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CALSSA Comments on DSGS Guidelines and Workshop

Additional submitted attachment is included below.

May 11, 2023

California Energy Commission
Docket Unit, MS-4
715 P Street
Sacramento, CA 95814

Re: Docket No. 22-RENEW-01—Comments on DSGS Guidelines and April 26 Workshop

California Energy Commissioners and Staff:

The California Solar & Storage Association (CALSSA) appreciates the leadership and work of the California Energy Commission (CEC) to develop programs for clean and reliable energy resources that can meet the needs of our changing climate. CALSSA also appreciates this opportunity to comment on the draft Demand Side Grid Support (DSGS) Program Guidelines, Second Edition (Draft Guidelines), and on the workshop held on April 26, 2023.

I. Eligibility and Participation

1. Third-Party Aggregators as DSGS Providers and Participants

The Draft Guidelines have added aggregators of customers as eligible DSGS providers (p. 2). CALSSA supports and appreciates this change for the reasons articulated in our prior comments and those of other parties.[1]

However, the Draft Guidelines now limit third-party aggregators to participating as DSGS providers. The CEC should restore the ability for aggregators of customers to participate in DSGS as eligible participants by making the following changes to Chapter 2, or otherwise clarifying that third-party aggregators can be DSGS participants.

A.2.a.i (p. 2): All customers of POUs <u>and aggregators of customers of POUs</u>.

A.2.a.iii, second bullet (p. 2): Customers <u>and aggregators of customers</u> participating through incentive Option 2 or Option 3 described in Chapter 4 and Chapter 5.

[1] CALSSA DEBA/DSGS program design proposal, submitted January 20, 2023, TN # 248480 (CALSSA Proposal), p. 10; CALSSA DEBA/DSGS revised proposal, submitted March 24, 2023, TN # 249422 (CALSSA Revised Proposal), pp. 6-7; CALSSA Comments on January 27, 2023, Workshop on DSGS and DEBA programs, submitted Feb. 17, 2023 (CALSSA January 27 Workshop Comments), TN # 248884, p. 5; Sunrun and Leap Revised Proposal—DER Program Design, March 17, 2023 (Sunrun Leap Revised Proposal), TN # 249330, p. 8; Generac DEBA & DSGS Program Recommendations, February 7, 2023, TN # 248681, p. 3.

2. Permission to Participate

The Draft Guidelines provide that for aggregators of customers serving as DSGS providers, before enrolling customers in the service territory of a publicly owned utility (POU) or a community choice aggregator (CCA), the aggregator must receive written permission from the applicable POU or CCA (p. 2).

Preliminarily, it seems the primary concern prompting this requirement is the need for LSEs to have visibility into DSGS activity in their territory that may affect their operations. The guidelines can add provisions to the reporting requirements to improve visibility, such as a nomination of capacity at the start of each month,[2] which would be communicated to LSEs as well as the CEC. For example, Sunrun and Leap have proposed a method for providing information similar to a "supply plan" to an LSE before each program month, with mid-month updates.[3] This or other means of providing visibility may reduce the concern and the need for a permission process. A requirement for notification similar to that for IOUs may be established instead and may be more appropriate.

A process to seek permission may create obstacles to robust participation in the program on the part of third-party aggregators, particularly given that each LSE requires a separate effort to obtain permission and there is no standard approach or guidelines for how the process will occur or the basis on which the decision may be made. If the requirement is retained, we suggest the following modifications to address some of these obstacles.

First, the Draft Guidelines should clarify that this permission process applies only when third-party aggregators seek to serve as DSGS providers, by adding "…as a DSGS provider" to the end of the language at section A.1.c.i on page 2 of the Draft Guidelines.

Second, the DSGS guidelines should include additional guidance and specificity on how POUs and CCAs would approach decisions about granting permission for third-party aggregators to operate as DSGS providers in their territory. This guidance is needed to inform aggregators about the basis on which a decision to deny permission might be made.

Third, the guidelines should provide that if a POU or CCA does not reach a decision about permission to operate in their territory within a reasonable period of time, the aggregator may serve as a DSGS provider in the territory. We suggest no longer than 30 days.

In the longer term, greater standardization in the process for seeking and granting permission would reduce the administrative complexity and resources needed to create DSGS aggregator programs across multiple LSEs. We recommend that the CEC consider creating a more standardized process, perhaps with a standard release form.

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[2] See also section II.4, Capacity Estimate and Nomination, below.

[3] Sunrun Leap Revised Proposal, pp. 12-13.

