Docket No.: R.20-11-003

Exhibit No.:

Date: September 1, 2021

Witness: Jin Noh

OPENING TESTIMONY OF JIN NOH
ON BEHALF OF THE CALIFORNIA ENERGY STORAGE ALLIANCE

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Q: Please state your name and business address.

A: My name is Jin Noh. I am Policy Director of the California Energy Storage Alliance ("CESA"). My business address is David Brower Center, 2150 Allston Way, Suite 400, Berkeley, CA 94704.

Q: Please summarize your professional and educational background.

A: In my capacity as Policy Director, I manage CESA's engagements at the California Public Utilities Commission ("Commission"), California Independent System Operator ("CAISO"), California Energy Commission ("CEC"), California Legislature, Federal Regulatory Commission ("FERC"), and other agencies. I have more than 6 years of experience in policy and regulatory work at these agencies. I hold a Bachelor of Arts in Public Policy Studies and Economics from Duke University and a Master's in Public Policy ("MPP") from the University of California, Berkeley.

Q: Have you ever testified before this Commission?

A: Yes.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of CESA. Founded in 2009, CESA is a non-profit membership-based advocacy group committed to advancing the role of energy storage in the electric power sector through policy, education, outreach, and research. CESA's mission is to make energy storage a mainstream energy resource that accelerates the adoption of renewable energy and promotes a more efficient, reliable, affordable, and secure electric power system for all Californians. As a technology-neutral group that supports all business models for deployment of energy storage resources, CESA's membership includes technology manufacturers, project developers, system integrators, consulting firms, and other clean tech industry leaders.

Q: What is the purpose of your testimony?

A: The purpose of this opening testimony is to submit our party proposal on various solutions that could be pursued by the Commission to address Summer 2022 and 2023 emergency reliability needs. We focus our proposal on the design, structure, and operations of a new Emergency Load Reduction Program ("ELRP") that incentivizes the procurement of new, incremental behind-the-meter ("BTM") resource capacity outside of the Resource Adequacy ("RA") framework to deliver fast, frequently dispatchable, and/or permanent demand response ("DR") including exports during heat-storm events. In addition to our ELRP proposal, we offer our recommendations around: the consideration of expedited Integrated Resource Plan ("IRP") procurement; the role of energy-only ("EO") energy storage procurement, contracting, and operations; various interconnection strategies; modifications to various DR programs, particularly those related to the Demand Response Auction Mechanism ("DRAM"); and the electric vehicle ("EV") and vehicle-grid integration ("VGI") aggregation pilot.

I. Introduction

Phase 2 of this proceeding launched expeditiously in response to Governor Newsom's Emergency Proclamation on July 30, 2021, which, among other things, directed the Commission and other agencies to facilitate the rapid deployment of clean energy and energy storage projects.[1] In the face of extreme weather events induced by climate change (*e.g.*, drought, heat waves, wildfires), the state has been faced with a perpetual state of resource supply shortfalls that has led to emergency and short-term, rather than forward-looking, resource planning. Rash responses to "play catchup" has unfortunately taken its toll as well – *e.g.*, higher resource procurement costs, heavy reliance on and deployment of temporary generation, and extension of once-through-cooling ("OTC") facilities. Until the direction from the Integrated Resource Planning ("IRP") proceeding has load-serving entities ("LSEs") procure and deploy record levels of clean energy and energy storage resources, immediate risk mitigation measures are needed to bridge the time between now and then.

CESA continues to support the intent, purpose, and importance of this proceeding in light of the stress faced by the electric grid thus far in Summer 2021, even leading to the joint agencies to issue a letter on June 29, 2021 to request that the CAISO use its tariff-based Capacity Procurement Mechanism ("CPM") authority through October 2021. Though not as concerning or alarming as the August 2020 rolling outages and emergency events, the joint agencies were appropriately guarding against any repeat events and observed significantly reduced hydroelectric production due to the prolonged West-wide drought,

[1] Order 2 of Emergency Proclamation. https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf

unforeseen limitations on thermal generation output (*e.g.*, Russell City Energy Center), and extreme heat events starting unseasonably early.[2] To address these urgent needs and risks heading into Summer 2022 and 2023, the Commission should seek to procure emergency reliability capacity from both supply-side and demand-side resources that adhere to the state's long-term decarbonization and policy objectives.

In this vein, CESA appreciates the opportunity to submit this testimony to present and respond to various proposals for distributed energy resource ("DER") procurement or programs, incremental emergency procurement or accelerated IRP procurement, and modifications to RA requirements.

II. Summary of Recommendations

As directed by Administrative Law Judge ("ALJ") of this proceeding, CESA strived to provide as much detail as possible for many of CESA's proposals in order to support immediate adoption by the Commission with minimal modifications, but given limited time and resources, there may be some proposals that require further development based on feedback and comments from Commission staff and parties to this proceeding. Based on this guidance and in response to staff conceptual proposals, CESA offers the following key recommendations:

- Given the results of the CEC's Mid-Term Reliability Analysis, CESA recommends the Commission work to ensure the timely deployment of the resources identified in the proposed Preferred System Plan.
- Staff's proposed IRP/RA penalty mechanisms should not be adopted, and instead, the Commission should develop and adopt an optional incentive to accelerate IRP procurement online dates.
- If incremental IOU procurement of energy storage resources is directed, solicitations need to launch as soon as possible and have contracts expeditiously approved by the

[2] *See* Joint Letter. http://www.caiso.com/Documents/CapacityProcurementMechanismSignificantEvent-JointStatementandLetter.pdf

Commission by February 25, 2022 while IRP 2023-2026 mid-term reliability solicitations must launch before the end of 2021.

- Pre-RA delivery of energy storage resources should be allowed and counted to support emergency reliability in the short term and RA needs in the long term, with contract provisions standardized and adopted and good-fit locations identified to support such EO operations.
- CESA's Petition for Modification on station power rules for hybrid and co-located resources should be expeditiously adopted to avoid unfair and unreasonable harm and ensure that these projects come online in a timely manner to support near-term system reliability.
- Provisional exports for BTM non-exporting energy storage should be enabled through a streamlined process, leveraging inverter capabilities.
- Eligibility of the Rule 21 non-export notification-only pilot should be expanded to include non-exporting storage retrofits to exporting solar generation, and the developer cap per circuit should be removed as well.
- Notwithstanding the lack of a capacity payment, the proposed modifications to the ELRP represent improvements that may encourage more participation but should be broadened to ensure that they encompass A.3 and A.4 customers.
- The EV/VGI Aggregation Pilot should be adopted with some clarification, and the sub-metering concept should be extended to BTM energy storage as well.
- The proposed supplemental DRAM solicitation is reasonable and modifications to DRAM will generally recognize the enhanced value of storage-backed DR.

In addition to the recommendations above, CESA proposes two new programs in accordance with staff guidance, detailed as much as possible and feasible given the limited staff resources and short few-week turnaround time available:

1. Enhanced Storage-Backed Demand Response ("ESB-DR") Program

2. Permanent Load Reduction ("PLR") Incentive Program

These two proposals are detailed as much as possible and feasible given the limited staff resources and short few-week turnaround time available; however, there are certainly gaps and specifics that need to be worked through, subject to Commission and stakeholder feedback and comments. To this point, CESA requests that additional opportunities to refine proposals be allowed if the Commission or others find merit in these new program proposal ideas.

III. Analysis of Need

On August 11, 2021, the CEC published the *Draft Preliminary 2022 Summer Supply Stack Analysis* ("Draft 2022 Net-Short Analysis"), which was undertaken in collaboration with the Commission and the CAISO, to "better inform the public about the potential implications if the 2021 California drought and western extreme weather events persist into summer 202, as current National Oceanic and Atmospheric Administration ["NOAA"] models predict."[3] In the analysis, the CEC "projects an additional 600 MW to 5,200 MW of resources may be required to ensure electric system reliability for peak and net-peak hours during summer 2022 without the use of contingency resources."[4]

Since the Commission explained that it may consider the results of the Draft 2022 Net-Short Analysis to inform its evaluation of electrical system reliability in Phase 2 of the present rulemaking, CESA underscores that this exercise only offers a snapshot of potential system needs under a conservative set of load assumptions. Specifically, CESA is concerned with the usage of a 22.5% planning reserve margin ("PRM"), which is equivalent to the use of a forecast with load greater than one with 1-in-10 weather event. In the CEC's Docket 21-ESR-01, Southern California Edison ("SCE") highlighted that the 22.5% PRM scenario, based on a 1-in-2 weather event with 9% demand variability, is essentially equivalent to a greater than 1-in-20 weather event since the 1-in-10 forecast in 2022 is only 6.6% higher than the 1-in-2

[3] *Draft Preliminary 2022 Summer Supply Stack Analysis* published by the CEC on August 11, 2021 at 2.
[4] *Ibid* at 4.

weather forecast while the 1-in-20 forecast is 8.3% higher.[5] Hence, the shortfall that the "extreme weather" scenario identifies represents an unlikely event for which long-term electric planning seldom accounts. As such, the procurement needed to meet this scenario would likely result in a loss-of-load expectation ("LOLE") well below 0.1, the industry standard.

The other scenario analyzed in the Draft 2022 Net-Short Analysis focuses on a 15% PRM, which does constitute a likely scenario for which both the Commission and its jurisdictional LSEs should plan for in a cost-effective manner. The 15% PRM case identifies shortfalls only in the 6-9 PM period in September 2022. The findings of this stack analysis are consistent with the operational experience of the CAISO in recent summers; reliability challenges are particularly likely as loads remain high while solar photovoltaic ("PV") output declines. Nevertheless, it is essential to underscore that this study does not follow industry-wide best practices for reliability planning, which target a LOLE of 0.1 or less. In essence, the Draft 2022 Net-Short Analysis seeks to identify the amount of incremental capacity needed to eliminate the possibility of supply shortfalls in the peak to net peak period of Summer 2022. This deficiency, however, may be considered acceptable given its likelihood and curing for it would unnecessarily increase ratepayer costs.

Subsequently, on August 30, 2021, the CEC presented the results of their Mid-Term Reliability Analysis ("MTR Analysis") – a joint effort by the CEC, CPUC, and CAISO to determine if capacity incremental to the amount considered in either the proposed Preferred System Plan ("PSP") or Decision ("D.") 19-11-016 and D.21-06-035 is required to ensure a LOLE equal or less than 0.1. During the workshop in which the MTR Analysis weas presented, staff noted that the analysis showed that incremental capacity is not required to attain a LOLE below 0.1 provided that the capacity associated with the proposed PSP is integrated in a timely manner. Notably, the MTR Analysis also finds that utilizing fossil-fueled capacity in place of the proposed PSP would not yield additional reliability benefits, demonstrating the

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[5] *Southern California Edison Company's Comments on the California Energy Commission's Draft Preliminary 2022 Summer Supply Stack Analysis (Draft 2022 Stack Analysis)* filed August 20, 2021 in CEC Docket No. 21-ESR-01.

viability of preferred resources. CESA views the MTR Analysis as offering a more accurate prognosis of the system's need relative to the Draft 2022 Net-Short Analysis as it:

1. Includes stochastic modeling of a wide set of demand and outage probabilities, versus the deterministic "snapshot" approach of the 2022 Draft Net-Short Analysis;
2. Incorporates the intraday chronological impacts of energy storage usage;
3. Focuses on the late spring to early fall months (May-October), when the CAISO system experiences significant variation in its resource mix;
4. Assumes a resource build associated with the most recent IRP assumptions, the proposed PSP; and
5. Expressly targets the attainment of a 0.1 LOLE, the industry standard for reliability.

Given the results of the MTR Analysis, CESA recommends the Commission work to ensure the timely deployment of the resources identified in the proposed PSP. According to the results shared at the August 30, 2021 workshop, the PSP and Procurement Scenarios of the MTR Analysis assume the capacity additions shown in Table 1,[6] which highlights substantial differences between the two assumed buildouts. These differences in 2022 result in the PSP scenario obtaining a 0.081 LOLE while the Procurement Scenario surpasses the 0.1 target with a LOLE of 0.194. Importantly, the Procurement Scenario registers LOLEs below 0.1 for all the other years analyzed, highlighting the importance of the 2022 deployment.

Table 1: Comparison of 2022 Scenario Additions in the MTR Analysis (MW)

Resource Type	PSP Scenario	Procurement Scenario	Difference
Geothermal	0	8	-8
Biomass	19	7	12
Shed DR	151	34	117
Wind	1,310	242	1,068
Solar	2,211	780	1,431
4-hr Energy Storage	2,159	936	1,221

[6] The CEC defined the PSP Scenario as the proposed PSP shared by the Commission with two key modifications: (1) offshore wind was rolled into onshore wind; and (2) 1,727 MW of capacity counted in the PSP and the baseline resources in the Commission's Reliability Need Assessment were removed from the PSP. The Procurement Scenario consists of the remaining NQC procurement included in D.19-11-016 (1,505 MW NQC) and D.21-06-035 (9,500 to 11,500 MW NQC, depending on the timing od the addition of long lead-time ("LLT") resources).

Total	5,850	2,007	3,843
NQC	2,753	1,070	1,683

The CEC's MTR Analysis demonstrates that, if Commission-jurisdictional LSEs undertake procurement in line with the proposed PSP, the state is well positioned to retain reliability in the 2022-2026 period. This level of procurement, however, differs substantially from the one foreseen in D.19-11-016 and D.21-06-035. In the Ruling regarding the proposed PSP, the Commission suggest that it could require the procurement of resources contained in the individual IRP filings and have LSEs face penalties and/or backstop procurement requirements with cost allocation arrangements, similar to those for D.19-11-016 and D.21-06-035.[7] Furthermore, the Commission also notes that it may require some of the capacity ordered in D.21-06-035 to be accelerated to 2023 in response to the Governor's Emergency Proclamation from July 30, 2021.[8]

In our review of these analyses, the need to ensure the timely addition of incremental capacity can be addressed in the IRP proceeding by requiring LSEs to procure the resources contained in their individual IRP filings, in addition to the outstanding procurement related to D.19-11-016 and D.21-06-035. CESA recognizes that there are significant complexities and barriers beyond the control of buyers and sellers of these resources that could hinder the deployment pace of these assets. Hence, CESA recommends the Commission consider providing incentives to ease the expedited integration of these assets, which given the composition of the PSP scenario is likely to come from intermittent generation coupled with energy storage. As such, given the difference between the PSP and Procurement Scenarios totals 1,683 MW net qualifying capacity ("NQC"), the Commission should considering incenting the acceleration of at least 2 GW of incremental NQC to be online by August 1, 2022, but also with additional or accelerated resources coming online by August 1, 2023. The magnitude and timing of this procurement acceleration seeks to

[7] CPUC, *Administrative Law Judge's Ruling Seeking Comments on Proposed Preferred System Plan*, issued under Rulemaking ("R.") 20-05-003 on August 17th, 2021, at 52.
[8] *Ibid.*

balance the need to ensure reliability during the net peak period with the interconnection and commercial realities of the Californian electric power sector.

IV. Expedited Generation and Energy Storage Procurement, Contracting, and Other Processes

To meet the residual, unmet needs for Summers 2022 and 2023, there is limited ability to bring on incremental in-front-of-the-meter ("IFOM") energy storage under compressed timeframes yet again, beyond those that are already contracted and under development. Despite its recent history of delivering replacement and/or new capacity in response to various grid emergencies (*e.g.*, Aliso Canyon, 2021-2023 system reliability, Summer 2022 emergency reliability), successive years of just-in-time procurement have contributed to developers operating on very tight timelines to procure batteries and equipment, with little margin of error related to many factors outside of the developers' control, such as Commission approval of investor-owned utility ("IOU") contracts, securing the necessary permits from authorities having jurisdiction ("AHJs"), proceeding through advanced stages of the interconnection process, negotiating metering configurations for the station power treatment (in the case of hybrid and co-located projects), and having network upgrades (if needed) built in time to support the project's contracted commercial online date ("COD").

With energy storage resources representing the largest source of incremental and/or replacement clean capacity in the near and long term, the Commission needs to consider new frameworks and approaches to standardize and fast-track their procurement and contract approval. Currently, we are seeing unprecedented storage procurement and buildout in support of procurement orders, such as those pursuant to D.19-11-016, D.21-03-056, and D.21-06-035. Record buildouts are unlikely to decrease in volume and velocity, as the Senate Bill ("SB") 100 build rates for battery storage were estimated as needing to increase by nearly eightfold compared to historical averages, or around 2 GW of battery storage annually through

2045.[9] Extreme weather events (*e.g.*, prolonged drought, heat waves) have further stressed the grid to the degree that the need for much of this energy storage capacity earlier has been highlighted and discussed across many forums, initiatives, and proceedings since energy storage represents as one of the few resource types that are able to support grid reliability and resiliency while keeping the state on its trajectory to reach 2030 and 2045 decarbonization goals.

After the CAISO was forced to initiate rolling blackouts in August 2020 for the first time in almost 20 years, the Commission, the CEC, and CAISO commenced diligently planning to implement market reforms and direct actions to minimize the likelihood of similar conditions in 2021. One such action was the directive to expeditiously increase the available capacity for Summer 2021, resulting in 3,961 MW of capacity additions in the June 2020 through August 2021 period, with 1,490 MW coming from battery energy storage systems ("BESS"). The full composition of these additions is included in Table 2 below.

