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CALSSA DSGS Comments

Additional submitted attachment is included below.

October 30, 2024

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

Re: Docket No. 22-RENEW-01—Comments on Draft DSGS Guidelines, Fourth Edition

California Energy Commissioners and Staff:

On October 4, 2024, the CEC released a draft of modified guidelines for the Demand Side Grid Support (DSGS) program for public comment, and on October 18, 2024, the CEC held a workshop on those draft modified guidelines. The California Solar & Storage Association (CALSSA) appreciates the opportunity to provide these comments in response to the draft guidelines and the workshop.

CALSSA is an association of distributed clean energy providers across the state. We have been closely involved in the development of DSGS, and in particular its Incentive Option 3, the market-aware storage virtual power plant (VPP) pilot. CALSSA members represent a majority of the storage VPP aggregators active in Option 3, and a significant majority of the enrolled capacity. These comments focus on proposed changes to Option 3 from the perspective of providers in the program.

1. General Comments on Modifying Guidelines

Foremost among the goals for Option 3 is scaling up participation of clean resources and bringing new resources into the program to provide reliability service, including both systems that are installed but sitting on the sidelines and newly deployed systems. Another important goal is to demonstrate the potential and capabilities of Option 3's innovative price-based approach as a pathway for using customer storage to provide reliability for extreme events. Testing out different approaches to enlisting demand-side resources is critical to developing a sustainable, reliable, and resilient energy system.

a. Program stability is key to success.

We very much appreciate the CEC's interest in ensuring that DSGS works well and its desire to make improvements between program years. That said, making changes to fundamental aspects of program design carries the inherent downside of decreasing program stability and continuity. Stability is needed over a period of years, both for customers and for the aggregators that serve them.

Changes that affect customer expectations about what is required of them and how they are compensated increase friction and risk confusion and dissatisfaction. Having stability avoids this friction.

Also, VPP aggregators develop materials for customer outreach and education over a period of several months, and the outreach and education process itself can take weeks or months. These efforts are complicated by changes to program design and are aided by stability.

Additionally, VPP aggregators have developed software and business solutions for participating in DSGS, investing significant resources into making sure that their participation works well for the program and for their customers. This process, too, takes several months. Companies cannot repeatedly go back to the drawing board and redevelop their solutions to adjust for changing program design.

b. Stability leads to reliability.

Stability of program design is also fundamental to creating a program that can be relied on to respond in a predictable manner. The CEC and CAISO will be more able to predict the capacity Option 3 can provide during events if the program's rules and behavior are settled so that patterns can be observed over more than a single year.

c. Changes that erode program value will discourage participation.

CALSSA and others have previously commented that the DSGS incentive levels are lower than the full value of the resource and lower than needed to spur robust participation.[1] The current Option 3 incentive level is sufficient to be able to engage customers, but the value is not high. Even without directly reducing the incentive level, changes can affect the value of participation and could lead to customers determining that it is not worth participating.

Similarly, adding complexity and administrative requirements increases the costs for VPP aggregators to participate, making it less financially viable to join or to stay engaged in the program.

The foremost concern of CALSSA members is the changes to the baseline approach that have been proposed in the draft modified guidelines and that have been raised in the questions for consideration from the workshop. Also, adding new EEA event triggers as the CEC has proposed will have negative impacts on compensation. We are especially concerned that the compound

[1] CALSSA Comments on Draft DSGS Guidelines, Third Edition, submitted March 22, 2024 (CALSSA March 2024 Comments), TN # 255235, p. 4; CALSSA Comments on Potential Modifications to DSGS Guidelines, submitted February 5, 2024 (CALSSA February 2024 Comments), TN # 254332, pp. 4-7; CESA Comments on the DSGS Program Guidelines, Third Edition, submitted March 22, 2024, TN # 255229, pp. 2-3; Comments of Advanced Energy United on Proposed Draft DSGS Program Guidelines Third Edition, submitted March 22, 2024, TN # 255239, p. 4; CALSSA Comments on DSGS Guidelines and April 26, 2023, Workshop, submitted May 11, 2023 (CALSSA May 2023 Comments), TN # 250129, pp. 6-7.

impact of these and other proposed changes discussed in these comments will not only inhibit program growth but will lead customers and aggregators to leave the program.

Because these changes risk declining growth or even contraction in Option 3 participation, we urge the CEC not to move forward with these changes.