II. DSGS Option 3

1. Incentive Values and Other Compensation Considerations

During the workshop, CEC staff posed questions for feedback, including regarding the incentive values: "Are the incentive values appropriate to spur incremental load reduction while maximizing the value of the strategic reliability reserve? Do you have suggestions for other reference points for capacity incentives?" The proposed Option 3 incentive level is not appropriate, and the guidelines should be revised to increase the incentive level as well as to clarify payment of incentives and administrative costs to VPP aggregators.

a. Incentive payment allocation and administrative cost recovery

As an initial matter, the Draft Guidelines should be clarified regarding compensation and cost reimbursement for an aggregator of customers serving as a DSGS provider. A third-party aggregator should be able to allocate incentive payments between itself and its customers pursuant to an agreement reached between them. The final guidelines should state that aggregators serving as DSGS providers shall pay a portion of eligible incentive amounts to their participating customers.

The Draft Guidelines also provide that the CEC will reimburse DSGS providers for administrative costs. It is appropriate for DSGS providers to be compensated for costs incurred in preparing a provider application package, complying with program reporting requirements, and other costs related to administering the program. In particular, the design of Option 3 requires significant administrative resources to monitor CAISO market prices and respond based on the LMP price triggers. Additionally, third-party aggregators serving as DSGS providers may incur substantial costs in obtaining permission to operate in each LSE territory. We support the Draft Guidelines' approach of reimbursing administrative costs up to 10% of incentive payments for all DSGS providers in addition to providing an incentive payment that the aggregator shares with the customer. The 10% cost recovery would not alone be sufficient as compensation for aggregators to participate in DSGS. While this is particularly true for aggregators of smaller resources such as residential battery systems, where the cost per customer is higher, it applies also to aggregations with commercial and industrial customers, given that many factors affect the economic feasibility of BTM storage resources in commercial and industrial applications. Furthermore, if the administrative cost reimbursement is reduced or eliminated, all administrative costs will need to be covered through incentive payments, which would thus need to be increased.

b. Proposed incentive level

Because the Option 3 pathway aims to take a capacity-based approach, the value of capacity is the appropriate measure of the incentive level for this program option. We recommend that the level be increased to more accurately reflect that value.

The value of capacity in California is largely determined in the capacity market through bilateral contracts and is not publicly available. However, the CPUC's 2021 Resource Adequacy Report provides useful data and can be a reference point if properly considered in context.[4]

That context includes the marked increase in capacity market values in recent years. As observed in an Assembly Committee on Utilities and Energy report on currently pending AB 1373:[5]

> The RA market has experienced significant constraint recently, largely driven by resource retirements across the western U.S. as well as extreme weather events causing California energy agencies to increase RA obligations for LSEs…. These changes have led to a market rush, practically at any cost, to buy resources needed to meet RA obligations for the next few summers. Energy sellers have seemingly taken note. As shown in Figures 1 and 2 below, both system and local RA prices have been increasing significantly over the last few years, and are projected to be even higher for the coming summers.

The referenced Figure 1 comes from the 2021 Resource Adequacy Report, Figure 4, showing the weighted average price of System RA for January and August, 2017-2021.[6] This bill analysis makes it clear that not only have prices increased greatly from 2017 to 2021, but that prices have climbed much higher since 2021. In short, the 2021 Resource Adequacy Report is useful but not up to date, and when it is used as a reference point, the values must be adjusted to account for the significant price increases since those contracts were executed.

The August (summer) system RA values for 2019 through 2021 from Figure 4 in the 2021 Resource Adequacy Report show a more than 100% increase in price over just those two years.[7] Now, two years later, it would be appropriate to increase values from the report by at least 100% to reflect comparable or greater price increases. Given the state of the capacity market, increasing by 100% may in fact undervalue the capacity resource in Option 3. Several factors have changed the landscape over this time period: the Covid pandemic and resulting constrictions in supply chains, the Ukraine war, increasing labor costs, and inflationary pressures generally.

Moreover, beyond better reflecting current capacity value, the incentive should also reflect the avoided costs of power outages that these reliability resources are designed to avert. The

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[4] California Public Utilities Commission Energy Division, 2021 Resource Adequacy Report, April 2023, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report_040523.pdf

[5] Assembly Committee on Utilities and Energy, AB 1373 (Garcia)—As Amended April 13, 2023, April 25, 2023, p. 6, https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202320240AB1373#.

[6] 2021 Resource Adequacy Report, p. 29.