Table 2: Generation Additions from June 2020 to September 1, 2021 (MW)

Fuel Type	Additions from June 1, 2020 -June 1, 2021	Incremental Additions by July 1, 2021	Incremental Additions by Aug. 1, 2021	Incremental Additions by Sept. 1, 2021	Total Additions by Sept. 1, 2021
BESS	675	343	472	3	1,493
Biofuel	6	0	0	0	6
Natural Gas	152	0	0	0	152
Geothermal	11	0	0	0	11
Hydro	41	0	0	0	41
Solar	1,497	0	498	0	1,995
Wind	263	0	0	0	263
Total	2,645	343	970	3	3,961
Cumulative Total	2,645	2,987	3,957	3,961	-

However, for energy storage to meet the state's urgent calling, the "old way of doing things" when it comes to procurement and contract approval cannot be continued. Energy storage resources need to be

[9] 2021 SB 100 Joint Agency Report published by the CEC on March 15, 2021 at 11. https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349

viewed as a "standard tool" in the resource toolkit, leading to an eventual move toward standard contracts and regular procurement cycles similar to what is in place for the annual Renewable Portfolio Standard ("RPS") Procurement Plan. Standardization of energy storage procurement, contracts, and approval processes likely cannot be achieved thoroughly in this proceeding, but streamlining and accelerated process proposals adopted herein should be potentially carried over on a going-forward basis unless substantiated otherwise.

To this end, CESA recommends that the Commission recognize energy storage operations and performance in Summer 2021 to fast-track, standardize, and make various adjustments (as detailed in subsequent sub-sections below) to their procurement and contract approval.

A. Staff's proposed IRP/RA penalty mechanisms should not be adopted, and instead, the Commission should develop and adopt an optional incentive to accelerate IRP procurement online dates.

The Commission staff proposes to impose fixed penalties for any LSE that fails to achieve CODs consistent with procurement orders, such as $50,000 per incident, or $10/kW-month for each month of delay. A grace period of up to six months from the expected COD may also be considered, and any procurement delays would be incremental to RA-related deficiencies and penalties. Staff framed this proposal as establishing minimum acceptable periods of delay – *e.g.*, by June 2022 for Tranche 1 projects that were supposed to be online by August 2021.

CESA strongly opposes these proposals and recommends that the Commission reject it from consideration. The current resource shortfall situation can be attributed to some degree on unforeseeable circumstances, such as the rapid pace of climate change impacts that accelerated and exacerbated the electric grid's supply-demand balance; however, it can also be partially attributed to the just-in-time planning and procurement approach taken in recent decisions to address shortfalls – with anywhere between 1-3 years of lead time to bring new incremental resources online. Applying an IRP procurement penalty mechanism at this time would not only be a retroactive penalty for procurement and contracts executed pursuant to D.19-11-016 but also does not account for the fact that it is already challenging to meet the COD under tight timelines, especially when certain factors are outside the seller's control, such as network upgrade construction delays or COVID-19 pandemic impacts on permitting offices, and the short lead time leaves little margin for error. With many LSEs imminently, if not already, embarking on a new round of resource solicitations to meet 2023-2026 mid-term reliability needs pursuant to D.21-06-035, the staff proposal will result in the unintended effect of significantly increasing resource procurement costs due to a combination of reduced market participation from bidders and offerors and increase the higher compliance risks that are most likely to be waterfalled down to the counterparty. At this time, when resource shortfalls are significant and urgent, the Commission should be inviting as much supply providers to participate in an LSE's IRP solicitation.

Rather than an IRP penalty mechanism, CESA recommends that the Commission adopt an optional IRP incentive mechanism that can encourage, but not require, IRP projects pursuant to either D.19-11-016 or D.21-06-035 to come online earlier. Like a "change order" request to bring projects online earlier, a process could be established by which the costs to the changed scope could be documented, substantiated, and reviewed for approval to pay for and recover the costs associated with accelerating projects. Projects would only be eligible if they are being sought to support urgent and emergency needs above and beyond the minimum compliance requirements (*e.g.*, MW, COD) for LSEs to bring resources online by a specified, earlier COD.

Alternatively, given our inability to access or view confidential and market-sensitive contract costs, CESA is unable to calculate an approximate premium to bring energy storage resources on a faster timeline, but the Commission staff may be able to calculate a proxy price adder to accelerate the COD of projects by one or more summer month(s) by comparing, for example, the engineering, procurement, and construction ("EPC") costs for project development on an accelerated timeline versus one on a "standard" timeline. It is likely more challenging to calculate an appropriate adder and may be difficult to contextual past contracts and projects in order to extract the premium associated with accelerating project timelines. However, this alternative approach streamlines the process in bypassing negotiation and/or regulatory costs of having to review any "change orders" to meet more accelerated project timelines.

i. Duration

CESA recommends that this proposal be adopted on a permanent basis, even if not always used, in order to have the processes and contracts in place to support emergency, short lead-time procurements going forward, if such needs arise in the future.

ii. Justification

An incentive to accelerate project timelines is justified since there are real and incremental costs associated with doing so, especially if prices are finalized and contracted assuming a particular COD. Developers bear costs associated with advanced equipment procurement ahead of their planned schedule (*i.e.*, "buying into" or "jumping" manufacturing lines or inventory for batteries, transformers, etc.) and potential overtime of human resources. There are also opportunity costs with deprioritizing other projects in other jurisdictions and markets in order to urgently meet needs or shuffle capacity toward California. These incremental costs should be compensated through an incentive mechanism. However, since there are many factors outside of the seller's control and because there are certain constraints that cannot necessarily be overcome (*e.g.*, supply chain limits), it should not be established as a requirement. There are likely a number of business-related, financing, interconnection, and construction factors that led to the seller contracting for the specified COD with the off-taker in the first place.

iii. Estimate of policy's impact

CESA is unable to assess the MW impact of accelerating the online date of projects because it is difficult to assess each developer's project-specific situation. However, given the volume and capacity of energy storage projects recently procured pursuant to D.19-11-016, there may be some projects that could assess their situations and bring its project online earlier, or have some of its capacity come online earlier with a phased approach (*e.g.*, 50 MW of a 100-MW storage project by one or few months, and the remaining 50 MW by the original

COD). Most likely, the scope of projects that would fall in the scope of this proposal is those that could move up COD (*e.g.*, September 2022) by several months in the summer in order to mitigate risks of system capacity shortfalls occurring earlier in the summer (*e.g.*, July 2021) due to various factors cited in the most recent system reliability analysis (*e.g.*, generator outages, drought-impacted hydro capacity, extreme heat weather events in early summer).

Considering the already compressed timelines of recent procurements, however, CESA views it unlikely that contracted projects could accelerate their COD by an entire year (*e.g.*, 2023 COD to 2022 COD), or the costs associated with such a drastic acceleration, and potential contract/price amendments may not be sufficiently covered by the any proposed incentive mechanism.

iv. Implementation requirements

CESA believes that this proposal is implementable, potentially without contract amendments since projects would be optionally accelerated ahead of the contracted COD. The source of the pool of incentive funds would also need to be identified, which could be drawn from other pools of penalty funds (*e.g.*, for RA/RPS compliance) or use existing cost recovery mechanisms to allocate costs associated with emergency or backstop procurement that may have been otherwise required to address potential shortfalls in intervening months between the accelerated COD and the contracted COD.

v. Potential risks

To avoid gaming of the COD to be eligible for the incentive mechanism, CESA recommends that this proposal only apply to projects that have already been contracted and have an agreed-upon price and COD between the seller and buyer. For new projects pursuant to D.21-06-035 that have yet to be contracted, sellers are likely to propose and commit to a specific COD at a certain price. In other words, for mid-term reliability procurement in solicitations that have just launched or are expected to launch later this year, the higher costs associated with an earlier COD will already be reflected in the bid or offer price to reflect what is feasible (*e.g.*, interconnection, project development timelines) and the costs for achieving earlier CODs in, say, 2023 or 2024 (*e.g.*, supply chain, construction).

vi. Statutory and/or regulatory justifications

This proposal appears to be in line with the Commission's view of what is reasonable, feasible, and justified based on the fact that it was proposed by staff as a Phase 1 proposal.[10] Previously, in Phase 1, CESA did not support such an incentive mechanism because it would have done little to support Summer 2021 needs and accelerate the online date of projects of projects coming online by August 1, 2021 pursuant to D.19-11-016 by several months. The likely need to amend contracts for projects in the midst of construction appeared infeasible, challenging, and risky. However, with the relatively greater lead time to Summer 2022 and 2023 CODs, it is reasonable to revisit this proposal.

Furthermore, prior to considering whether the Commission should direct the IOUs to procure additional capacity in lieu of having the CAISO procure capacity through the CPM for any particular month in Summer 2022/2023, the Commission should explore the degree to which procured energy storage resources could be incentivized to accelerate their deployments if shortfalls or gaps can be covered in this way. In this sense, by avoiding CPM backstop procurement, it is reasonable to have the costs and funds for this pool of incentives to be funded through the same mechanisms used to recover costs from bundled and unbundled customers.

B. If incremental IOU procurement of energy storage resources is directed, solicitations need to launch as soon as possible and have contracts expeditiously approved by the

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[10] Attachment 1: Final Staff Proposal and Guidance to Parties from *Administrative Law Judge's Ruling Introducing a Staff Report and Questions to the Record and Seeking Responses from Parties in Opening and Reply Testimonies* issued on December 18, 2020 in R.20-11-003 at 9. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M355/K738/355738415.PDF

Commission by February 25, 2022 while IRP 2023-2026 mid-term reliability solicitations must launch before the end of 2021.

If incremental capacity needs are identified, solicitations for Summer 2022-2023 should be launched as soon as possible and have any resulting contracts expeditiously approved by the Commission by February 25, 2022, consistent with reasonable timelines for energy storage project development milestones. To achieve this timeline, the following requirements are suggested:

- Launch IOU solicitation(s) for Summer 2022/2023 emergency reliability needs no later November 26, 2021
- Submit executed contracts for Commission approval via Tier 1 advice letter by January 15, 2022
- Final Commission approval by February 25, 2022 (if not earlier)

This above proposed timeline is necessary to account for various project development timelines that need to be accommodated, as discussed in more detail in our Petition for Modification in R.16-02-007 several years ago,[11] provide developers with market certainty on expected timelines, and ensure a minimal level of Commission and stakeholder review of resulting contracts. The proposed timelines also serve to bind the IOUs to complete the bid/offer solicitation, negotiation, and contracting process within a reasonable amount of time in order to provide a reasonable amount of time for Commission and stakeholder review and account for project development next steps upon Commission final approval.

In addition, upfront yet flexible procurement parameters should be established to clearly outline the eligible resource types that merits expedited Tier 1 contract approval, the specific evaluation criteria, and the issues that are likely out of scope. Some of these key parameters for

[11] *California Energy Storage Alliance's Petition for Modification of Decision 19-11-016* filed on April 1, 2020 in R.16-02-007 at 7-8. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M331/K080/331080307.PDF

energy storage resources can facilitate a streamlined and expedited contract approval process and include the following:

- **Recognition of energy storage operations for reliability:** Observed operations of energy storage to provide capacity and energy during the RA availability assessment hours ("AAH") and the net load peak period should be recognized and facilitate more expedited contract review. Similarly, the Commission should recognize that charging considerations for energy storage are handled in the interconnection study process and, where applicable for Local RA purposes, in the local capacity requirements ("LCR") studies.
- **Recognition of precedence and energy storage operations for greenhouse gas ("GHG") emissions reduction:** Energy storage resources have been demonstrated to operate its charge and discharge cycles in accordance with CAISO wholesale energy prices. With CAISO marginal prices reflecting GHG adders and being shown to closely correlate with marginal GHG emissions,[12] an upfront demonstration of GHG emissions reduction upon submission to the Commission for contract approval should be determined to be unnecessary. The Commission should also leverage precedents on how such upfront demonstrations are overly complex and unnecessary, particularly in cases where energy storage procurement is made consistent with IRP portfolios and procurement requirements, which already account for decarbonization objectives.[13]
- **Precedence on contract types:** If energy storage resources have been reviewed extensively and previously approved under a particular contract type, the

[12] *SGIP GHG Signal Working Group Final Report* published in R.12-11-005 on September 6, 2018 at 127.
[13] *See, e.g.*, Resolution E-5100 at 19 and Finding of Fact ("FOF") 1 and Resolution E-5101 at 14.

Commission should streamline their approval, focusing on the inputs and assumptions of the net present value ("NPV") evaluation itself rather than the contract structure.

- **Precedence and/or authorization on cost recovery mechanisms:** Under emergency or directed procurement orders, for example, the Commission has a well-established history of using the Cost Allocation Mechanism ("CAM") to leverage the IOUs to allocate costs to all benefitting customers. Delays to review or respond to concerns with well-established precedence should be avoided where reasonable and possible.
- **Positive NPV energy storage projects:** Under least-cost best-fit ("LCBF") evaluation methods, the IOU will select projects that not only have a positive NPV but also the highest in or within the highest tier of the bid stack.[14] Given the limited range of eligible projects that can meet 2022 or 2023 COD, the Commission could find it sufficient that the IOUs pursued and contracted for positive NPV projects.

If sufficient showings are made to align with the above procurement parameters and precedents, along with other parameters specified in the authorizing procurement order, the contract review process can be streamlined and expedited by "deeming" contracts compliant and avoid the need to consider these questions in reviewing contracts for approval. To avoid extensive back and forth with data requests to fill informational gaps regarding contracts and the solicitation process, the Commission should extensively specify the documentation and showings required. CESA has observed this issue as a source of delays in certain advice letter submittals.

[14] We recognize that the "best-fit" side of the assessment includes qualitative assessment, including for feasibility to achieve COD, such that the absolute highest NPV may not necessarily always be selected, but the broader point is that there may be value in positive NPV projects in general.

Furthermore, due to the lack of public data on Maximum Cumulative Capacity ("MCC") positions, CESA is unsure whether or to the degree to which MCC Category 1 limits could constrain the IOUs if the Commission opts to direct procurement by the IOUs to support emergency reliability needs. A significant majority of the four-hour standalone IFOM energy storage projects is seemingly procured by the IOUs to meet various procurement obligations related to Assembly Bill ("AB") 2514 energy storage mandates, identified IRP needs, CAM-related procurement, and emergency reliability needs, whereas community choice aggregators ("CCAs") appear to have mostly procured hybrid and co-located storage projects subject to MCC Category 4 limits. Depending on whether and the degree to which this could be a constraint, CESA recommends that the Commission relax or reallocate these limits as reasonable and allowed to not serve as a barrier to energy storage procurement.

Finally, CESA notes that, to position potential IRP procurements to meet mid-term reliability needs in the 2023-2026 period, solicitations need to be launched before the end of 2021, accounting for the two-year interconnection study timeline (or three years for QC 14) in addition to the additional two- to four-year observed time it has taken for any necessary network upgrades for deliverability to be constructed by the utilities. If some of these projects with 2024-2026 COD are later identified as potential candidates for acceleration, it could support Summer 2023 needs to a greater degree. However, without LSEs launching solicitations before the end of the year, CESA fears that this optionality could be lost or reduced.

i. Duration

CESA recommends that this proposal be adopted on a permanent basis in order to guide the Commission in issuing procurement orders in the future. Certain components may need to be revisited over time to refine, for example, contract structures, and/or return to LCBF evaluations that maximize NPV, but many structural elements related to establishing timelines and streamlining contract review and approval could persist beyond supporting the immediate needs of Summer 2022/2023.

ii. Justification

To arrive at our proposal, CESA reverse engineered the proposed procurement timeline and process from the COD of when incremental energy storage projects are needed to be online and back to the various intermediate project development milestones that must be met to reasonably bring projects online. Generally, for any emergency procurement order and frankly for any general IRP-related procurement, the timeline for the procurement order, solicitation process, and regulatory review period should be mapped and planned to ensure at least 18 months between final Commission approval and the target COD and at least four to six years between expected new-build storage projects and the target COD, as a rule of thumb.

For IOU contracts that require Commission approval, the regulatory submission and review process can present challenges with bringing incremental capacity online in an expeditious fashion if not coordinated and streamlined in appropriate ways. In setting the regulatory review process and standard, the Commission has historically balanced the urgency of the reliability need with the appropriate level of due process, such as procurement related to 2021-2023 system reliability where the Commission determined that "Tier 3 advice letters represent an appropriate vehicle to balance a need for expedited approval and appropriate due process for parties wishing to weigh in on an LSE's procurement approval requests."[15] By contrast, a Tier 1 advice letter process was found to be appropriate for Summer 2021-2022 procurement in recognition of the immediacy of the need and short lead time. Regardless of the appropriate level of review, CESA believes that energy storage is ready for more standardized contracts and streamlined review processes, and until such processes can be formally developed and adopted, the Commission must be cognizant of the fact that untimely final, unappealable approval of a contract will hold up investors and banks from making project financing available, thus impacting battery and equipment procurement and

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[15] *See* FOF 28 of D.19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023* issued on November 13, 2019 in R.16-02-007. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

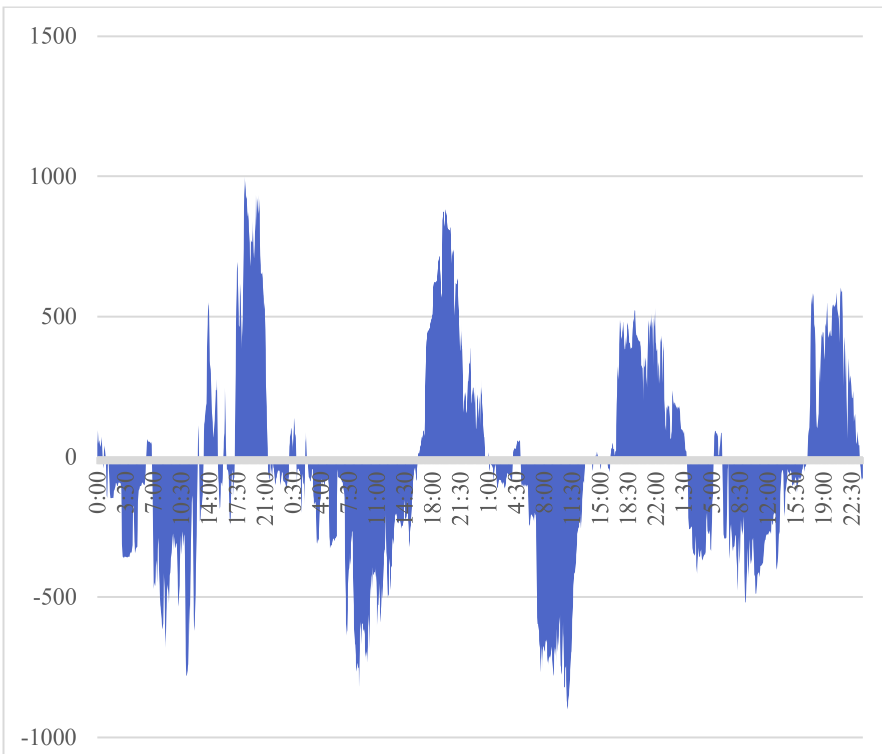
construction schedules. To avoid delays, developers must put up significant at-risk capital on their balance sheets pending final Commission approval, after which they will be able to access capital markets.

