP was designed for, and adheres to, a strict load reduction methodology which does not account for exports to the grid beyond customer host load. The current LIP guidelines severely undervalue energy storage's contribution. The Joint DER Parties believe that there is a need for a new measurement paradigm.

Per existing California Independent System Operation (CAISO) rules and participation models, the Distributed Energy Resource Provider (DERP) model is best suited for BTM assets that also export to the grid. However, this model is not currently utilized primarily because BTM resources do not have a qualifying capacity (QC) methodology, and thus may not receive compensation for their capacity. This report and proposal seek to rectify this barrier.

The annual decisions in the 2020 and 2021 RA proceedings, D.20-06-031 and D.21-06-029, included a list of issues to be addressed prior to developing a QC value for BTM storage and hybrids:

1) Forward determination of capacity associated with renewable production, consumption, charging, and export,
2) RA requirements associated with customers providing capacity,
3) Wholesale market participation including metering, dispatch control, and communication with CAISO,
4) Cost for energy associated with consumption, charging, and export,
5) Changes such that net energy metering (NEM) and self-generation incentive program (SGIP) resources are compensated for capacity, while discounting for their NEM and

SGIP compensation as necessary to ensure that the resources do not receive compensation beyond their value,

6) Load forecasting and adjustment for BTM resources,

7) Interaction of such resources with existing BTM resources such as proxy DR, and

8) Deliverability determination.[5]

D.20-06-031 also stated that*:*

> [A]ddressing these issues will require consideration and coordination in multiple Commission proceedings and CAISO stakeholder initiatives. However, the Commission remains interested in the possibility of increasing value for BTM hybrid resources. The Commission will request CAISO and CEC participation in a joint public workshop later this calendar year to plan the joint agency steps necessary to establish NQC [Net Qualifying Capacity] values for hybrid BTM storage/solar resources with the goal of counting these resources in the RA program.[6]

The workshop referenced in this decision was held on November 24, 2020, and presentations were made by leaders and key staff of the CAISO, California Energy Commission (CEC), and California Public Utilities Commission (CPUC or Commission).[7] The discussion was robust and many issues, existing solutions, and future potential pathways were discussed. However, further efforts toward achieving the objective of BTM virtual power plant (VPP) resources providing resource adequacy capacity have stalled.

D.21-06-029 reiterated the list of eight issues first enumerated in D.20-06-031 and that a capacity value should be determined "... after the underlying issues are addressed and after the

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[5] R.19-11-009, *Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program*, p. 32 (June 25, 2020) ("D.20-06-031").
[6] D.20-06-031 at 33.
[7] Capacity Valuation for BTM Hybrid Resources Workshop (November 24, 2020) ("November 2020 BTM Workshop"). See workshop materials linked at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history.

Commission has determined that BTM resources will be providing incremental, reliable capacity benefits."[8] This Decision also affirmed the Commission's commitment to "addressing the challenges outlined above and exploring options to better leverage the capabilities of BTM distributed energy resources" and authorized the creation of this working group to address these issues.[9] It is our hope that this proposal provides the necessary context to move forward.

The Commission previously found that the "market informed" pathway[10] referenced in past Joint DER Parties' proposals was insufficient. Specifically, D.21-06-029 cited the need for more robust dispatch criteria that ensures reliable dispatch and performance, a measurement and verification mechanism, penalty structure and reflection in forecast,[11] as required by D.15-11-042, to bestow out-of-market, "load-modifying" resources with a capacity value. Further, the CAISO has made clear that it will not count any resource that is not in its markets toward a load-serving entity's (LSE) resource adequacy obligations.[12] This stance from CAISO may effectively preclude this pathway from consideration by the CPUC. Even if the CPUC were to revisit the criteria adopted in D.15-11-042 pertaining to load-modifying resources and adopt strong dispatch criteria and other program features to ensure reliability of market informed resources the Joint DER Parties are concerned that the CAISO would not count the resource, effectively risking double procurement. Thus, this proposal focuses on the "market integrated" pathway for BTM storage and hybrid resources.[13]

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[8] R.19-11-009, *Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program*, p. 54 (June 24, 2021) ("D.21-06-029").
[9] D.21-06-029 at 55.
[10] Track 4 Proposal at 4-5.
[11] D.21-06-029 at 53.
[12] *See* R.19-11-009, *CAISO Reply Comments on Track 3.A Proposals*, pp. 1-2 (September 18, 2020).
[13] Track 4 Proposal at 5-8.

That said, D.21-06-029 notes that "LSEs are free to reduce their peak loads in any way they choose. If deployment of BTM resources reduces an LSE's monthly peak load, it will consequently become embedded in the load forecast and reduce the LSE's RA requirement for the following year."[14] Because event-based, "load-modifying" resources (essentially the type of "market-informed" resource dispatch the working group would envision) have no capacity value per D.15-11-042, the only way that DERs are able to reduce an LSE's RA requirement under the CEC's forecasting process is to pursue a type of "permanent load shifting" to the CEC through consistent battery cycling and peak shaving throughout the year.

B. Development of Proposal

In formulating this proposal, the Joint DER Parties looked back to prior working group reports, relevant policy discussions, and regulatory activity. This report incorporates those prior findings, and updates them, as applicable. Examples include, but are not limited to:

- Federal Energy Regulatory Commission (FERC) Order 2222;[15]
- CAISO compliance filing with FERC Order 2222;[16]
- Multiple Use Application Working Group report, submitted to Rulemaking (R.) 15-03-011 in August 2018;[17]
- Gridworks' report on Transmission-Distribution Interface in 2017;[18]

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[14] D.21-06-029 at 55.
[15] *FERC Order No. 2222*, 172 FERC ¶ 61,247 (September 17, 2020), *available at* https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf ("FERC Order No. 2222").
[16] Federal Energy Regulatory Commission, Docket No. ER21-2455, *California Independent System Operator Corporation Tariff Amendment to Comply with Order No. 2222* (July 19, 2021), available at http://www.caiso.com/Documents/Jul19-2021-TariffAmendmentoComplywithFERCOrderNo2222-ER21-2455.pdf ("CAISO FERC Order 2222 Filing").
[17] R.15-03-011, *Multiple-Use Applications for Energy Storage: Final Working Group Report* (August 9, 2018) ("MUA Working Group Report").
[18] Gridworks, *Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid* (June 2017), available at http://gridworks.org/wp-content/uploads/2017/01/Gridworks_CoordinationTransmission.pdf ("Gridworks T&D Paper").

- Presentation slides from November 24, 2020 workshop on DER capacity valuation; and[19]
- Decisions and rulings from several Commission dockets, including but not limited to: Integrated Distributed Energy Resources (IDER), and SGIP.

The Joint DER Parties held ~~three~~four public meetings to discuss the contents of this report - both the treatment of the eight barriers articulated by the CPUC and the Joint DER Parties' proposals, on December 21, 2021, January 4, 2022, ~~and~~ January 11, 2022, and February 8, 2022. We received useful feedback at each of these meetings from the three state energy agencies, utilities, and other stakeholders. Feedback from these discussions has been integrated into this proposal. This proposal and its contents and assumptions are our own and, even with this feedback, do not represent the views of any party that has participated in these discussions. The Joint DER Parties ~~currently have three~~will schedule at least one additional public ~~meetings scheduled, for January 28, 2022, February 8, 2022 and February 22, 2022.~~meeting in the near future.

C. Barriers Identified by the CPUC

Several issues identified by the Commission should be addressed as part of the work to increase the value and better leverage the capabilities of BTM storage and hybrid resources. We recommend that the list of issues presented in D.20-06-031 and reiterated in D.21-06-029 be modified and some issues reconceptualized to better enable constructive discussion and progress to resolve issues and move forward with this effort. The table below summarizes our reconceptualization, which is reflected in the following discussion.

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[19] Capacity Valuation for BTM Hybrid Resources Workshop (November 24, 2020), https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy/energy_programs/electric_power_procurement_and_generation/procurement_and_ra/ra/official-btm-workshop-slides.pdf ("November 2020 BTM Workshop Slides").

Table 1: Reconceptualization of Eight Barriers

Barrier from D.20-06-031 / D.21-06-029	**Relevance**	**Replacement issue, if applicable**
Forward determination of capacity associated with renewable production, consumption, charging, and export.	Relevant, with reframing.	QC methodology and associated recommendations to align with Slice of Day reform, if adopted.
RA requirements associated with customer providing capacity.	Undefined and relevance unclear, customers provide capacity load resources now under Proxy Demand Response (PDR).	Proposals: Must-offer obligations, Availability Assessment Hours / Slice of Day, supply plan showings.
Wholesale market participation including metering, dispatch control, and communication with CAISO.	Metering and dispatch control addressed in existing CAISO tariff. Communication or visibility may be relevant, with reframing. Retail capacity settlement must be addressed.	Visibility and communication at the transmission-distribution interface for significant DER Aggregation (DERA) penetration; and permit use of submetering for retail capacity settlement.
Cost for energy associated with consumption, charging, and export.	Only relevant for standalone and/or grid-charging storage, and not solar-only charged storage.	Sale for resale associated with standalone BTM storage. Also, distribution service to access the wholesale market during deliveries, which is covered in the FERC jurisdictional WDAT.
Changes such that NEM and SGIP resources are compensated for capacity, while discounting for their NEM and SGIP compensation as necessary to ensure that the resources do not receive compensation beyond their value.	Relevant, with reframing.	RA incrementality framework for services and NEM.
Load forecasting and adjustment for BTM resources.	Relevant and primarily within jurisdiction of the CEC.	N/A
Interaction of such resources with existing BTM resources such as PDR.	Not relevant.	Remove from list of barriers.
Deliverability determination	Relevant & within jurisdiction of CAISO.	Leveraging and streamlining the existing DG Deliverability study framework.

II. EIGHT BARRIERS IN D.20-06-031 & D.21-06-029

A. Forward Capacity Determination

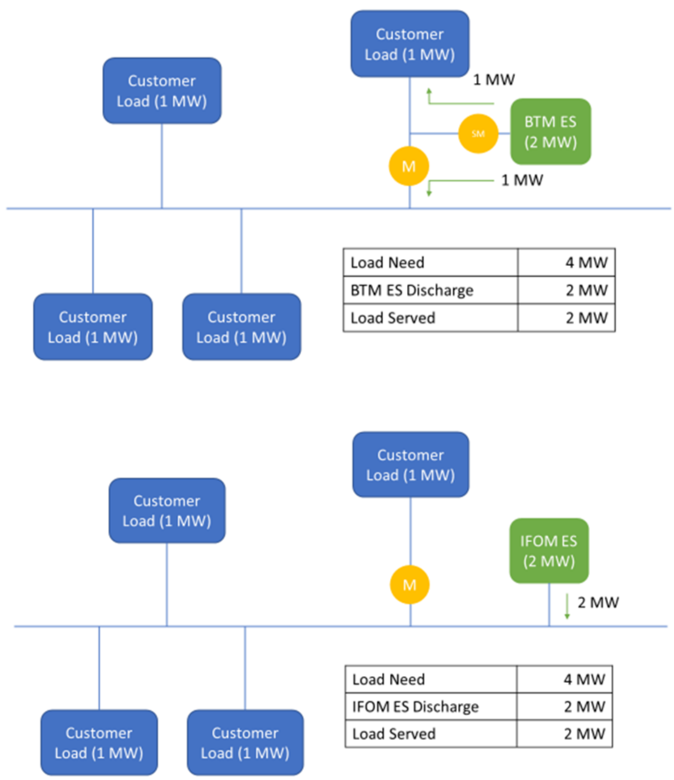
Forward determinations of capacity for any resource type are critical not only for mid- and long-term planning, as done in the Integrated Resource Planning (IRP) modeling analysis, but also for forward planning of the adequacy of the RA portfolio in meeting 1-3 year-ahead showings. Currently, unless the resource is weather-sensitive (*e.g.*, hydro) or demand response (DR), most resource types have their forward capacity "counted" based on upfront resource counting rules in place in the RA program (*e.g.*, four-hour maximum continuous output for front of meter (IFOM) energy storage resources, average effective load carrying capability (ELCC) for solar/wind), the contract capacity and delivery terms of the resource (*e.g.*, imports), and the deliverability secured by the export-capable resource as established by its net qualifying capacity (NQC) value. Until determined otherwise,[20] forward determinations of capacity value are relatively straightforward in this way and do not hinge on modeled or operational performance, except in the case of demand response resources that are subject to LIPs and the associated incorporation of *ex ante* and *ex post* load impact analysis over the forecast period.

As directly measurable and physical assets, unique forward determinations of capacity are not necessary for BTM hybrids and storage resources to support IRP and RA planning and counting. When directly metered and measured to account for all device-level discharge, inclusive of both discharge to serve customer load and export to the grid, the broader demand response approaches are not applicable to BTM hybrids and storage resources since they are no

[20] In the RA Enhancements Initiative and in proposals submitted to the CPUC in R.19-11-009, the CAISO has been developing an unforced capacity (UCAP) methodology to incorporate forced outages to assess an operational capacity value. Whether this is adopted by the CAISO and/or CPUC is unclear at the moment, so it is not addressed here.

longer "load limited" and can functionally operate just like any other IFOM energy storage resource. The only difference for BTM hybrids and energy storage resources is that the discharge may serve onsite customer load first before injecting into the grid, though onsite customer load also represents the load that must be served from a system perspective.

Figure 1: Representation of QC of BTM ES versus IFOM ES



In other words, there is no longer a need to simulate reference loads and reflect observed loads to forecast performance based on customer load reductions, as is typically done in the LIP process. To the same end, unlike traditional demand response that has to justify its load reduction potential, BTM hybrids and storage resources are backed by physical installed capacity that is separate from customer load, which can reliably and consistently deliver its output regardless of customer load levels if exports are allowed and included in capacity valuation. As a result, forward determinations for BTM hybrids and storage resources should be established based on the contract capacity of the resource aggregation~~ while leveraging the capacity counting rules in place for IFOM hybrids and energy storage resources. ~~.

~~The QC for BTM hybrids and storage resources should use the resource counting rules in place for their IFOM counterpart hybrid and energy storage resources. For IFOM energy storage resources, the rules have been unchanged since the adoption of QC rules in D.14-06-050.[21] Specifically, the Pmax, or QC, of the IFOM energy storage resource is determined by the maximum output over four or more consecutive, uninterrupted hours and on three consecutive days, subject to testing and verification as well as deliverability assessments (which is covered in a subsequent section).[22] Functionally, there is no difference between standalone IFOM and BTM energy storage in this regard, so long as they can meet these minimum capabilities and be tested and verified in accordance, with one exception: BTM storage resources are represented by aggregations of individual devices.~~

~~As directly measurable and backed by physical capacity, forward determinations of an aggregation of BTM hybrid and energy storage systems can apply a simple additive approach. That is, the QC of the aggregation would be the summation of the individual QC of the BTM hybrid and energy storage resources, as illustrated in the example below.~~

~~[21] R.19-11-009, *2022 Filing Guide for System, Local, and Flexible Resource Adequacy (RA) Compliance Filings* at 22 (October 18, 2021) ("2022 RA Guide").~~
~~[22] D.14-06-050, Appendix B at 9-10.~~

~~Table 2: Example Additive Calculation of August QC (27% ELCC)~~

~~BTM Solar Nameplate kW~~	~~BTM ES Nameplate kW~~	~~Daily kWh per kW~~	~~Daily kWh~~	~~Effective ES QC kW~~	~~Effective Solar QC kW~~	~~Effective Additive QC kW~~
~~7~~	~~5 (4h)~~	~~8.5~~	~~59.5~~	~~5.0~~	~~1.25~~	~~6.25~~
~~10~~	~~14 (2h)~~	~~8.5~~	~~85.0~~	~~7.0~~	~~1.81~~	~~8.81~~
	~~25 (2h)~~			~~12.5~~		~~12.50~~
	~~100 (3h)~~			~~75.0~~		~~75.00~~
~~750~~	~~500 (4h)~~	~~8.5~~	~~6,375.0~~	~~500.0~~	~~138.97~~	~~638.97~~
~~Effective Additive QC kW of DER Aggregation~~						**~~741.53~~**

~~During the three working group meetings from December 22, 2021 through January 11, 2022, certain stakeholders raised concern with counting the battery discharge to serve onsite consumption as part of the QC value, which may be captured in planning forecasts as load modifiers. To this end, the below section on load forecasting addresses this issue around "backing out" the load-modifying effects of storage in order to avoid double counting, but the additive QC methodology above that accounts for storage output that reduces onsite load and exports to the grid should still stand. In serving onsite customer load, the BTM hybrid and/or energy storage resource would be reducing overall load on the grid similar to demand response, so long as the forecasts are adjusted to not double count their impacts.~~

a. Use of Contract Capacity

~~While equivalent QC methodologies based on physical capabilities should be used for BTM hybrid and energy storage resources as for their IFOM counterparts, and should be used as a starting point for calculating their "physical" QC, contract capacity will likely need to~~Contract capacity should be used to determine the actual RA capacity that DER aggregations (DERAs) will be obligated to deliver, accounting for the unique considerations of DERAs also serving various onsite customer needs and affording flexibility in the composition of individual customers in aggregations. The use of contract capacity is not unique to BTM hybrid and energy storage resources since other resource types (*e.g.*, imports, DR, IFOM energy storage) similarly may contract for capacity amounts less than total capabilities due to multiple-use applications[23] and multiple off-takers,[24] among other reasons.

~~For example, the additive approach for an aggregation is appropriate for QC valuation, but since the CAISO is not optimizing each individual site for dispatch, but rather having resources participate within, and be scheduled and dispatched within, a single sub-LAP, the actual contract capacity for the DER aggregation of BTM hybrid and energy storage resources may be different. As a result, so long as the contract capacity is less than the additive QC of the individual DER projects that constitute the DERA, the forward determination of capacity for BTM hybrid and energy storage resources in an aggregation can be simplified in this way. For example, rather than calculating the customer behavior at each individual site, a DER aggregator may conduct~~ A DER aggregator conducts analysis on a portfolio level to determine its appropriate contract capacity, an amount that the DERA can reliably and consistently deliver. Such approaches are allowed for DR resources and should be allowed for BTM aggregations using DERP.

~~Furthermore,~~ BTM resources, by nature, provide services to the end-use customer. For BTM hybrids and energy storage, one of those services is resiliency, where a customer may seek to reserve a portion of the onsite battery's capacity as reserves to have resiliency to planned,

[23] A 100-MW energy storage resource may have 50 MW dedicated toward the RA Program and another 50 MW contracted for some other grid service, in accordance with the CPUC MUA Decision, D.18-01-003.