[7] 2019 price: $3.97, 2021 price: $8.07.

economic cost of blackouts is substantial. For example, in 2019, after a Public Safety Power Shutoff in PG&E territory affecting nearly 2 million customers for about 2 days, estimates of the cost ranged from $1 billion to $2.5 billion.[8] While it is difficult to quantify these avoided costs precisely, this is a factor that should be included in weighing the appropriate incentive level. Moreover, the threat to public health and safety associated with unplanned and potentially prolonged power outages is substantial and of the highest concern to all stakeholders.

The incentive provided through the Emergency Load Reduction Program (ELRP) is not a useful reference point for the capacity incentives in DSGS. As explained during the workshop on the SB 845 load shift goal held on April 19, 2023, the CEC seeks to pilot a pathway for BTM storage to support the grid under peak conditions through a capacity-based incentive.[9] ELRP is a different kind of program, designed around energy-only payments, a different compensation structure that is not directly comparable. DSGS Option 1 is the appropriate DSGS pathway to use ELRP compensation as a reference point, and it currently does so. Option 3 should take a different approach basing the incentive level on the value of capacity, as discussed above.

The incentive value should also not rely on the level of compensation in existing DR programs. DSGS Option 3 is an innovative approach to providing emergency reliability resources. It aims to better engage BTM batteries that have not been able to participate successfully in supply-side demand response (DR) capacity programs.[10] Since the compensation in existing DR programs like the Capacity Bidding Program (CBP) have not spurred large-scale adoption, they should not be used as a reference point for the compensation level a successful program needs.

The currently proposed incentive level for Option 3 is lower than the levels proposed both by CALSSA and by Sunrun and Leap.[11] The Draft Guidelines extend the program season to include May, whereas both those proposals were for a June-October season. This expansion should also be reflected in the incentive level.

Furthermore, the CEC seeks to set the incentive value at a level sufficient to spur participation and provide a meaningful reliability resource. The aggregator model is a key to maximizing the reliability value of BTM battery resources, but to enable the model, the incentive level must provide enough value to allow an aggregator to attract and enroll customers, operate the

[8] *The Guardian*, California power outages could cost region more than $2bn, some experts say, October 11, 2019, https://www.theguardian.com/us-news/2019/oct/11/california-power-outages-cost-business-wildfires.
[9] Lead Commissioner Workshop on SB 846 Preliminary Load Shift Goal, April 19, 2023. https://www.energy.ca.gov/event/workshop/2023-04/lead-commissioner-workshop-sb-846-preliminary-load-shift-goal.
[10] Lead Commissioner Workshop on SB 846 Preliminary Load Shift Goal, April 19, 2023. https://www.energy.ca.gov/event/workshop/2023-04/lead-commissioner-workshop-sb-846-preliminary-load-shift-goal.
[11] CALSSA Revised Proposal, pp. 8-11; Sunrun Leap Revised Proposal, p. 17.

aggregation, and provide data for measurement and verification, while also offering sufficient incentive to encourage customer participation. Customer value must outweigh the opportunity cost of responding to DSGS events when doing so results in lost bill savings or ACC-based export credits. The current incentive levels do not accomplish this, and will lead to very little uptake by both customers and aggregators.[12]

Finally, for new resources, even with an increased incentive level, DSGS will not spur deployment if not paired with funding aimed at that goal. The lack of an upfront deployment incentive is a significant obstacle to new resource deployment. The Distributed Electricity Backup Assets (DEBA) incentive is a key piece of the puzzle in building the reliability reserve as contemplated by AB 205. Therefore, it is important to have a clearer understanding of the availability and extent of DEBA funding, to fully assess the compensation under DSGS and how well it will enable new BTM batteries to come online and support reliability.

2. Day-of Trigger

At the workshop, the CEC posted the question of whether the guidelines ensure that incentive recipients deliver appropriate value and whether a day-of trigger should be considered for Option 3. The existing design ensures that the program will provide reliability value through dispatching at times of high grid value, and adding a day-of trigger will add substantial complexity with only slight additional value if any.

Energy Emergency Alert (EEA) notifications would be the most likely day-of trigger to be added to the program. Over the past 3 years, there were approximately 2 to 3 times as many days on which the price-based trigger was met as days with a day-of emergency notification (either EEA or AWE [Alerts, Warnings, and Emergencies] before 2022), with each of the emergency notifications happening on a day that also met the price threshold. Based on this history, it can be expected that a price-based trigger will already call an Option 3 program event on virtually any day that has a day-of EEA event notification going forward, and that the price-based trigger will dispatch resources to also help avoid the need for emergency notifications.

However, adding day-of events will add to the requirements of participating in the program and thus will add to the staffing and financial resources needed to operate an aggregation in the program. VPP Aggregators will need to be prepared to dispatch resources on significantly shorter notice. The addition of EEA events will add uncertainty and make it more difficult to model the program, to explain it to customers and enroll them, and to operate resources during program events. Moreover, the added complexity would require a corresponding increase in the incentive value, either by increasing the proposed incentive payment amount or by adding a higher incentive specific to day-of dispatches.