Credit to California's early leadership with the AB 2514 energy storage targets, the energy storage industry is now a global marketplace where California LSEs must compete with utilities and buyers in other jurisdictions and countries to secure battery supplies and other equipment. Unless developers have already secured an inventory of these supplies in advance, purchase orders for new batteries and transformers requires at least nine months of lead time, with project construction typically taking 12 months. These project development activities can occur in parallel, but it typically only starts upon the Commission approving the energy storage contract via a final, unappealable Commission decision or resolution.

To this end, the schedule of expected Commission approval of resulting contracts must take into account these timelines, which also supports market certainty for developers to have confidence that they can quickly deploy energy storage project capacity. At the same time, CESA recognizes that the Commission staff and other interested stakeholders may be hard-pressed or "cornered" to review energy storage contracts on a short timeframe if they are submitted with late and closer to the expected COD. In light of this concern, CESA also believes it is important to set minimum timelines for IOU solicitations and a deadline for contract submittals for staff/stakeholder review and Commission approval to maintain a reasonable level of due process rights and review period while providing more end-to-end certainty on the schedule of the solicitation process, contract negotiations, and minimum time needed for contract review.

Beyond the consideration of project timelines, there are many reasons to streamline and expedite energy storage contract review and approval based on key observations and Commission precedent, which highlight how certain questions about energy storage do not need to be extensively reviewed to merit contract approval. For example, the operation of energy storage resources in the CAISO market point to how they are operating as envisioned to "fill the duck curve" and provide the energy-shifting behavior in support of net load peak needs. As of August 24, 2021, the CAISO has experienced the potential for shortfalls in at least three days of Summer 2021: July 9, 10, and 12.[16] In order to better understand the role of BESS on these days, CESA leveraged the five-minute battery output data that the CAISO publishes on its "Today's Outlook" website. As shown in Figure 1 below, BESS assets have consistently contributed to grid reliability across these difficult days, sustaining positive output (*i.e.* discharge) in the 4 – 9 PM period. Notably, the five-minute output of BESS assets remained positive beyond 9 PM in the latter three days, maintaining discharge well beyond 11 PM.

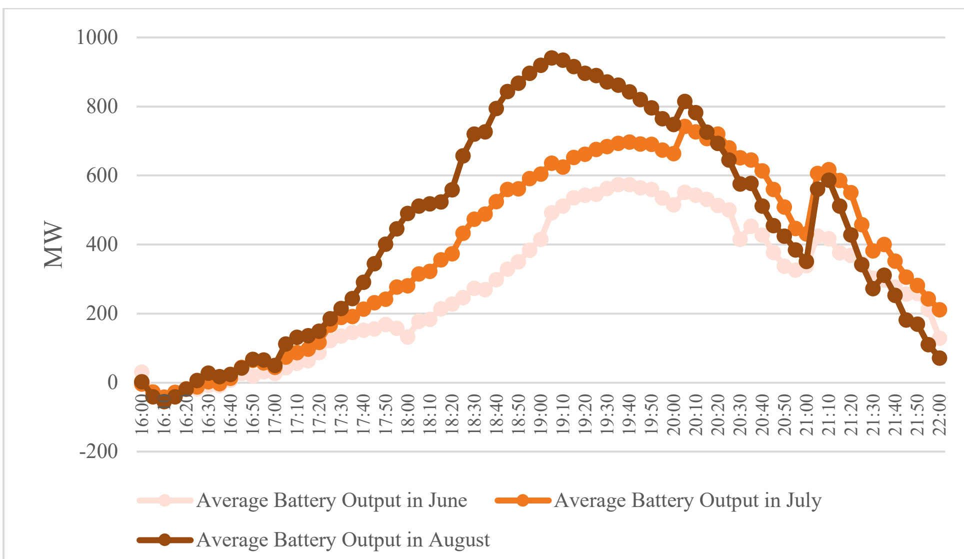
Figure 1: BESS 5-Minute Output from July 9 - July 12, 2021 (MW)



[16] CESA has selected these days for its analysis as the CAISO activated the voluntary conservation program "Flex Alert" in those days to minimize evening loads and mitigate the risk of undersupply.

Beyond the days in which the CAISO issued a Flex Alert, the output of BESS assets has contributed to reliability on a regular basis. To demonstrate the consistency with which BESS contributes to reliability in the afternoon and evening periods, CESA calculated the average five-minute output of BESS in the CAISO footprint, by month. Complied in Figure 2 below, this data shows the steady growth of the average five-minute output of BESS across the three months analyzed (consistent with the information included in Table 1), as well as the reliability with which BESS discharges during the lapse that encompasses the peak and net peak periods. In particular, CESA's analysis shows that energy storage's contributions to the grid have continued to increase as more has come online throughout the summer, going from an average five-minute maximum of 575 MW in June 2021 to 941 MW by August.

Figure 2: Average 5-Minute Output of Battery Storage in CAISO (16:00 - 22:00 in June 15 - August 21, 2021)



Given the quantifiable benefits of BESS and the fact that current planning process estimate that the state will require approximately 50 GW of energy storage to fulfill SB 100 goals, CESA recommends the Commission consider the advantages of instituting standardized contracting method for energy storage resources.

Finally, in reviewing contract prices, the Commission should recognize that energy storage resource procurement costs will likely be relatively more expensive to bring projects online with short lead time as compared to projects that can be brought online with more standard timelines, reflecting how energy storage is now a global market and the potential supply constraint limitations for batteries and other equipment. For example, based on the 2 GW (8 GWh) capacity shortfall for Summer 2022 under extreme weather scenarios of the Draft 2022 Net Stack Analysis, CESA understands that there is limited excess manufacturing capacity of this magnitude for 2022,[17] unless claimed capacity from other markets is rerouted to California in support of its nearer-term priorities[18] or some existing manufacturing capacity is claimed as soon as possible. This will come at a cost, but even if so, the Commission should keep in mind the bigger-picture role of energy storage in supporting the state's long-term decarbonization goals and reliability objectives. Furthermore, solicitations to meet Summer 2022/2023 needs must be launched and completed as soon as possible for developers to claim and procure these battery supplies before other global buyers do so. Even as many battery manufacturers have plans to ramp up its physical manufacturing capacity up to three-fold in the next few years, LSEs should launch solicitations for 2023-2026 mid-term reliability needs before the end of 2021 as well to not only align with project development timelines (*e.g.*, interconnection study, upgrades) but also to secure battery and equipment manufacturing supplies in an increasingly global and competitive energy storage market.

iii. Estimate of policy's impact

Certainty around procurement timelines and regulatory approval will invite greater market participation in California's resource solicitations in general but will play a vital role for solicitations with extremely tight lead times, such as needs for Summer 2022/2023, in

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[17] Note that manufacturers are reluctant to share proprietary information, so CESA could only qualitatively report on orders of magnitude regarding battery supply chain constraints and risks.

[18] Such re-routable capacity is limited since some manufacturers produce batteries in a "made-to-order" fashion, while others have limited capacity to redirect from other global markets to California, on the order of 500-1,000 MWh. Though manufacturers may be limited in their supply for 2022, some developers and system integrators have bulk purchased an inventory of batteries to support their national and global portfolio of energy storage projects, which could be redirected to nearer-term priority markets like California.

securing battery supplies and having a sufficient window to complete project development activities. Overall, the ability of incremental energy storage resources to meet Summer 2022 needs will be limited at this stage, but with the adoption of our proposal above, there could be opportunities for some projects to expand existing sites or increase the net peak deliverability of existing standalone generation facilities (*e.g.*, storage retrofits); the scope of new-build storage to meet Summer 2022 needs will be limited. Meeting the need for Summer 2023 is more feasible yet still challenging, where a greater range of energy storage projects in advanced stages of interconnection could be eligible.

Furthermore, CESA believes that a potential means by which to expedite the solicitation process and adhere to the proposed timelines above would be for the IOUs to return to the bid stack in recently-run solicitations (*e.g.*, pursuant to D.19-11-016 or D.21-03-056) to identify whether shortlisted, uncontracted project(s) in advanced stages of interconnection could move forward to meet Summer 2022/2023 needs, so long as the project(s) scored a positive NPV and could meet the urgent COD requirements. Although not selected as project(s) with the highest NPV and thus maximizing ratepayer net benefits, the positive NPV scoring of the project indicates benefits exceeding costs such that it would still make it worthwhile to pursue as a clean alternative. In the past, the IOUs have leveraged ongoing or recent solicitation processes to accelerate projects to meet urgent and evolving needs. For example, the 2018 Aliso Canyon energy storage projects leveraged the ongoing solicitations as part of the biennial energy storage procurement cycle to identify projects in the bid stack that could be repurposed to come online within 6-8 months,[19] highlighting a potential parallel for purposes of Summer 2022/2023 emergency reliability.

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[19] *See, e.g.,* Resolution E-4798 issued on August 18, 2016 at 3: "Although SDG&E was not originally mentioned in the Resolution E-4791, the Resolution was modified based on comments to find it reasonable that SDG&E leverage its ongoing 2016 Preferred Resources Local Capacity Requirement ("LCR") Request for Offer ("RFO") to find projects that could conceivably come online in the same time frame."

iv. Implementation requirements

This proposal is fully within the power and control of the Commission and leverages existing data, observations, processes, and structures in place today in order to streamline energy storage procurement and contract approval. In CESA's view, there are few downsides to adopting this proposal. While the IOUs may not want to have solicitation launch and timelines to be rigidly structured in this way, CESA believes that our proposal still maintains reasonable timelines and appropriately builds on lessons learned from previous solicitations and review processes.

v. Potential risks

CESA sees limited risks to this proposal. In fact, the risk is associated more with the reduced likelihood of procuring or accelerating energy storage deployment to address Summer 2022/2023, as well as Summer 2024 needs, unless CESA's proposal is adopted herein.

vi. Statutory and/or regulatory justifications

As discussed in more detail in our proposal above, the proposal is justified based on past Commission precedent for approving energy storage procurements and contracts. This proposal represents a synthesis of many of the findings and conclusions made in past Commission decisions and resolutions. Granted, there may be instances to deviate from past approaches or contract approval practices, which can be specified in future Commission procurement authorizations or orders to reflect evolving or emerging needs and conditions. For example, the recent IRP decision (D.21-06-035) specified specific performance characteristics and requirements for certain procurement categories (*e.g.*, Firm Dispatchable Clean Generation, Long-Duration Energy Storage, Diablo Canyon Replacement). Yet, the fundamental premise holds: upfront and clear procurement parameters and eligibility criteria will facilitate efficient procurement processes and streamlined contract approvals.

C. Pre-RA delivery of energy storage resources should be allowed and counted to support emergency reliability in the short term and RA needs in the long term, with contract provisions standardized and adopted and good-fit locations identified to support such EO operations.

CESA proposes that the Commission allow and encourage the IOUs (and other non-IOU LSEs) to contract for resources that can be operational in any time in Summer 2022 or Summer 2023 but may not obtain an NQC value in time for these periods. However, as EO energy storage resources in the interim that operate in the CAISO market consistent with RA must-offer obligations, such resources can still provide incremental reliability benefits more immediately, to the degree that there are such resources online now or in the near future. Standardized contract language to this end should be considered and adopted for consideration in this proceeding, such as allowable time ranges between initial delivery date as EO energy storage and RA deliveries from the energy storage resource achieving full capacity deliverability status ("FCDS").

While this construct is being used on an *ad hoc* basis by the IOUs, the Commission should consider ways to account for such pre-RA delivery contracts from other LSEs that are also subject to tight timelines to bring energy storage resources online by 2023 and 2024 pursuant to D.21-06-035. As CESA understands it, the Commission does not review and approve CCA and direct-access energy service providers ("ESPs") contract structures; as a result, EO energy storage resources would not count toward compliance to their IRP and RA procurement obligations in months when EO energy storage could provide RA-like benefits in accordance with must-offer obligations at eligible locations but would not be reflected in monthly supply plans since EO energy storage resources would not have deliverability and be listed on the CAISO's NQC list. To support CCAs in meeting their obligations with tight lead times and still deliver on reliability needs, a process should be developed for non-IOU LSEs to make separate "showings" to the Commission and the CAISO for such resources to count toward reliability obligations.

In support of this proposal, CESA recommends that the Commission collaborate with the CAISO to identify locations where EO energy storage resources could support emergency reliability needs. A potential methodology could involve an assessment of locations where there is significant transmission congestion due to the significant penetration of solar-only generation at a particular node or location in addition to some available unallocated peak transmission deliverability.

To demonstrate the concept, CESA conducted an analysis of some potential locations at which EO energy storage resources may be procured to meet the residual need for the effective PRM requirements. CESA reviewed the *Transmission Capability Estimates for Use in the CPUC's Resource Planning Process* ("2021 Transmission Capability Estimates"), a white paper published July 2021 by the CAISO, to identify solar-heavy areas with limited EODS. The 2021 Transmission Capability Estimates details the capability of the existing and approved transmission to accommodate resources with FCDS and EODS that covers all areas where there is commercial interest even if deliverability constraints are not identified. Using this source, CESA identified solar-designated zones with estimated EODS capabilities under some threshold – in this case, equal or less than 300 MW. CESA's reasoning for this process is that these areas find themselves constrained from an abundance of intermittent assets with an operational profile that could be complemented by energy storage. By expediting the procurement of storage in these areas, CESA believes that storage can take advantage of and increase the limited off-peak EODS by charging energy storage and discharging in support of net load peak needs where FCDS is available. For example, the areas identified by CESA are described below.

Table 3: Solar-Designed Areas with Estimated EODS Capabilities under 300 MW

Affected Zone	**Transmission Constraint**	**Estimated EODS Capability (MW)**	**Estimated FCDS Capability (MW)**	**Area Delivery Network Upgrade (ADNU) cost (USD, millions)**
Southern Nevada	GLW-VEA Area Constraint	269	300	$175
Imperial, non-CREZ within San Diego	San Diego Internal Constraint	290	968	$89

Non-CREZ within San Diego	San Diego Oceanside Constraint	280	280	$133
Carrizo	Kern-Lamont-Stockdale 115 kV line	125	3	NA

Using a similar or different approach above, CESA recommends a broader analysis be conducted across multiple or all locations to guide near-term procurement efforts as a proof of concept.[20] For energy storage resources that are sited in qualifying locations, the IOUs or other LSEs should be able to procure and contract for these resources to meet or reduce effective PRM needs for a defined short period until peak transmission deliverability upgrades are built (if needed), FCDS is achieved, and deliverability is allocated.