2. Proposed Baseline Calculation Changes

The CEC has proposed two changes to the current method of measuring performance:

(1) apply a baseline deduction to all batteries, eliminating the zero baseline that applies to batteries installed after July 1, 2023, and that are not supported by SGIP; and

(2) increase the baseline deduction that currently applies to nonresidential batteries from 0.028 to 0.074 of the battery's nominal energy storage capacity per hour.

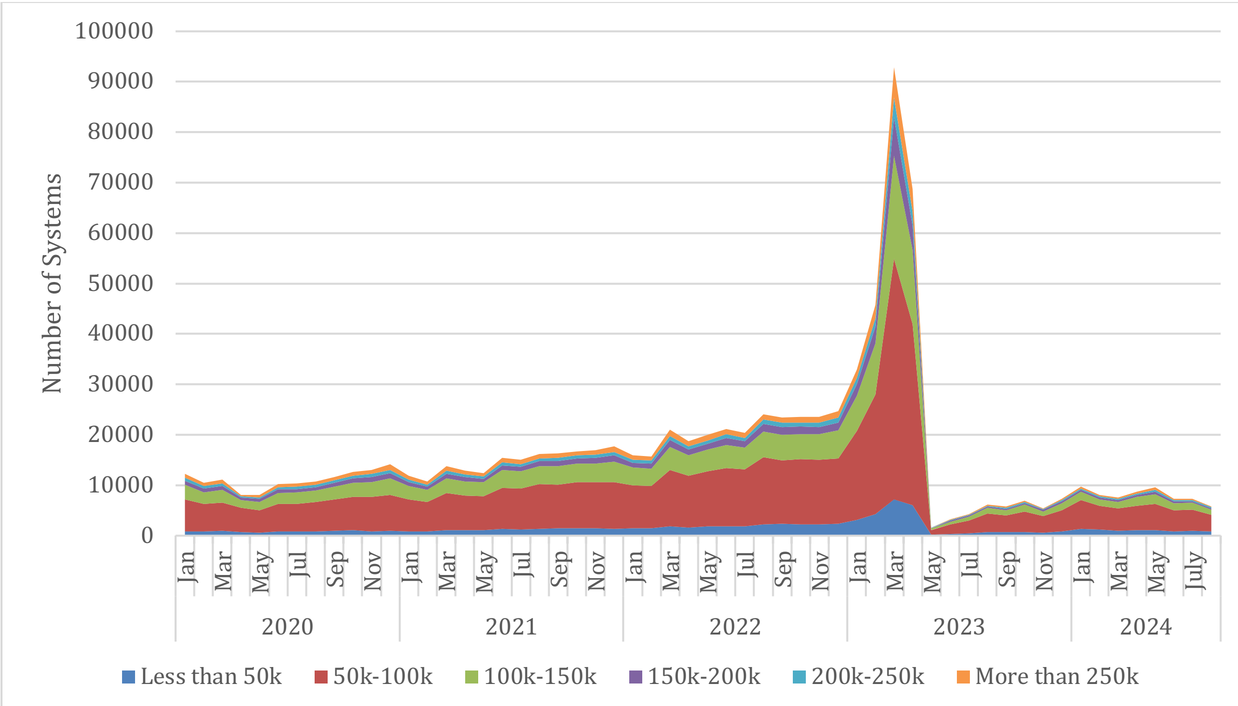
Both of these changes would set back the program by reducing the value of participation and should not be implemented.

a. Option 3 motivates storage adoption and performance during times of grid need.

Every battery system that is installed and participates in DSGS helps during times of grid stress. This capacity should be valued and compensated appropriately, recognizing that these are reliability resources that would not be available without the program.

Many customer batteries that are already deployed do not respond to reliability events. DSGS Option 3 is a way to enlist this installed base of batteries as reliability resources.

Option 3 also helps bring new storage resources online, at a time when sources of value are greatly needed to increase distributed generation and storage adoption. The rate of adoption for customer solar dropped precipitously after the change to net metering resulting in the net billing tariff (NBT). Even a year and a half after the change, current customer solar installations are less than one quarter of what would be expected if the trend had continued from before the net metering change, as shown in the graph below for residential solar system installations.



Source: CALSSA analysis of DG Stats, Census Data

The proportion of solar that is paired with storage has increased since the transition to the net billing tariff, but customer storage adoption is less than would be expected if the pre-NBT pace had continued. NBT does not by itself motivate significant customer uptake of storage. DSGS provides additional value that helps make the case for customers to install batteries.