Further, sufficient notice is needed to ensure that batteries are charged and able to deliver capacity. For a stand-alone battery, notice must be longer than the battery duration to allow

[12] This is true even if aggregators operating as DSGS providers are reimbursed for administrative costs, and even more so if there is no administrative cost reimbursement.

full charging from the grid. For a solar-paired battery, limitations on charging from the grid mean that the resource will need sufficient notice to charge from solar during the day and hold the charge for dispatch during the event. This represents an additional complication that could be added to the program. Past day-of emergency notifications have had relatively little notice. In 2022, the year when the longest notice was provided, notice for day-of EEA events averaged about 5 hours. In 2021, average notice was under 3 hours, and in 2020, it was under 1 hour.

For the foregoing reasons, a day-of trigger should not be added to Option 3.

Any added day-of events should not only count toward the 35-event maximum for Option 3,[13] but should also have a separate maximum number of events. We recommend no more than 5 day-of events per season that are not also triggered by the day-ahead LMP trigger. CEC-issued dispatch signals would also help reduce some of the uncertainty in day-of dispatches.

3. Aggregator Capabilities and Obligations

In the list of minimum capabilities and obligations to which VPP aggregators must adhere (p. 16), the language "Sign a Customer Agreement Form with each participating customer" should be changed to reflect that in aggregator agreements with customers, the common practice does not involve signatures and instead occurs online, and the language should clarify that there is no specific required form. We recommend the following wording in place of that language:

- Enter into an agreement with each customer for participation in the program.

The guidelines may also incorporate some minimum requirements for customer terms, such as set out in Sunrun and Leap's comments on the Draft Guidelines.[14]

Also, the requirement that VPP aggregators must verify, provide, and comply with the participants' Rule 21 interconnection agreements raises concerns, as it presents a substantial hurdle that will likely reduce enrollment. The CEC should consider another approach, such as a customer attestation as part of the terms and conditions in the aggregator's agreement with the customer.

4. Capacity Estimate and Nomination

We recommend that the last sentence on page 16 be revised to reflect that Option 3 provide capacity inclusive of exports rather than load reduction, and to more closely align with the language in the top two paragraphs on page 18 that refer to the nominated capacity.

- At the time of enrollment, and before each month the VPP aggregator participates in DSGS, the VPP aggregator must estimate the total ~~load reduction~~ capacity each of its

[13] Draft Guidelines, p. 17.
[14] Sunrun and Leap Comments on Draft Demand Side Grid Support Program Guidelines, May 11, 2023, TN # 250110, p. 10.

> VPP ~~aggregation~~ aggregations will provide during a DSGS event and must provide that capacity nomination to the CEC.

The guidelines might also provide that the VPP aggregator, if not a POU or CCA, should also provide the capacity nomination to the LSE for the territory where the VPP aggregation is located.

5. Daily Program Hours

On page 17, the Draft Guidelines state that program events may occur between 4:00 p.m. and 10:00 p.m. Page 18 refers to the 4:00-9:00 p.m. program window. The program window should be 4:00 p.m. to 9:00 p.m. The hour from 9:00 to 10:00 p.m. falls outside the peak hours of most time-of-use (TOU) rates and outside the peak period of most demand charge rates. Including that hour in DSGS complicates TOU and demand charge bill savings. Event hours should align with the 4:00-9:00 p.m. peak hours to simplify event participation and improve performance.

6. Maximum Events

The language of the sentence on page 17 following the number of maximum events ("If a given resource is called more than 35 times events within the program months, the 35 events with the highest performance shall be used to determine demonstrated capacity") can be interpreted to mean that a resource may be required to dispatch more than 35 times during a program year. The sentence should be clarified to specify that after 35 events have been called, resources no longer are required to dispatch. A fixed cap on the number of events is necessary for certainty. However, the CEC may wish to specify that if a resource elects to dispatch more than 35 times in a program year, the demonstrated capacity may be based on the 35 events with the highest performance.

7. Test Events

CALSSA has two recommendations regarding the guidelines for test events, in the second paragraph on page 18. First, the meaning of a "full-duration program event" might be misunderstood. In addition, the requirement may not be necessary: even if there is no event that lasts the full length of a given resource's nominated capacity duration (2, 3, or 4 hours), as long as the resource has provided capacity in response to the program triggers, it will have provided reliability service and can be compensated at the capacity incentive level for its duration. For these reasons, the CEC may consider omitting this requirement. Similarly, the CEC may consider removing the provision about extending program events that last less than the relevant capacity duration to serve as a test event of the full nominated duration.