Where appropriate, this process may also identify storage resources that could serve as network resources, or storage as transmission assets ("SATA") that would enable their interconnection outside of the generation queue cluster and instead be approved through the Transmission Planning Process ("TPP").

i. Duration

CESA recommends that the proposal to be adopted on a permanent basis to have the processes and contracts in place to support emergency, short lead-time procurements going forward. Having such regulatory and planning tools in place may be helpful if such needs arise in the future. However, CESA is not advocating for EO energy storage resources to

[20] CESA observes that the generation-related hosting capacity data, known as the Generation Integrated Capacity Analysis ("ICA"), could also be leveraged to identify where energy-only storage resources could be located on the utility distribution grid and offer RA-like services. Generation ICA data should highlight locations where there is limited capacity to support generation onto the grid at particular time periods, using the 576-hour profiles developed by the IOUs, which could be used to site energy storage resources to charge where there is limited or no generation-related hosting capacity in the mid-day (or peak solar generation hours) and where there is significant generation-related hosting capacity in the net load peak period. As CESA understands it, the ICA is limited to focus on distribution capacity and does not inform whether distribution generation can be wheeled to and fully deliverable to the bulk transmission system to count as a System RA resource. To the degree that the accounting for System and Local RA need can be unbundled to support emergency reliability, the ICA represents a potential helpful tool to leverage and pursue energy-only storage resources.

count toward RA requirements as a permanent policy change, but only used on a temporary basis to support near-term emergency reliability needs until the full range of IRP procurements are able to come online with deliverable capacity. The requirement for generation and storage resources to have FCDS to count for System RA should remain to ensure that the appropriate network upgrades are built to make the capacity of the resource available to the bulk transmission system, no matter the level of generation by other resources on the grid. This represents an important pillar for qualifying RA resources, but at this time and until procurement cycles are able to "catch up" and return to normal such that interconnection, upgrade construction, and project development timelines are taken into account in lead times, a temporary pathway for EO energy storage resources at strategic locations can serve as an effective stopgap solution.

ii. Justification

Due to the long process of existing or new resources to obtain FCDS and count as qualifying resources in the IOUs' or LSEs' RA supply plans, the procurement and/or allowance of EO energy storage resources to count toward or reduce the effective PRM requirements could enable immediate-term availability of energy storage to provide incremental energy that operates like an RA resource. Without deliverability, for example, independent study process ("ISP") projects could be brought online in as little as eight months, with deliverability requested and studied in conjunction with the next QC to support eventual RA deliveries.[21] Similarly, projects on track for RA deliverability but awaiting deliverability-related upgrades could also leverage this proposal to support emergency reliability needs in the interim during this pre-RA delivery period. If existing deliverability is

[21] Since QC 15 will be delayed by one year to April 2023 (instead of April 2022), certain QC 14 projects that demonstrate electrical independence and are sited at congested substations could elect to also be studied and brought online as an EO energy storage resource in the ISP in the interim to support Summer 2022/2023 needs. Upon completion of FCDS interconnection studies, the project could be eligible for RA deliveries.

available, interim deliverability could also be allocated by the CAISO until the actual FCDS upgrades are built for a specific project.[22]

Meanwhile, the identification of good-fit network resources could help relieve the current Queue Cluster ("QC") 14 "supercluster" and the projects remaining from all previous QC rounds that are similarly impacted by the cumulative volume of interconnection requests. If the Commission and CAISO cooperate to identify good-fit projects currently in the interconnection to instead enter the network resource application process, it could advance select projects to bypass the queue and be able to come online more quickly while relieving the resource burden on CAISO and utility interconnection teams to study the remaining generation and storage projects. Historically, CESA has observed that the network resource process has historically had a very low success rate for developers, but this process could be enhanced to relieve pressure on the queue, avoid line upgrades, and provide some certainty to developers that projects can be monetized.

As a point of reference regarding potential pre-RA delivery contract provisions, SCE previously advocated for such workaround proposals when lead times were short, such as in the case of IRP procurement pursuant to D.19-11-016.[23] In fact, SCE included such contract

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[22] *Tariff Amendment to Implement Summer 2021 Market Enhancements* (ER21-1536) filed on March 26, 2021 at 5 and 37-38. https://www.caiso.com/Documents/Mar26-2021-Tariff-Amendment-2021SummerReadiness-ER21-1536.pdf

[23] *Comments of Southern California Edison Company (U 338-E) on Revised Proposed Decision Requiring Electric System Reliability Procurement for 2021-2023* filed on October 31, 2019 in R.16-02-007. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M319/K001/319001136.PDF. *See also* at 12: "SCE created a contract to allow for reliability benefits to be provided without actually providing RA. In this agreement, for the time period prior to receiving an NQC/EFC, the project is required to submit bids into the CAISO market consistent with RA must offer obligations. Capacity payments are then prorated based on whether or not the facility followed these requirements. In this respect, the obligations are similar to the RA program, in that the facility needs only to make itself available to the market, and specific dispatching was handled by market mechanisms. Although all projects counted towards the procurement requirement should ultimately be required to provide system RA, the Commission should allow this type of approach as an interim mechanism until projects can qualify for RA counting given the aggressiveness of an August 1, 2021 online date."

provisions in their Aliso Canyon Energy Storage ("ACES") 1 RFO[24] due to the six-month lead time to COD, which was approved by the Commission[25] without any issue related to these contract provisions despite a real emergency reliability issue tied to the moratorium at the Aliso Canyon natural gas storage facility. The parallels between the Aliso Canyon situation and this current emergency reliability situation points to how similar contracting approaches are precedented and could be used to support expeditious procurement of incremental energy storage capacity. Similarly, Pacific Gas and Electric Company ("PG&E") recently contracted for energy storage resources with contract provisions involving an "Interim Must Offer Obligation" for the period between COD and the beginning of RA deliveries, which Commission staff approved.[26] Since CESA is not a bidder in these solicitations, access to contract language, or unredacted versions, is limited for CESA to be able to propose specifics on how to actualize EO energy storage resources for system reliability purposes, but the Commission could build on the templates established by PG&E and SCE to adopt minimum provisions as standard means to count energy storage procurements in the near term and allow CCAs and ESPs to pursue similar means for their obligations.

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[24] *See* SCE Advice Letters 3454-E at 9-10 and 3455-E at 9. *See also*, for specific description of the product, SCE Advice Letter 3456-E at 6-7: "The Product that SCE will purchase and receive during the Pre-RA Delivery Period (the period from achievement of the Initial Delivery Date until the RA Delivery Date) is Seller's obligation to submit economic bids for energy and/or ancillary services at the Project's full capacity every trading day into the CAISO day-ahead and real-time markets consistent with the requirements of a Resource Adequacy Resource. Essentially, the Pre-RA Delivery Period Product is the available capacity that a Resource Adequacy Resource would provide, but without the RA compliance instrument. To the extent the Seller does not bid into the markets in this manner on any trading day, it receives no contract payments from SCE for the trading day. The Product SCE will purchase during the Pre-RA Delivery Period is consistent with the Resolution because it provides additional available capacity to the CAISO Grid to help alleviate electric reliability concerns associated with the partial shutdown of Aliso Canyon."

[25] *Resolution E-4804. Southern California Edison Company (SCE) requests approval of three resource adequacy only contracts with Western Grid Development, LLC, AltaGas Pomona Energy Storage Inc., and Grand Johanna LLC* issued on September 15, 2016. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K245/167245981.PDF

[26] *See* PG&E Advice 6289-E submitted on August 6, 2021. https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6289-E.pdf

iii. Estimate of policy's impact

The MW impact of the interim policy changes is difficult to estimate since not all projects will need to be contracted as EO resources with pre-RA delivery. There may be many of projects that are able to secure the upgrades needed to achieve full deliverability as typical RA resources, but adopting CESA's proposal will provide additional flexibility to bring certain energy storage resources in a timely manner, potentially accelerating initial delivery of RA-like services by several months (*e.g.*, July 2022) even though actual RA deliveries will occur by a later date (*e.g.*, October 2022).

iv. Implementation requirements

A full assessment of location-by-location potential for energy-only storage interconnections and operations to support emergency reliability needs requires close coordination with the CAISO. Above, CESA provides an illustrative example and elaborates on the potential to use a combination of existing transmission capability estimates and an assessment of transmission congestion pricing to identify locations where energy storage can leverage the excess solar generation potential to shift energy to the net load peak periods of need.

Furthermore, since EO resources would not count and qualify in LSEs' monthly RA supply plans, a close accounting would need to be developed to quantify the number of energy storage resources operating as energy-only resources but in accordance with must-offer obligations to offer RA-like services. In doing so, the Commission and CAISO can assess the full supply stack in meeting the 15% PRM as well as the "effective" 17.5% PRM (or some other "effective" PRM established in this proceeding) and determine whether incremental procurement is still needed.

v. Potential risks

While there is some risk that the generation or storage cannot deliver its capacity at all times since transmission upgrade needs have not been fully studied, such pre-RA delivery period operations from resources in the deliverability study process can support incremental reliability needs in the near term and provide RA benefits in the long term once full capacity deliverability is secured. Since the emergency reliability needs are not needed for RA compliance purposes, this workaround could be a means to expedite emergency capacity procurement. Additionally, some of the physical risks of undeliverable energy storage capacity can also be mitigated by a fuller assessment of eligible locations where EO energy storage could provide RA-like services.

vi. Statutory and/or regulatory justifications

Given the fact that the Commission has allowed the use of pre-RA deliveries for PG&E and SCE energy storage procurements, there are solid regulatory justifications for adopting CESA's proposal. Furthermore, in their concept proposal, Commission staff also seems to be open to the idea of procuring firm supply resources that can be available for dispatch to meet the net peak but that do not otherwise meet RA capacity obligations, as well as temporary generation facilities, suggesting that the Commission sees value in leveraging non-RA resources in the interim for emergency reliability.[27]

D. CESA's Petition for Modification on station power rules for hybrid and co-located resources should be expeditiously adopted to avoid unfair and unreasonable harm and ensure that these projects come online in a timely manner to support near-term system reliability.

CESA submitted a Petition for Modification ("PFM") of D.17-04-039 in R.15-03-011 requesting that the Commission issue a Proposed Decision as soon as possible to modify D.17-04-039 and D.18-01-003 as follows:[28]

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[27] Staff Concept Proposal at 24-25.

[28] *Petition for Modification of Decision 17-04-039 of the California Energy Storage Alliance to Address Hybrid and Co-Located Resources* filed on March 19, 2021 in R.15-03-011. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M372/K332/372332171.PDF

- Affirm that the rules for standalone IFOM energy storage, including the permitted netting rules, apply equally to hybrid and co-located resources.
- Affirm that hybrid and co-located resources have the right to self-supply their internal power needs, including station service, and avoid retail energy charges, as is the case with any conventional generator.
- Affirm that a single 'high-side' meter is sufficient for the purposes of delineating between wholesale and retail electricity draws.

As explained in detail in the PFM, CESA examined each of the various operational modes of hybrid and co-located resources and illustrated how the proposed modifications to the existing station power rules pursuant to D.17-04-039 combine with self-supply provisions in place for generation resources to appropriately assess station power for hybrid and co-located resources. A case-by-case assessment of operating modes of hybrid and co-located resources revealed that no differentiation is needed based on the hybrid versus co-located resource market participation configuration and how the existing rules and tariffs apply readily to ensure appropriate delineation of wholesale and retail energy. CESA urges the Commission to act on this PFM as soon as possible.

i. Duration

The relief sought in CESA's requests is intended to be permanent modifications to the station power rules for hybrid and co-located resources. There is no reason for the provisions to only be in place on a temporary basis, which only serves to create uncertainty for hybrid and co-located resource procurement as to how to configure and meter the project and/or determine the financeability of and solicitation bids/offers for the project depending on rules for its station power treatment. With the proposed modifications merely extending rules and tariffs in place for standalone IFOM energy storage and standalone generation resources, the Commission should not need additional time or process to review the applicability to hybrid and co-located resources, which should be on a level playing field as other resource types and configurations. Considering station power rules were already reviewed as part of

R.15-03-011, there is no reason to adopt CESA's proposed modifications on a pilot or temporary basis, subject to further review or revisiting at a later time.

ii. Justification

As explained in detail in the PFM, clarifications on station power rules are urgently needed given the significant volume of hybrid and co-located projects currently being contracted and constructed. Until station power rules are clarified in accordance with the requests in CESA's PFM, hybrid and co-located projects are subject to case-by-case treatment on how existing rules for standalone generation and standalone storage projects are applied. The current case-by-case determinations are not scalable or efficient, creating disputes and uncertainty around the appropriate station power treatment that delay projects when timely commercial operation of these projects is tantamount to near- and mid-term reliability. If inappropriately and inconsistently applied – or applied in ways that may uneven the playing field for the treatment of station power some resources compared to others – progress may be impeded and sub-optimal resource selection outcomes could occur, and projects could be subject to "overbilling" of station loads where permitted netting and self-supply applies.

Importantly, disagreements on the interpretation of the existing station power and self-supply rules as it applies to hybrid and co-located resources have led to unanticipated, material impacts on project costs and development timelines. With these negotiations typically occurring late in the interconnection process and with most hybrid and co-located resource projects coming online over the 2021-2023 period, this realization is reached far after projects have been contracted, posing a risk that these contracted projects may become unfinanceable, or worse, canceled when the Commission should be doing everything in its ability to bring online as many resources as possible. This is an issue that also impacts incremental procurement that may occur in this proceeding or pursuant to D.21-06-035 since technical project design considerations are impacted by whether the rules allow for self-supplied energy (*e.g.*, running separate circuits). A basic assessment of station loads (*e.g.*, transformer, HVAC, and inverter idle losses) multiplied by the applicable average retail tariff charge (*e.g.*, \$0.1689/kWh) instead of the average wholesale price (*e.g.*, between \$0.02/kWh and \$0.06/kWh) would show obvious material financial harms on projects.[29]

iii. Estimate of policy's impact

As detailed in CESA's PFM,[30] an estimated 871 MW of paired storage capacity in hybrid or co-located project configurations is contracted to come online in Summer 2022 and 2023. Already, 846 MW of paired storage capacity has come online if these resources came online as contracted, according to publicly-available procurement documents. Thus, the impact on the viability of many projects is significant that are being relied upon to support near-term system reliability needs.

iv. Implementation requirements

CESA views limited implementation challenges related to the requested modifications in the PFM. The billing systems and tariffs are already in place, and the CAISO has affirmed that it can modify its tariff to reflect the clarifications provided by the Commission.[31]

v. Potential risks

CESA views no risk associated the modifications and clarifications requested in the PFM. In fact, risk can be attributed to the lack of action on the PFM, leading to material and financial harm and even cancellation of projects that are needed for near-term system reliability.

vi. Statutory and/or regulatory justifications

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[29] *See for reference* Energy Information Administration data for average wholesale and retail prices: https://www.eia.gov/electricity/state/
https://www.eia.gov/todayinenergy/detail.php?id=46396

[30] CESA's PFM at 2.

[31] CAISO's Response in R.15-03-011 at 3-4. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M378/K738/378738797.PDF

As explained in CESA's PFM, the Commission, as the local regulatory authority, ultimately has jurisdiction over the retail sales of station power. The Federal Energy Regulatory Commission ("FERC") conceded that it lacked statutory authority to regulate station power and left it up to the states to determine the amount of station power that would be subject to state-jurisdictional retail energy sales and rates.[32] Hence, this is well within the wheelhouse of the Commission to determine expeditiously.

V. Interconnection Strategies

Delayed or slow interconnection processes represent major barriers to bring online significant quantities of clean generation and storage projects, let alone accelerate or expedite their deployment. Consistent with Order 14 of Governor Newsom's Emergency Proclamation that requested that the CAISO take all actions available, including waivers to its existing tariff processes, to expedite the interconnection process for transmission-connected resources, the Commission should explore and pursue all such actions for IFOM and BTM energy storage as part of this proceeding. CESA thus appreciates the Commission's addition of interconnection and related strategies in the Phase 2 Amended Scoping Memo. Larger and structural reforms are likely needed in the appropriate Commission proceeding (*e.g.*, R.17-07-007, R.21-06-017) or via the CAISO's forthcoming Interconnection Process Enhancements ("IPE") Initiative, but two immediate strategies could be pursued to enable greater operational capacity and streamline the interconnection of some retrofitted capacity.

In addition to CESA's two more detailed proposals below, CESA generally comments on the potential benefit of enforcing or increasing utility interconnection staffing requirements. CESA's members report major delays in interconnection studies by the utilities – a function in part on the volume of interconnection requests and in part on the inability or inefficiency of the utilities to conduct these studies

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[32] *Duke Energy Moss Landing v. CAISO*, 132 FERC ¶ 61,183 at P 2 (2010); and *Calpine Corp. v. FERC*, 702 F.3d 41, 47 (D.C. Cir. 2012).

with existing resources. Yet, although the Commission required the IOUs to commit additional resources to their interconnection study and distribution upgrade teams as well as to the IT solutions that support these teams, in order to facilitate faster processing for all microgrid and resiliency projects,[33] the IOUs generally proposed to reorient team members and leverage technology improvements to support efficiency gains in interconnection.[34] Generally, CESA is a proponent of IT solutions to streamline interconnection and achieve efficiencies and understands that the interconnection staffing requirements were directed in developing near-term 2020 resiliency strategies for smaller, customer-sited generation and storage systems; however, it may be time to reconsider this approach since there are limits to the current approaches to larger IFOM generation and storage projects, and in turn, require higher staffing requirements to support the record buildout levels ahead.

Along the same lines, additional support and improvements are needed to support timely network upgrades, which can delay the COD of many energy storage projects that are needed for near- and medium-term reliability. Additional utility staffing will be helpful in this regard, but the Commission should also potentially explore allowing third-party builders to support the construction of these network upgrades. There are legal, liability, outage scheduling, and work supervision issues that will likely need to be figured out. Despite the complexities of these issues, it may be worthwhile to find ways to bring additional resources to support the buildout of transmission and distribution upgrades.

A. Provisional exports for BTM non-exporting energy storage should be enabled through a streamlined process, leveraging inverter capabilities.

CESA proposes that the IOUs develop and establish a streamlined interconnection process that would allow BTM standalone non-exporting energy storage resources to provide "provisional exports" on an exceptional basis to support emergency reliability needs. Leveraging

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[33] *See* D.20-06-017 at OP 3 and 10.
[34] *See, e.g.*, PG&E Advice 5917-E, SCE Advice 4275-E, and SDG&E Advice 3590-E submitted on August 17, 2020.

the UL 1741/SA inverters and UL Power Control Systems ("CRD") that are often typically used in lieu more expensive physical relays to ensure Rule 21 non-exporting operations and/or ensure export of electrical power to the distribution utility's electric system is minimized (*i.e.*, control inadvertent export), existing BTM standalone non-exporting energy storage resources should be allowed to switch off their import-only mode and allow for exports as well in order to support incremental load reductions ("ILR") as part of their participation in the ELRP.