[24] LSE A may contract for 50 MW and LSE B may contract for 50 MW of a 100-MW RA resource. There is no double counting of capacity toward an LSE's obligations.

rolling, or PSPS-related outages. Demand charge management is another common use case for batteries deployed at Commercial and Industrial customer sites. Considering these customer needs, it is again appropriate to allow for the use of contract capacity ~~that is~~. Furthermore, as discussed further in Section C below, DER providers will contract for a certain amount of capacity, knowing that battery performance will be assessed for its capacity deliveries using the ~~additive QC value based on total maximum physical capability and point of interconnection limits, as described above~~metered generator output (MGO) methodology, which will account for ~~a derate~~other "typical" use of the ~~portfolio's QC value.[25] Such contract capacity approaches are consistent with existing multiple-use application (MUA) rules, where capacity can be differentiated to serve RA needs versus onsite customer needs~~battery output for retail customer purposes.

Contract capacity is sufficient for forward QC determination purposes since the onus will be on the DER provider to conduct analysis on how much capacity will actually be delivered on a day-by-day basis using the MGO methodology. To elaborate, a DER provider could contract for a certain MW of capacity from the aggregation of BTM hybrid and energy storage resources, having already accounted for, through their own analysis, the amount of actual capacity that they would count for when battery output is measured and baselined using the MGO methodology. Put another way, there is no need to require additional ex ante analysis to justify the contract capacity amount since DER providers would have every incentive to deliver on their contract capacity and would accordingly select a conservative contract capacity value. Moreover,

~~[25] Any derate should not be prescriptive to, say, automatically assume a 20% derate accounting for onsite resiliency purposes. This can be determined by the DER provider, who will conduct analysis on customer-by-customer needs and behavior, and will ultimately contract for an amount that they can commit to reliably and consistently delivering, subject to the various RA penalties and contract provisions.~~

contrary to some working group participants' concerns about overcounting of contract capacity, this would be avoided under the MGO methodology, discussed further in sections below. If, for example, a DER provider contracted for 10 MW of capacity and did not account for the 2 MW that would be typically included in the battery's baseline, the MGO methodology would reflect only 8 MW of capacity delivered - an outcome that would clearly come with penalties. As such, DER providers would rationally conduct their own analysis of the customer loads of their resource portfolio to understand the optimal amount of contract capacity that would be incremental to this expected typical retail usage.

Finally, contract capacity ~~should~~can be ~~used~~relied upon to account for customer attrition or migration out of DERAs and portfolios. Unlike traditional DR portfolios where QC levels may be different on a year-by-year basis in this regard, customer movement of this kind is less likely for aggregations of BTM hybrids and energy storage because solar and battery storage technologies are relatively high capital investments requiring long-term contracts, thus disincentivizing such behavior absent another long-term revenue stream. Especially in cases where BTM hybrids and/or energy storage were developed with RA contracts in mind, there may have been physical design decisions in the resource development process (*e.g.*, sizing) that would discourage movement out of RA portfolios in this way. It is also important to add that customers are accustomed to participating on a long-term basis without discernible signs of much customer attrition, such as with the SGIP, which requires operations and evaluation for at least 10 years. Notwithstanding these points, the use of contract capacity can address any customer attrition concerns, where DER providers may enroll more customer capacity in their DERA/portfolio than their actual contract capacity with any given LSE.

b. Heterogeneous DER Aggregations & Dual Participation

~~While the above additive approach works well and more obviously for homogenous DERAs involving only BTM hybrid and energy storage resources, forward~~Forward capacity determinations and counting methodologies for heterogeneous DERAs must also be closely considered since Order No. 2222 explicitly directs the creation of market pathways for DERAs that include a mix of demand response (load reduction only) and DERs capable of injections into the grid (*e.g.*, BTM hybrids, storage, V2G). Especially where forward capacity determinations for demand response differ from that of BTM hybrids and energy storage resources, there are questions about whether and how they should be "mixed and matched" to determine an "aggregate" QC value for the heterogeneous DERA. For example, DR resources currently establish forward capacity values using LIPs, which use statistical studies and regression analyses to develop an *ex ante* forecast of customer portfolios and load impacts while taking into account *ex post* historical performance, energy use, ambient temperature, etc. Preliminarily, we suggest that any DR portfolio that includes BTM hybrids and energy storage could ~~calculate~~ determine the QC component for BTM hybrids and energy storage separately ~~using the additive method~~ and then calculate the traditional DR portion separately using the LIP.

At the same time, we are aware that there are active conversations about potential QC methodology changes in a working group at the CEC that will be considered for adoption by the CPUC for the 2024 RA year, at the earliest. One of the QC methodologies that has been proposed is a contract capacity approach, backed by collateral assurances based on actual performance relative to contract capacity, as proposed by demand response providers (DRPs); by contrast, CAISO has favored using an ELCC model that looks at portfolio-based capacity value of DR resources as variable resources. In our view, the DRP-proposed contracted capacity approach for DR resources ~~will more readily marry with our proposed additive QC methodology by simply summing the QC value of DR and BTM hybrid and energy storage resources.~~is preferable. With submetering pathways that directly measure resource output, such an approach is feasible and distinguishes the load impacts of direct customer load reductions relative to their baseline based on the facility meter from the load served in part or in whole from the BTM hybrid and energy storage resource's discharge.

Finally, in cases where a customer dual participates in a DERA with an exporting BTM hybrid and/or energy storage resource and in a DR portfolio or program, additional consideration is needed to separately and incrementally measure and distinguish storage output from DR to avoid double counting load reductions. While the Joint DER Parties propose separate ~~settlement~~settlements at the premises and device meters, a performance evaluation methodology may need to be established in these instances where a customer is enrolled in a DERA and with a DRP, depending on the frequency of dispatch and overlapping performance periods. For example, a customer with a 5 kW energy storage resource providing 1 kW of load reduction could be counted as providing 1 kW of DR as measured at the premises meter *and* 1 kW of storage output at the device meter—an assumed 2 kW response that should actually be measured as the customer providing 1 kW in actual load reductions. Reconciliation may be needed at the premises and device meter to identify actual performance in these cases.[26] According to a stakeholder at the January 11, 2022 working group meeting, other ISOs are considering approaches to treat all load reductions to zero as DR—*i.e.*, up to the point of export. At this time, the Joint DER Parties raise this question as an issue that should be addressed in future policy discussions on dual DR participation, whereas the focus of this proposal is currently on

[26] The concept of Incremental Load Reduction (ILR) is being piloted in the Emergency Load Reduction Program (ELRP), which may shed insight into how ILR and/or exports could be accounted.

homogenous DERAs consisting of BTM hybrid and energy storage resources, without dual enrollment of any given customer in a DR portfolio or program. Given the complexities of this matter of reconciling metered output/reductions, this particular issue should be instead considered in the near future. Deferral of this issue should not detract from the CPUC's consideration of the proposals specific to homogenous aggregations, as appropriate, for adoption in R.21-10-002.

c. Alignment with RA Slice-of-Day Reform

D.21-07-014 evaluated various RA restructuring proposals and directed parties to the RA proceeding to develop the details around PG&E's Slice-of-Day (SOD) framework. Any adopted proposals for BTM hybrid and energy storage resources must align with the structural elements and counting methodologies developed by the RA Reform Working Group in R.21-10-002. If inconsistent with the SOD reforms, efforts made to address the eight barriers for BTM hybrid and energy storage resources would be wasted and/or disruptive by creating a different interim approach that quickly becomes obsolete. In light of these reform discussions, it is thus reasonable to align with the SOD framework as much as possible from the start since much of the implementation of any changes for the SOD structure and for BTM hybrid and energy storage resources would likely be similar, with implementation likely occurring in 2024 at the earliest.

However, much is still up for debate and development, making it difficult to align with one specific framework. Instead, the Joint DER Parties aim to take into consideration the various common elements of different SOD variations. As of the drafting of this report and proposal, we observe two main "variations": (a) Southern California Edison's (SCE) monthly 1-hour, 24-slice proposal; and (b) Gridwell's seasonal 2-slice gross and net peak proposal.

Across the two variations, there are relative merits and differences in terms of slice and showing design, as well as in certain resource counting methods (*e.g.*, ELCC versus exceedance for solar and wind). Each of these differences has impacts on administrative burden, transactability, over-/under-procurement risks, and reliability assurances, but without diving into the merits of those specific designs in this proposal, we identify some common elements that require specific consideration for BTM hybrid and energy storage resources.

Specifically, each of the SOD variations would require LSEs to show RA resources in one or more slices of the day for a particular showing period, with a resource's ability to produce during that particular slice of day determining how much RA capacity would count for that slice. As explained above, the QC methods for IFOM and BTM hybrid and energy storage resources can be ~~the same, with~~similar in terms of their showing to particular slices~~ also done in the same way~~. As dispatchable resources, IFOM and BTM hybrid and energy storage resources can be shown in the particular slice as needed to meet an LSE's RA obligations and as contracted. In addition to a discharging obligation for the particular slice in which it can be "counted" for capacity, energy storage resources would also count "negatively" toward the slice for which it has a charging obligation using any shown "excess capacity." Similar to its IFOM counterparts, BTM hybrid resources should account for onsite charging availability from its paired generation resource before determining and accounting for any additional excess energy needs (if any) from the grid, while BTM standalone energy storage resources must demonstrate excess energy is available in other non-shown slices to fully charge the resource and ensure its QC.

Another area of potential alignment with the SOD reforms is in regard to RA must-offer obligations (MOO), which could maintain the current 24x7 MOO and allow the CAISO market to optimize energy deliveries across the day, or slice-specific RA requirements could be put into place. On the one hand, the 24x7 MOO has general advantages in allowing the CAISO market to optimize energy deliveries across the day and in avoiding disruptive impacts from the current to new RA structure, even though it would complicate how BTM resources could oscillate between wholesale and retail participation. In turn, a slice-specific MOO would more cleanly account for and differentiate wholesale and retail participation in discrete slices where BTM hybrid and energy storage resources are shown, but there would likely be more global complications and inefficiencies in a slice-specific MOO structure. Overall, at this stage, each of the SOD reforms propose maintaining the 24x7 MOO, though SCE indicated that its month-hour slice framework would "count" DR resources in specific shown slices *and* apply a MOO for those specific slices. To this end, separate mechanisms will need to be considered to facilitate wholesale and retail participation of BTM hybrid and energy storage resources, including for the costs for energy associated with consumption and charging and for the incrementality of compensation, which are addressed in the sections below.

Finally, the two variations take different approaches to resource counting rules. The Joint DER Parties' proposal most readily aligns with the current QC counting rules and can be more easily adapted to SCE's proposal, so long as the resource is shown in, and is capable of performing in specific slices, and has sufficient charging energy in other slices. By contrast, the Gridwell proposal would apply ELCC approaches to determine the QC value of resources in the two slices for gross and net peak. If this SOD proposal is adopted and approved by the CPUC in June 2022, there is no reason to believe that BTM hybrid and energy storage resources should be assessed any differently from their IFOM counterparts. In fact, the CPUC has demonstrated the capability to implicitly calculate and adopt ELCC values that reflect the effect of BTM solar, thus impacting the ELCC value of IFOM solar;[27] although, the CPUC declined to adopt ELCC capacity values for BTM solar at the time. Models used to calculate ELCC are therefore capable of assessing BTM hybrid and energy storage resources. Consistent with the Joint DER Parties' proposal to similarly apply IFOM QC methods to their BTM equivalents, it should similarly apply if the Gridwell proposal is adopted.

Notwithstanding this general principle of IFOM and BTM equivalence in QC methodologies, the Joint DER Parties do not endorse the use of ELCC methodologies for calculating the QC value of BTM hybrid and energy storage resources. Since consideration of the merits of the use of ELCC methodologies is currently ongoing in the CEC's DR Working Group and in the CPUC's SOD Reform workshops that have been occurring from September 2021 through January 2022, the Joint DER Parties do not dive into the details of whether the slice-specific QC counting rules as proposed by SCE or the ELCC modeled values more appropriately capture the BTM hybrid and energy storage resources' actual contribution to reliability. This evaluation will be better channeled through the aforementioned working groups and workshops. In general, if slice-specific QC counting rules as proposed by SCE work for IFOM hybrid and energy storage resources, there is no reason to believe they do not work similarly for their directly metered BTM counterparts.

~~A.~~B. RA Requirements Associated with Customer Providing Capacity

The second barrier identified in D.20-06-031 pertains to "RA requirements associated with customer providing capacity." There is operational precedent for customer participation in market-integrated RA resources through the CAISO's PDR model, which is used for bidding and scheduling of economic demand response resources that are either aggregated and managed by

[27] *See* D.19-06-026.

third parties (e.g., Demand Response Auction Mechanism, direct-to-LSE contracts for "pure RA" such as SCE's LCR) or by investor-owned utilities (IOUs). The CAISO tariff includes generic requirements for resources providing market-integrated system RA capacity through PDR, including:

- A MOO for economic bidding or self-scheduling of RA MW in the Integrated Forward (Day-ahead) Market (IFM) and Residual Unit Commitment (RUC), for all hours of the month ~~(when the resource is "physically available")~~ and in the Real-Time Market (RTM) to match day-ahead market (DAM) scheduling or for any RA capacity not scheduled in the IFM.
- Must be able to be dispatched at least: 4 hours per dispatch, 3 consecutive days per month, and 24 total hours per month.

Furthermore, system and local RA resources are subject to the CAISO's Resource Adequacy Availability Incentive Mechanism (RAAIM), which incentivizes resources for bidding during Availability Assessment Hours (AAHs), currently set at 4:00 p.m. – 9:00 p.m. Third party-managed PDR capacity in the wholesale market must be shown on LSE and resource supply plans, and the CPUC in D.21-06-029 has also signaled its intent to require IOU-managed PDR capacity on supply plans, rather than being credited to LSEs' RA obligations.[28]

Aggregated DERs participating through the CAISO's DERP model are currently ineligible to provide RA.[29] At a minimum, this needs to be rectified through a coordinated effort from the CPUC to establish a QC value and MOO and by the CAISO to develop and adapt an appropriate DERA deliverability methodology. Neither the CPUC or CAISO can do this on their

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[28] D.21-06-029 at 27-31.
[29] http://www.caiso.com/Documents/ParticipationComparison-ProxyDemand-DistributedEnergy-Storage.pdf, *see* Slide 8.

own since RA value, MOO and deliverability are interrelated matters. Upon approving RA eligibility for DERAs that participate through the DERP model, the Joint DER Parties believe that the same basic RA operational requirements (i.e., MOO, RAAIM and AAH provisions, supply plan showings) should apply to DERA discharges as they currently apply to load curtailment resources that participate through PDR~~, reflecting any modifications to these elements that may occur under the Slice of Day RA framework currently under consideration.~~.

We further recommend that any of these elements be modified accordingly to reflect a final Slice of Day RA framework, which is currently under consideration. For instance, the Slice of Day framework may only require resources to be available (*i.e.*, bid into the market) and shown on supply plans for the hours for which they are contracted. Ultimately, the Joint DER Parties recommend RA resources participating through DERP ultimately adhere to any availability, bidding, and showing requirements applicable to all resources under Slice of Day.

~~B.~~C. Wholesale Market Participation

The third barrier identified in D.20-06-031 is "wholesale market participation, including metering, dispatch control and communication with CAISO." Overall, a BTM hybrid or energy storage resource can participate in CAISO markets as a Proxy Demand Resource (PDR) or a DERP, which allows a market participant that owns and operates DERs[30] in aggregate to operate in response to a CAISO schedule, award, or dispatch signal. Any individual DER cannot exceed 1 MW and DERAs must meet a minimum capacity requirement of 0.1 MW[31] to participate in the CAISO's day-ahead, real-time, or ancillary services markets. DERAs must execute a DERP

[30] Eligible DERs are defined by the CAISO as a distribution-connected resource, regardless of size or whether it is connected behind or in front of the end-use customer meter.
[31] Previously, DERAs were required to meet a 0.5 MW minimum capacity requirement, but this was recently lowered to 0.1 MW pursuant to FERC Order No. 2222.

Agreement (DERPA)[32] to adhere to the terms of the CAISO Tariff, which includes the following applicable DERA participation requirements:[33]

- A DER participating in a DERA may not participate in more than one DERA and may not participate in a CAISO market as an individual resource separate from the DERA.
- A DER participating in a DERA may not also participate in a retail NEM program that does not expressly permit wholesale market participation.
- Each DERA must be located in a single Sub-LAP.
- A DERA must provide a net response at its PNode(s) that is consistent with CAISO dispatch instructions and applicable Generation Distribution Factors.
- DERAs are Scheduling Coordinator Metered Entities (SCME), and Scheduling Coordinators (SCs) for a DERA must have entered into SC Metering Agreement.

To introduce this topic, the following schematic[34] illustrates the current communication and coordination processes associated with DR and DERs participating in wholesale markets. This graphic reflects that communication with DERs and DERAs is routed through the SC. The specifics are discussed in the sections below.

[32] CAISO Tariff, Appendix B.21.
[33] CAISO Tariff, Section 4.17.3.
[34] Gridworks T&D Paper at 7.

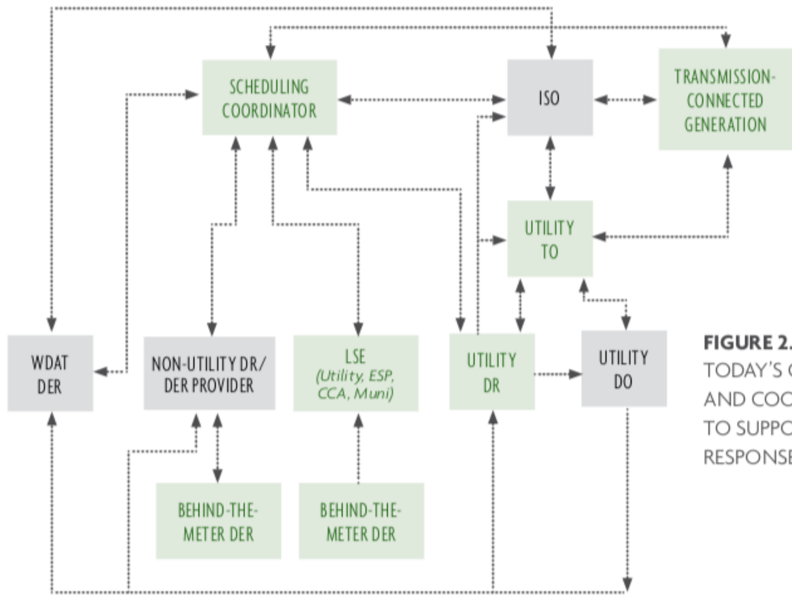

FIGURE 2.
TODAY'S COMMUNICATION AND COORDINATION LINKS TO SUPPORT DEMAND RESPONSE (DR)

This section discusses each of the three topics—metering, dispatch control, and communication—individually.

a. Metering

Metering for both PDR and DERP resources is addressed with the SCME option as articulated in Sections 6.3.1 and 10.3 of the CAISO Tariff. For context, aggregations of residential systems mean many individual small resources within a Sub-LAP, thus making direct ISO metering cost-prohibitive and logistically complex to manage. For these resources, the SCME handles meter data for market participation by DERs—day-ahead, real-time, and ancillary services. With this option, the SC polls individual meters in an aggregation; performs the validation, estimation, and editing; and submits the resulting settlement quality meter data to the CAISO.