The Draft Guidelines call for VPP aggregators to define test events for their aggregations. If the approach is changed so that the CEC or another entity calls test events, they should be called at least a day ahead.

8. Measuring Performance

The guidelines should clarify that the calculation to determine demonstrated capacity (p. 18) is done separately for each month.

This section specifies that the performance calculation is different for resources with a permission-to-operate (PTO) date on or after June 1, 2023. For other resources, the PTO information is not needed. In the list of information required for a claim package for Option 3 (p. 20), the PTO date should be required only for resources with a PTO date on or after June 1, 2023.

9. Customers Participating in DSGS and ELRP

The Draft Guidelines provide that a participant is not eligible to receive incentives through the DSGS program if the participant's resource that is participating in DSGS is enrolled in an emergency load reduction program offered by a CPUC jurisdictional entity, or if the resource is receiving payment or accounting for the same reduction in electricity use through another utility or state program (p. 2). These provisions avoid dual participation and dual compensation with the same resource.

There are scenarios in which a customer has separate resources that could participate in both DSGS and ELRP. For example, some CALSSA members may install both a battery and electric vehicle service equipment (EVSE) at the same customer site. Each of these resources is metered at the device level, and their performance can be measured separately. Both ELRP and DSGS provide for measurement at the device level. In this scenario, the storage resource could be enrolled in DSGS Option 3 while the EVSE is enrolled in ELRP Subgroup A.5 (Vehicle-Grid-Integration Aggregators). We believe this would be consistent with the guidelines' limitations on dual participation.

III. DSGS Option 1

As set forth in the Draft Guidelines, Option 1 provides energy payments and—for combustion resources, which would not dispatch during an EEA Watch or EEA 1 absent an executive order—standby payments. In IOU and CCA territory, Option 1 is only available to water agencies and customers participating with backup generators, while it is open to all customers of POUs.[15]

CALSSA addresses Option 1 as a pathway for DSGS participation for customers using BTM energy storage. We recognize that some provisions of Option 1 are designed to best accommodate the participation of combustion resources, yet believe that this pathway can be modified to also provide greater opportunity for noncombustion resources like batteries. This is particularly so because it may not be possible for third-party providers to participate as DSGS

[15] Draft Guidelines, pp. 2, 8-9. Option 1 is also available to customers of federal power marketing administrations.

providers through Option 3 in some POU territories, but their customers would like to offer their batteries as reliability resources through DSGS.

1. Program Hours

The Draft Guidelines eliminate the 4:00-9:00 p.m. program availability time frame, instead providing that resources may dispatch at any time identified in EEA notices. For BTM resources, the optimal time for dispatch is during the 4:00-9:00 p.m. window to be consistent with system peak hours and the peak period in most TOU rates. The expansion to other hours is workable as long as there is no negative impact if a customer or provider chooses not to dispatch outside those 4:00-9:00 p.m. hours.

2. Minimum Dispatch Hours

CALSSA has previously advocated for minimum dispatch hours to be added to the existing Options 1 and 2. [16] This would create greater certainty and better enable providers to attract customers to DSGS. Minimum dispatch hours would not be appropriate for combustion resources, but may be appropriate to include in the guidelines for noncombustion resources, or at a minimum for demand-response resources and batteries, which are first in the Option 1 dispatch loading order.[17] The minimum dispatch hours could also be limited to customers in POU territories. The CEC should consider this modification if it can be done without adding substantial complexity. CALSSA recommends a minimum of 20 dispatch hours.

3. Expansion to IOU and CCA Territories

CALSSA recognizes that the CEC is seeking to strike a balance in limiting the extent to which it expands DSGS beyond POU territories. There are multiple reasons why further opening up eligibility to IOU and CCA customers would be appropriate. These include that AB 209 expressly allows that expansion, that DSGS is funded through taxpayer funds and should not be limited to a subset of customers, that many customers of CCAs may not have access to Option 3 because of a lack of permission to operate a VPP aggregation or because a VPP aggregation cannot meet the minimum aggregated capacity, and that greater flexibility will allow greater participation and provide larger and more meaningful reliability benefit to avert grid emergencies. We urge the CEC to consider these factors as it continues to examine future expansion of the program.

Sincerely,

/s/ *Kate Unger*

Kate Unger
Senior Policy Advisor
California Solar & Storage Association

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[16] CALSSA Revised Proposal, pp. 16-17.
[17] Draft Guidelines, p. 9.