A provisional export review process and operationalization pathway could be established as a condition of ELRP participation and/or enrollment in other DR programs in support of emergency reliability needs. In this way, the IOUs can have mechanisms to monitor performance and integrate communications and triggers related to the ELRP and other DR programs to signal when provisional exports are allowed (*e.g.*, turn "off" import-only mode) and the period by which the system must return to its non-exporting operations (*e.g.*, turn "back on" import-only mode).

i. Duration

The proposal could initially be in place temporarily to support Summer 2022 and 2023 needs and be revisited for its adoption on a more permanent basis, if value is found to maintain this process. In the long term, having such a process to enable provisional exports from non-exporting energy storage systems may be valuable in providing the distribution system with operational flexibility to leverage and tap into otherwise stranded export capacity and support system capacity shortfalls. Importantly, CESA notes that policies to enable and compensate exports for broader DR and RA services could make this type of process obsolete since many BTM energy storage projects would find the costs and process associated with securing a full continuous export permit to be justified.

ii. Justification

A provisional export pathway is a cost-effective and efficient means to procure additional operational capacity from existing BTM non-exporting energy storage systems. Generally speaking, when the state of charge of the storage system exceeds the onsite customer load at any time, the storage system will have residual capacity to potentially support the grid, if not for their interconnection agreements preventing exports across the point of common coupling and to the grid. Depending on onsite customer loads and needs at other times of the day and/or the opportunity costs of delivering this energy to the grid versus maintaining it for the customer, this capacity could be made available to the grid during system capacity shortfalls.

For various reasons, however, encouraging or requiring these systems to be studied for and secure full continuous export permits may not be worthwhile or rational. First, as existing systems with executed interconnection agreements, the study process will take time, and securing the rights for continuous export may trigger distribution upgrades. Second, outside of Net Energy Metering ("NEM") systems, there is no compensation mechanism in place to pay for BTM energy storage exports, leading to no revenue/value stream to be in place to offset the potential additional costs in time and/or upgrades to operate as a continuous export asset. Programs like the ELRP and other DR programs now recognize and compensate exports in terms of ILR measurement and settlement, but these voluntary energy-only payments are subject to uncertainty regarding the number and duration of events and the amount of payments due to the after-the-fact invoicing and settlement structure. It thus can be hard to make the case for any major operational change or increase in investments to support continuous exports beyond the few extreme weather days in the summer.

To better realize any available export capacity from BTM non-exporting energy storage resources, CESA believes that a provisional export pathway will provide a more cost-effective and enticing means for the storage resource owner and operator to make these incremental energy exports available for the system grid. Rather than facing the hurdles of follow-on interconnection study processes or potential distribution upgrade costs, the IOUs can operationalize existing storage export capacity to support emergency reliability needs.

iii. Estimate of policy's impact

There is a number of project- and customer-specific considerations to estimate the MW impact of a provisional export pathway,[35] but CESA estimates that there is at least 54 MW of standalone non-exporting storage that could benefit from this proposal based on data from the Self-Generation Incentive Program ("SGIP").[36] However, there is likely much more capacity that would be available from Rule 21 non-exporting standalone storage that did not participate in SGIP. CESA was only able to find data from SCE on their Rule 21 queue, amounting to 351 MW of in-service, non-exporting energy storage.[37] Some portion of this capacity could be interested in a provisional export pathway.[38]

Table 4: Total Rated Capacity of Operating Standalone Energy Storage Projects in the SGIP Large-Scale Storage Budget

Program Administrator	Sum of Rated Capacity [kW]
Center for Sustainable Energy	6,399.91
Pacific Gas and Electric	7,333.80
SoCalGas	9,021.01
Southern California Edison	31,358.49
Grand Total	**54,113.20**

iv. Implementation requirements

Implementation of this proposal should be feasible based on the technical capabilities of existing battery inverters, the existing communication channels and triggers for the ELRP

[35] Available exports will depend on storage installed capacity, minimum customer load at the time of discharge and need (*e.g.*, more available for export on weekends due to low commercial load), and any state-of-charge limitations for technical reasons or for customer needs (*e.g.*, resiliency).

[36] Data based on the SGIP Real-Time Public Report, available at selfgenca.com, accessed on August 31, 2021. Calculation is based on projects from the Large-Scale Storage Budget, which has been active since 2017. Data has been filtered to only include standalone projects not paired with any other technology. Operating projects have been determined to be projects marked as "Paid" or "PBI in Progress".

[37] Data based on SCE's "Wholesale Distribution Access Tariff (WDAT) and Rule 21 – Interconnection Queue" updated as of July 1, 2021 and available at https://www.sce.com/business/generating-your-own-power/Grid-Interconnections?ecid=van_gridinterconnections. Capacity calculated based on the Rated MW of projects including only Energy Storage that were marked as "In-Service", including those with Conditional PTOs.

[38] In an informal member survey in response to conversations with PG&E regarding their A.3 ELRP implementation, CESA found that there could be 15 MW of standalone non-exporting storage capacity that would be interested in taking advantage of this pathway across projects in PG&E territory.

and other DR programs, and mechanisms in place to recognize the ILR of exports during emergency reliability events (as adopted in D.21-03-056).

v. Potential risks

In bypassing a full interconnection study process, CESA understands that there may be some potential risk of safely and reliably enabling provisional exports without taking into account distribution system conditions, including the impact of other generation facilities at or near a particular location. To guard against such risks, CESA recommends that the IOUs utilize and assess the generation ICA data to determine if provisional exports from BTM non-exporting energy storage systems would create constraints or overloads. If an initial planning assessment using 576-hour profiles reflects available hosting capacity, then a provisional export permit to a certain capacity level should be approved and to be utilized/activated to provide emergency export-related ILR only during ELRP events. The actual allowable export level should be allowed to exceed the provisional export permit when the IOU's DERMS or similar system operational data reveals it is feasible to do so on a more real-time basis.

vi. Statutory and/or regulatory justifications

There are many processes and strategies already adopted by the Commission that point to the technical feasibility and consistency with precedents of CESA's proposal. Across many IOU interconnection processes and tariffs, inverter PCS is increasingly being utilized to support modifications to interconnection generation facilities and ensure NEM integrity for NEM-paired storage systems.[39] In R.19-09-009, the Commission also "modernized" the NEM tariff to allow temporary transitions to non-export mode during the period before Public Safety Power Shutoff ("PSPS") events using the UL PCS CRD to help existing solar-plus-

[39] *See, e.g.*, PG&E Rule 21 Section Ee and PG&E Electric Schedule NEM2 Special Condition 9 NEM Paired Storage.

storage systems to better provide backup power.[40] In this way, the Commission has leveraged the existing inverter PCS capabilities as a cost-efficient means to support different and urgent use cases and applications. Similarly, the PCS can be leveraged to support provisional exports to support summer emergency reliability needs in relative short order.

B. Eligibility of the Rule 21 non-export notification-only pilot should be expanded to include non-exporting storage retrofits to exporting solar generation, and the developer cap per circuit should be removed as well.

CESA recommends that the recently-adopted Rule 21 notification-only interconnection pilot be modified to make non-exporting storage retrofits to exporting standalone solar eligible and eliminate the "developer cap":[41]

> "Eligible projects: shall total less than or equal to an aggregate of 30 kilovolt-amps (kVA) and may consist of one of the following options: i) one new non-export energy storage system, ii) one new non-export system with energy storage system and solar, or iii) one new energy storage system plus any existing generation systems ~~**where the combined system is non-export**~~; shall be limited to 10 non-export projects ~~**for each developer**~~ at any one circuit; shall use a Underwriter Laboratories (UL)-certified Power Control System with an Open Loop response time of two seconds or less and set to a non-export mode; shall be limited to 120 Volt or 240 Volt services that use a self-contained meter; shall not be located on or within a quarter mile distance from any networked secondary portion of the utility's grid; shall be operated in a manner that does not increase a customer's peak

[40] *Decision Adopting Short-Term Actions to Accelerate Microgrid Deployment and Related Resiliency Solutions* (D.20-06-017) issued on June 17, 2020 at 39-40 and Conclusions of Law 18-19.
[41] D.21-06-002 at OP a(b).

> load; shall use inverters pre-approved by the utility; shall be installed such that when connected to a single phase-transformer with 120/240 Volts secondary voltage the aggregated gross output is balanced as practicable between the two phases of the 240 Volt service; and shall only be installed by eligible developers, as described below."

In addition, as shown above, CESA recommends that the "developer cap" of 10 non-exporting storage projects per circuit adopted for the pilot be eliminated altogether.

i. Duration

In line with the temporary nature of the pilot adopted in D.21-06-002, CESA's proposed modifications would continue to apply on a two-year basis and be evaluated during this adopted trial period.[42] Upon evaluation, as planned in accordance with D.21-06-002 and considered in the draft DER Action Plan 2.0,[43] the Commission can assess whether to adopt the pilot, including CESA's proposed modifications, on a permanent basis. Thus, no separate determination needs to be made in this proceeding regarding the duration of the proposal.

ii. Justification

Storage additions or retrofits to existing standalone solar represents an immediate means to shift solar generation to the net load peak period while leveraging existing interconnection agreements and capacity in place. The ready-made nature of this strategy to add incremental capacity is evidenced, for instance, by the significant amount of storage additions to IFOM solar projects to meet the near-term system reliability needs for the 2021-2023 period.[44] While not at the scale of utility-scale storage retrofits to existing IFOM

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[42] D.21-06-002 at OP 1(a) and 5.
[43] *See* Draft DER Action Plan 2.0 Vision Element 2B Action Element 1 at 13.
[44] *See, e.g.,* Resolution E-5101 at 2-3. 620 MW of contract amendments were executed and brought online within one year by August 1, 2021.

standalone solar projects, the same principle applies where significant amounts of storage could be added to existing BTM standalone solar projects.

Moreover, to provide greater flexibility and get as much retrofitted capacity as possible, regardless of who does the storage additions, the developer cap is not needed. Typically, pilots generally have a learning objective, where some also have a market transformation or diversity objective; in this case, however, the developer cap may be overly limiting when the critical deciding factor is the technical safety and reliability of the storage interconnection, demonstrated by falling within the eligibility criteria and for developers in meeting a good-actor track record. Ideally, the pilot would afford as many developers the opportunity to become familiar and test out the process, but the urgent need for capacity should suspend this particular objective in the interest of getting as much capacity online as quickly and as safely possibly. The criterion around the cumulative impacts on any given circuit is maintained, so the technical safety and reliability concerns are not being compromised with this change in the pilot.

iii. Estimate of policy's impact

The MW impact of this proposal is difficult to estimate given the lack of clear data,[45] but in reviewing SCE's Rule 21 data alone, there is 153.85 MW of standalone exporting solar projects across 106 projects that could benefit from expanded eligibility for the notification-only pilot.

iv. Implementation requirements

Modifications to the pilot is incremental and feasible, with the IOUs having already launched the pilots, developed the auditing details, and forms to be used. Each of these forms and processes would just need to be incrementally modified to reflect the proposed change to

[45] For example, in assessing existing standalone solar projects, PG&E only reports WDAT projects (97 MW across 68 projects) and SDG&E combines Rule 21 and WDAT projects (40.77 MW across 14 projects).

eligibility criteria above. Falling fully within the Commission's jurisdiction and oversight, no inter-agency coordination is needed.

v. Potential risks

CESA does not see technical risk of expanding eligibility of the pilot to include non-exporting energy storage retrofits to existing exporting solar generation facilities. First, exporting standalone solar systems have already been studied in the interconnection for maximum exports in the mid-day solar generation periods – a "worst-case" scenario for the solar generation facility. Adding non-exporting storage will only serve to reduce the mid-day export impacts, thus improving the technical reliability impacts on the grid, and importantly, to reduce the level of load served in the net load peak, thus contributing the emergency reliability needs that are the subject of this proceeding.

Fundamentally, since the important factors of determining material grid impacts against the applicable Rule 21 screens relate to the size of the system and the export levels across the point of common coupling, the non-exporting storage addition would not be impacting either of these factors. The storage system, as a non-exporting component, would not be shifting the timing of exports or increasing the level of exports, instead supporting greater levels of solar self-consumption during the net load peak period. Functionally, there is limited difference between a non-exporting storage addition to an existing standalone solar with a standalone solar generator with reduced mid-day exports, below its worst-case export capacity and potential – the latter which would not raise operational or reliability concerns for the distribution utility.

vi. Statutory and/or regulatory justifications

CESA understands that this proposal could be considered a "relitigation" of an adopted Commission decision, which may require a Petition for Modification to D.21-06-002 by CESA or some other party, or potentially upon the Commission's own motion. However, in light of the urgency of the need for capacity and the narrowness of the change to the eligibility requirements and parameters, CESA recommends that the Commission adopt the aforementioned proposal and deviate from the usual process on an exceptional basis.

In addition to the above, CESA notes that some of the changes to the eligibility criteria were adopted as last-minute revisions to the Proposed Decision leading to D.21-06-002, without much explanation to the changes in response to and/or citation of parties' comments. For example, the first revision to the Proposed Decision broadly defined eligible project types as follows:[46]

> "eligible projects shall be one non-export energy storage or non-export storage plus existing generation systems totaling less than or equal to an aggregate of 30 kVA capacity."

Thereafter, the second revision to the Proposed Decision specified the type of eligible projects broadly defined eligible project types to cover those involving the combination of solar and storage resources.[47] To the Commission's credit, the Proposed Decision was revised to include the addition of a completely new solar and storage system, where both components of the combined system is configured as non-exporting – a key use case that falls within the technical considerations of the pilot process and responds to parties' comments.[48]

On the other hand, if the Commission finds it necessary for a Petition for Modification of D.21-06-002 to be filed and served, CESA urges the Commission to rule on and adopt the modifications requested in a potential future Petition. Typically, a decision on

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[46] Proposed Decision Rev. 1 at 14.
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M385/K993/385993637.pdf

[47] Proposed Decision Rev. 2 at 14.
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M386/K710/386710048.pdf

[48] Tesla comments on Proposed Decision in R.17-07-007 at 3.
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M380/K579/380579123.PDF
CESA comments on Proposed Decision in R.17-07-007 at 5.
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M378/K737/378737744.PDF

petitions have taken at least six months or more, but given the urgency and importance of the emergency reliability issues being targeted in this proceeding, immediate resolution on such a Petition should be pursued.

VI. Emergency Load Reduction Program (ELRP) and Other Demand Response (DR) Modifications

Given the lead times required to build new IFOM generation and energy storage projects, the Commission is appropriately considering a wide range of BTM resource strategies, including modifications to the recently-established ELRP pilot, further modifications to existing DR programs, and more expansive consideration of the role of EVs and VGI resources as DERs. Overall, CESA is generally supportive of the proposed changes in the staff concept paper as being incrementally helpful, but the foundation of the ELRP as a voluntary program fails to position the program as an "insurance policy," as framed by the Commission and other stakeholders. Unless structured with some form of upfront payments, there will be limited interest in participating in a program with uncertain compensation for their response. Further, a voluntary program is no replacement for a capacity program that can support forward planning by securing commitments. Currently, the ELRP amounts to a hope and prayer that customers will first enroll and then respond, which does not reduce the stress of grid planners and operators in determining whether there is sufficient capacity. In other industries, an insurance policy is a payment to cover catastrophic and unforeseen events, where the policy will step in when such events materialize; however, the current ELRP is not structured in this way.

A. Notwithstanding the lack of a capacity payment, the proposed modifications to the ELRP represent improvements that may encourage more participation but should be broadened to ensure that they encompass A.3 and A.4 customers.

As a voluntary pay-for-performance program involving after-the-fact energy payments, the ELRP fell short of CESA's vision for the potential of a program to support emergency summer reliability. Without capacity or some form of upfront payments to encourage participation, CESA anticipated that the program may have limited participation or enrollment, even if they could supplement other DR program participation through measurements of payments for ELRP-triggered ILR. Some of these predictions have borne out, with staff sharing their understanding that potential customers have chosen to not participate in the program for Summer 2021. It will be helpful to assess the reasons for this lack of participation in better diagnosing modifications that could be made to the program, but CESA suspects that the unattractiveness and uncertainty of the financial incentive is the main culprit to reported subpar participation levels.

To spur greater participation in the ELRP, staff proposed changes that can be summarized as follows:

- Increase compensation rates from $1/kWh to $2/kWh for Group A.1 and Group A.2 customers
- Reduce Group A.1 Minimum Size Thresholds
- Remove the compensation collar that bounds ELRP compensation for an event to between 50% and 200% of the pre-nominated quantity
- Add the day-of ("DO") trigger for Group B customers
- Require PDRs in Group B to bid at or below $900/MWh in the CAISO real-time market ("RTM")
- Expand eligibility to include residential customers

Generally, CESA welcomes the increase in ELRP compensation to $2/kWh but request that it be extended to all customer groups in the program. As long as ILR is delivered from ELRP participants, CESA does not see any reason for Base Interruptible Program ("BIP") to be compensated at a higher level than those participating as Rule 21 Exporting DERs (A.3) and Virtual Power Plants ("VPPs") (A.4). Short of a capacity payment in exchange for ELRP participation and performance,[49] the higher energy payment will be more attractive to enroll customers across all sub-group types. Understandably, the A.3 and A.4 sub-group eligibility only recently opened in August 2021 for PG&E and SCE customers, so information regarding their interest and participation may be more limited, but payments should be consistent and not narrowly focused on a particular customer type.

In addition, CESA is supportive of the removal of the compensation collar that bounds ELRP compensation for an event to between 50% and 200% of the pre-nominated quantity. As a voluntary program, compensation should be provided for any level of ILR in response to an ELRP-related trigger and should not require a pre-nomination, which is a structure more reminiscent of a capacity program – something that this program clearly is not. If, for example (as CESA understands it), a customer provided 40% of their pre-nominated quantity, their actual ILR would not be paid, amounting to free load reductions that contradict the voluntary nature of the program.