As discussed above, the incentive level for Option 3 is sufficient but not high. The effective level of compensation has motivated customers to join the program. If the CEC modifies the baseline deduction to the demonstrated capacity, that will impact the effective level of incentives received by customers. This will make it harder to enroll new customer batteries, which in turn will set back our state's reliability and clean energy goals.

b. The zero baseline in Option 3 should be retained.

CALSSA previously urged the CEC to not apply a baseline deduction for new batteries installed after Option 3 went into effect, because new storage resources that are enrolled and participate from the beginning are incremental in that the program motivates their operation as emergency reliability resources.[2] The CEC adopted that approach in Option 3, providing that battery resources with a permission to operate on or after July 1, 2023, that do not receive SGIP

[2] CALSSA Responses to Request for Information on Clean Energy Alternatives for Reliability (CALSSA RFI Responses), submitted Nov. 30, 2022, TN # 247836, pp. 16-17.

funding have no deduction applied. Changing the approach to include the baseline deduction for these battery resources will reduce the motivation for installing and enrolling batteries to perform for grid benefit during reliability events.

c. ***The level of Option 3 compensation does not exceed its reliability value*** **(<u>Question for Consideration 3</u>)*.***

Additionally, concerns about double compensation do not serve California's energy system at a time when we need more clean, reliable energy, including from distributed resources.

When the grid is stressed and there is a reliability event, DSGS Option 3 discharge addresses a critical grid need that otherwise could be met with less-clean resources. Option 3 resources help avoid the need to use peaker plants and other combustion resources to meet peak demand.

The reliability value is the value of avoided costs for procuring capacity and energy during critical hours and grid emergencies. When customer batteries provide value to the customer in terms of bill savings as well as to the grid in terms of emergency reliability, value stacking is appropriate and consistent with the DSGS program's goals.

d. The baseline changes may lead many currently participating customers to leave the program without increases to the incentive rate.

The CEC has proposed changes to the baseline calculation to address its concern that the original baseline deduction values were not set accurately.

With the changes proposed by the CEC, as a general rule, the value of participation will be lower, in a range of a 15% to 35% decrease in compensation. The impact will be more pronounced for longer-duration resources. As a result, it will be harder to enroll new customers. Also, many existing customers will disenroll. The program's growth and success will slow, and it may even contract.

If the current prescriptive baseline values were set inaccurately, the lower customer incentives after the baseline values are adjusted indicate that the incentive levels were likely set lower than needed for program success.

Thus, if the CEC determines that the proposed changes to the baseline calculation are appropriate, it should re-evaluate the incentive levels for Option 3 and consider making a counterbalancing adjustment to them. An increase in the incentive rate would help account for the value of the reliability service provided by Option 3 resources and could help avoid customer and provider attrition. Given the 15% to 35% decrease in compensation, we suggest the CEC increase the incentive bonus by 25%, or from 30% to 55%.

Further, the CEC should extend the bonus, at this adjusted level, to include the 2027 program year.

*e. **The proposal to change the baseline calculation is based on untested assumptions and outdated, unrepresentative data.***

At the workshop, the CEC said that the proposed changes to the baseline take into account the effects of the NBT and observed behavior of nonresidential batteries in 2023. The effects of the NBT are not yet known, and the CEC should not make changes that will so substantially erode the value of Option 3 on the basis of assumptions. One important consideration with respect to the impact of NBT is that each version of the Avoided Cost Calculator (ACC) has different export compensation rates, and the export rates vary greatly between the version of the ACC effective for 2023-24 and the version effective for 2025-26. The number of BTM battery systems that will be participating in DSGS while responding to 2024-24's set of export rates is a small subset of the full Option 3 fleet. Additionally, not all batteries installed after July 1, 2023, are interconnected under the net billing tariff, so removing the zero baseline for this reason would be overbroad.

Similarly, the 2023 performance data is not a solid basis on which to make such an impactful program change. During the partial program year in 2023, providers were focused on enrolling customers and starting to provide capacity in response to program events. The lead time for performance in 2023 was too short to effectively develop strategies to optimize response to events. CALSSA members aggregating nonresidential customers have said that they expect their 2024 performance to be significantly stronger.

*f. **The CEC should not switch to a measured baseline for Option 3** **(<u>Question for Consideration 2</u>)**.*

The CEC has asked for input on whether to switch from a prescriptive baseline to a measured baseline for a more accurate determination of demonstrated capacity. Changing to a measured baseline would seriously undermine the program.