The MUA working group's report described the responsibilities of the SCME for PDR and DERP resources:

> [T]he scheduling coordinator polls the meters, performs the validation, estimation and editing (VEE) and submits the resulting settlement quality meter data (SQMD)

to the CAISO. This entity is required to adhere to the requirements of the Local Regulatory Authority (LRA), e.g., the CPUC. In the case of the utilities, the CPUC has jurisdiction over approval of metering equipment, rules on error rate, VEE process, etc. In the absence of LRA requirements, the SCME must adhere to CAISO technical metering and VEE requirements prescribed in the CAISO's BPM for metering. SCs have an agreement with the CAISO and are held to audit requirements to ensure that they are providing accurate SQMD data. Audit is a yearly attestation that they are following the rules for SCMEs. SCME was created originally to facilitate demand response.[35]

As the CAISO articulated in its Order 2222 filing to FERC:

DER participation in the CAISO's markets is not new to the CAISO or the UDCs. Several hundred DERs comprising over 2 GW of capacity already participate in the CAISO markets. Just as for these resources, the CAISO tariff requires DERAs to use a scheduling coordinator for all bidding, scheduling, and dispatch. The scheduling coordinator communicates between the CAISO and the resource to ensure ongoing operational coordination. Scheduling coordinators also must report any outages consistent with sections 9 and 30 of the CAISO tariff. Outage data is public on both the CAISO's OASIS and its public website for outages.[36]

Metering for DERAs participating in the wholesale market has been addressed and does not require any further development. With regard to the settlement methodology for BTM energy storage, direct metering at the device level is the most effective and accurate method of quantifying total capacity contribution – both load impacts and exports – for BTM energy storage and hybrid aggregations.

At the wholesale level, FERC approved ~~the~~ CAISO's proposal for a submetering configuration, the meter generator output (MGO) methodology, which was filed as part of the CAISO's Energy Storage and Distributed Energy Resource (ESDER) Phase 1 proposed tariff revisions. The MGO methodology allows for three options: 1) load reduction only, 2) generation offset only, and 3) load reduction and generation offset, wherein the metered response of load

[35] MUA Working Group Report at 22-23.
[36] CAISO FERC Order 2222 Filing at 25.

and production are combined.[37] We recommend that the CPUC require IOUs to develop a similar methodology for BTM retail capacity settlement.

The MUA working group discussed the need for the CPUC to develop requirements for submeter equipment and data, as well as enhancements to utility systems and cost recovery. Some stakeholders, including the IOUs, Olivine, and CAISO, believed at the time that the CPUC should address these issues in advance of the MGO methodology being used for retail settlement.38 Since the MUA working group report was submitted to the CPUC in August 2018, the CPUC has yet to approve the use of a submetering methodology for purposes of retail capacity settlement, including measuring RA contribution under the LIP methodology currently required for DR and BTM DERs.

In discussing this topic at working group meetings, IOUs cautioned that their billing systems are not ready to accommodate measurement of retail capacity settlement at the battery submeter. For the near term, however, such modifications may not be necessary. The IOUs could develop a manual process for retail capacity settlement. Further, in its most recent decision in the emergency reliability docket[39], the CPUC adopted a staff proposal for a new Emergency Load Reduction Program (ELRP), Option A4 for BTM storage aggregation, and Option A5 for Electric Vehicle aggregation.40 This option explicitly allows for performance measurements at the submeter.

In working group meetings, IOU representatives have indicated that permanent submetering capability would likely require several years to implement. With specific regard to

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[37] MUA Working Group Report at 23.
[38] *See* MUA Working Group Report at 20.
[39] R.20-11-003, *Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023* (December 2, 2021) (D.21-12-015).
[40] D.21-12-015 at Conclusion of Law 16 and Attachment 2 at 15.

ELRP submetering, it was generally discussed that the process will be helpful in providing lessons learned and best practices for pursuing a broader submetering effort. While a permanent methodology and requisite upgrades to utility systems may be needed for the long term, the Joint DER Parties recommend taking an interim approach that can be tested~~, using the ELRP process as a start~~ and adjusted over time.

~~This means that submetered data at the device level would be compared to the overall retail meter to understand the interaction between the two.~~ Apart from the ultimate resolution of the final methodology under ELRP, the Joint DER Parties point to the metered generator output (MGO) methodology currently in place at CAISO for wholesale market settlement of storage-backed demand response resources. If the MGO approach is adopted for retail capacity settlement purposes, as well as for use with a DERP resource, wholesale and retail settlement for a resource adequacy resource would be aligned. Scheduling coordinators would provide the same aggregated meter data to the CAISO as to the IOU. The IOUs would have the same capability as the CAISO to audit meter data.

The only difference the Joint DER Parties recommend to the MGO baseline would be the inclusion of exported energy and charging energy in the baseline. DER Providers should have the option of choosing between a 10-in-10, 5-in-10 or control group methodology to calculate the output baseline. As with the MGO baseline for PDR resources, the relevant comparison period in non-event days is for the exact period in which the battery was dispatched on the event day. Further, no consideration is needed for on-site load with direct submetering of BTM generation and storage, for several key reasons. First, only the BTM hybrid or storage system is actually responding to market dispatches, and not host load. Grid services dispatches by these systems are optimized by the aggregator and are seamless to the customer. Thus, it is not appropriate to measure event performance against customer activity, as the customer's load does not respond to the event. Second, the battery output is a direct and empirical measurement of event response, and is thus superior to any constructed counterfactual. Third, any load met with on-site hybrid or battery discharge would have otherwise been consumed from the grid. Fourth, a baseline is applied to the BTM system discharge only, and for the exact hours in which the resource is dispatched on an event day, to capture an estimation of normal output during event hours on non-event days. Fifth, and finally, a customer's retail bill will naturally account for any increases or decreases in load that would have to be served by grid supply, in absence of the BTM battery. This, taken with a baseline on the BTM system, obviates the need for any subtractive billing.

Another key consideration is the protocol for submetering. This has both policy and implementation ramifications. For example, who actually owns and is responsible for the submeter; how does the submeter communicate the data and who receives the data (it could be the DER provider, a third-party Meter Data Management Agent or the utility distribution company (UDC)); and how is the data validated. Furthermore, whether the UDC's Advanced Metering Infrastructure system can be utilized would inform whether the process could be mostly automated or would require non-automated steps along the way.

The Joint DER Parties recommend that the IOUs be directed to develop an interim methodology, based ~~first~~ on the CAISO's MGO methodology ~~developed for ELRP Option A5~~, for calculating retail capacity settlement at the battery submeter for BTM storage and hybrid resources. The data submittal requirements for the baseline and performance calculation are detailed in the CAISO's BPM for demand response[41], and meter and submission standards are detailed in CAISO's BPM for metering.[42]

[41] CAISO. Business Practice Manual for Demand Response. V.3. Appendix B. April 1, 2020.
[42] CAISO. Business Practice Manual for Metering. V.22. April 14, 2021.

~~a.~~b. *Dispatch control*

Our presumption is that this item refers to dispatch control of *either* individual resources within an aggregation *or* an entire aggregation, *or* both. The question is presumably who should have ultimate dispatch control over the aforementioned. Currently, for DERs participating in the wholesale market, that duty rests with SCs. We are not aware of any reason to change this structure, nor any reason to change it.

Dispatch control by the CAISO is not required for DERAs, according to our review of the CAISO tariff and applicable BPMs. Given that the SC framework, including the SCME option, was created by the CAISO through its own initiatives, it is reasonable to presume that the CAISO would modify the framework to give itself more direct control over small, aggregated resources if it desired that direct control. Similarly, the IOUs have not, to our knowledge, advocated strongly for IOU dispatch of DERAs.

However, the IOUs/UDCs and the CAISO have expressed some concern that exporting distribution-interconnected resources may be dispatched by the CAISO at suboptimal times, thus potentially overloading the distribution system. Coordination between the transmission operator, DERA resource, and distribution utilities over the dispatch of distribution-interconnected resources is necessary, and it is also likely necessary to review this type of scenario in the interconnection process. In the event that a resource must be curtailed due to distribution system conditions, the Joint DER Parties' understanding is that this constitutes an instance of forced outage. Stakeholder coordination has occurred to address ~~this~~the issue of coordination and is discussed later in this section along with recommendations for additional actions.

~~b.~~c. *Communication*

We presume "communication" to refer to real-time communications between the DERA and the CAISO. The CAISO tariff requires telemetry for resources 10 MW or greater participating in energy markets, and for resources of all sizes providing ancillary services. For PDR and DERA resources that do not meet either criterion, SCs are required to communicate with the CAISO for ongoing coordination and report any outages. The CAISO tariff[43] also requires the SC to submit revenue-quality meter data for before, during, and after intervals in which the resource provides ancillary services. The CAISO has noted that the "Commission has already found that the CAISO's metering and telemetry provisions for DERAs are just and reasonable."[44]

When telemetry is required—either in the case of a DERP of any size providing ancillary services, or if the total DERA capacity is equal to or greater than 10 MW—the CAISO tariff does not require each individual DERP resource to provide direct telemetry. The CAISO attested to the sufficiency of its current metering and telemetry regulations for DERAs in its Order 2222 compliance filing to FERC.[45]

Communication between the resource and CAISO is not an issue within the CPUC's jurisdiction, and appears to have been resolved for aggregated distributed resources, to both the satisfaction of the CAISO and its regulator, FERC. Thus, as with metering in the wholesale market, the Joint DER Parties recommend that this issue be removed from the list of issues requiring resolution before establishing a QC value methodology for BTM hybrid resources.

~~c.~~d. Recommended Replacement Issues

We refer back to the potential issue of ensuring coordination between UDCs, the ISO, and DERAs at the transmission-distribution interface. Gridworks facilitated a working group process in 2016 and 2017 on transmission-distribution interface coordination, focused on a future

[43] CAISO Open Access Transmission Tariff (effective as of December 15, 2021) ("CAISO Tariff").
[44] CAISO FERC Order 2222 Filing at 21.
[45] *Id.* at 22.

with a high level of DERs. The working group included all three IOUs and the CAISO. In 2017, the working group authored a report identifying issues and preliminary recommendations.[46]

In its Order 2222 compliance filing, CAISO stated that:

> [SCs] for UDCs can submit planned and forced outages, allowing the UDC to pre-empt or override CAISO dispatch. For example, the CAISO has worked with UDCs during recent years to coordinate highly dynamic public safety power shutoffs to avoid wildfire risk during inclement conditions.[47]

At the workshop on November 24, 2020, the CAISO described developments to improve UDC and CAISO coordination and avoid negative impacts on the distribution system. In summary, the CAISO explained that it had been addressing these issues in a working group process with the UDCs and had, at the time of the workshop, developed processes that work over the short- to medium-term, while noting that "high DERA participation requires enhanced Transmission/Distribution Operations coordination."[48] Considering that the level of DERA participation is far from high, and likely will not reach a high level in the near future, the Commission could reasonably consider this issue resolved for the purposes of setting a QC value and path to market for DERAs, while simultaneously setting a clear path forward to address any additional issues.

That said, it is important to point out that CPUC Rule 21—which governs interconnection to the distribution system and is the recommended interconnection process for BTM storage and hybrid resources—requires projects to pass through multiple screens focused on ensuring that

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[46] Gridworks T&D Paper; *see* TD Interface Coordination – What's needed for the high-DER future grid? (January 18, 2017) https://gridworks.org/wp-content/uploads/2019/07/MTS-T-D-Interface-170118-Final.pptx.pdf.
[47] CAISO FERC Order 2222 Filing at 25.
[48] November 2020 BTM Workshop Slides, slide 23. The CAISO noted that it had 1) established a detailed DERA review process, which included ISO NRI process integration; 2) developed DERA availability (red/green) manual process; and 3) identified availability to provide information using existing market reporting mechanisms.

export will not overload the distribution system, and ensuring safety and reliability. Rule 21 provides for open communication between the resource and UDC, and then from the resource to the CAISO. Thus, major concerns about reliability and safety should already largely be addressed within Rule 21. If the Commission wishes to provide further clarity, Rule 21 could be amended to clearly delineate responsibility for the resource to communicate any scheduled outages or dispatches to the UDC and CAISO.

For the reasons discussed above, we recommend deleting the named issue entirely from the CPUC's consideration and replacing it with the following two issues:

> ~~Wholesale market participation including metering, dispatch control, and communication with CAISO.~~
>
> Visibility and communication at the transmission-distribution interface for **significant** DERA penetration; and,
>
> Permitting use of submetering for retail capacity settlement.

~~C.~~D. Cost for Energy Associated with Consumption, Charging, and Export

As BTM resources are subject to retail rates, wholesale participation necessitates ensuring that BTM storage resources do not charge at wholesale rates and discharge at retail rates. Currently, BTM hybrids and storage operating under Demand Response Provider Agreements (DRP-A) avoid these issues by "remaining on the retail side" and interconnecting as non-exporting systems, with any storage charging kWh assessed at retail rates regardless of if they are scheduled and cleared through the CAISO wholesale energy market, and any discharge to customer load avoiding retail charges. By contrast, even though there is no BTM hybrid and storage resource participation in DERPAs to date, the CAISO recently implemented tariff modifications pursuant to FERC Order No. 841 that clarified how the CAISO will similarly "simplify" wholesale-retail participation issues for DERP aggregations by "zeroing out" wholesale charges for charging through the CAISO's settlement software, where the UDC indicates that it is unable to net out wholesale energy purchases from its retail billing.[49] In this way, while short of differentiating between wholesale and retail charges, the CAISO will avoid double-billing for retail and wholesale participation.[50]

On the one hand, simplifications to "keep all things retail" are appropriate for BTM non-exporting storage systems, including all activity dispatched due to a wholesale market schedule and dispatch. As long as the energy is not exported past the retail meter to the grid, the energy does not enter wholesale jurisdiction. However, such simplifications do not fairly account for any energy exported past the retail meter, or injected to the grid, which enters wholesale jurisdiction. Without a fair accounting of charging energy for exports, it also dulls the operational incentives for BTM hybrid and storage resources to participate in the CAISO wholesale market, except for the incentives and penalties in place from RA capacity requirements and contracts. For exporting BTM hybrid and storage resources, it is obviously uneconomic to have storage charging at retail rates and then to discharge exports at wholesale rates. Economic charging incentives via CAISO wholesale energy prices are not passed through or exposed to the BTM resource if subject to retail rate schedules, which lack the granularity or dynamism in prices—for example, with 2-3 time-of-use periods and established rates. These issues were deferred with the issuance of D.17-04-039[51] and as part of working group efforts in R.15-03-011, and they merit revisiting now.

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[49] *See* CAISO Tariff Section 10.3.1.4.
[50] Docket No. ER19-468-002, *California Independent System Operator Corporation Compliance Filing* at 10-12 (January 21, 2020).
[51] D.17-04-039 at 41 (further development was identified as needed to the "attendant utility protocols, processes, or specific metering configurations to make these determinations now").

First, the CAISO tariff currently leaves discretion to the CPUC to assert where retail rates should apply, and FERC has previously denied calls for electric storage resources to be required to choose between participation in either wholesale or retail markets due to the complexity of accounting and metering practices;[52] FERC affirmed in Order No. 841-A that these issues can be worked out in cooperation with distribution utilities and local electric regulatory authorities (*e.g.*, the CPUC), and that such metering and accounting requirements can be developed.[53] With this history and context in mind, the CPUC, in collaboration with the IOUs and CAISO, should develop an accounting mechanism to check for the eligibility of wholesale charging and appropriately create settlement procedures. Retail bills can then be adjusted accordingly upon conducting after-the-fact analysis. In the end, this will require the creation of an accounting process for subtracting usage in a given settlement interval from the retail bill, which may or may not require upgrades to billing systems and development of protocols to accommodate these procedures.

Second, the recent CPUC approval of the use of submetering allows for distinctions to be made regarding the periods and intervals during which BTM charging energy can be assessed wholesale rates. Overall, the IOUs have expressed that submetering represents a "fundamental shift" of DR practice, shifting from performance measurement at the premise level to the device or technology level. However, the CPUC recently evolved its perspective on submetering in adopting and refining the ELRP, which allows submetering for performance measurement for the Virtual Power Plant Aggregators (Customer Group A.4) and EV and Vehicle Grid Integration Pilot (Customer Group A.5), subject to these systems meeting applicable standards established

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[52] *FERC Order No. 841*, 162 FERC ¶ 61,127 at P 322 (2018).
[53] *FERC Order No. 841-A*, 167 FERC ¶ 61,154 at P 142 (2019) (citing *FERC Order No. 841*, 162 FERC ¶ 61,127 at P 324 (2018)).

by the CPUC if and when adopted.[54] In addition to separate submeters, any direct measurement approaches should allow for internal storage device or inverter approaches to metering storage charge and discharge. As long as there is SCME oversight and auditing, settlements and performance measurement should be allowed using such diverse submetering approaches.

Overall though, among the eight issues, the issue of appropriately assessing the cost for energy associated with charging is lower on the priority list since any unfavorable wholesale energy arbitrage and charging at retail rates at all times may be offset by contracted capacity payments and obligations. At the same time, this issue should not be overlooked either since how BTM hybrid and energy storage resources bid, schedule, and dispatch in the wholesale market will be impacted by underlying rate structures of the customer.

a. Use of Submetering

In the past and most recently in R.20-11-003, the utilities have opposed the adoption of submetering to measure the performance and payment of RA until the CPUC first adopts submetering for the purposes of retail settlements and until various issues are addressed:[55]

- Rules and responsibilities for sub-meter equipment;
- Sub-meter data accuracy requirements;
- Sub-meter certification requirements;
- Rules and responsibilities for data collection, vetting, VEE, storage, and processing;
- Reconciliation of meter data management between the submeter and premise meter for billing and settlement purposes;
- Billing system and tracking system enhancements; and

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[54] D.21-12-015 at Conclusion of Law 16 and Attachment 2 at 15.
[55] MUA Working Group Report at 19-20.

- Cost recovery for any of the aforementioned system upgrade, implementation, and operation and maintenance (O&M) costs.