Finally, CESA supports the expanded eligibility of the ELRP to include residential customers. This change will be particularly helpful for V2X customer participation in the A.3 sub-group if aggregations are allowed to meet the minimum 25 kW export threshold. Presumably, the EV/VGI Aggregation Pilot is intended to test that ability of V2X resources in such an application, which we support and elaborate on further in the next section.

Importantly, while falling short of CESA's vision for the ELRP, we supported the recognition and compensation for DER exports as part of the ILR measurement and calculation. As a potential proof of concept for future DR programs, CESA viewed this element of the ELRP as incremental progress toward more fully realizing and activating the otherwise stranded capacity

[49] CESA still recommends that a capacity payment be developed in lieu of the voluntary energy-only payment for the ELRP. If pursued, CESA's proposed ESB-DR enrolled capacity incentive could be incorporated into the ELRP. This may be preferable if standing up a new program presents startup and implementation challenges. If the ELRP maintains its current structure, CESA then recommends consideration of our proposed ESB-DR Program proposal.

that could be delivered from BTM energy storage and bidirectional EV storage resources (referred to collectively herein as "V2X"). CESA is thus encouraged to see A.3 and A.4 customer eligibility in the ELRP has not been deferred to May 2022, as allowed in D.21-03-056. Combined with our interconnection strategies discussed above, CESA looks forward to seeing the participation and performance results of Rule 21 Exporting DER and VPP in the ELRP.

B. The EV/VGI Aggregation Pilot should be adopted with some clarification, and the sub-metering concept should be extended to BTM energy storage as well.

CESA appreciates and welcomes the Commission's continued consideration of the utilization of EV participation to address the emergency reliability needs identified in R.20-11-003. Many of the key barriers to facilitating EV participation in DR programs are known and have persisted for some time. In parallel to considerations in this proceeding, the Commission should strive to begin addressing the barriers recently summarized in a workshop report, prepared pursuant to D.20-12-029 in the DRIVE proceeding (R.18-12-006).

The staff concept proposal included the launch of a new EV/VGI Aggregation Pilot as a test-of-concept within the ELRP, recognizing their resource potential and alignment with VGI as a Commission policy priority. Specifically, staff proposes to allow aggregators utilize networks of managed one-way charging ("V1G") or bi-directional electric vehicle supply equipment ("EVSEs") to be eligible to participate in ELRP, provided the aggregation can contribute ILR exceeding the Minimum VGI Aggregation Size Threshold of 25 kW within an IOU service territory. CESA is strongly supportive of this pilot concept but requests several areas of clarification. We also offer some recommendations related to specific elements:

- **Dispatch requirement:** Staff requires that the IOUs dispatch the VGI aggregators for at least 30 hours per season including ELRP events and compensate the aggregators for the ILR delivered during the dispatched hours. Furthermore, V2X discharge is prohibited outside of the IOU dispatched hours. CESA interprets the 30 hours per season as a minimum dispatch requirement that is compensated at the ELRP rate, regardless of whether the dispatch is for an ELRP event or for some other purpose. As a pilot, CESA sees learning benefits in forcing the IOUs to find use or value for VGI through a minimum dispatch requirement, but definition around the purposes of non-ELRP-related dispatch should be specified. Otherwise, pilot participants may not have an understanding of how frequently or when they will be utilized for IOU-defined purposes, which may deter participation if it poses risk to customer charging and host site needs.

- **Export restriction:** Staff proposes that, in case the EVSE is located on a different meter from the related host site meter, the aggregator is permitted to virtually aggregate the standalone EVSE meter(s) with the host site load on the different meter to partially bypass the V2G export restriction on the standalone EVSE meter(s); however, the virtual load aggregation of all standalone EVSEs and the related host site must not be negative at any time, even when the host site is participating in an event called by another DR program. CESA is unclear on what is allowed here. Upon first read, CESA believes that staff is proposing that the export restriction is limited to the aggregation but not for a single site. In other words, any single site can export to the grid, but the aggregation cannot be net exporting (or "negative at any time"). If so, this appears reasonable, but staff should also explain the reason for specifying the limitation in this way.[50]

Finally, CESA strongly supports staff's conceptual proposal to use EVSE sub-meters in the pilot. As expressed in our Phase 1 testimony, EV participation in existing DR programs is limited by the inability to recognize the contribution of load curtailment from EVSE load separate

[50] For example, it appears that this may be a settlement issue, where a net exporting aggregation would be difficult to assess against a baseline.

from the host facility load. By directly metering EVSE performance, more accurate baseline calculations are possible for the load curtailment provided by the EVSE load directly. Especially for large EV fleets where there is limited or no onsite host customer load but significant EV load, there is tremendous load curtailment opportunity that would go unrecognized by baselining methodologies using the facility load. Like stationary energy storage resources, EVSEs are physically separate from the host facility and perform differently from the host facility's load curtailment resources (*e.g.*, EVSEs are not temperature sensitive). Recognizing this, the FERC recently approved the CAISO's proposal and tariff changes to apply submetered measurement and performance settlement using the Metered Generator Output ("MGO") methodology, developed within Phase 3 of the Energy Storage and Distributed Energy Resources ("ESDER") Initiative. In the approving Order, FERC explained that " as CAISO points out, EVSE might have very different load profiles from their onsite host load, and therefore might have very different responses to CAISO dispatch." As a result, "[FERC] therefore agree[s] with CAISO that the proposed revisions will better capture EVSE's distinct characteristics, provide more accurate price signals to EVSE owners, and create incentives for them to participate in demand response programs."[51] To fully incorporate sub-metering strategies beyond just for CAISO energy market participation, the Commission should also enable their use across existing DR programs and for the purposes of delivering emergency reliability and RA capacity services. Through this pilot, the use of EVSE sub-meters can be validated, though it should not delay Commission action in adopting a commercially-viable pathway for EVSE sub-metering technologies to enable DR and other VGI value streams for a broad set of customers.[52] Similarly, the use of the MGO sub-

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[51] *Order Accepting Tariff Revisions* issued on September 30, 2020 in Docket No. 20-2443-000 at 8. http://www.caiso.com/Documents/Sep30-2020-LetterOrderAccepting-EnergyStorageandDistributedEnergyResourceStakeholderESDERPhase3-ER20-2443.pdf

[52] The IOUs' recently-filed PEV Submetering Protocol requires customer-owned EVSE submeters meet a 1% field accuracy standard, which is above and beyond the 1% lab and 2% field accuracy standard delineated in NIST Handbook 44 Section 3.40, thus holding EVs to a higher standard than other responsive loads such as

metering baseline should be extended to BTM storage as well as part of the ELRP and for all DR programs.

C. The proposed supplemental DRAM solicitation is reasonable and modifications to DRAM will generally recognize the enhanced value of storage-backed DR.

A smart immediate strategy for Summer 2022/2023 emergency reliability is to conduct a supplemental DRAM solicitation with certain modifications, which represents a ready-made vehicle to procure incremental short-term capacity. CESA is thus supportive of these actions. In addition, staff proposed the following modifications as a condition of conducting a partial-year supplemental auction:

- Evaluate bids higher for resources able to participate in RTM and/or agree to $500/MWh bid cap
- Require Proxy Demand Resources ("PDRs") to bid at or below $900/MWh in the CAISO real-time market
- Restrict Resource ID movement on supply plans
- Apply penalty based on level of capacity shortfall
- Apply limits through 2021/2022 load impact protocol ("LIP") processes

CESA is directionally supportive of the changes to evaluate bids higher for those that participate in the RTM and recognize higher levels of performance through penalties based on the level

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smart thermostats. This final protocol also does not consider the difference in lifetimes between revenue-grade utility AMI and commoditized EVSE product offerings. Furthermore, the PEV Submetering Protocol, as filed, does not support submetering for commercial and industrial customers or multi-unit dwellings, which represents a sizable percentage of the EV market. Furthermore, the PEV Submetering Protocol, as filed, does not support submetering for commercial and industrial customers or multi-unit dwellings, which represents a sizable percentage of the EV market. Several existing EV TOU rates require EVSE be on a separate meter, which strips the incentive for EVs to respond to grid conditions through any programs or incentives other than EV TOU rates. For example, existing DR programs or the proposed ELRP could both fall short of adequately leveraging the capabilities of EVs, as separately-metered EV loads are not able to reduce the baseline of other on-site loads.

of capacity shortfall. As a reverse auction that selects resources based on the least cost and do not necessarily award projects with higher levels of performance capability like storage-backed DR, the bid evaluation criteria to more highly value resources that frequently and actively participate in the RTM is welcome. The 2018 DRAM Evaluation Report pointed to high-performing demand response providers ("DRPs") delivering up to 98% of contracted capacity,[53] a level of performance that storage-backed DR resources are capable of reaching. Despite generally opposing bid caps, its use as an optional bid parameter in the solicitation is not problematic, so long as it remains that way. Furthermore, CESA supports applying a penalty for a shortfall in the DR capacity shown on the monthly supply plan relative to the contracted capacity, which is reasonable to ensure that DR portfolios materialize as contracted. This guards against overestimating contract capacity in the DRAM without any penalties, leading to overclaiming available DRAM capacity from reliable DRPs and less assurances of the contracted capacity amount.

VII. Enhanced Storage-Backed Demand Response (ESB-DR) Program Proposal

In Phase 1 testimony, CESA proposed a new grid capacity investment and service program outside of the RA framework that can address key gaps missing in the suite of IOU DR programs and procurement mechanisms. In particular, there is a current gap in programs that support new resource investment in fast-start, frequently dispatchable DR resources such as storage-backed DR resources that address the emergency reliability needs in the summer net load peak hours. Such resources are not currently supported or incentivized sufficiently in the current suite of DR options and represent the very type of resources that, if procured and deployed, would mitigate concerns identified by the Department of Market Monitoring ("DMM") in its analysis of DR performance relative to their "count" for RA credits or supply-plan

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[53] *Energy Division's Evaluation of Demand Response Auction Mechanism Final Report* ("DRAM Evaluation Report") at p. 76 as attached in *Administrative Law Judge's Ruling Issuing Evaluation Report on the Demand Response Auction Mechanism, Noticing January 16, 2019 Workshop, and Denying Motion to Require Audit Reports in the Evaluation Report*, issued on January 4, 2019 in A.17-01-012, et al. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M254/K771/254771618.PDF

capacity.[54] "Enhanced DR" options are not available in current DR programs that set participation and performance requirements based on a minimum standard (or an upper limit) as opposed to compensating resources that can do more. Although the current DR programs have been structured in this way to support technology neutrality and encourage broader customer participation, this lowest-common-denominator approach has not adequately valued resources that do not face the same limitations as traditional DR resources.

CESA observed that many parties focused on the risks of customer attrition associated with "extracting more" out of existing DR programs, such as through increases in the number of calls beyond the current program parameters. This problem is again the focus of Phase 2 as the Commission explicitly considers measures to minimize loss of DR enrollment and mitigate customer attrition effects.[55] However, resources such as BTM battery and thermal storage are capable of frequent cycles to provide load response that is separate from the host customer load, thereby reducing and/or eliminating customer attrition effects since the host customer does not directly experience the load response. To deploy these resources, however, a multi-year program is needed to, instead of setting requirements to enable easy customer enrollment and disenrollment, support capital investments in new storage resources with project lifetimes ranging between 10 and 30 years.[56] The Commission, LSEs, and the CAISO will have better assurances as well that capacity is backed by real "steel in the ground" (*e.g.*, in the form of energy storage projects); though installed

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[54] *Report on system and market conditions, issues and performance: August and September 2020* ("DMM Report") published by the CAISO Department of Market Monitoring on November 24, 2020 at 33 and 56. For example, DMM explains: "The additional capacity not available in real-time is associated with long-start proxy demand response resources which have no obligation to be available to the ISO's residual unit commitment (RUC) or real-time markets if not scheduled in the integrated forward market. These underlying resources have start-up times of 5 hours or greater. Most of this underlying capacity was offered in the day-ahead market at the $1,000/MWh bid cap while also submitting high startup and minimum load costs, resulting in resources being uneconomic to commit in the day-ahead market."

[55] *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2* issued on August 10, 2021 in R.20-11-003 at 5.

[56] See, *e.g.*, *Order Establishing Term-Dynamic Load Management and Auto-Dynamic Load Management Program Procurements and Associated Cost-Recovery* issued on September 17, 2020 by the State of New York Public Service Commission in Case 18-E-0130, Case 20-E-0112, and Case 20-E-0113 at 2: "The current DLM program structures pay for yearly performance and result in a bias towards short-term, low-capital investment solutions." https://assets.documentcloud.org/documents/7216843/DLM.pdf

capacity does not necessarily translate on a one-for-one basis to operational or contract capacity, there is greater assurance of the latter simply based on the fact that it is backed by physical capacity. Likewise, as physical resources are deployed under an enhanced DR program, the capacity "procured" can be committed on a longer-term basis, alleviating concerns about fluctuating participation levels on year by year.

Like the ELRP, CESA continues to support new enhanced DR programs that can operate outside of the RA framework. There are logical and feasibility reasons for doing so. Significantly, with this proceeding focusing on emergency reliability needs that are above and beyond the current RA requirements established based on a 1-in-2 LOLE standard, there is no immediate policy or planning-based reason to require new programs supporting emergency reliability needs to function within the RA framework. Any identified heat-storm-driven "capacity" needs using 1-in-5 or 1-in-10 conditions are not yet incorporated in the RA planning framework and have to be taken up in the RA proceeding (R.19-11-009). If the Commission eventually decides to revise its planning standard accordingly, the Commission can then consider whether to incorporate load-modifying storage resources within the RA framework – at which point they should be attributed RA credits or supply-side RA value. Some proxy of capacity value for Summer 2022 could be used to inform compensation levels without it being required to be tagged as "RA" *per se* and being subject to RA must-offer obligations. Furthermore, incrementality issues are simplified since any capacity that delivers during the months and hours pursuant to this program would be than the higher than 1-in-2 planning standard and not captured in the CEC load forecasts for RA purposes.

To attract the capital investments necessary to "procure" the enhanced DR needed to support emergency reliability needs, however, after-the-fact energy payments alone will not support the capital investments needed to provide incremental emergency reliability resources. CESA instead recommends a capacity reservation payment that is paid in part upfront to support deployment and in part on an ongoing basis based on test and actual dispatches, with adjustments to the ongoing payment portion based on actual performance.

A. General Program Design

To address the gaps and needs discussed above, CESA proposes an Enhanced Storage-Backed Demand Response ("ESB-DR") Program Proposal that is elaborated in the below sections and in response to the Commission staff's guidance questions. Fundamentally, the proposed ESB-DR is intended to help bring the incremental new capacity resources online to support emergency reliability needs in the near term through a program structure that supports the deployment of fast-start and frequently dispatched resources such as BTM energy storage. Largely, the proposal mirrors our Phase 1 proposal, with some modifications.

i. Program trigger[57]

The ESB-DR Program should use a CAISO market-informed trigger that sets dispatch based on market conditions, as reflected in prices that indicate emergency reliability needs and resource scarcity. Even as the ESB-DR Program operates outside of the RA framework and thus outside of the CAISO market, the IOUs should use day-ahead market prices to inform dispatch while providing advanced day-ahead notice to ensure that ESB-DR resources are prepared to respond (*e.g.*, having sufficient state of charge in the case of storage). Similar to the IOU DR programs, existing processes could be used where the CAISO alerts the IOU schedulers to activate their DR programs and the IOU or LSE can then bid load/demand in ways that reflect the expected performance of the ESB-DR resources.

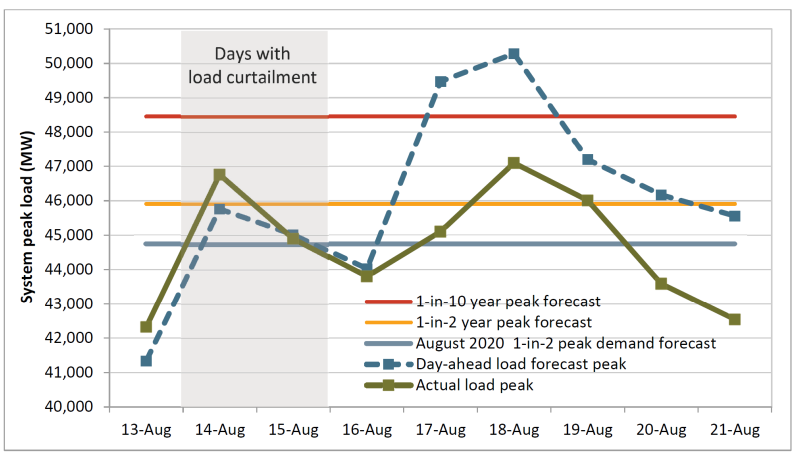
In assessing at what price to set the dispatch trigger, CESA contemplated two different approaches that could be pursued for the ESB-DR Program. On the one hand, since the ESB-DR Program operates outside of the RA framework and because emergency reliability capacity needs are not yet reflected through revised RA planning standards (*e.g.*, 1-in-5, 1-in-10), a case could be made to not have ESB-DR resources triggered before reliability DR resources that count for RA capacity. In this way, ESB-DR resources would not be

[57] The proposed triggers are unchanged from the Phase 1 testimony due to limited time and resources, but this is intended to be illustrative. These could be updated and/or refined if the Commission wishes to develop this proposal further.

displacing or be utilized before resources that actually count toward RA requirements. On the other hand, one of the value propositions of our proposed ESB-DR Program is that it could support enhanced DR resources that could be utilized as fast-start, frequently-dispatched DR resources unlike many other traditional DR resources and programs that may have limits to their participation and face risks of customer attrition if called upon too frequently. By setting ESB-DR behind reliability demand response resources ("RDRRs"), which have a minimum bid price of $950/MWh, the very advantages of our proposed ESB-DR resources would not be leveraged.