In advocating for a program pathway like what became Option 3, CALSSA discussed at length the negatives of measured baselines.[3] The design of Option 3 heeded those concerns, and the storage VPP pilot did not include a measured baseline. After less than two years of operation, the CEC should not abandon an innovation that makes Option 3 much more effective and useful than many demand response programs using a measured baseline.

A top consideration worth repeating is that a battery that routinely reduces peak load during non-event days and likewise reduces peak load during emergency events provides more value to the grid than a resource that provides the same load reduction on event days but does not reduce peak load—or does less to reduce peak load—on other days. Subtracting the discharge on non-event days from that on event days reduces the incentive for the resource to cycle during non-event days, to avoid reducing the comparative performance during events. Good program design does not discourage and discount performance that benefits the grid in

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[3] See, e.g., CALSSA DEBA/DSGS revised proposal, submitted March 24, 2023, TN # 249422, p. 15; CALSSA RFI Responses, pp. 17-18.

different ways—that is, load shaping on a regular basis that makes the grid more efficient and cost-effective, and response to extreme conditions during high-market price events.

3. Adding EEA Event Triggers to Option 3

The CEC has proposed adding CAISO Energy Emergency Alert (EEA) triggers to Option 3. While the workshop presentation said that the trigger would be added for bonus compensation, the added trigger would actually reduce compensation, and it would greatly complicate program participation.

a. There are many reasons that Option 3 should not include EEA triggers.

The CEC previously proposed adding EEA triggers in both spring 2023 and early 2024, at which time CALSSA provided numerous reasons why these triggers should not be added.[4] Adding EEA triggers remains a bad idea.

- Option 3 was designed to pilot a market-aware day-ahead price-based approach.

This approach addresses emergencies and also helps avoid them. Real-time dispatch is not required for the program to provide emergency reliability. Neither Option 2 nor Option 3 has a real-time requirement.

- The statute creating DSGS does not require real-time response.

AB 205 and AB 209 directed the CEC to implement a program that provides "on-call emergency supply and load reduction for the state's electrical grid during extreme events" and that "provides incentives to reduce customer net load during extreme events with upfront capacity commitments and for per-unit reductions in net load."[5] The statute allows the CEC flexibility in how resources provide service during extreme events, and does not include a requirement for real-time response. Option 3 provides on-call capacity during extreme grid stress as signaled by high prices.

- Program diversity is a strength.

Other DSGS program options (Option 1 and the new proposed Option 4) and other separate programs (for example, the Emergency Load Reduction Program) respond to EEA events. Those approaches can address sudden onset emergencies that were not foreseen the day ahead—which are rare events. Option 3 provides a unique and complementary service, and offers grid reliability service on a more regular basis, heading off emergencies as well as responding to them. Adding EEA events to Option 3 will be duplicative of other pathways, while undermining this pathway in several ways.

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[4] CALSSA March 2024 Comments, pp. 1-4; CALSSA February 2024 Comments, pp. 2-4; CALSSA May 2023 Comments, pp. 6-7.
[5] Public Resources Code § 25792.

We need a grid that can run reliably on clean energy. Demand-side solutions can help address this need. Responding to EEA events is not appropriate for all customers—indeed, no single approach will work well for all customers. We will need alternatives that enlist those customers, and Option 3 provides an opportunity to test out one such alternative.

- Simplicity is key to success, and adding new triggers undermines that.

Option 3 does not need to be the be-all and end-all of emergency reliability service to be effective. Trying to make it do more will in fact make it harder for Option 3 to do what it does well, by making it more challenging for customers and providers to participate.

- The price-based trigger is sufficient to meet grid reliability needs.

Virtually all EEA events over the past years have occurred on days when CAISO day-ahead prices already triggered Option 3 resources to dispatch. This shows that Option 3 is well positioned to meet emergency needs and the price-based trigger lines up well with times of acute need. There is little additional benefit to including EEA triggers in Option 3. Again, to the extent that any additional hours would be included from a day-of EEA event, DSGS addresses those short-notice events through other options.

- Adding EEA events makes the program much more complex for new and existing customers.

Including multiple program triggers means Option 3 will be more complex and harder to explain. Added to that, including events that call on batteries to discharge with minimal notice is much more challenging for customers, making it harder to convince them to participate.