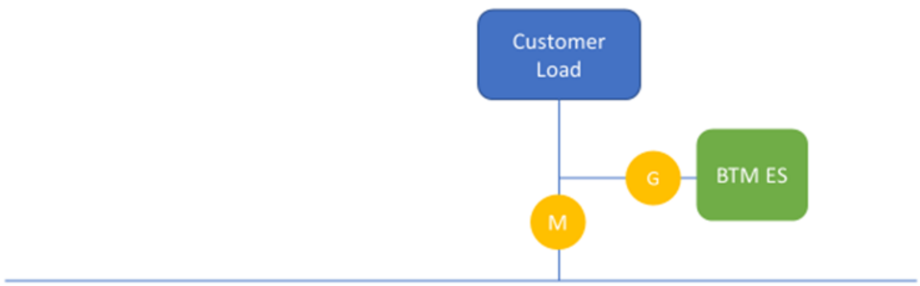
As explained further below, submeters are important to the tracking of wholesale versus retail charging of exported energy but also require an accounting methodology since there is no physical way to distinguish electrons as constituting dispatch for wholesale versus retail charging. With the submeter not including data on onsite retail load, it can clarify directly what is being provided by the BTM storage device in a hybrid or standalone configuration and can lend itself to more granular accounting approaches to help differentiate wholesale versus retail energy. Similarly, the extension of QC methodologies for IFOM hybrid and energy storage resources to their BTM equivalents hinges on the ability to submeter BTM storage devices independently to be treated similarly to IFOM resources. To avoid complications related to billing and settlement, estimation approaches could be used.

~~a.~~b. Application of Accounting and Station Power Rules

Some may say that BTM storage is entirely retail by its definition, but the fact that BTM storage is located behind a customer meter should not limit its ability to operate like an IFOM wholesale energy storage resource if the BTM storage device can be separately metered and wholesale versus retail activities can be identified and accounted for. Without proper submetering, BTM storage could charge at wholesale and discharge to offset retail load or be compensated at retail under NEM export compensation, but such situations can be avoided by metering BTM storage charge and discharge in response to CAISO market prices to distinguish when such activities are wholesale versus retail activities.

Stakeholders could identify and agree upon a particular accounting methodology. For example, Last-In First Out (LIFO) accounting is a common methodology for inventory valuation that matches the sale of inventory with the cost of the most recent inventory cost, which provides more favorable matching of costs and revenue. Since energy storage is a form of "inventory" of electrons for later sale, it could be similarly applied to establish a common, agreed-upon accounting approach to look back and appropriately handle when wholesale charging has taken place and also ensure that only the energy supplied to the grid (exported) is allowed wholesale treatment.

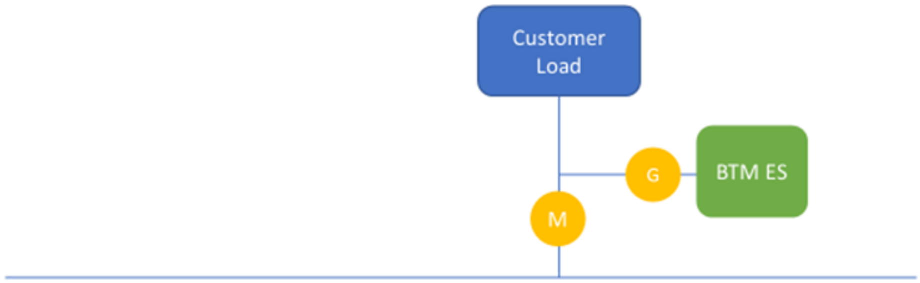
Figure 2: Charging Example 1



Interval	1	2	3	4	5
Meter M	+10	+10	-10	-10	5
Meter G	+10	+10	-10	-10	0
Load	0	0	0	0	5
Wholesale	+10	+10	-10	-10	0
Retail	0	0	0	0	5
(+) indicates consumption or charge; (-) indicates exports or discharge					

In the above example, a BTM energy storage resource provides 10 kWh to the grid in Interval 3, captured by Meter M. This triggers a 10 kWh settlement at the wholesale rate. To capture the charging energy, the most recent charging to this amount of energy is looked for, recorded by Meter G and can be seen in Interval 2. As a result, the customer is paid for 10 kWh at the Interval 3 rate and pays for 10 kWh at Interval 2 rate. Likewise, in Interval 4, another 10 kWh discharge to the grid triggers this same process and the look back identifies Interval 1 is the most recent charging of this energy. The customer pays for 10 kWh at Interval 1 rates and earns 10 kWh at the Interval 4 rate. There are no retail charges as no retail consumption occurs.

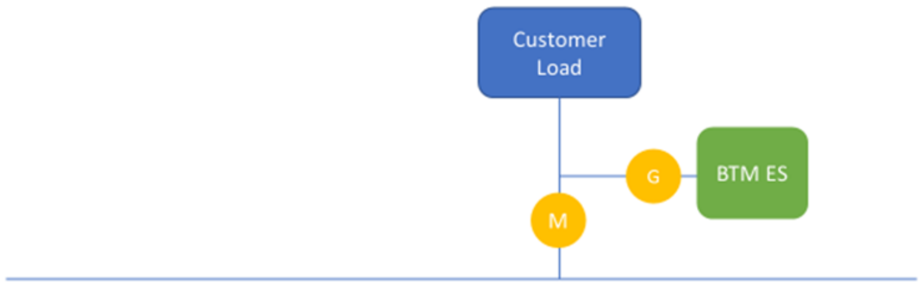
Figure 3: Charging Example 2



Interval	1	2	3	4	5
Meter M	+15	+15	0	0	5
Meter G	+10	+10	-10	-10	0
Load	5	5	10	10	5
Wholesale	0	0	0	0	0
Retail	15	15	0	0	5
(+) indicates consumption or charge; (-) indicates exports or discharge					

In another scenario (above), the customer never discharges to the grid, meaning they are not eligible for any wholesale treatment. This means all their charging is consumed by retail loads and the full 35 kWh must pay the retail rate, with the 20 kWh of stored energy assessed at the applicable retail rates in Intervals 1 and 2, but done so as to manage onsite customer load needs and avoid retail charges in Intervals 3 and 4.

Figure 4: Charging Example 3



Interval	1	2	3	4	5
Meter M	+15	+15	-5	-5	+5
Meter G	+10	+10	-10	-10	0
Load	5	5	5	5	5
Wholesale	0	+10	-5	-5	0
Retail	15	5	0	0	5
(+) indicates consumption or charge; (-) indicates exports or discharge					

In a final scenario (above), the energy storage system provides 5 kWh to the grid in Interval 3, which is eligible for wholesale payment, which triggers a lookback to settle 5 kWh from Interval 2 to be paid at wholesale rates to appropriately treat the charging energy. Again, in Interval 4, there is 5 kWh discharge to the grid, which again triggers a look back and is found in Interval 2. The customer thus pays 10 kWh of energy in Interval 2. The customer also consumes 25 kWh of retail load over the 5 time-intervals and pays for 25 kWh at the retail rate (15 kWh in Interval 1, 5 kWh in Interval 2, and 5 kWh in Interval 3).

The LIFO method may be one accounting approach, but others could also be considered and discussed on the merits. For example, there are other approaches such as First-In, First-Out that is also commonly used to match and expense older "inventory" first, or there could be time-value matching of charging and discharging periods to do this accounting based on high-low combinations of wholesale and retail rates. Regardless, the broader point is that an accounting methodology should be agreed-upon, developed, implemented, and utilized.

With the CPUC moving toward RA SOD reforms, there may be opportunities to explicitly "show" BTM hybrid and energy storage resources for the specific "slices" in which the resource would count for RA capacity, along with showings in slices with excess energy. If must-offer obligations are limited to the specific slices in which BTM hybrid and energy storage resources are shown, as currently proposed by SCE for traditional DR resources, this could ease some of the accounting challenges if similarly extended to apply to BTM hybrid and energy storage resources operating as DERPs. Currently, it is not possible to operate in the retail domain and wholesale market domain at the same time as a Non-Generator Resource (NGR) or DERP, where resources are constantly available and settled for wholesale operations, thus precluding any retail operation without incurring CAISO deviation penalties.

However, if the 24x7 MOO is maintained for BTM hybrid and energy storage resources under a SOD framework, the station power rules established in D.17-04-039 for IFOM energy storage resources can be extended to BTM hybrid and energy storage resources to resolve the distinction between wholesale and retail uses of grid-supplied charging energy. As affirmed in FERC Order No. 841, any electric energy drawn from the grid to charge energy storage resources, including efficiency losses, for later resale should be subject to a wholesale rate.[56] D.17-04-039 affirmed that all energy that is consumed and not resold is station power and inherently retail. Whereas D.17-04-039 focused on IFOM energy storage resources and defined station power as those loads that are not essential to the "production" of stored energy for later

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[56] *FERC Order No. 841*, 162 FERC ¶ 61,127 (2018). *See also Southern California Edison Co. v. FERC*, 603 F.3d 996 at 1000-1 (2010). Any electric energy for resale is wholesale and all electric energy used for end-use consumption and not resold is station power and retail.

reuse, the same station power principle can be applied to BTM hybrid and energy storage resources using submetering approaches.

In the examples above, the customer load is treated as equivalent to station loads and could similarly be netted in response to CAISO dispatch, *if* the absolute value of charge or discharge exceeds that of the station loads. Since energy storage exports will only occur if there is lower customer load than what is available to discharge, the netting rules can readily apply to storage discharge, though accounting mechanisms may still need to be developed to account for wholesale charging.

~~b.~~c. Keeping Everything Retail by Forgoing Energy Settlements

The use of submetering and development of accounting protocols can help distinguish wholesale and retail treatment of grid-charged energy in response to CAISO dispatch and enable wholesale and retail participation for DERPs. However, in the alternative and/or in the near term, to minimize complexities and provide time to develop the aforementioned accounting protocols, the CPUC and CAISO could establish and maintain that all DERP participation should have their charging energy in response to CAISO dispatch assessed at retail rates; in addition, they could determine that any storage discharge in response to CAISO dispatch should forgo wholesale energy settlement payments in order to avoid any duplicative payment for export compensation rates established under the NEM tariff or through some other mechanism.[57] Ultimately, such a simplified approach may be reasonable if BTM hybrid and energy storage resources are able to access capacity payments and are subject to capacity obligations. In addition, as discussed further below, the forgoing of wholesale energy settlement payments will also clarify any

[57] In addition to the NEM tariff, which compensates exports at the retail rate under NEM1 and NEM2 or potentially under Avoided Cost Calculator rates under the proposed NEM3 successor tariff, there are other proceedings where export compensation rates are being contemplated by the CPUC, such as in Phase 2 of PG&E's Day-Ahead Real-Time Pricing Application.

jurisdictional concerns about interconnecting BTM hybrid and energy storage resources under the Rule 21 tariff instead of the Wholesale Distribution Access Tariff (WDAT). Considering the CAISO already has tariff provisions in place to not settle the storage resource's negative energy for charging,[58] the inverse may also be true for the CAISO to also be able to not settle the storage resource's positive energy for discharging exports.

At the same time, the Joint DER Parties recognize that keeping all things retail leads to concerns that BTM hybrid and energy storage resources are not optimized for energy in the CAISO wholesale markets because of the lack of exposure to wholesale energy prices, which signal when the energy of a capacity resource is needed and how to efficiently dispatch the capacity resource. Recognizing this concern, and until accounting practices are developed and agreed upon for wholesale-retail differentiation, the Joint DER Parties propose that BTM hybrid and energy storage resources be contracted as RA resources with netting of any energy settlements. BTM hybrid and energy storage resources would still bid, schedule, and dispatch in the CAISO wholesale market for energy and make their energy available via bids in accordance with RA rules, but the capacity contracts with LSEs would be structured in a way to "pay back" or net energy settlements to the LSE.

A model that could be adapted would be PG&E's Long-Term RA Agreement with Energy Settlement (LTRAA-ES) contract, which could compensate BTM hybrid and energy storage resources with a "premium" capacity payment that already incorporates an assumed or modeled level of energy settlement.[59] Under this type of structure, the seller is required to pay

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[58] CAISO Tariff Section 10.1.3.4.

[59] By contrast, an RA-Only contract only pays the seller for the capacity attributes of the resource, with the seller retaining dispatch rights and energy and ancillary service revenues, resulting in a "cheaper" RA contract since energy-related dispatch and revenues are not incorporated. Tolling agreements could achieve the same ends, but such a contract may not be appropriate for BTM hybrid and energy storage

PG&E a settlement payment that is calculated on a daily basis using the day-ahead price for the highest priced hours, less the day-ahead price for the lowest priced hours, adjusted for efficiency and variable O&M cost. As a result, the BTM hybrid and energy storage resource would only be paid capacity payments while requiring the seller to pay back a contracted energy settlement amount that would ensure that resources are operating in the market in accordance with modeled dispatch at the time of contracting. The seller would still be settling energy dispatch with the CAISO (addressing their concerns about resources not economically integrating in their market) and would provide assurances that there are no net sales of energy, thereby addressing jurisdictional concerns. In line with the daily availability of RA resources, such energy settlements with the CAISO and payments to the buyer could occur on a daily basis.

This is just one means[60] by which we can achieve the goals of integrating and exposing BTM hybrid and energy storage resources to CAISO wholesale energy prices, providing visibility to the CAISO on available, committed, and scheduled resources, and maintaining the ability of these resources to interconnect on a state-jurisdictional tariff, at least until accounting frameworks are developed to enable greater wholesale-retail differentiation. A simplified approach may also be preferable to address complex questions about how to ensure that these BTM resources are paying for the use of the transmission and distribution system. Since retail rates are not being bypassed through wholesale market integration, these questions around payment for use or cost recovery do not apply.

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resources since the off-taker typically exercises full authority to charge and discharge the battery and acts as both the SC and market participant. Because BTM resources also need to be co-optimized for onsite customer needs, a contract based on the LTRAA-ES may be more appropriate.

[60] Real-time pricing (RTP) was also raised in the working groups as a means to expose CAISO wholesale energy prices to BTM hybrid and energy storage resources. While it addresses the exposure-related issue, this may not address the CAISO's concerns about market integration, visibility, dispatch, and control, with RTP being more fairly categorized as a market-informed model for realizing capacity and energy benefits of BTM resources.

~~D.~~E. Appropriate Incremental Compensation

The fifth issue is:

> [C]hanges such that net energy metering (NEM) and self-generation incentive program (SGIP) resources are compensated for capacity, while discounting for their NEM and SGIP compensation as necessary to ensure that the resources do not receive compensation beyond their value.

The Commission has clarified in SGIP decisions that SGIP payments are a technology incentive, not a payment for services. While the SGIP has a performance-based incentive (PBI) structure where 50% of incentives are paid out over a 5-year period, these payments are based on energy generated or discharged in a given year regardless of when or why the energy was generated/discharged. In adopting the PBI structure, the Commission did not adopt staff's proposal that PBI payments be based on generation/discharge during system peak hours.[61] Thus, PBI payments are based on energy throughput rather than providing grid services.

In a more recent decision, the CPUC provided pathways for SGIP energy storage systems to participate in capacity-based DR programs and directs CAISO participation to meet program greenhouse gas rules. Rather than meeting the round-trip efficiency metric, "legacy" storage systems can integrate into CAISO markets (Section 5.2.3 of SGIP handbook). In creating this rule, the CPUC never found that receiving SGIP incentives and participating in CAISO markets was a form of double compensation. With respect to SGIP, the CPUC has also clarified that:

> [C]ustomer payment or reduced rates received for enrollment in an economic DR program integrated into the CAISO or the DRAM is considered payment for services, not an incentive. As such, SGIP PAs should not, at this time, reduce SGIP incentives for any SGIP project that also is enrolled in an economic DR program integrated into the CAISO or the DRAM.[62]

[61] D.11-09-015 at 29-32.
[62] D.19-08-001 at 66.

Additionally, when addressing incrementality in the Integrated Distributed Energy Resources proceeding, the Commission reaffirmed its position that SGIP and net energy metering are not a form of payment for services provided:

> We address arguments that distributed energy resources receiving SGIP incentives or net energy metering tariffs should not be eligible for another incentive. We reiterate that payments distributed energy resources receive for enrollment and participation in this pilot are in return for a service provided, and therefore not an incentive.[63]

The Joint DER Parties agree, however, that there is a need for ~~an~~ incrementality ~~framework~~considerations specific to RA. Given prior Commission decisions, SGIP incentives should not impact storage systems' compensation for RA and/or other types of payment for services, as long as the SGIP-funded systems are not subject to dispatch in accordance with market conditions. The Joint DER Parties propose to extend this treatment of SGIP incentives to any solar or storage technology incentives, including Solar on Multifamily Affordable Housing (SOMAH), Multifamily Affordable Solar Housing (MASH), and any successor renewable energy or storage incentive program, insofar as these programs do not require dispatch in response to electric system needs.

~~Specific to net metering, there is precedent in the IDER proceeding, and specifically the Partnership Pilot adopted in D.21-02-006[64] for only valuing the storage portion of a BTM resource on a NEM tariff. We recommend that this principle be extended to solar and storage paired resources on a NEM tariff that participate in a DERA, specifically for capacity payment. As discussed earlier in this proposal, there may be a need under a SOD RA framework, if adopted, to account for the metered output of the solar to ensure charging sufficiency.~~

[63] D.21-02-006 at 51.
[64] ~~D.21-02-006 at Ordering Paragraph 10.~~

Accounting for the energy portion of NEM resources was discussed in a working group meeting, with several key takeaways. First, the CAISO clarified that its tariff does not categorically prohibit NEM resources from participating in a DERA - rather, the CAISO tariff specifies that a NEM resource may participate in a DERA if its tariff explicitly allows for wholesale market participation.[65] Second, it was suggested that a compliant NEM tariff be designed with a lower NEM export rate with the value of ~~capacity~~energy removed. The working group sees some merit in the latter recommendation ~~and~~, as discussed more fully in the incrementality section later in this proposal.

Thus, this barrier should be removed from the list as it is inconsistent with prior Commission precedent, and replaced with the need for a consistent incrementality framework for RA. Any considerations of incrementality should be based on a set of principles articulated later in this section.

~~E.~~F. Load Forecasting and Adjustments for BTM Resources

The three agencies—CEC, CPUC, and CAISO—coordinate their forecasting processes for RA and each have distinct roles and requirements. LSEs submit year-ahead forecasts to each of the three agencies. The CEC is responsible for the statewide forecast, also called the Integrated Energy Policy Report or "IEPR" forecast, as well as the RA forecast. The CPUC sets year- and month-ahead system, local, and flexible capacity requirements and allocates DR, local capacity, Cost Allocation Mechanism (CAM), and Reliability Must Run (RMR) credits to LSEs. The CAISO performs annual local capacity and flexible capacity technical studies focused both on the year-ahead and ten years forward, which informs the capacity requirements set by the

[65] *See* CAISO Tariff Section 4.17.3.

CPUC. The CAISO also performs a day-ahead and real-time forecast to ensure reliable operation of the grid, and validates supply plans as part of the RA process.