As such, CESA believes a more appropriate price trigger could be informed by assessing 2020 day-ahead market prices during the days where load was shed (*e.g.*, August 14 and 15) and/or projected to reach historic levels (*e.g.*, August 17-19, September 5-6) in line with the emergency reliability needs tied to heat storm events, particularly in the net load peak hours.[58] These load conditions are illustrated in the graphs from the DMM Report below:[59]

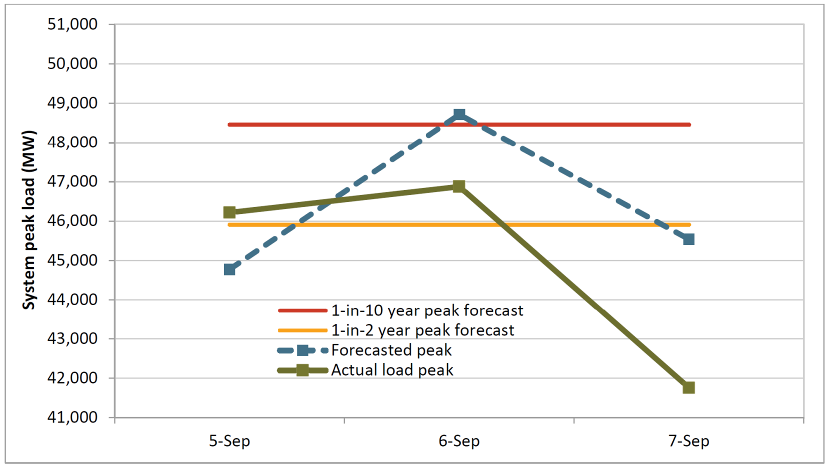
Figure 3: Actual Peak Load in the ISO Compared to Day-Ahead Forecast Peaks (August 13-21, 2020)



[58] DMM Report at 7-9 and 11. Note that DMM reported how the "difference between the forecasted load peaks and the actual load peaks on August 17 to 19 appears to be due in large part to both the conservation efforts of Californians and out of market production."

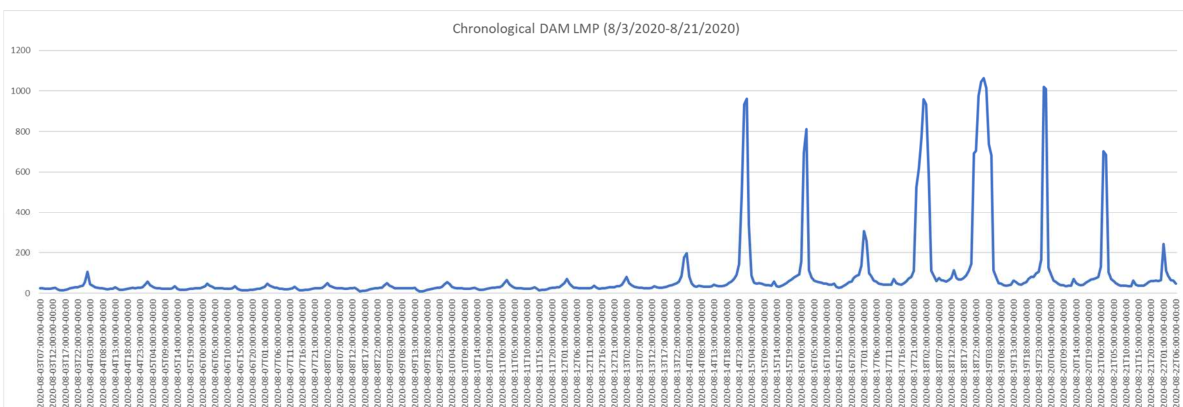
[59] DMM Report at 12-13.

Figure 4: Actual Peak Load in the ISO Compared to Day-Ahead Forecast Peaks (September 5-7, 2020)



In CESA's analysis of CAISO day-ahead market price data, we observe major price spikes, particularly in hour ending 19 and 20 on those high load days, generally exceeding $800/MWh in most territories but still falling below the $950/MWh minimum bid for RDRRs. See, for example, the day-ahead market price trends from August 3 through August 21, 2020.[60]

Figure 5: CAISO Day-Ahead Locational Marginal Prices (August 3-21, 2020)



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[60] The data has been obtained through the OASIS Portal (http://oasis.caiso.com/mrioasis/logon.do) and assessed the Locational Marginal Prices ("LMP") for the Day-Ahead Market (DAM) of all hours of August 3, 2020 through August 21, 2020, as well as August 24, 2020 through September 2020.

To make some more use of ESB-DR resources beyond the most extreme of days, CESA proposes looking at the percentile of day-ahead prices across these days to identify the appropriate level to set a trigger dispatch. Whereas the development of programs for traditional DR resources would use this information to identify the number of calls that would fit within the program parameters and limitations, the ESB-DR has greater flexibility and capability to support more frequent needs. However, those capabilities should be balanced with the fact that ESB-DR represents resources that are outside of the RA framework and have the potential to be utilized ahead of what should be used as day-to-day RA capacity, including both PDRs and RDRRs. As a result of the enhanced capabilities of our ESB-DR resources, there is no science to what the trigger point should be, but we <u>preliminarily propose setting it at $750/MWh</u> roughly based on observed day-ahead market prices at the 97th percentile on those extreme weather and load days.[61]

Table 5: Percentiles of CAISO Day-Ahead Locational Marginal Prices (August-September 2020)

Percentile (0-1)	For the hours of August 13-16	For the hours of September 6-9
0.50	48.12	51.06
0.75	78.82	74.88
0.90	166.53	122.36
0.95	372.99	215.83
0.96	522.23	298.97
0.97	711.90	363.14
0.98	824.23	391.39
0.99	936.30	437.75
1.0	962.51	868.68

CESA is open to discussing with the Commission, CAISO, and other stakeholders on what the appropriate trigger point should be and looks forward to feedback.

ii. Demonstration that program will deliver benefits during net peak

[61] *Ibid*.

By using direct measurement approaches and positioning these resources to operate as RA-like resources, the incremental storage build will support net load peak needs at the level of enrolled capacity of the program (*i.e.*, 50 MW if the program is fully subscribed). Using the QC accounting methodology for IFOM energy storage resources, the enrolled capacity for BTM energy storage would count in the same way, inclusive of both discharge to serve onsite load and exported to the grid.[62] While this is debated within R.19-11-009, this new proposal could support a better understanding of how to develop and adopt capacity counting methodologies for BTM hybrid and energy storage resources.

iii. Program performance requirements

As a condition of receiving ESB-DR reservation payments, these resources must participate in events that are triggered based on a pre-set CAISO market-informed price point in the day-ahead market, which are intended to target the net load peak period needs where prices have generally peaked. Furthermore, eligible resources must be capable of providing at least four-hour continuous energy in order to support the duration of the net load peak period (5-9pm) as well as to position these resources for potential future RA consideration, though resources capable of providing up to six-hour continuous energy are also eligible.

iv. Compensation structure

CESA preliminarily recommends a capacity reservation payment set at $1.20/W or $1,200/kW for a base four-hour energy storage system, but we are open to feedback and revisions to this structure. At this time, CESA only specifically proposes a reservation payment for BTM energy storage resources (including both battery storage and thermal storage resources) but we do not foreclose the development of other or varied reservation

[62] There should be no difference from a QC counting perspective between IFOM energy storage and BTM energy storage for its maximum four-hour continuous output. For the latter that serves both onsite customer load and exports to the grid, the onsite customer also represents load that must be served. An IFOM energy storage resource with the same physical capacity located a block away that exports its full capacity would also need to serve that customer's load and would be counted as such.

payment structures for other forms of DERs, so long as they are able to meet the base eligibility and performance criteria. Due to our knowledge and expertise with energy storage but less so with other DER technology types, we defer to other stakeholders on how our proposed ESB-DR could be adapted to accommodate to non-storage DER technologies.

The $1.20/W reservation payment level for a base four-hour energy storage system adapts the SGIP structure, which offers declining step incentive rates for commercial customers at $0.35/Wh (currently in Step 3) and for small residential customers at $0.25/Wh (recently in Step 5 but now has dropped to $0.20/Wh Step 6 levels), with flexibility on the duration of the system and incentive rates that reflect the different Watt-hours of the actual storage project in kind. Rather than proposing carve-outs and differentiated rates per customer sector, we recommend starting with the $0.30/Wh as a "mid-point" that could create opportunities for all types of customers.[63] Instead of setting a per-Watt-hour payment level that varies based on energy duration, CESA proposes to simplify this structure as a capacity reservation payment in $/W or $/kW that aligns with the net load peak period needs and potential future RA requirements, leading us to arrive at $1.20/W or $1,200/kW.[64] This reservation payment amount is roughly consistent with the assumed cost of new entry used in the 2021 Avoided Cost Calculator.[65] Importantly, CESA makes a further distinction from SGIP in that SGIP makes incentive payments based on the installed capacity of the project

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[63] We note that the SGIP commercial budget has held steady at Step 3 incentive rates for some time, likely due to higher costs of these projects. By contrast, residential projects have experienced substantial uptake. Even though we are basing the ESB-DR reservation payment at a higher rate than what is currently available in SGIP for small residential customers, this may be appropriate for simplicity, without the need for sector-specific carve-outs. *See* the SGIP Program Metrics page for the latest rates: https://www.selfgenca.com/home/program_metrics/

[64] $0.30/Wh * 4 h = $1.20/W.

[65] The 2021 Avoided Cost Calculator value for the net cost of new entry for battery storage is valued at $120/kW-year, less than the 2020 value of $195/kW-year.

whereas we propose that the ESB-DR be based on "enrolled" capacity for the reservation payment rate.[66]

CESA believes that the reservation payment can be adapted in different ways to meet various objectives. Given the higher cost but significance and prioritization for projects supporting low-income and disadvantaged community customers, CESA supports a reservation payment structure that recognizes the incremental costs and value-add of developing such projects, such as through an equity adder component. Similarly, longer-duration ESB-DR resources (*e.g.*, 6-8 hours) could be supported with duration-based adders that recognize the need for longer-duration resources in emergency reliability events, particularly during prolonged heat waves such as those experienced in August 2020. At the same time, since these incremental hours of duration may not be "utilized" as frequently based on observed CAISO day-ahead market prices and the trigger price we have set, the incremental reservation payments could perhaps be discounted for the incremental hours beyond the base four-hour requirement. These adders would ultimately reduce the MW capacity that could be supported through the ESB-DR, but the Commission can decide whether to structure it in a way to pursue different objectives with a lower target, or alternatively, could choose to increase our proposed budget accordingly.

To drive deployments, the ESB-DR reservation payment should be apportioned such that part of it comes in the form of upfront payments with the remaining funds coming through ongoing performance-based payments to recoup the full qualifying payment amount. Similar to SGIP, CESA recommends that the reservation payment could be divided 50/50, where half of the full qualifying payment amount ($1,200/kW) is paid to the resource upon

[66] For example, a 7-kW energy storage system could enroll at and reserve ELRP payments for 8 kW if they can deliver 7 kW of load reduction along with 1 kW of exports during the dispatch period. As a grid service program supporting new-build resources, installed capacity is less relevant if exports are allowed and the reservation payment can be used to support the enrolled capacity amount. So long as the promised capacity amount is delivered, the installed capacity is less relevant.

completing interconnection, achieving permission to operate ("PTO"), and conducting a test dispatch to demonstrate the capacity of the resource. The other half of the full qualifying payment amount would be paid on an ongoing basis after the fact. This type of split payment structure has generally worked for commercial storage projects (*i.e.*, under the performance-based incentive ["PBI"] structure) and could be similarly appropriately applied to residential projects that seek ESB-DR reservation payments for reliability services. Annual capacity-based pay-for-performance amounts can be calculated for each of the ten years the resource is expected to perform, with payments reduced if not achieving the required level of performance. Performance tiers (*e.g.*, 95% and above, 90%) could be established at which payments would be reduced, but because of the high performance expected of resources participating in our proposed ESB-DR, CESA does not envision the need to have performance tiers at lower levels as done for other DR programs or mechanisms (*e.g.*, reduced payment at 80% of qualifying capacity).

v. Program eligibility and enrollment

Battery energy storage, thermal energy storage ("TES"), permanent load-shifting ("PLS"), V2X resources, and other DERs that can meet base performance requirement should be eligible for the program. Due to the urgency of the Summer 2022/2023 needs, the program will be open to enrollments on a rolling first-come, first-served basis with the appropriate yet streamlined vetting processes to participants. Initially, CESA proposes a two-year duration (2022-2023) for the availability of enrollment incentives. Additionally, the proposed program can give preference to projects that can come online by August 2022, and in descending order, priority to projects that can come online in the earlier part of the 2022-2023 program period.

vi. Measurement and verification

The performance measurement will be conducted using direct-measurement approaches for the full discharge, without an assessment against the customer meter. Similar to the proposed use of EVSE sub-meters for the EV/VGI Aggregation Pilot, the use of the MGO sub-metering baseline should be extended to BTM storage as well as part of the ESB-

DR and for all DR programs. In the past, the IOUs have cited the lack of billing and settlement infrastructure[67] and the lack of Commission approval of the MGO sub-metering baseline as a retail baseline (even though it has been adopted as a CAISO wholesale baseline), but as being done with the ELRP for exports, manual processes should be used in the interim. In much of the same way, this will enable direct measurement approaches that avoid the challenges around baselining energy storage performance to the host customer facility meter and instead on the sub-metered charge and discharge.

B. Program administration

CESA recommends that the IOUs serve as the administrator as a start since they are already administering the ELRP, but we are open to non-IOU LSEs as well following the appropriate processes.

C. Program marketing, outreach and education

CESA recommends that marketing, outreach, and education ("ME&O") leveraging existing avenues and channels to support other DER programs, such as SGIP, ELRP, and other DR programs.

D. Program budget

CESA proposes that the program <u>establish a 50-MW capacity target</u> for the new ESB-DR Program – a small fraction of the capacity shortfall identified in the Draft 2022 Net-Short Analysis (*i.e.*, less than 8% of the low-end 600-MW capacity shortfall) – in order to balance "piloting" this new program design and structure and to advance a hedge strategy in case the extreme weather scenarios bear out. Also, since a 0.1 LOLE can be maintained with the IRP procurement in

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[67] *See* D.19-07-009 at 81, FOF 108, and COL 29.

accordance with D.21-06-035 and in line with the proposed PSP, a large program as proposed in our Phase 1 testimony can be revisited at another time, especially after some pilot data is collected and level of enrollment is measured.

To establish the program budget and procure new DR capacity that is fast-starting and frequently dispatchable,[68] payment structures are needed on a long-term basis to support the recovery of the fixed costs of new capital investments as well as the variable costs of delivering the grid service. They must reflect their 10- to 30-year lifetimes, depending on the technology, and thus assume higher new capacity values. Consistent with the assumed cost of new entry used in the 2021 Avoided Cost Calculator, the program budget could be extrapolated by using the $120/kW-year cost of new entry,[69] which on a 10-year basis,[70] amounts to $1,200/kW. To meet the target 50 MW with new resource investments that deliver services across a 10-year period, CESA arrived at a <u>$60-million proposed budget for the program</u>.[71] If the proposed ESB-DR budget is too substantial, it can be adjusted downward with a lower capacity target. Some portion of this budget could be allocated for program administration, but if leveraged alongside ELRP-related administration, some of these costs could potentially be shared.

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[68] Alternatively, the Commission could assume that capacity value of ESB-DR resources at the capacity procurement mechanism ("CPM") soft-offer price cap of $6.31/kW-month since CPM resources may be required via backstop procurement to meet the emergency reliability need, with ELRP resources having the incremental benefit of supporting the state's policy goals. Whereas the CPM is intended to contract for and secure existing capacity, the ESB-DR Program is targeting new incremental build such that basing a program budget based on $6.31/kW-month is already low. Moreover, DR programs that merely allow for the provision of capacity services already exist through the BIP or the Capacity Bidding Program ("CBP"), among others.

[69] *Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update* published on April 16, 2020 in R.14-10-003 at 12. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M334/K786/334786698.pdf

[70] The 10-year basis for projecting the proposed budget is in line with minimum equipment eligibility requirements of SGIP. Since the Commission found this minimum lifetime requirement to be sufficient to deliver ratepayer value as a long-standing asset for SGIP purposes, the similar rationale could be applied here, even though many resources could have longer lifetimes. *See* 2020 SGIP Handbook Section 4.2.1 at: https://www.selfgenca.com/documents/handbook/2020. Furthermore, this is consistent with the contracting requirements for new resources pursuant to D.19-11-016. *See* Conclusion of Law 28 of D.19-11-016: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

[71] $112/kW-year * 10 years * 50 MW * 1,000 kW / 1 MW = $56,000,000

E. Implementation timeline

The specific administration and implementation steps can be developed if the Commission and other stakeholders find merit in this type of idea and wish to pursue it further.

F. Program duration

In contrast to our Phase 1 proposal, CESA proposes a two-year duration (2022-2023) for the availability of enrollment incentives, after which funds can be returned to ratepayers. However, since the program is supporting long-term physical deployments, program evaluation will need to occur after the initial two-year program period.