In particular, existing DSGS customers will find out that the program rules they agreed to have changed in a fundamental way, requiring their batteries to do more. Adding new requirements midstream will lead to a poor customer experience, a reduced value proposition, and fewer customers participating.

- Adding EEA events makes the program much more complex for aggregators.

Both customer engagement and program operation become significantly more complex and challenging with the addition of a second trigger involving day-of dispatch.

Aggregators must do additional software and operational strategy development to incorporate EEA events. For providers not using Olivine dispatch signals, this may require adding a costly new manual process or software integration.[6]

- Battery providers need notice to ensure batteries have sufficient charge to respond fully to events.

[6] See section 4 below regarding test events for more discussion of the obstacles posed by needing to add events signaled by Olivine.

A day's notice is important to ensuring that customer batteries are sufficiently charged to respond optimally during a DSGS event. This is particularly true for solar-charged batteries. It is also problematic to call on batteries after the on-peak period begins, because providers will not know in advance to retain charge for use in DSGS events.

Option 3 is designed to maximize the potential of BTM storage to provide reliability value. BTM batteries are well suited to a day-ahead approach for predictability and reliability. With real-time events, it is more difficult to predict the capacity that will be provided.

- **Adding EEA events will decrease overall compensation, even with the 10% bonus.**

Option 3 is designed as a standby program, with a certain value paid for the standby capacity. Adding these events into the determination of capacity and the compensation for program participation will undermine the program's goal of having capacity ready on standby status.

The proposal to add 10% bonus compensation in months when there are additional EEA dispatch hours is far from sufficient to make up for the lost compensation.

Including EEA events in the calculation of average demonstrated capacity will decrease the average substantially if an EEA event is called after a battery has begun to discharge rather than holding its charge for an event.

As one example, assume a residential (2-hour) battery has a 20% backup reservation and cycles on a time-of-use schedule on most days. If an EEA is called at 6:45 pm, then the battery would be dispatched from 7 pm to 9 pm. The battery would likely have already discharged about 45% of its capacity by 6:45 pm, reducing the capacity available to discharge during the event hours substantially compared with a price-based program event. When that lower discharge is included in the calculation of average demonstrated capacity for the month, it can reduce the average significantly, with a greater impact if there are fewer price-based events during that month. The impact on compensation can *often* exceed 10%, and potentially can exceed 40%.

There are unknowns, and including EEA events will not predictably decrease the compensation by that high an amount—but this is partly the point. The unpredictability of compensation is highly problematic for customers and the aggregators that serve them. One of the positive features of the Option 3 program design is that it offers some predictability about compensation. Adding EEA events to the performance calculation undercuts that feature.

In summary, the many reasons why adding EEA event triggers to Option 3 is problematic far outweigh the reasons to include them. The CEC has developed a different approach in Option 3 and should not attempt to make it more like other programs that already offer response to EEA events. The pilot should continue so that it can demonstrate the efficacy of the price-based approach.

b. Any storage VPP construct with EEA or other same-day triggers should be a separate program option, not a part of Option 3 (Question for Consideration 4).

The CEC asked whether there should be an emergency-only construct for storage VPPs that is similar to Option 4 and that is separate from the Option 3 design. This is a reasonable pathway if the CEC wants to have EEA-dispatched storage VPP events.

Customers and aggregators should be able to choose whether to participate in the price-based Option 3, the EEA-based new option, or both. On days with an EEA event, the EEA option should govern dispatch, performance measurement, and compensation. Option 3 measurement and compensation should be separate and based on days without EEA events.

In the event that the CEC decides to include a storage VPP pathway that includes EEA events, CALSSA will provide input on appropriate compensation rates and other program elements.

4. CEC-Initiated Test Events

a. Including CEC-dispatched test events adds complexity for little added value.

The CEC proposes having the CEC call test events for August, September, and October, rather than having DSGS providers call test events in all months, as the current guidelines provide. In the workshop, the CEC offered two reasons for making this change:

(1) to test providers' capabilities to respond to test events with the same amount of notice as a program event, and

(2) to see the total capacity value of the DSGS program during a coincident event—we understand this to mean an event that is called at the same time in all IOU territories.

Neither of these provides a sufficient reason for making this change. Program events already test providers' ability to respond to events with day-ahead notice, and there is no clear reason why that ability must be shown every month of the season. Most of the events in 2024 occurred in all IOU territories, but even when that does not happen, it is simple to add the results from separate events in the different territories. If the CEC's concern is to see the total capacity value during a full-duration event, again, it is not clear why that would need to be done every month.