Relevant to this topic is the current categorization of demand side resources as either "supply side" or "load modifying." Supply-side demand resources are event-based, dispatchable, integrated into the CAISO wholesale market, reflected on LSE supply plans, and removed from the CEC load forecast used to set RA obligations. Load-modifying demand resources, on the other hand, have a consistent, predictable profile on a day-to-day basis, based on voluntary customer response to a rate, tariff, or program and not dispatched or event-based, and are embedded in the CEC forecast used to set RA obligations.

We understand the fundamental concern to be ensuring that customer-sited storage is not double-counted in both the load forecast and supply plans, which we agree must be avoided. Each agency's role in the forecasting process is discussed, below, while identifying any areas where more work is or may be needed.

a. CEC Forecasting Process

The CPUC's annual RA reports describe the CEC's process to forecast electric demand:

> Jurisdictional and non-jurisdictional LSEs must submit historical hourly peak load data [to the CEC] for the preceding year, and monthly energy and peak demand forecasts for the coming compliance year based on a "best estimate approach" that are based on reasonable assumptions for load growth and customer retention . . . To establish the year-ahead load forecast, the CEC first calculates each LSE's specific monthly coincidence factors using the historic hourly load data filed by each LSE. The adjustment factors are calculated by comparing each LSE's historic hourly peak loads to the historic coincident CAISO hourly peak loads. These factors make each LSE's peak load forecast reflective of the LSE's contribution to total load when CAISO's load peaks. The CEC then reconciles the aggregate of the jurisdictional LSEs' monthly peak load forecasts against the CEC's monthly 1-in-2, weather normalized peak-load forecast, for each IOU service area. This reconciliation evaluates the reasonableness of the LSEs' forecasts. As part of the reconciliation, if the aggregate LSE forecasts differ significantly from CEC's forecasts for reasons other than load migration the CEC may adjust individual IOU service area forecasts. Additionally, as specified in D.05-10-042, the CEC makes adjustments to account for the impact of energy efficiency (EE) and distributed

> generation (DG). The sum of the adjusted forecasts must be within 1 percent of the CEC service area forecast. If the aggregated LSE forecasts diverge more than 1 percent from the CEC's monthly weather normalized forecasts, the CEC makes a pro-rata adjustment to reduce the divergence to below 1 percent.[66]

The CEC further detailed its electric demand forecasting process at the joint agency workshop in November 2020,[67] and described some adjustments needed. In this presentation, the CEC explained that forecasted supply-side demand program impacts are added back into Transmission Access Charge (TAC) area hour loads, and that event-based, supply-side demand programs are modeled as supply. Load-modifying demand programs are included in the hourly demand forecast. The CEC receives information on a year-ahead basis from LIP reports filed by third parties and IOUs. These reports are submitted to, and verified by, the CPUC. The CEC pointed out that these impacts were only submitted on an *ex ante* basis, and not trued up *ex post* to ground truth DR program estimates in future forecast years. The CEC also explained that it does not have visibility into hourly performance of storage or solar PV. The CEC could receive program impacts on an *ex post* basis with submetered BTM production data, which is not captured in the current LIP.

The CEC explained that, for the 2021 RA demand forecast, the CEC made several relevant changes. First, all LSEs are required to submit year-ahead forecasts and supporting data, including load modifiers. Until 2021, load modifier data was only requested from IOUs. Second, all LSEs may submit load-modifying programs for adjustment to that LSE's forecast. Third, the CEC is now requesting additional data for energy storage from LSEs, including and not limited to: battery and PV capacity, dispatch procedure, applicable tariff, and commitment to produce

[66] CPUC's 2019 RA Report at 5-6. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf.
[67] November 2020 BTM Workshop, presentation by Lynn Marshall.

during RA hours if applicable. The controlling factor, as the Joint DER Parties understand it, is the statewide IEPR forecast.

In a working group meeting on January 11, 2022, the Joint DER Parties posed the following question for discussion: How can we begin to address concerns surrounding the capability of accurately accounting for load-modifying BTM DERs embedded in the CEC's IEPR forecast (and subsequent RA forecast adopted by the CPUC), and BTM DERs on the supply side, while avoiding double counting?

Several ideas and barriers were offered and discussed. The first idea is to differentiate based on whether a resource is new or existing. For a new BTM DER that is not yet installed, and therefore not yet in the interconnection data set used by the CEC, the LSE could include expected new DER deployment that the LSE intends to use for supply-side resource purposes in the following year, based on their contracting for such resources, as part of the forecast data the LSE submits to the CEC as part of the IEPR forecasting process.

The CEC highlighted that the problem is not synchronizing what the LSE forecasts as supply versus demand side (or load-modifying) DER deployment in its submissions as part of the IEPR process, but rather, the statewide IEPR forecast itself. The CEC includes a statewide forecast of "autonomous" growth of BTM PV and storage in the IEPR forecast, and it is within that forecast that resources must be identified as either supply-side or load-modifying. The IEPR forecast includes assumptions of future BTM PV and storage installations informed by interconnection data, recent trends and economic analysis, including such studies as SGIP studies.

The Joint DER Parties asked whether the statewide IEPR forecast was informed at all by LSE RA forecast submissions. The CEC does not use LSE forecasts as an input to the IEPR DER forecast. The response, in summary, was that the CEC may pursue more comprehensive and granular data collection for BTM storage in the future. There is not currently a comprehensive data resource for storage performance data. The CEC may address this data gap in the future through data collection regulations. While this would support improved CEC zonal modeling and forecasting of DER growth, it would not necessarily map to LSEs and would not resolve the question of how to define any particular resource as incremental to the CEC forecast. That mapping, however, could be supported by data from third parties, LSEs, and the CAISO.

The current process for identifying load-modifying and supply-side DR resources was discussed as a possible corollary for supply side BTM resources, as there is some relevant precedent here. Indeed, even prior to the CPUC's bifurcation decisions in 2014 and 2015, dispatchable, event-based DR resources, which are also inherently demand-side resources, were accounted for as supply resources. The capacity of both load-modifying and supply-side DR resources are calculated on a year-ahead basis by LSEs and more recently third-parties using the LIP. The CEC incorporates the year-ahead LIP into its IEPR forecast. In further discussion with the CEC, the Joint DER Parties learned that receiving accurate DERA dispatch data from CAISO and LSEs is key so that the effects can be removed from recorded load data and add that data back to hourly loads, akin to the current process for supply-side demand response.

The Joint DER Parties recommend further discussion on this topic. In the near term, we recommend that adjustments to the forecast for supply-side BTM DERs be approached on a case-by-case basis and a more formal strategy integrated into the improvements to a forecasting process at the CEC. In a follow-up discussion with CEC forecasting staff, the Joint DER Parties and CEC committed to further discussions to work through the details and identify any forecasting data needs or analytical challenges.

~~a.~~b. *CPUC Forecasting Process*

The CPUC establishes system, local, and flexible RA requirements (inclusive of a 15% Planning Reserve Margin) for LSEs in decisions approved annually in June, applicable for the subsequent RA delivery year. The system RA requirement is based on the 1-in-2, weather normalized, monthly peak load forecast in the CEC IEPR, while local and flexible RA are based on studies performed by the CAISO, as described below. LSEs are required to make year-ahead RA showings for each product by October 31, demonstrating 90% of system and flexible requirements and 100% of local requirements. LSEs also must submit a month-ahead showing demonstrating that they have met 100% of their system and flexible RA obligation for each month of the year, and, for June through December, that they have met 100% of their local RA obligation.

During the RA compliance year, LSEs can adjust their load forecasts on a monthly basis to account for load migrations, which must occur at least 25 days before month-ahead compliance filings are due. LSEs submit these monthly forecasts to the CEC for evaluation; the CEC then reviews the revised forecasts and customer load migration assumptions. The revised monthly load forecasts update the year-ahead forecast and inform monthly RA obligations. The CPUC's Energy Division also uses these monthly forecasts to recalculate load shares, which are then used to reallocate CAM and RMR credits on a quarterly basis.

These month-ahead adjustments are solely focused on load migrations and cannot account for "changing demographic or electrical conditions,"[68] which the working group interprets to include updated assumptions around new or incremental DER interconnections or operations. Below, this report reviews the possibility that "changing electrical conditions" could

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[68] 2019 Resource Adequacy Report at 8. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf.

be included as load-modifying adjustments to month-ahead RA obligations, alongside load migrations.

~~b.~~c. CAISO Forecasting Process

LSEs submit forecasts to the CAISO, which are used to monitor day-ahead and real-time market operations and reliability. The CAISO uses the statewide forecast for transmission planning and to set flexible capacity 3-hour net load ramp requirements. LSEs file day-ahead forecasts with the CAISO each day, for each TAC area. The CAISO performs a day-ahead demand forecast that considers, among other things, the following factors: weather, BTM forecasted and actual solar PV production, and demand.

Each year, the CAISO conducts a Local Capacity Technical Analysis, which identifies the capacity required in each local capacity area in 1-in-10 weather year and N-1-1 contingencies, based on forecasted load, and existing resources and transmission. The CAISO also performs a Flexible Capacity Technical Analysis each year. The CAISO produces a year-ahead and 10-year ahead forecast for each. The CPUC uses these analyses to set year-ahead local and flexible capacity requirements for LSEs in its jurisdiction.

The CAISO has explained that receiving forecasted BTM solar PV data is essential, as total BTM PV capacity is expected to increase substantially over the next decade. To improve daily forecasting, it may be necessary for the CAISO to receive data from other BTM resources.

~~c.~~d. Assessment of Existing Forecasting Processes for BTM Resources

From the Joint DER Parties' review of existing forecasting processes, it appears that there is a need to receive more granular data for BTM resources. As articulated in the discussion of the CEC load-forecasting process, submetered BTM resource data would be helpful to assess *ex post* load impacts, as well as a process for identifying new and existing BTM storage resources that will be used in supply-side aggregations, to ensure these resources are not embedded in, and fully incremental to, the load forecasts that are used to set an LSE's RA obligation.

Possible modifications to the process could include a specific true up for LSE procurement of BTM resources for capacity, which can be informed by estimation of supply-side BTM DER capacity at specific nodes, which is possible and done today for other demand-side resources. Based on the basic principle of additionality, LSEs could submit how much capacity they receive from existing BTM systems and how many systems are anticipated to come online, to determine incrementality to existing forecast assumptions as needed. This adjustment process should be timed to enable reflection in year-ahead RA showings in October at a minimum~~, and should also be carried over to month-ahead showings, rather than only allowing for month-ahead adjustments based on load migrations as described above~~. This especially pertains to ensuring that any CAISO dispatch of exporting BTM DERs is fully incremental to the routine, non-export cycling of batteries during non-event hours that should be embedded in an LSE's load forecast it submits to the CAISO, as well as the CAISO's assumed BTM profiles that are baked into its market runs.

The Joint DER Parties are open to exploring ways to enhance coordination between DERAs, LSEs, the CEC, and CAISO to ensure high-confidence accounting of BTM DERs in operational and planning forecasts.

~~F.~~G. Interaction with Existing BTM Resources such as Proxy DR

The penultimate issue identified by the Commission is the "interaction of such resources with existing BTM resources such as proxy DR,"[69] though it is not entirely clear what this refers to. One interpretation is that the concern is whether the PDR model and baseline methods could

[69] D.20-06-031 at 32; D.21-06-029 at 53-54.

be expanded to accommodate exporting BTM resources. Another may be the question of how to determine the "interactive effects" of exporting BTM RA resources compared to curtailment DR in real-time operations, such that the value of these resources can better be accounted for in planning on an *ex post* and *ex ante* basis. Regarding the latter, such effects are influenced by many variables, including an evaluation of the market bids and dispatch order of curtailment PDRs versus exporting BTM resources, as well as ELCC studies that determine the reliability contribution of incremental resources in relation to all other resources, based similarly on "first in/last in" dispatch in the supply stack.

As to any potential interaction between the resource types, we do not propose that the same resource be allowed to dually participate in both a PDR and DERP aggregation. Further, the CAISO has proposed to create a new load reduction option within the DERP model, and has not articulated, to the Joint DER Parties' knowledge, any issues associated with PDR and DERA interaction. Thus, interaction does not appear to be an issue, but enablement of DERA resources remains unresolved. The Joint DER Parties recommend the following actions to enable existing processes and frameworks to enable exporting BTM resources.

First, Rule 21 should be amended to enable interconnection of market-integrated DERAs. This must include deliverability considerations, as described below, as well as a tariff for accessing distribution service for charging and discharging energy that is settled at wholesale.

Second, the Commission must set metering and accounting rules to enable multiple-use DERAs ~~by determining when~~ . As discussed in Section D above, the Joint DER Parties propose that, to minimize complexities in the near-term, the CPUC and CAISO should establish that all DERP participation settles charging and discharging energy ~~should be settled at wholesale versus retail. This will set the stage for the CAISO to amend its DERP model such that DERAs are no~~

~~longer settled at~~at retail rates, with contract structures that expose BTM resources to wholesale energy prices and optimize cycling while netting any wholesale energy ~~prices for all charging and discharging for all hours of the day, which results in these resources paying twice – at both wholesale and retail levels – for~~settlements. Over time, the ~~same charging energy. Enhanced settlement processes~~ CPUC and ~~coordination between the~~ CAISO~~, DERPs, and LSEs~~ can ~~ensure that wholesale energy is only paid for once. One such solution would be for the CAISO to bill a storage device at the LMP for charging energy directly preceding a market award. This charging energy can be credited~~work to develop necessary submetering and accounting protocols to determine when and how to settle charging and discharging energy at wholesale versus retail..

Third, to enable DER providers to manage DERAs as an RA resource in the CAISO's DERP model, the Joint DER Parties recommend that the Commission's Rule 24/32 tariffs be amended to explicitly account for customers that participate in a DERA, rather than solely as a DR resource that participates through either the ~~LSE's load settlement with the CAISO and also removed from retail generation charges on~~PDR or Reliability Demand Response Resource (RDRR) models. The overall allowances and requirements of Rule 24/32 – such as processes for a DER provider to access a customer's ~~bill. The~~ Revenue Quality Meter Data, DER provider registration at the Commission ~~would play a big role in figuring out these rules, including determining the symmetrical treatment for discharged energy.~~, and UDC review of customer Service Agreements submitted to the CAISO to ensure that customers are not participating in two supply-side programs – are equally applicable regardless of whether a customer is part of a DERA versus PDR aggregation. These changes may need to be pursued as part of the Demand Response proceeding, but the Joint DER Parties posit that many, if not all, of the needed amendments will be non-substantive and could be submitted without policy findings by the Commission.

Finally, as discussed above, the ~~Commission~~CPUC needs to establish a QC methodology for exporting BTM resources as a foundational action. The Joint DER Parties recommend adopting the value for IFOM storage and hybrids as a starting point for consideration. The QC should be the full discharge capacity of the battery, as measured at the inverter. This proposal is discussed further later in this report, under Section III – PROPOSALS.

~~G.~~H. Deliverability Determination

Deliverability is an important feature of the RA program for exporting IFOM generation and storage facilities. To provide RA capacity, a resource must request and obtain deliverability status as part of the Queue Cluster interconnection process; for distributed generation (DG) and energy storage resources connecting on the distribution system, this process is known as distributed generation deliverability (DGD) process. ~~.~~The CPUC's RA Program is designed to provide sufficient resources to the CAISO to ensure safe and reliable operations of the grid in real time, where "deliverability" is required to qualify as an RA-eligible resource. In essence, generator deliverability is intended to ensure that the electrical grid can accommodate the full output of all capacity resources, and that any individual generator or storage resource seeking deliverability will not be limited in their dispatch by other capacity resources. If a resource cannot be "deliverable" taking into account the simultaneous dispatch of existing and proposed capacity units in an electric area, then transmission upgrades may be identified to address this "deficiency" in deliverability.[70] ~~to assess whether the existing transmission capacity can support~~

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[70] See CAISO Generator On-Peak Deliverability Assessment Methodology (March 2020), http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf. http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf.

~~the requested deliverable MW, or if existing capacity is not sufficient, then to identify necessary network upgrades to the CAISO-controlled transmission grid. This deliverability~~

The DGD assessment process is available to resources interconnecting under the WDAT or Rule 21 tariff. The study process results in a deliverability assessment of MW quantities of Potential ~~Distributed Generation Deliverability (DGD)~~DGD at specific nodes on the CAISO-controlled grid for assignment to specific DG facilities already interconnected or seeking interconnection on the distribution system. The DGD application window spans mid-March to mid-April~~. After~~, while the technical assessment occurs in February and results in a DGD assignment by May. Specifically in regards to the study process, after using the most recent Phase 2 interconnection study deliverability power flow base case and taking into account prior commitments of deliverability, the CAISO adds to the study model by identifying all nodes that have non-zero distributed generation MW in one of the most recent Transmission Plan renewable portfolios along with the interconnection requests.[71] To be eligible to obtain a deliverability status assignment, the DG facility must: (1) have an active interconnection request[72] and be assigned a queue number; and (2) be in commercial operation or have a commercial operation date (COD) that is no later than three years from the last date on which the application was submitted for the current cycle. Notably, NEM DERs currently do not get deliverability since they are netted with the load - an issue that must ultimately be addressed, but non-NEM resources can obtain deliverability.

[71] CAISO Business Practice Manual for Distributed Generation at 11-12.
[72] Notably, relevant to BTM hybrid and energy storage resources is the requirement that interconnection requests can be in no smaller than 0.01 MW increments. *See* CAISO Tariff Section 40.4.6.3.1.3.

Unlike Transmission Plan Deliverability (TPD) allocation, which is assessed and administered by the CAISO, the DGD process is annually administered by the UDC.[73] Upon completion of the deliverability assessment, the IOU Participating Transmission Owners (PTOs) will assign deliverability status on a first-come, first-served basis in a priority order, first for existing facilities in commercial operation (prioritizing projects with earliest COD to the most recent COD), and then proceeding to assign deliverability to active interconnection requests (again, prioritizing projects with earlier CODs).[74] Once assigned deliverability, the facility must come online within six months of the COD specified in the interconnection agreement to retain such assignment, unless any delay was due to the UDC's completion of necessary deliverability-related upgrades. Any Potential DGD that is not assigned and remaining is called "unassigned Potential DGD"—and will be preserved for the next cycle.

~~However~~With all of the above in mind, however, there are several key areas where the process and categories of deliverable RA will need to be modified to support exporting DERs as RA-eligible capacity. ~~Unlike~~First, unlike resources under a DRP-A that currently recognizes load reduction only, NGRs under the ~~DERPA~~DERP-A currently do not qualify for RA because of the previously-assumed lack of deliverability assessment methodology for an aggregation of export-capable DER resources, along with the rules around 24x7 availability for RA resources, which are addressed above. Even for DRP-A resources, the lack of a deliverability assessment methodology for an aggregation of DER resources prevents RA capacity payment for the incremental export capacity from DR resources~~. This was recognized by the~~, which points to how any effort to address deliverability issues is not wasted, regardless of one's view of the PDR

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[73] CAISO Tariff Section 40.4.6.3.