G. Estimated megawatt contribution/load impact

By using direct measurement approaches and positioning these resources to operate as RA-like resources, the incremental storage build will support net load peak needs at the level of enrolled capacity of the program (*i.e.*, 50 MW if the program is fully subscribed). Using the QC accounting methodology for IFOM energy storage resources, the enrolled capacity for BTM energy storage would count in the same way, inclusive of both discharge to serve onsite load and exported to the grid.[72] While this is debated within R.19-11-009, this new proposal could support a better understanding of how to develop and adopt capacity counting methodologies for BTM hybrid and energy storage resources.

H. Potential interaction with other existing programs

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[72] There should be no difference from a QC counting perspective between IFOM energy storage and BTM energy storage for its maximum four-hour continuous output. For the latter that serves both onsite customer load and exports to the grid, the onsite customer also represents load that must be served. An IFOM energy storage resource with the same physical capacity located a block away that exports its full capacity would also need to serve that customer's load and would be counted as such.

Dual enrollment should be allowed in other DR programs as appropriate, and contracting for or participation in other grid services should be allowed outside of potential dispatch periods. As RA-like resources, it could be prevented from operating in other supply-side programs.

I. Prior similar program experience in California or elsewhere

With the ESB-DR Program mirroring many elements of the SGIP, some may ask why our proposed ESB-DR Program is necessary if SGIP currently has funds available. To this point, CESA responds that SGIP is quickly depleting funds even though the waitlist data points to substantial demand from customers for BTM energy storage systems. Without SGIP funds, BTM energy storage resources have limited means to support new deployments for various purposes (*e.g.*, customer bill management, resiliency) and are ill-fits for the current suite of DR programs. Competitive solicitation opportunities for generation capacity and/or distribution services are available but can be challenging to participate in and represent one-off, "lumpy" opportunities that are not conducive to steady deployments.

Importantly, the ESB-DR Program is seeking to provide an important reliability service, a goal which is significantly different from that of SGIP. As a market transformation program, SGIP projects are not required to deliver reliability services and have much reduced obligations, focusing instead on customer needs through voluntary response to retail rates and following real-time GHG emissions signals as required by the program. By contrast, while mirroring the SGIP structure in some ways in terms of setting payment rates that drive deployment, the ESB-DR Program has more significant obligations, representing payments for services as opposed to a market transformation technology incentive. These distinctions highlight how our proposed ESB-DR Program is not duplicative with SGIP.

J. Program funding and cost recovery mechanisms

The specific funding mechanisms can be developed if the Commission and other stakeholders find merit in this type of idea and wish to pursue it further. It could supplement the existing ELRP and be funded through the same cost recovery mechanism, or it could have its own separate account.

K. Potential risks

The potential risks will likely be on the implementation side, which exist to startup or launch any new program. To the degree that the program can leverage existing program administration capabilities, with additional budget/funding, CESA's proposed ESB-DR Program could complement the foundations in place for either SGIP or the ELRP.

In terms of customer interest and participation, this reservation payment level is consistent with uptake levels seen in SGIP, where incentive levels generally around this level have still driven deployments. Whether a market transformation technology incentive as in the case of SGIP or a grid-service payment such as the one for the proposed ELRP, these "revenue streams" only need to cover a portion of the costs, with a combination of private capital, customer bill savings, and other stacked value streams (*e.g.*, other incremental and complementary grid services) being able to cover the rest of the costs, in addition to the less quantified benefit of customer resiliency in some cases. The Step 5 incentive rate for small residential customers was set at $0.25/Wh,[73] which translates to $1/W for the base four-hour energy storage system that would be eligible for the proposed ELRP. On average, for small residential customers investing in an energy storage system with four or greater hours of duration, the SGIP incentive claim was $3,341, representing approximately 15% of the total eligible project costs ($21,858). For commercial customers, all of the program administrators ("PAs") are currently in Step 3, where the incentive rate is set at $0.35/Wh, translating to $1.40/kW for the base four-hour energy storage system that would be eligible for the proposed ELRP. On average for commercial customers investing in an

[73] This is the most recent SGIP step for small residential customers with robust customer participation data. Step 6 just opened for small residential customers, but reservations and data reflecting those reservations are actively ongoing.

energy storage system with four or greater hours of duration, the SGIP incentive claim was $310,493, representing approximately 24.4% of the total eligible projects costs ($1,271,760).[74]

VIII. Permanent Load Reduction (PLR) Incentive Program Proposal

CESA implores the Commission to consider the significant role of DERs that can commit to permanently reduce customer load during the net load peak hour to a specified load level in support of identified emergency reliability needs. Under the PLR Incentive Program, CESA proposes that the Commission establish a new DER deployment incentive program that would seek to achieve the goals of this proceeding through a different approach. Rather than traditional DR approach involving event days, hours, and triggers, or a market-informed approach as proposed above for the ESB-DR Program, a permanent load modification strategy could be tested and pursued.

While most of the ESB-DR resources discussed above encompass fast, dispatchable resources, the same ends can be met with resources that are able to provide permanent load curtailment with shifted operations. PLS, for example, differs from traditional DR in that it is a form of BTM load modification that is paired with a non-battery alternative ("NBA") form of energy storage that is able to reliably reduce peak demand without incurring a burden on the participating facility. Large thermal energy storage ("LTES") for cooling or heating loads is another example, but so are other forms of PLS that are akin to dynamic functional energy storage resources and have outsized capacity contributions during heat storm events, such as increased capacity water tanks on hills for potable water systems and flow diversion facilities at wastewater treatment plants.

A. General Program Design

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[74] Note that certain outliers in the SGIP data may be leading to these results. These numbers were calculated based on the SGIP Real-Time Public Report downloaded on January 8, 2021, available here: https://www.selfgenca.com/report/public/

In contrast to a traditional DR arrangement where a system is only occasionally curtailed, and non-curtailment days are used to set the baseline, this program would pay incentives to customers who adopt technologies that commit to either physically or through controls to reduce customer load "permanently" across the entire net load peak period. Rather than setting a baseline on an event and non-event basis, the baseline would be established on the customer's highest 12-month peak load during the net load peak period (5-9pm), as measured in any 15-minute interval. For example, if the customer's annual peak load baseline is measured at 17 kW, the PLR incentive would be paid to the customer based on the difference between this baseline (17 kW) and the committed load level during the net load peak period (*e.g.*, 12 kW), or 5 kW of PLR.

For PLS resources, under a baseline validation dispatch ("BVD") approach, the IOU would schedule specific times with a PLS asset owner to suspend system operation in order to show what load would be there in the absence of such a BVD event, which would allow an LSE to compare the actually observed load before, during, and after the event with the expected values from the file. The innovation would be to not count any additional demand associated with this BVD towards monthly demand charge billing. This could be accomplished by excluding the time BVD time period from calculations of monthly demand, a reimbursement to the customer of the difference through a special tariff, or another mechanism that meets the same need but is easiest for the LSE to implement.

i. Program trigger

The appeal of this program is that it does not require a program trigger. Instead, as a condition of receiving the PLR incentive, the customer commits to permanently reduce and manage their load during the net load peak period, thus enabling the CAISO, Commission, and IOUs to account for this reduced level of load that needs to be served at this time period.

ii. Demonstration that program will deliver benefits during net peak

As discussed in relation to technologies with enhanced DR capabilities, BTM energy storage and VGI resources could also provide similar benefits to the net load peak by committing to PLR services. In contrast to requiring a trigger and subsequent out-of-market dispatch, the PLR from the customer site can be accounted for in planning and operations in advance, avoiding the need to do after-the-fact baselining and compensation.

In addition to BTM energy storage and VGI resources, many PLS assets, including but not limited to LTES, give their greatest kW contribution to overall system capacity at extreme 1-in-10 heat storm conditions. Unlike static assets, such as lighting, many PLS assets are "dynamic" in that their curtailable load is variable, and often tied to variables such as ambient air temperature. Research by the University of California showed that the NAESB showed that this approach "under-predicts its impact on the electric grid by as much as 77%, between 38% and 57% on average"[75] Essentially, LTES and many dynamic functional energy storage resources have outsized capacity contributions during heat storm events and have the added advantage of potentially addressing evolving grid needs as macro-load shapes change over time, including current and/or growing overgeneration issues. These are the very types of resources that should be pursued in this proceeding.

Water and wastewater processing are both very good candidates for rapidly deployed and long-lived PLS installations. The water and wastewater sector consume roughly 18% of all electric energy in California.[76] Building cooling and refrigeration loads are also good candidates for PLS, representing over 30% of building energy load and a greater fraction of peak power.[77] Typical PLS installations start in the low hundreds of kW and are often greater than 1 MW, meaning that even a modest number of projects can start to deliver significant impacts. Because PLS is inherently load modifying, there are no interconnection issues of any kind, significantly speeding time to commercial operations. With mature and rapidly

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[75] *Valuation of Thermal Energy Storage for Utility Grid Operators* case study prepared by the Western Cooling Efficiency Center at the University of California, Davis. https://wcec.ucdavis.edu/wp-content/uploads/2017/11/Thermal-Energy-Storage-Case-Study.pdf

[76] *California's Water-Energy Relationship: Final Staff Report CEC-700-2005-011-SF* published by the California Energy Commission in November 2005 at 1.

[77] *See* California Commercial End-Use Survey: https://www.energy.ca.gov/data-reports/surveys/california-commercial-end-use-survey

deployable technology in place, regulatory implementation solutions in hand, and a considerable amount of overall grid power associated with this approach, the potential grid impact is significant with less policy development needed, such that PLS warrants attention in this proceeding. Although these solutions may impose new requirements such as data visibility and reporting, the fact that those requirements have already proven acceptable to industry in other venues should provide greater confidence that they will be workable here.

iii. Program performance requirements

Performance requirements are simplified under a PLR approach, with much of the determination on whether the underlying technologies and control schemes can feasibly achieve the PLR for the 5-9pm period is done in advance during the application and review process. If an applicant is seeking a PLR incentive for 5 kW, then the customer is expected to maintain that reduced load level for the entire 5-9pm period.

iv. Compensation structure

The proposed compensation structure will need to be refined, but to support the deployment of PLR-enabling technologies and achieve the RA-reducing benefits of PLR participants, a $/kW incentive structure should be developed that matches the lifespan of the enabling technology and reflects the avoided costs for reduced load served during the net load peak period. For example, using the hourly Avoided Cost Calculator values for the 5-9pm period on a 365-day period, the program could produce a $/kW-year value that is then multiplied by either the lifespan of the PLR-enabling technology or the duration of the commitment for PLR services and levelized to arrive at a $/kW incentive for PLR levels.[78]

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[78] As a simple example, using the 2021 ACC, assuming that a system maintained reduced load from 5-9pm every day in 2022, a system would provide $231.01/kW-year during 2022. Calculated by summing the Total Levelized Value for the hours 5-9pm every day of 2022. All components of avoided cost (Cap and Trade, GHG Adder, GHG Rebalancing, Energy, Generation Capacity, Transmission Capacity, Distribution Capacity, Ancillary Services, Losses, and Methane Leakage) are included. If this incentive was provided for five years of PLR, this would amount to a PLR incentive of approximately $1,155/kW. However, the ACC projects

There are also additional considerations as to whether the PLR is a hard or soft limit for exceeding the committed customer load level, where it could be physically limited, punitively punish with surcharges (similar to overage fees under "subscription" plans), or subject to contractual liability or default.

v. Program eligibility and enrollment

Any customer who can commit to providing PLR incentives should be eligible for the program. It only involves the customer demonstrating in advance the means by which PLR will be assured, either through inverter-based control schemes in the case of BTM energy storage and V2X resources, physical relays or other limiting mechanisms for generation and storage resources, advanced DR controls for more traditional V1G and DR, or energy efficiency technologies. Cost reductions in sensor technologies have increased the economic viability of continuously monitoring PLS assets.

vi. Measurement and verification

After the initial determination and validation of the PLR amount, measurement and verification thereafter mostly involves monitoring to ensure PLR limits are not exceeded, thus eliminating the need to handle invoicing and complex settlement procedures under DR approaches. All participating technologies would need to be subject to continuous monitoring by the program administrator. For PLS assets in particular, they could be required to install a submeter for affected load in order to allow even better visibility.

B. Program administration

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increased avoided costs in future years beyond 2022. Because of this, CESA suggests using an average annual value that incorporates all of the years the system would participate in the PLR.

CESA recommends that the IOUs serve as the administrator as a start since they are already administering the ELRP, but we are open to non-IOU LSEs as well following the appropriate processes.

C. Program marketing, outreach and education

CESA recommends that ME&O leveraging existing avenues and channels to support other DER programs, such as the SGIP, ELRP, and other DR programs. Given the intersection of LTES as both an efficiency and load-shifting investment, there may be synergies with existing energy efficiency programs as well.

D. Program budget

The program budget can be set upon setting incentive levels. As a starting point to meaningful produce sufficient data and customer participation to evaluate the program for future consideration or adoption, a $50-million program budget is preliminarily recommended.

E. Implementation timeline

The specific administration and implementation steps can be developed if the Commission and other stakeholders find merit in this type of idea and wish to pursue it further.

There may be some issues that need to be resolved to bring a large amount of net peak load reduction online next year via PLS, such as attribution, accounting, and reliability of compensation, but many of them are in the process of getting resolved.[79] Consequently, an opportunity exists for this proceeding to clear away the remaining hurdles, thus opening the gates

[79] *See, e.g.*, Resolution E-5106 issued on November 12, 2020 and Advice Letter E-5705, *et al*. submitted for Commission approval on January 4, 2021. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M350/K762/350762070.PDF

to the entry into the market of a class of assets that could deliver a significant benefit to system emergency reliability in 2021 and the years to come.

F. Program duration

As a potentially valuable learning opportunity, CESA recommends that the program last the remaining duration of the ELRP (2022-2025).

G. Estimated megawatt contribution/load impact

The MW contribution will only be determined upon setting incentive levels and determining an appropriately-sized budget.

H. Potential interaction with other existing programs

To avoid double-count load-reducing impacts in the net load peak period, participating resources in this program should not be eligible to participate in other supply-side DR programs since they are assessed for performance in the overlapping AAH period. Outside of programs that operate in these same hours, PLR resources should be eligible to provide non-overlapping services.

I. Prior similar program experience in California or elsewhere

This program resembles the PLS Program,[80] which was discontinued around 2017 due to the availability of SGIP funds. However, while LTES is eligible for SGIP, funds are limited and may not be sufficient going forward to capture the full load-shifting potential. In contrast to SGIP, a technology incentive program that only requires projects to meet minimum cycling requirements

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[80] *See, e.g.*, PG&E's PLS Program Manual: https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/demandresponse/pls/pls_tes_program_manual.pdf

and reduce GHG emissions based on their operations in response to a real-time GHG signal, this program would be committing PLR during the net load peak period, providing an enhanced capacity-reducing grid service.

Furthermore, for other DERs that can provide the same PLR capabilities (*e.g.*, BTM storage, VGI), there are no such programs in California to CESA's knowledge that is similar. The most comparable structure may be PG&E's Electric Schedule BEV, approved via D.19-10-055. Instead of a customer charge and traditional maximum kW demand charge, the BEV rate established a subscription-based model for monthly kW allocation, with a structure for paying overage fees if exceeding the subscribed amount of kW. In contrast to the reliability and grid planning objective of CESA's proposed PLR Incentive Program, PG&E's BEV rate was proposed and adopted to provide greater fuel-switching incentives for commercial EV drivers by reducing the levelized cost of electricity per kWh provided to EVSE operators. There are some parallels where a specific load service level is specified, but PG&E's BEV rate is a financial incentive and limit, whereas CESA's proposed PLR service is intended to be a more consequential commitment to assist in long-term resource and grid-investment planning.

In Hawaii though, a similar concept has been developed to physically or electronically limit the maximum export level of the customer upon interconnection of energy storage resources, such that technical review screens are based on the size of the lesser of either the total generation capacity or programmed limit for export, leveraging the available control technologies and standards.[81] In the inverse, a combination of DERs and inverter-based controls could be used to set a maximum customer load level to provide PLR services during the net load peak period.

J. Program funding and cost recovery mechanisms

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[81] *See* Hawaii Public Utilities Commission ("HPUC") Docket No. 2014-0192. https://dms.puc.hawaii.gov/dms/dockets?action=search&docketNumber=2014-0192

The specific funding mechanisms can be developed if the Commission and other stakeholders find merit in this type of idea and wish to pursue it further. It could supplement the existing ELRP and be funded through the same cost recovery mechanism, or it could have its own separate account.

K. Potential risks

The potential risks will likely be on the implementation side, which exist to startup or launch any new program. To the degree that the program can leverage existing program administration capabilities, with additional budget/funding, CESA's proposed PLR Incentive Program could complement the foundations in place for either SGIP or the ELRP.

Q: Does this conclude your testimony?

A: Yes. I appreciate the opportunity to submit this testimony on behalf of CESA.

Appendix A:

Declaration in Support of Opening Testimony of Jin Noh on Behalf of the California Energy Storage Alliance

DECLARATION IN SUPPORT OF OPENING TESTIMONY OF JIN NOH ON BEHALF OF THE CALIFORNIA ENERGY STORAGE ALLIANCE

I, Jin Noh, am the Policy Director for the California Energy Storage Alliance (CESA). Having worked for CESA for over six years, I am currently managing policy and regulatory affairs for CESA and its over 100 member companies. My business address is 2150 Allston Way, Suite 400, Berkeley, CA 94704. I declare under penalty of perjury that the foregoing facts in this document are true and correct.

Executed on September 1, 2021 at Berkeley, California.

Jin Noh