An important note here is that the proposed guidelines are unclear about whether the CEC-called test events would be only fully separate test events—i.e., a test event that is required only when there are no program events during a month—or also would apply to a decision to extend a program event to the full resource duration.

First, if the CEC would call only fully separate test events, those will be rare in August and September, the months in which prices are most likely to trigger program events. This means that Option 3 providers would need to prepare for CEC-dispatched test events for three months each season, even though such events would often happen a maximum of once per season—meaning they would expend resources for little return to the program.

Second, if the CEC would also call test events that extend the duration of a program event, it would put the CEC in the position of making judgment calls about imposing potentially unnecessary additional burden on customers and providers, given that there will always be a chance that a program event will be called later in the same month that will render the CEC-called test event irrelevant. It is much better to leave such calls to providers.

This requirement for CEC-dispatched test events also appears to be inconsistent with the guidelines allowing VPP aggregators to do multiple test events and apply the highest performance to the demonstrated capacity for the month. That option should not be eliminated.

If the CEC believes it is necessary to have a coincident full-duration program event to show the total capacity value, then the CEC can require a full-duration event on the last day of the month if no full-duration events have occurred that month, or it could require providers to treat the first program event of each month as a full-duration event.

b. This requirement will impose significant and unnecessary new costs for providers that don't use Olivine.

Not all providers use Olivine's dispatch notifications. The program guidelines do not require that, and the program should not be changed to effectively require it now. Providers should remain free to determine program events through their own methods.

Adopting a test-event approach that effectively requires providers to use Olivine signals presents a significant new cost and barrier. Providers that access CAISO LMP data directly have already expended resources to develop a workable participation pathway, and they should not be required to expend further resources to develop another method for receiving dispatch signals for test events. This is especially true given that test events will happen infrequently, so that the added costs far outweigh the possible benefit.

For example, one CALSSA member that does not use Olivine has automated the process of dispatching for test events by providing that if there were no full-duration events during a month, their dispatch platform directs a full-duration test event on the last day of the month.

Providers may find that the added costs of complying with this requirement are too great to continue participating and may feel forced to leave the program. Even if only one provider is in this situation, the program change is unwarranted.

Additionally, some DSGS providers that currently use Olivine may decide that they would like to develop their own dispatch logic for future use because it is a more efficient and less resource-intensive alternative for them. Requiring providers to use Olivine for test event notifications would inhibit this kind of innovation.

5. Minimum Nominal Power Rating

The CEC proposes to increase the minimum total nominal power rating for a storage VPP aggregator from 100 kW to 500 kW. While the CEC may see this as a small program change, it could have significant unintended consequences for customers, providers, and the program's overall success.

Increasing the threshold could mean that existing providers and their customers will be forced to leave the program. Some existing Option 3 providers and partners meet the 100 kW limit but do not have 500 kW of assets enrolled. These companies and their customers would be forced out of the program. Companies would need to explain to customers that had planned to participate for a period of years that they are no longer able to do so. Stranding existing customers that were expecting to continue participating in the program is an extremely unfortunate consequence. This would pose a problem both for those frustrated customers and for the companies that engaged them.

Also, this appears to apply not only to providers whose total power rating is currently between 100 kW and 500 kW now, but also to providers who experience a dropoff in customer enrollment for the 2025 program season. This is a very real risk because if the proposed changes discussed above are adopted, there may be contraction in program enrollment. Making the change from 100 kW to 500 kW minimum nominal power rating could greatly compound the resulting reduction in enrolled capacity.

It would not be fair to apply this higher minimum size requirement only to newly enrolling DSGS providers, in an attempt to avoid this impact on current participants.

Furthermore, this change would also create a barrier to entry for startup and smaller companies, further reducing the potential for growth.

6. Option 3 Performance Reports

The draft modified guidelines include a new requirement for Option 3 performance reports, which would require Option 3 providers to submit submeter data in a specified format for the prior month for all of their sites that were active that month. These reports would be due within three business days after the end of each month.

The three-day timeline is unreasonably short. It takes time and resources to collect the data and ensure that it is accurate. Additional time is needed to convert data to the specified format. **We recommend that the deadline be by the end of the following month.**

The guidelines should add to this requirement that the performance reports should contain submeter *or inverter* data, to align the language of this requirement with the provision allowing Option 3 VPP aggregators to provide data from a battery inverter or submeter and with the provision specifying the participant-level data required as part of an Option 3 claim package.