[74] CAISO Business Practice Manual for Distributed Generation at 19.

or DERP model as being the preferable or viable path forward in realizing BTM export capacity. This was recognized by CAISO as requiring "follow-on effort" by the CPUC to determine the rules by which DERAs could qualify for RA "recognizing their unique deliverability challenges."[75]

Second, while these current~~The CPUC's RA Program is designed to provide sufficient resources to the CAISO to ensure safe and reliable operations of the grid in real time, where "deliverability" is required to qualify as an RA-eligible resource. In essence, generator deliverability is intended to ensure that the electrical grid can accommodate the full output of all capacity resources, and that any individual generator or storage resource seeking deliverability will not be limited in their dispatch by other capacity resources. If a resource cannot be "deliverable" taking into account the simultaneous dispatch of existing and proposed capacity units in an electric area, then transmission upgrades may be identified to address this "deficiency" in deliverability.[76]~~

~~These~~ processes are more readily translatable for transmission-connected IFOM generation and energy storage resources,~~ but~~ BTM hybrid and energy storage resources will also need to demonstrate deliverability to qualify exports for RA using the existing DGD process, likely with some modifications. ~~DER deliverability means the output from the DER can be delivered to the aggregate CAISO load simultaneously with other Full Capacity Deliverability~~

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[75] 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* at 7 (August 9, 2018) (MUA Report). *See also* MUA Report at 8 (where the working group notes that "DERP-A does not qualify for Resource Adequacy, with no active CPUC proceeding to address DERP-A for BTM").
~~76~~

~~[76] See CAISO Generator On-Peak Deliverability Assessment Methodology (March 2020), http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf. http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf.~~

~~Status resources in a load pocket without being constrained by the transmission capability. Notably, NEM DERs currently do not get deliverability since they are netted with the load, but non-NEM resources can obtain deliverability. Unlike Transmission Plan Deliverability (TPD) allocation, which is assessed and administered by the CAISO, the DGD process is annually administered by the UDC.[77] Distributed generation and storage resources interconnecting under the WDAT or Rule 21 are eligible for this annual process, which starts with a technical assessment in February and results in a DGD assignment by May. To be eligible, resources must meet commercial online dates within three years, with retention of allocated DGD allowed up to 6 months from the original commercial online date. Any Potential DGD that is not assigned and remaining is called "unassigned Potential DGD"—and will be preserved for the next cycle.~~The current deliverability study and allocation processes present a number of challenges for BTM energy storage resources. By virtue of the annual cadence of the DGD allocation process, ~~VPP aggregators~~DERP-A resources face challenges in aligning their customer acquisition and project development cycles with the current study and allocation process; unlike IFOM generation and storage projects that have a handful of discrete projects, BTM aggregations can involve tens or hundreds of projects that would need to align with these processes. In addition, the current process is limited by the CPUC allocating renewable portfolios through the IRP process and UDCs estimating the ~~potential~~Potential DGD available for allocation, which could upfront limit the amount of resources that could qualify for RA; to this end, it is important to point out how the ~~potential~~Potential DGD has declined to zero in 2021, reflecting a broad trend by which the CPUC and UDCs have allocated few resources to be eligible to receive ~~potential~~Potential DGD. Finally, the current DGD allocation process can be limited by how any necessary upgrades are

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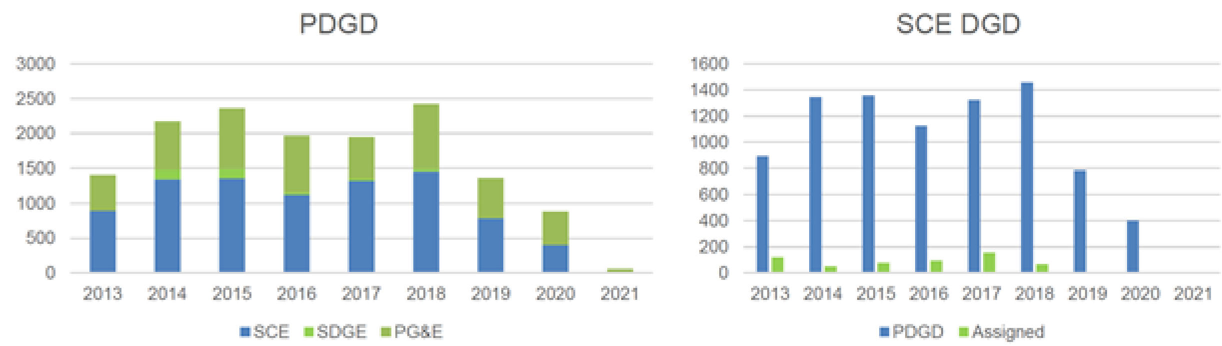
~~[77]~~

~~[77] CAISO Tariff Section 40.4.6.3.~~

funded and built—these are typically upfront financed by interconnection customers for their *pro rata* share of the network upgrade.

Figure 5: Potential DGD & Utilization of Potential DGD[78]



There is nothing that inherently prevents exporting DERs from being deliverable, but the current process is better suited for large project development and not conducive to organic, bottom-up, customer-driven adoption of DERs, thus presenting barriers to the ability of export-capable DERs to qualify their full capacity for RA. DERAs interconnect at different sites and different times, where each site is not always planned for or known as part of an aggregation from the onset. It is not practical, for example, to expect that BTM hybrid or storage design and installations be held up in a 2- to 6-year cluster study process on a project-by-project basis within a single customer acquisition and deployment cycle. Without timely results on any deliverability-related upgrades, if necessary, optimal storage design (*e.g.*, sizing of the storage device relative to customer load to optimize export capacity) is also held up. In contrast to larger IFOM projects, the key consideration for BTM hybrid and storage projects is their aggregate impacts, which cannot be assessed upfront all at one time.

[78] *Transmission-Distribution (T&D) Interface Coordination Working Group* at Slide 14, presentation by Songzhe Zhu (CAISO) for DER Deliverability Educational Working Group (July 16, 2021).

a. Alternatives to Participant Funding Model

The time is ripe for the CPUC to consider a reformed approach to distribution planning and interconnection in recognition of the aforementioned barriers and the record levels of clean generation, energy storage, and DER buildout expected[79] and required to meet the state's SB 100 goals.

The FERC recently issued an Advanced Notice of Proposed Rulemaking (ANOPR) presenting potential reforms to improve the electric regional transmission planning and cost allocation and generator interconnection processes, especially given the lead time for transmission upgrades and the *anticipated future* clean generation and storage necessary to advance the nation's decarbonization goals and reliability objectives, including those that are not yet in the interconnection queue.[80] To this end, FERC raised interesting potential reform ideas for stakeholder comment on whether transmission facilities could be built prior to generators entering the interconnection process in anticipation of future generation and storage planning and procurement scenarios. Perhaps in response to the FERC ANOPR, CAISO also raised questions for stakeholder comment in its 2021 Interconnection Process Enhancements Initiative regarding whether longer-term Phase 2 reforms should consider a revised TPD allocation process whereby TPD is allocated to LSEs with RA obligations, similar to the DGD allocation process, in lieu of the current CAISO-wide annual process.[81] Similarly, by virtue of some of the questions posed by the CAISO, they are open to different interconnection application requirements for locationally-

[79] R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future* at 7-10 (July 2, 2021), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF.
[80] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 at P 44 and 48 (2021).
[81] *2021 Interconnection Process Enhancements Preliminary Issue Paper* at 9-10 (September 30, 2021), *available at* http://www.caiso.com/InitiativeDocuments/PreliminaryIssuePaper-InterconnectionProcessEnhancements2021.pdf.

flexible resources such as standalone batteries—something that could be similarly applied to BTM hybrids and storage resources. While recognizing that transmission interconnection and deliverability follow different requirements and processes, the FERC and CAISO considerations create an opportunity to assess whether similar proactive and preemptive approaches could be taken to accommodate BTM hybrid and storage export capacity and ensure that they are deliverable for RA purposes.

Outside of California, several states have embarked on new models to support DER interconnection and associated distribution upgrades. The Massachusetts Department of Public Utilities (DPU), for example, launched a docket and issued a Straw Proposal to consider alternatives to DER interconnections following the cost causation principle, whereby cost responsibility follows cost incurrence.[82] To accommodate forecasted load growth or enable the interconnection of capacity beyond currently proposed facilities, DPU staff developed options to either: (1) allow its jurisdictional Electric Distribution Companies (EDCs) to propose distribution system upgrades to this end and assess a Common System Modification fee[83] that is paid by interconnection facilities upfront regardless of whether their interconnection triggered upgrades;[84] or (2) establish Capital Investment Project (CIP) fees associated with specific distribution upgrades and have the EDCs upfront fund the CIP and recover the costs through a reconciling charge.[85] In either case, the DPU staff proposal recognizes that DERs have aggregate

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[82] *Vote and Order Opening Investigation*, D.P.U. 20-75 (October 22, 2020), *available at* https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber/20-75.

[83] DPU staff did not propose a specific fee but proposed a number of different possible structures, such as a minimum fee, fixed $/kW fee, cost ceiling, or a fee based partially or entirely on export capacity.

[84] *Attachment A: Distributed Energy Resource Planning Proposal and Request for Comments*, D.P.U. 20-75, Att. A (October 22, 2020), *available at* https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12796088.

[85] The CIP fee would represent the $/kW cost of the investment, scaled to the capacity of the interconnecting DER.

operational and infrastructural impacts and are developed in smaller and modular increments over time while distribution upgrades are lumpy in nature.

In Maryland, an Interconnection Workgroup filed a Small Generator Facility Interconnection Phase III Report that similarly considered alternatives to Maryland's existing "causer pays" model of funding distribution grid upgrades required for new interconnections, among other topics. The Maryland Public Service Commission subsequently issued Order No. 89933 to act on recommendations for a workgroup.[86] Under the Maryland Cost Allocation Model proposal, jurisdictional utilities can recover the costs of upgraded hosting capacity through the ratemaking process or a regulatory asset, whereby all interconnection customers using the upgraded capacity would pay their proportional share of the costs based on the share of the upgraded capacity attributable to them and pay fees to reduce the amounts needed to be recovered through rates. Below a certain threshold, some small interconnection customers would not be charged these upgrade capacity fees. While discouraging preemptive expansion, utilities could size hosting capacity upgrades based on forecasted need.

The above represents a sampling of some of the federal policy landscape and state-specific policy debates and pilots being explored to address the growing and urgent challenge of aligning resource procurement and project development processes with interconnection and T&D infrastructure buildout. Undoubtedly, lessons learned could be drawn from outside California, but these developments point to the need and potential for California to also think expansively on issues around interconnection and deliverability reform to facilitate the development of BTM hybrid and energy storage resources with the greatest range of capabilities, inclusive of their export capacity.

[86] Docket No. PC44, *Order No. 89933*, *Order on Recommendations of Interconnection Workgroup* (September 9, 2021).

~~a.~~b. *LSE Allocation & Participant Fee Model*

Rather than the current model where a lump sum fee or participant financing is assessed for each project interconnection or for the upfront *pro rata* share of a project within a cluster study window, the CPUC and CAISO should coordinate on developing a new model or revisions to the existing model that: (1) proactively identifies necessary distribution upgrades to accommodate export capacity deliverability based on LSE interest and/or procurement needs; and (2) fairly allocates or passes through the costs associated with deliverability-related distribution upgrades to participants and/or developers via $/kW fees.

First, in terms of proactively identifying necessary distribution upgrades to accommodate export capacity deliverability, the CPUC and CAISO should collaborate in developing a process by which LSEs can proactively seek existing DGD allocations and/or request study for incremental deliverability based on their anticipated "enrollment" or "participation" of BTM hybrids and storage resources with export capacity. For instance, a community choice aggregator (CCA) could indicate its plans, either as part of the regular IRP filings or through an aggregated interconnection request with the CAISO, for 10 MW of BTM hybrid and/or storage export capacity through pending or expected bilateral contracts or program/tariff enrollment. Interconnection and deliverability studies will subsequently be conducted as part of the normal cluster study processes to identify the necessary upgrades, if any, and then to allocate existing available or new incremental deliverability to the requesting LSE to accommodate these aggregated exports. Since the CAISO will not be studying individual project interconnection requests, the grouping of individual BTM hybrid and storage sites into an aggregated interconnection request will require an understanding of distribution topology; however, since the deliverability studies are intended to capture aggregated impacts to be able to deliver export capacity to the CAISO bulk electric system, these groupings can occur at specific nodes of the T&D interface where transmission or distribution upgrades may be needed.

This process generally aligns with the current DGD process and the existing policy-driven needs assessment where the CAISO performs a deliverability study in the Transmission Planning Process (TPP) to determine nodal MW quantities of deliverability status that can be assigned to DG resources, without requiring any additional delivery network upgrades and without adversely affecting the deliverability status of existing generation resources or proposed generation in the interconnection queue. However, as we understand it, unless the CPUC provides the CAISO with IRP resource portfolios for the CAISO to study as potential policy-driven needs and projects, the CAISO will have nothing to study to accommodate deliverable DERAs. In many ways, since the IRP resource portfolios are also a function of what LSEs include in their individual IRPs, there may be some consideration of how LSEs can submit granular information about the location of intended or planned DERAs to meet their various decarbonization goals and reliability objectives.[87] Alternatively, in the next revision to the IRP busbar mapping process, there could be some priority given to how energy storage resources in the system portfolio could be mapped to specific busbars where LSEs have indicated procurement interest (not only based on commercial interest in the transmission queue cluster) or for particular policy reasons (e.g., local capacity needs). At the same time, for this to work, we emphasize that the CPUC would need to establish a clear and upfront QC methodology for BTM hybrid and energy storage resources. Absent that, for example, LSEs are unlikely to include such resources in their individual IRPs.

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[87] This is an area that requires further exploration as to the degree to which locational granularity could be provided in individual IRPs. We have observed that LSEs' planned resources may not always be granularly provided, sometimes listed as "generic" resources subject to the CPUC's busbar mapping process.

Next, under the current approach, the CAISO apportions these Potential DGD quantities to UDCs, including both the IOUs and publicly-owned utilities within the CAISO controlled grid, who then assign deliverability status to eligible ~~distributed generation~~DG resources~~.~~ ~~However~~; however, in contrast to this approach, ~~this~~the CPUC and CAISO should consider a new model or revisions to the existing model that would instead allocate DGD quantities to LSEs, not just the UDCs, who would then be responsible for assigning DGD to BTM hybrid and storage resources that the LSE either contracts for (bilateral RA contract with counterparty) or commits to provide RA services via programmatic terms, conditions, and requirements (program enrollment).[88] With LSEs, beyond the utilities, having a better understanding of procurement needs and locations, it may be a more efficient means to allocate deliverability to BTM hybrid and energy storage resources through a process not entirely managed and controlled by the UDCs.

~~Second~~Second, the process and rules for how upgrades are financed and built merit reexamination. Under a potential new model, once the costs of any transmission or distribution upgrades have been identified to enable the requested deliverability, the LSE ~~would~~could then fairly allocate the costs for the upgrades on a *pro rata* basis, such as via a $/kW fee structure, based on export capacity.[89] How these upgrade costs are passed onto developers should be left up to the LSEs to take into account the unique characteristics of their service population, where different fee structures may be developed. For example, a location-specific fee structure could be established to align with the specific upgrades at that particular node, or a "common" fee

[88] Since Phase 2 interconnection and deliverability studies incorporate generation and storage projects in planning and power flow models in accordance with their commercial online dates, it may lend itself to LSEs sourcing BTM hybrids and storage via bilateral RA contracts to provide binding phased and/or final commercial online dates to shift some of the risk.

[89] Importantly, the fees or pass-through of costs should be based on export capacity, not installed capacity or facility size.

structure could be established to support broader objectives and ensure equity of project development, which may be particularly relevant for LSEs with more diverse customer bases (*e.g.*, rural and urban, high- and low-income). Alternatively, the recovery of these upgrade costs could also be achieved through bilateral contracts with specific vendors, or "interconnection fees" could be collected over time to build up a pool of funds for future upgrades regardless of whether upgrades were triggered. With the CPUC actively considering slice-of-day reforms, the export capacity and deliverability upgrades should be aligned with the intended operations and shown slices and avoid overcollection based on DER export in the worst-case scenario.

Granted, certain provisions will need to be developed to provide safeguards against the possibility of LSEs or ratepayers bearing the unrecovered costs of system upgrades when there is an "under-subscription" or underutilization of the upgrades. In addition, to avoid duplicative infrastructure investments, the identification of any upgrades should coordinate with the utilities' distribution planning process to support load forecast related or load project upgrades ("multiple-value projects"), with the proportional and incremental costs shared with the resources seeking deliverability upgrades associated with export capacity. In some cases, there may not need to be upgrades if the utilities' Integrated Capacity Analysis (ICA) tool shows available hosting capacity.

In the long term, the CPUC could potentially develop an export tariff that efficiently prices and takes into account deliverability-related distribution upgrades needed in the aggregate and over a longer time horizon. However, this may require long-term technology implementation, which would require further exploration in a rulemaking. In addition, if preemptive distribution upgrades are allowed and utilities can earn a rate of return on these rate-based investments, then it may need to be addressed in ratemaking proceedings or specific rate cases, whereas currently distribution upgrades are financed by third-party participants without a rate of return that likely will be paid off before the full depreciation timeline of the asset. To ensure installed capacity from the distribution upgrade is fully utilized, utility performance metrics may also need to be developed to avoid overestimates of required export capacity.

In conclusion, considering the above, the CPUC will need to work with the CAISO to adapt the current deliverability assessment methodologies to allow for preemptive and aggregated analysis of upgrades necessary to support BTM hybrid and storage export capacity. This action cannot take place in the RA proceeding alone and may require follow-up in a CAISO initiative given that deliverability methodologies fall within the purview of its tariff. For the CPUC's part, the current Rule 21 proceeding (R.17-07-007) is positioned to further refine proposals addressed in this report regarding distribution upgrade cost sharing and allocation.[90] The current "causer pays" model for individual or clusters of BTM interconnection customers may need to evolve to one that preemptively identifies any necessary upgrades and allocates those costs in an alternative way, such as via a fee.

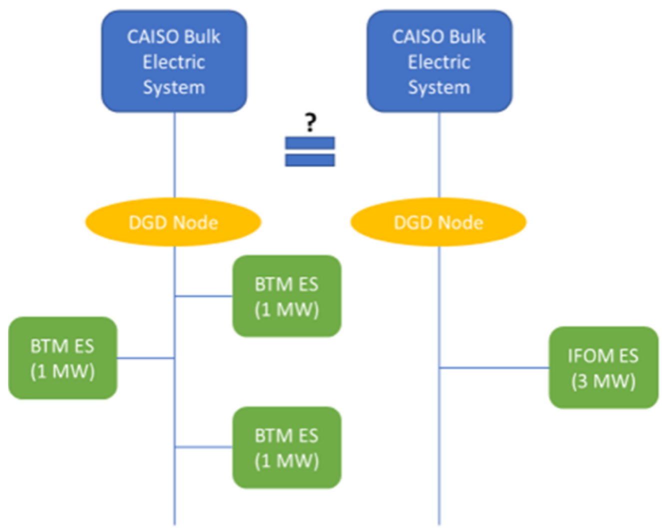
~~b.~~c. Deliverability Study Methodology and Process

Currently, the deliverability study methodology for RA resources is performed annually to focus on on-peak demand conditions.[91] Specifically, the study involves an assessment of simultaneous dispatch of all generation in HE18-22 and HE15-17 in the summer months.[92] Under the DGD process, the CAISO performs deliverability studies based on interconnection

[90] R.17-07-007, *Assigned Commissioner's Second Amended Scoping Memo and Ruling for Phase II of Proceeding* (May 12, 2021) (*see* Issue 12: "How should the Commission address cost sharing of distribution upgrade costs in general?").
[91] CAISO Tariff Section 40.4.6.1.
[92] *See* CAISO Generator On-Peak Deliverability Assessment Methodology at Tables 3.1 and 3.2. Non-intermittent generators are assessed at the PMax set to the highest summer month QC in the last three years, with energy storage generation set to the 4-hour discharging capacity limited by the requested maximum output from the generator.

customers seeking deliverability capacity allocation, ~~likely~~ modeled to specific nodes, and informs the UDCs of the results.[93] In addition, the CAISO outlines how it can process any interconnection study as applicable via WDAT or Rule 21, so long as any adverse impacts on the CAISO-controlled grid are mitigated, consistent with Appendix DD. To this end, a copy of the WDAT or Rule 21 System Impact Study must be provided.[94] Finally, upon completion of interconnection studies and allocation of deliverability, DERs must go through a New Resource Implementation (NRI) process to model the DER into the CAISO's full network model, register the SC, and execute a participating generator agreement prior to going into operation.

Figure 6: Representation of DERA versus IFOM ES at DGD Nodes



~~However, while~~

While there is a deliverability study process available today for single-site DERs seeking interconnection through the WDAT or Rule 21 process and seeking deliverability through the DGD process, there is no explicit process in place today ~~applicable~~affirming the applicability to BTM aggregations—one of the key barriers to allowing BTM hybrid and energy storage

93 CAISO Tariff Section 40.4.6.
94 CAISO Tariff Section 25.2.

resources to receive a QC value. ~~To develop this methodology, some~~Given the nodal nature of the ~~key questions or areas of development include:~~

- ~~**Degree of alignment of**~~ DGD ~~**nodes with sub-LAPs:** Currently, DERs within a DERA must be located in a single sub-LAP and cannot exceed 20 MW,[95] and DGD assessments are conducted for specific "nodes" at the T&D interface.[96] If well-aligned, this could help facilitate a consistent~~ deliverability study process ~~for DERA interconnection study processes and DERA operations.~~

- ~~**Representation of DERAs in**~~, however, the ~~**DGD study process:** Since the CAISO does not necessarily have visibility into the specific DERs or distribution-level constraints, the CAISO should affirm whether DERAs behind a simple node can be modeled similarly for a single-site~~Joint DER ~~and a multi-site DERA. For example, is~~ Parties believe that there ~~any~~is no need to change the current deliverability study methodology. As illustrated in the figure above, there should be no difference in the DGD study model for a 10-MW single-site IFOM energy storage resource versus ten 1-MW BTM energy storage resources behind the same node and with the same intended operations~~? If not, then~~. Since the CAISO does not necessarily have visibility into the specific DERs or distribution-level constraints, the CAISO should explicitly clarify that DERAs behind a single node can be modeled similarly for a single-site DER and a multi-site DERA. If not, then the CAISO should specify how the DGD process could

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[95] ~~CAISO Tariff Section 4.17.A. Sub-LAP is a defined subset of pricing nodes within a default load aggregation point (default LAP). Sub-LAPs were initially developed with the advent of congestion revenue rights to reflect major transmission constraints within each utility service territory. The Sub-LAP rule for DERPs ensures that they do not create additional congestion.~~

[96] ~~In each utility's 2021 Potential DGD Assessment Report, Potential DGD is reported at 29 nodes for PG&E and at four nodes for SCE (Antelope, Etiwanda, Mira Loma, and Vista Substations). Most likely, sub-LAPs are in excess of these DGD nodes, so it would be helpful to map them to each other to determine where aggregations can be made and where deliverability can be shared by aggregated resources.~~

be modified to allow for DERAs with specific informational submission requirements that support DGD study models.

~~**Coordination**~~Furthermore, an additional area of clarification is around whether and how deliverability studies at the DGD nodes align with, overlap, or interplay with sub-LAPs, which is how DERAs are defined. Currently, DERs within a DERA must be located in a single sub-LAP and cannot exceed 20 MW,[97] whereas DGD assessments are conducted for specific "nodes" at the T&D interface.[98] In our review of the CAISO tariff and interconnection procedures, and through conversations with CAISO staff, we understand that the DERA market participation rules and the deliverability study process are not related. For example, if there is a DERA that falls within a single sub-LAP but some portion of the aggregation can be mapped to one DGD node and another portion at a separate DGD node, the DGD assessment will produce deliverability results separately for each portion, though they will be studied in the overarching deliverability assessment for their interactive effects (i.e., there may not be one-to-one effects). As a result, the Joint DER Parties do not see any changes required in this regard, except that it would be helpful to provide these explicit clarifications to the CPUC, LSEs, and market participants to inform how they construct DERAs and understand the various factors and risks associated with DERAs that span multiple DGD nodes.

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[97] CAISO Tariff Section 4.17.A. Sub-LAP is a defined subset of pricing nodes within a default load aggregation point (default LAP). Sub-LAPs were initially developed with the advent of congestion revenue rights to reflect major transmission constraints within each utility service territory. The Sub-LAP rule for DERPs ensures that they do not create additional congestion.

[98] In each utility's 2021 Potential DGD Assessment Report, Potential DGD is reported at 29 nodes for PG&E and at four nodes for SCE (Antelope, Etiwanda, Mira Loma, and Vista Substations). Most likely, sub-LAPs are in excess of these DGD nodes, so it would be helpful to map them to each other to determine where aggregations can be made and where deliverability can be shared by aggregated resources.

As discussed above, the applicability of the current commercial viability and deliverability retention criteria will also require some clarifications or revisions to accommodate BTM hybrid and energy storage project development. Whereas COD is more clear and appropriate for IFOM projects, DERAs are almost always built over time (i.e., not all at once), where VPP contracts are typically executed in a way where certain development milestones are in place for customer sites are progressively developed and incorporated into the VPP portfolio - e.g., 2 MW in 2023, an incremental 2 MW in 2024, and an incremental 2 MW in 2025 for a total VPP contract of 6 MW. Such resource buildout is not unique or new since the CAISO currently accommodates phased construction of IFOM projects upon mutual agreement in advance with the CAISO and PTO.[99] Similar rules should apply to DERAs, but the process could benefit from refinements to not make this a case-by-case process but a broadly applicable rule for BTM hybrid and energy storage resources. Explicit clarifications are also needed to affirm that phased development for DERAs do not jeopardize the lost retention of deliverability under the current process, so long as a power purchase agreement (PPA) or off-take contract is in place that stipulates the development milestones. These clarifications and refinements are all necessary to mitigate transaction costs, avoid delays, and minimize uncertainty for DERAs seeking deliverability and for LSEs in having confidence to be able to procure from these resource types.

- In addition to the affirmations and clarifications to the CAISO assessment of DGD and modifications to the process, there will need to be coordination of distribution system impacts with transmission system impacts~~:~~. While the DGD process outlines CAISO grid deliverability, it does not specify or consider distribution system deliverability that ensures that generation capacity at the facility's point of interconnection is able to be

[99] CAISO Tariff Appendix DD Section 6.7.1.

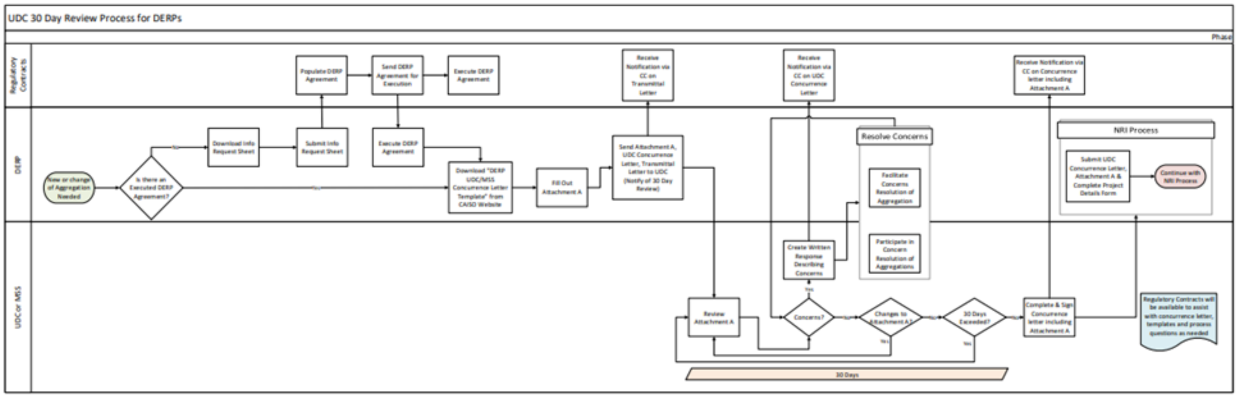
wheeled through the distribution system and to the CAISO grid. Such considerations are included in the WDAT tariff[100] but not reflected in the Rule 21 tariff.

- ~~**Mitigating need for restudies:**~~ To the degree possible, the DGD process should also avoid the need to restudy existing DER interconnections and instead leverage the ICA hosting capacity information available and a more streamlined "check" process when studying DERs as aggregations. Whether and what is needed for a "check" process should be explored. If a FERC-jurisdictional interconnection agreement is required, some assurances would be needed that a resource connected under Rule 21 and converting to WDAT will not require restudy, especially if the resource's electrical characteristics will be substantially unchanged after the conversion.

For example, in addition to the applicable interconnection tariff and requirements, DERPs must also satisfy a 30-day concurrence review process for the UDC to confirm that the DERA's energy-only wholesale market participation does not pose any concerns to the safe and reliable operation of the distribution system, meets all applicable UDC tariff requirements, and does not raise any concerns with prohibited market participation (*e.g.*, participation in a retail NEM program, participation in another DERA, or participation as a PDR/RDRR resource).[101] Upon successful completion of this UDC review and certification, as evidenced by a UDC concurrence letter, the DERA can then enter the CAISO's NRI process.

[100] *See, e.g.*, SCE WDAT Tariff Section 3.2.3.1 and Section 6.3.3.
[101] CAISO Tariff Section 4.17.4.

Figure 7: DERA Concurrence Review Process[102]



Like with IFOM energy storage, the current deliverability study methodology must also be modified to align with the CPUC's movement toward SOD reforms as well as to procure and deploy BTM hybrid and storage resources with cost effectively identified and built deliverability-related upgrades. For example, rather than accommodating maximum DER export at any time and maximum generation and discharge for all other generation and storage at the same time (worst-case conditions), as is the case with the current on-peak deliverability study methodology, the methodology should be modified to reflect expected operations and in line with the specific slices of the day that the resource is being contracted or committed for to provide its export capacity. <u>This issue or idea is still under discussion and may be evolving, but we raise it here to highlight another area of potential alignment with SOD reforms as they are developed and/or adopted.</u>

[102] CAISO Tariff Section 4.17.4. *See also DERP Participation Guide and Checklist Version 1.0* at 7 (effective August 26, 2016).

~~c.~~d. *Unbundling Local and System Deliverability Using Hosting Capacity Analyses*

To facilitate the use of BTM hybrids and storage to meet local RA needs, the CPUC should explore an unbundling of system and local RA attributes in order to leverage the added and unique benefit of DERs in specific Local Capacity Areas to address Local RA needs. Today's environment of significant local supply constraints has led to numerous LSEs seeking Local RA waivers over the past 4-5 years due to insufficient offers or bids with "unreasonable" commercial prices or terms.[103] DERs can be well-positioned to immediately deliver this value and more cost-effectively and immediately relieve local supply constraints.

Typically, a resource that is able to be deliverable and qualify for both System and Local RA results in added value to LSEs in being able to stack value and meet multiple compliance objectives. For DERs, however, this could present barriers by requiring VPPs to be subject to upgrades to enable export capacity to be delivered to the bulk CAISO transmission system, even though they could be cost-effective local RA-only resources. From a power flow perspective, where there is sufficient hosting capacity at a particular location, any exports may not even, in actuality, be "wheeled" from the customer site to the bulk electric system since they would be consumed by nearby customers on feeders and circuits in close proximity. This raises the question of whether BTM hybrid and energy storage resources indeed need to pursue a lengthier deliverability study process and incur additional costs related to system deliverability upgrades. Having this additional pathway to unbundle system and local RA attributes could present cost-effective means to get deliverable BTM hybrid and storage export capacity.

[103] *See* CPUC Local Waivers Issued: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/local-waviers-issued.

In addition, LSEs will likely uniquely value procurement of BTM hybrids and energy storage resources to support local resiliency and economic development objectives more so than any System RA obligation. For example, when procuring BTM hybrids and energy storage resources, a CCA in Los Angeles will likely not seek the development of such VPPs and DERAs from customer sites in San Francisco, even though it could do so in order to meet System RA procurement needs or short positions. More likely, although stacking System RA value would be further beneficial, BTM hybrid and energy storage resources have unique value for its local attributes and services in the LSE's immediate service area and, by its nature as a customer-sited DER, for its delivery of value to the customer directly. To this end, the Joint DER Parties are unaware of any VPP contracts or procurement by an LSE that was developed for customer sites outside of that LSE's service area and customers. If requiring deliverability studies and upgrades to support System RA needs by virtue of the bundling of System and Local RA attributes can lead to delays and high costs that ultimately drastically reduce the success or viability of BTM hybrid and energy storage export capacity, perhaps the bundling of System and Local RA attributes should be targeted.

~~Understandably, RA bundling may be a broader issue that warrants further consideration for its implications across other resource types and the structures of the RA Program; but, if deemed viable and worthwhile, such reforms would advance VPP development and growth to support RA capacity needs as well as a number of other policy and customer priorities.~~

Taking the above into account, the Joint DER Parties believe that the existing integrated capacity analysis (ICA) data and tools should be leveraged to the degree feasible to enable the delivery of exports from BTM hybrid and energy storage resources where DER hosting capacity at the line section or node level is available on the distribution network. After significant investments made in developing and implementing the tool, the ICA represents a valuable asset that quantifies the capability of the distribution system to integrate DERs within thermal ratings, protection system limits, power quality, and safety standards. As we understand it, the ICA is currently being used to support and accommodate solar PV interconnection on the distribution system based on solar configurations and generation/shape profiles, but it also could be used to develop technology-specific ICA values, such as peak-shaving energy storage. To similar ends, the ICA could be adapted to support the calculation of ICA values for deliverable exports of BTM hybrid and energy storage systems during the RA Availability Assessment Hours or other specified periods of need.

Granted, the use of the ICA is in flux, where R.14-08-013 has discussed and directed continued refinement of the tool, and the ICA has been the subject of improvements via data validation plans regarding the accuracy of the ICA values. As such, whether the ICA could be used for this purpose may require further discussion and consideration, but we highlight the potential for the ICA to be used to more immediately and flexibly enable export capacity from BTM hybrid and energy storage resources, recognizing that any exports to the grid may be accommodated at a particular location on the distribution system. Such outcomes may be likely because the export capacity is most needed during the RA Availability Assessment Hours and may be consumed by other customer loads in close proximity, thus serving load locally, which is the very purpose of the RA Program. Local load served means that there is less system load to serve as well.

On the one hand, since the ICA is dynamic and subject to change based on distribution grid conditions, there is some level of uncertainty of how much export capacity any given BTM hybrid and energy storage resource may count over time. Especially when any capacity on the distribution is not "reserved" on a consistent basis through a process similar to the study for and allocation of deliverability, the BTM hybrid or energy storage output may be limited in their dispatch by other capacity resources over time. Such uncertainty or fluctuating values may not be ideal for DER providers as well. On the other hand, despite the fluctuating "deliverability" as measured by the ICA, it represents a viable interim measure until the resources are able to secure the deliverability necessary and build the associated upgrades if required, creating a runway for these resources to immediately provide local export capacity akin to interim deliverability. In other cases, system deliverability may not be sought altogether if sufficient hosting capacity exists on the system to accommodate export capacity locally, where providers and LSEs must merely accept the fact that the qualifying level of "deliverable" export capacity may evolve over time as the ICA changes over time. Due to the changing nature of the available hosting capacity, such resources would need to have their RA "count" inclusive of exports updated regularly as well, which should be available as an option if it proves more economic to do so. Like the regular updates for load-reduction potential for DR resources under the LIP, a similar update process may need to be developed for resources that pursue this option. Understandably, RA bundling may be a broader issue that warrants further consideration for its implications across other resource types and the structures of the RA Program. For one, there may need to be consideration of substitution rules for RA resources that do not secure system deliverability since they cannot be replaced in RA supply plans with any other System RA resources. Moreover, since this is a topic that has not been sufficiently vetted, the CAISO reported that there could be impacts to existing deliverability availability and allocations based on system-level power flow impacts of resources (i.e., less local load means less system deliverability for other resources) that warrant further review. Yet, if such a pathway is deemed viable and worthwhile, such reforms would advance VPP development and growth to support RA capacity needs as well as a number of other policy and customer priorities.

~~d.~~e. *Applicable Interconnection Tariffs*

To enable exporting BTM hybrid and energy storage resources to participate in the wholesale market and/or to be studied for deliverability, there are potential questions regarding whether the utilities' FERC-jurisdictional WDAT or CPUC-jurisdictional Rule 21 tariff applies. Nothing within CAISO requirements[104] or its tariff[105] prevents the participation of DERs in the CAISO markets that have been studied under a state-jurisdictional process and thus do not require interconnection pursuant to a WDAT. The DERA Order examined and rejected the suggestion that DERs must be studied pursuant to WDAT before they may participate in a DERA.[106]

Importantly, in Order No. 2222, FERC declined to exercise jurisdiction over the interconnection of DERs to distribution facilities regarding their participation in ISO and RTO markets[107] and clarified that a DER requesting interconnection to the distribution facility for the purpose of directly engaging in wholesale transactions (*i.e.*, not through a DERA) would create a "first use" and any subsequent DER interconnecting to that distribution facility for the purpose of directly engaging in wholesale transactions would be considered a FERC-jurisdictional

[104] *California Independent System Operator Corp.*, 155 FERC ¶ 61,229 (2016) ("DERA Order"), *available at* https://www.caiso.com/Documents/Jun2_2016_OrderAcceptingProposedTariffRevisions_DistributedEnergyResourceProvider_ER16-1085.pdf.