Because incentive claim packages already require the same data to be submitted, the guidelines should state that submitting a claim by the reporting deadline that includes submeter or battery inverter data satisfies the new Option 3 performance report requirement.

The CEC should ensure that the guidelines and guidance from Olivine clearly state that providers may submit incentive payment claims up to monthly, and that claims will be processed when submitted rather than at the end of the program season. Option 3 providers have found CEC and Olivine guidance on this point unclear.

The CEC should direct Olivine to handle claims processing and payment as quickly as possible once a provider submits a monthly claim that also provides the data required in this new performance report.

7. Additional Program Modifications (<u>Question for Consideration 1</u>)

a. Provide a cloud API pathway for submitting monthly data and for communicating dispatch signals.

To reduce the added administrative burden of providing data monthly, the CEC should not require data to be provided manually in a format specified by Olivine. Instead, an option should be available in which Olivine queries cloud APIs made available by participating OEMs and aggregators and formats the data after receiving it. This is standard practice for nearly all modern grid service programs and gird services aggregation platforms (e.g., Virtual Peaker, Texture, etc.).

Olivine offers an OpenADR integration pathway (which would ostensibly allow them to use the OpenADR protocol to query data from participating devices). However, there is no standard OpenADR integration approach, and integrating with individual OpenADR instances requires significant development/test time and effort from OEMs and other program participants; thus, this is not a tenable solution.

Program participants that do not offer a cloud API can continue to use the manual or OpenADR integration pathways, but when a DSGS provider or participant's cloud API is available, Olivine should be required to integrate with it, as one of the specified formats in which device-level data can be shared with the CEC.

Olivine should also offer a similar option in which DSGS providers can use their cloud APIs to receive event signals from Olivine. DSGS providers that choose to continue receiving event signals using the existing methods would be able to do so.

b. Increase the maximum customer site discharge during program events.

The guidelines currently require that any customer site participating in Option 3 must provide no more than 1,000 kW of discharge during any program event hour. Our understanding is that this limitation was placed on the program from concern that greater discharge may present difficulties for CAISO in managing the grid. If the program operated in 2024 without raising issues at this level, and given that larger sites are studied for grid impacts before being granted permission to interconnect, the CEC should consider increasing this limit to 5,000 kW or another appropriate higher maximum discharge level.

8. Funding Certainty

The workshop presentation showed that the DSGS program budget includes $127.5 million in currently appropriated funding. That amount includes $75 million that was allocated in SB 108 in 2024; however, that allocation can be used for DSGS or other purposes. During the workshop, when asked what portion of that $75 million will be used for DSGS, CEC staff said they will determine the amount that is needed to support the needs of the grid for this summer, and that next steps will be determined after the CEC knows the amount of funding left thereafter.

It is very important for the CEC to provide greater certainty about the amount of funding available to DSGS. While we understand that the CEC is working to balance among different programs and provide funding to enable them to continue, the approach of not committing funds to DSGS until needed for the current year does not give enough certainty for providers.

Providers and customers make decisions about what programs to participate in on a multiyear basis. Providers need to give customers some assurance that compensation will be sufficient to justify their effort in enrolling.

Because DSGS pays incentives on a first-come, first-served basis, there should be a clear cushion in the budget so that providers can be assured that funds will be available to pay all claims for more than one year. Unless aggregators have assurance that they can meet commitments to compensate customers, it can be too great of a financial risk to encourage customers to participate.

The CEC should provide more information before the end of this year about how much of the $75 million will be dedicated to DSGS, to enable Option 3 providers and participants to make necessary business decisions.

9. Conclusion

We applaud and appreciate the CEC's dedicated and thoughtful approach to DSGS program design and implementation. We also appreciate the interest in refining the program and improving the user experience, as well as the opportunity to provide input based on the experience of several DSGS Option 3 providers.

Smart program design is important. Once a program is in place, continuity and certainty are at least as important as optimizing the design. While the impetus to make adjustments stems from a desire to improve the program, participants in Option 3 need a stable outlook for a period of years. With that stability, the program can work well for the grid while providing a positive experience for customers, and can scale up to become a more important part of a clean, reliable energy system.

Sincerely,

/s/ Kate Unger

Kate Unger
Senior Policy Advisor
California Solar & Storage Association