[105] *See* CAISO Tariff Section 25.2 ("Any proposed interconnection by the owner of a planned Generating Unit, or its designee, to connect that Generating Unit to a Distribution System of a Participating TO will be processed, ***as applicable***, pursuant to the Wholesale Distribution Access Tariff ***or CPUC Rule 21***, or other Local Regulatory Authority requirements, if applicable, of the Participating TO") (emphasis added).

[106] DERA Order at P 60.

[107] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 at P 90 and 96 (2020) ("Order No. 2222").

interconnection.[108] The "first use" test was established in Order Nos. 2003 and 2006 for distribution-system interconnections. In cases where the distribution facility, at the time of the request, is not used to transmit electric energy in interstate commerce or subject to wholesale open access, such interconnections are governed by the applicable state or local law. Any subsequent resources interconnecting to the same distribution facility for FERC-jurisdictional purposes (*e.g.*, to make wholesale sales in interstate commerce) must use the FERC-jurisdictional Generator Interconnection Procedures and Generator Interconnection Agreement established in Order Nos. 2003 and 2006 and later amended in Order No. 845.

While it is seemingly clear that DERs interconnecting under Rule 21 can participate in DERAs, the IOUs have consistently asserted that DERAs selling a FERC-jurisdictional product (*i.e.*, wholesale sale of electric energy) to the CAISO market (*i.e.*, a product other than demand response) must have a FERC-jurisdictional interconnection under an Open Access Transmission Tariff.[109] In fact, each of the utilities' Rule 21 clearly outlines the applicability of Rule 21 by listing two key exceptions to CAISO Tariff interconnection, which include NEM generating facilities and generating facilities that do not export to the grid or sell any exports sent to the grid.[110] To this end, since the Federal Power Act gives FERC jurisdiction over the transmission of electric energy in interstate commerce and the "sale of electric energy at wholesale", the CPUC and utilities should consider whether Rule 21 interconnection can be maintained for DERAs if DERAs forgo wholesale energy payments as a condition of being Rule 21 exporting RA resources. In this way, the DERAs would not be selling a FERC-jurisdictional product and would only be providing RA capacity—a state jurisdictional program and product.

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[108] Order No. 2222 at P 97.
[109] *National Ass'n of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277, 1282 (D.C. Cir. 2007).
[110] Rule 21 Section B.1.

To be clear, DERAs would still be market integrated and subject to bidding, scheduling, and dispatch requirements like any other RA resource. However, rather than settling for energy payments, the CAISO would zero out any wholesale energy settlements for any discharge and exports to the grid and instead have the dispatch of the DERA in accordance with its must-offer obligation and NQC be reflected in modified capacity payments. For example, a 10-MW NQC DERA that is consistently scheduled and dispatched in the CAISO markets at 10 MW across its shown periods would be able to retain the full 100% RA capacity payments. Whereas if the 10-MW NQC DERA is consistently scheduled and dispatched in the CAISO markets at 9 MW across its shown periods, the DERA would then be subject to prorated capacity payments at 90% of its NQC. The mechanics and details will need to be worked out, but the same concept of adjusting demonstrated and delivered capacity relative to the NQC value could be implemented. Since RA resources are subject to a must-offer obligation and may not always be scheduled and dispatched, any adjustments will need to be carefully crafted to ensure that any derates are reasonably structured (*e.g.*, tolerance band) and ideally align with periods when the capacity is most needed (*e.g.*, most critical hours where RA capacity delivery is particularly needed).

Meanwhile, any concerns about being unable to separate wholesale from retail use for DERs located BTM unless those DERs are interconnected and metered separately from the retail load, such as under the WDAT, can be readily addressed by adopting submetering protocols and approaches. This is not contingent on whether DERAs are interconnecting under WDAT versus Rule 21.

III. PROPOSALS

The proposals in this section focus on implementation in the near term, to facilitate RA transitions and operations for BTM hybrid and energy storage ~~and storage hybrid~~ resources, starting in RA year 2023. Where relevant, and consistent with the discussion in Section II of this proposal, we also include issues for resolution over the long term.

A. Qualifying Capacity Methodology

~~The QC methodology for BTM storage and storage hybrid resources should initially be set as equivalent to the methodology for IFOM resources. The Joint DER Parties further recommend that as, and if, the QC methodologies for these IFOM resources change in the future (e.g., if an ELCC or exceedance methodology is adopted for IFOM resources) then the methodology for BTM should change accordingly. We do not advocate for any particular methodological approach other than what has been adopted by the CPUC. As of the writing of this proposal, IFOM resource counting methodologies for standalone storage and storage hybrids, respectively, are as follows:[111]~~

~~Standalone storage: Pmax of storage unit.~~

~~Storage hybrids: Total QC = Effective ES QC + Effective Renewable QC~~

~~*Effective ES QC* equals the minimum of: (1) The energy (MWh) production from the renewable resource from 2 hours after the net load peak until 2 hours before the net load peak assuming charging is done at a rate less than or equal to the energy storage's capacity. This renewable charging energy is then divided by 4 hours to determine the QC; or (2) the QC of the energy storage device.~~

~~*Effective Renewable QC* equals the remaining renewable capacity, net of the capacity required to charge the battery at a constant rate over the available charging hours, multiplied by the ELCC factor for the month.~~

~~The Joint DER Parties recommend that the QC value be inclusive of battery exports, for resources using the DERP model. The QC should be the full discharge capacity of the battery, as measured at the inverter, rather than host load as is currently the case for DR resources, whether backed by an energy storage device or hybrid system or not.~~ The QC for an aggregation of

~~[111] California Public Utilities Commission, *2020 Qualifying Capacity Methodology Manual*, pp. 19-20 (November 2020).~~

BTM storage and/or hybrids will be based first on its contracted capacity. The Joint DER Parties do not recommend an ex ante estimation method based on the load impact protocol or any such methodology. To the extent that an alternative is needed, we recommend that the historical settlement of a resource aggregation - if that aggregation is made up entirely of like customers - be used in lieu of contracted capacity, if sufficient historical settlement data exists.

Retail and wholesale ex post capacity settlement will occur using a variation of the MGO methodology adopted by the CAISO, as articulated in Section 5.1 of the CAISO's BPM for Demand Response (April 1, 2020), as the basis for this measurement. The recommended modifications are to 1) include exported and charging energy in settlement and baseline calculations, and not zero out exports and charging energy as is currently done with the CAISO's adopted MGO baseline methodology for PDR, and 2) require no comparison to customer load consumption. These modifications will require regulatory action by both the CPUC and CAISO. The CAISO must adopt this modified settlement methodology for BTM resources in a DERA, and the CPUC must require the IOUs to adopt the same methodology for retail capacity settlement.

As with the current MGO framework in place for PDR resources, the baseline should only be applied for the hours on non-event days in which the BTM storage device is actually dispatched to respond to an event. This is consistent with the SOD framework, and the MGO methodology itself. There is no need to measure outside of these hours, as there is not a motive to modify battery dispatch in advance of an event in order to "improve" the appearance of battery discharge during an event. Baselining was originally put in place for pure DR resources that are not backed by an asset, in order to capture any increases in host customer load in advance of an event which would artificially make the customer's load reduction look greater than it would be otherwise. BTM battery resources do not have a similar incentive, and so traditional baselining approaches that look at hours prior to an event are unnecessary. Further, comparing battery performance during the look back period for the same hours as the event gives a fully accurate picture of what the battery would have done anyway. Resource providers should have the option to select what type of baseline to apply using the MGO methodology - 10-in-10, 5-in-10 or a control group methodology.

CAISO would retain the ability to audit meter data, as would the IOUs if they adopt this approach for retail capacity settlement purposes. On the retail side, there is no need for subtractive billing. The customer's bill will reflect how much power they purchased from the utility - no further calculation is needed.

With specific regard to charging sufficiency, under any RA framework including but not limited to Slice of Day if adopted, the following should be considered:

- **Standalone BTM energy storage:** ~~If interconnected to not increase customer peak load through~~ BTM standalone energy storage ~~charging, these (aggregated)~~ resources ~~do not need to meet the charging sufficiency test using~~ must demonstrate excess energy ~~to receive a QC. If they seek to increase the customer peak load, they may need to demonstrate charging sufficiency. This structure~~ is ~~consistent with the current Rule 21 Section N criteria for an expedited interconnection process for~~available in other non-~~exporting storage facilities.~~shown slices to fully charge the resource and ensure its QC.
- **Hybrid BTM energy storage:** Typically, a charging energy sufficiency test will be unnecessary since the majority of the hybrid BTM energy storage systems will charge exclusively from onsite generation to claim the full federal Investment Tax Credit and ensure NEM eligibility, and thus not charge from the grid. By virtue of leveraging its

onsite generation source to ensure charging sufficiency, this "negative" RA showing is not necessary. If hybrid BTM energy storage seeks to charge a portion from the grid for RA purposes, then they may need to demonstrate charging sufficiency. In these instances, BTM hybrid resources should account for onsite charging availability from its paired generation resource before determining and accounting for any additional excess energy needs (if any) from the grid.

~~A.~~B. Incrementality

There is a need for a universal incrementality framework for DERs, as well as for IFOM resources providing multiple services. Importantly, incrementality must be defined and assessed consistently across the different ~~Commission~~CPUC proceedings. To be clear, however, it is not necessary to develop a full incrementality framework before assessing QC value for BTM storage and hybrids, nor to facilitate participation of these resources in the CAISO wholesale market.

D.18-01-003 established the initial rules for multiple-use applications and adopted a singular incrementality rule, focused on payment for provision of services:

> Rule 11. In paying for performance of services, compensation and credit may only be permitted for those services which are incremental or distinct. Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation.[112]

That rule has not been augmented or updated. As discussed earlier in this proposal, the CPUC has thus far determined that incentives and payment for services are distinct, in both the IDER and SGIP proceedings. In keeping with this precedent, and consistent with Rule 11, the Joint DER Parties recommend the following incrementality principles to guide determinations of

[112] R.15-03-011, *Decision on Multiple Use Application Issues*, Appendix A, p. 2 (January 11, 2018) ("D.18-01-003").

QC value for BTM storage and hybrid resources. Instances in which incrementality considerations would be relevant:

- For net-metered customers.
  - ~~Capacity valuation: The Joint DER Parties propose that the QC for the resource be the same as that for a standalone storage unit and no renewable production be considered in the QC calculation.~~
  - Energy settlement: The Joint DER Parties propose that the CPUC create a new NEM tariff that explicitly allows for wholesale market participation. Any assumed energy value could be subtracted from the NEM rate collected by the customer for exported energy during the hours in which the resource is required to be available to the market. Until such a NEM tariff is created and adopted, the current *de facto* prohibition on resources participating in both NEM in a DERA remains.
- Adjustments to the forecasting process.
  - Require LSEs to include contracted supply-side DER resources in their year-ahead forecast, and require identification of whether customer storage in these aggregations is existing (already deployed at the time of contracting) or will be newly installed.
  - Overall, encourage increasingly granular DER data to inform forecasts (e.g., incorporating submetered BTM resource data in CEC forecasting to assess *ex post* load impacts).

Additionally, instances in which incrementality considerations are not relevant:

- The collection of a storage or renewable energy technology incentive. Such incentives include, but are not limited to: SGIP, SOMAH, MASH, and any successor renewable energy or storage incentive program, *insofar as these programs do not require dispatch in response to electric system needs.*
- Provision of other, non-RA services, including but not limited to distribution-level services, and customer-level services such as back-up power and resiliency.

~~B.~~C. Must-Offer Obligation

We recommend that the same basic RA operational requirements apply to BTM storage and hybrid DERA resources as they currently apply to load curtailment resources that participate through PDR. The MOO for BTM solar and storage or standalone storage resources should be structured to coincide with times when these resources are expected to be needed the most, or contracted for under the ~~Slice of Day~~SOD framework~~, according~~. According to the current AAH, ~~currently~~these hours are set at 4:00 p.m. – 9:00 p.m. Under a SOD framework, the availability requirement would coincide for the slices, or hours, in which the resource is contracted for and shown on an LSE's supply plan. These resources would retain an obligation to bid in all hours, consistent with all other CAISO resources. The MOO for BTM hybrid and storage resources require economic bidding or self-scheduling of capacity in the IFM and RUC, for all hours and in the RTM to match DAM scheduling or for any capacity not scheduled in the IFM.

~~C.~~D. Metering and Settlement – Retail

As discussed in Section II, we recommend that the IOUs be directed to develop an interim methodology for retail capacity settlement at the battery submeter, rather than at host load. Such an approach already exists for energy settlement in the wholesale market, and should be mirrored for capacity. In the near term, that methodology should be based upon the MGO methodology, an approach ~~which we understand to~~ already in place at the CAISO for settlement of storage-backed DR resources. This approach can be ~~in development to measure~~harmonized, if appropriate, with performance measurements under the ELRP. There will be lessons learned from this process that will be helpful to a broader submetering effort. While a permanent methodology and requisite upgrades to systems may be needed for the long term, we recommend taking an interim approach that can be tested~~, using the ELRP process as a start~~ and adjusted over time.

For the medium- to long-term, we recommend that the IOUs be directed to work with third parties and other interested stakeholders to develop a fulsome methodology that will require updates to billing systems and the like. This effort can begin following the Summer 2023 season~~, or at some point after performance data from BTM systems under ELRP Option A5 is available.~~.

~~D.~~E. Sale for Resale

In the immediate term, all BTM hybrid and energy storage resources providing and contracting for RA capacity will remain and be subject to the applicable retail rates but will still be required to be integrated in the CAISO market and be made available through bids, scheduling, and dispatch in accordance with RA MOOs and other rules. Contract structures (or alternative means if identified) ~~should~~could be developed, such as adaptation of PG&E's LTRAA-ES contract, to incentivize CAISO market participation while ensuring no net sale of energy.

In either a new phase/track of this proceeding, in another appropriate rulemaking,[113] or through a dedicated working group process, the CPUC should direct the development of an agreed-upon accounting framework to enable wholesale-retail differentiation regarding the cost for charging energy storage resources and the payment for discharging from such resources. Some of the accounting methodologies or examples presented in the Joint DER Parties' Implementation Track – Phase 2 Proposal should serve as a starting point for discussion and development.

~~E.~~F. Forecasting

Based on the Joint DER Parties' evaluation of existing forecasting processes, and working group discussions to date, we have identified two primary needs: (a) more granular data for BTM storage and hybrid resources should be incorporated into the CEC forecasting process and (b) an accounting process needs to be developed whereby LSEs can identify how many storage resources will be used in supply side aggregations on a year-ahead basis based on

[113] These issues could be taken up in either the High DER OIR (R.21-06-017), successor Energy Storage OIR or MUA-focused proceeding, or some other venue since an RA docket may not solicit participation from all of the right experts and stakeholders.

contracting and expected program participation. As articulated in the discussion of the CEC load-forecasting process, submetered BTM resource data would be helpful to assess *ex post* impacts, as well as a process for identifying new and existing BTM storage resources that will be used in supply-side aggregations, to ensure these resources are not embedded in, and fully incremental to, the load forecasts that are used to set an LSE's RA obligation. Further, receiving accurate DERA dispatch data from CAISO and LSEs is key so that the effects can be removed from recorded load data, and added back to hourly loads, akin to the current process for supply-side DR.

LSEs should also be required to true-up LSE procurement of BTM resources for capacity, which can be informed by estimation of supply-side BTM DER capacity at specific nodes, which is possible and done today for other demand-side resources. Based on the basic principle of additionality, LSEs should submit how much capacity they receive from existing BTM systems and how many systems are anticipated to come online. This adjustment process should be timed to enable reflection in annual year-ahead RA showings at a minimum, and should also be carried over to month-ahead showings.

The Joint DER Parties look forward to working with the CEC, CPUC, and CAISO to ensure high-confidence accounting of BTM DERs in operational and planning forecasts, starting with establishing appropriate data channels for both resource performance and location. This process may start with the next IEPR cycle.

~~F.~~G. Deliverability

The CPUC should adopt the QC proposal above for BTM hybrid and energy storage resources, recognizing that the actual RA qualification will be based on NQC, which will be developed with the follow-on CAISO and CPUC processes. Meanwhile, the CPUC should express directional support and guidance related to the aggregated deliverability methodology and process modifications included in this proposal. Specifically, the CPUC should encourage the CAISO to ~~refine~~clarify the proposal that would apply the DGD study criteria to the assessment of requested and aggregated MW quantities of Potential DGD at specific nodes on the CAISO-controlled grid. Upon the final adoption and approval of the DGD proposals by the CAISO, the CPUC should request that the CAISO notice the CPUC and RA stakeholders.

In parallel, the CPUC should direct CPUC Energy Division staff to convene a working group to modify Rule 21 study criteria and processes to assess distribution-side deliverability-related upgrades in the individual Rule 21 interconnection study processes. This same working group should also be tasked with creating a new model for requesting, allocating, and retaining TPD and relevant distribution upgrades. Specifically, the new model would:

- Proactively identify transmission and distribution upgrades to accommodate export capacity deliverability based on LSE interest and/or procurement needs~~.~~ (e.g., IRP portfolios to be submitted to the CAISO's TPP for the purposes of conducting policy-driven studies and assessments).
- Fairly allocate or pass through the costs associated with deliverability-related upgrades to participants and/or developers via $/kW fees.
- Accommodate phased development and COD in commercial viability criteria.
- Mirror this proactive upgrade identification and cost allocation approach in the Rule 21 study process.

Finally, given the broader implications to the RA Program of unbundling System and Local RA attributes, the CPUC should further explore ~~this~~the issue of leveraging or adapting the existing ICA tools to accommodate export capacity locally in a subsequent track in this proceeding (perhaps in coordination with the High DER rulemaking) in Summer 2022, recognizing the unique local nature/interest and localized value-stacking opportunities of DERAs. Specifically, this follow-on process should consider issues around whether and how the ICA tools could be used or adapted, the process by which RA values inclusive of exports can change and be updated as ICA values change, and how RA substitution rules would need to be modified, among other potential RA-specific issues. This should be taken up for further consideration in Summer 2022, upon considering and/or adopting the various proposals here in June 2022.

IV. CONCLUSION

The Joint DER Parties appreciate the Commission's consideration of this proposal and look forward to working with Staff and other parties on the issues addressed herein.

Respectfully submitted,

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