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CALIFORNIA ENERGY COMMISSION

CALIFORNIA NATURAL RESOURCES AGENCY

REVISED Proposed Draft DSGS Program Guidelines, 5th Edition (underline-strikethrough)

Demand Side Grid Support (DSGS) Program Guidelines, Fifth Edition

(Assembly Bill 205, Assembly Bill 209, 2022)

February 2026 | CEC-300-2026-001-D2

California Energy Commission

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PREFACE

The state created the Demand Side Grid Support (DSGS) Program as part of the statewide Strategic Reliability Reserve (SRR) to develop clean, demand-side resources capable of reducing net-peak demand during extreme events. The DSGS Program was originally envisioned as a $314 million program to build 1 GW of demand-side resources for the state by 2030. To date, only $109.5 million has been allocated to the program with no new funding allocations authorized in the 2025-26 Budget. Additionally, in 2023, in response to a directive in Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022), the CEC, in consultation with the California Public Utilities Commission and California Independent System Operator (ISO), established a statewide load flexibility goal of 7,000 MW by 2030.[1] In support of California's transition to 100 percent clean energy, the DSGS Program seeks to grow clean, load-flexible resources under the SRR without interfering with resource adequacy, as well as act as a sandbox to scale demand flexibility solutions for achieving the statewide load flex goal.

The DSGS Program launched in August 2022 with an emergency load reduction participation option and enrolled 44 individual participants to help respond to the September 2022 extreme heat event, providing over 3,100 MWh of load reduction. These resources were vital for allowing the state to maintain grid reliability during the 2022 heat event. The program has continued to expand participation opportunities in each year of its existence targeted toward growing clean demand side resources for SRR, including California ISO market-integrated demand response incremental capacity, a market-aware behind-the-meter storage virtual power plant (VPP), and an emergency load flexibility VPP focused on smart thermostats and heat pumps. In just three years, the DSGS Program has expanded to four participation options with over 448,000 participants and an estimated 1,145 MW enrolled, with nearly 1GW from clean resources. It has been reported to include the world's largest storage VPP with over 124,000 customers enrolled throughout the state.

During the design and early implementation of the DSGS Program, CEC staff – working with its colleagues across state agencies, industry, and other stakeholders, and embracing the learnings from its sandbox – have identified challenges and areas of opportunity for improvement under the program that warrant exploration, discussion and feedback in a public process. However, given the uncertainty around the program's long-term funding and the quickly approaching 2026 program season, this guideline revision is limited to essential modifications to provide clarity on program requirements, incorporate lessons learned on incrementality, and align with the program's goals and current funding level. If additional funding is authorized for the program to continue beyond the upcoming 2026 program season, CEC staff will engage in further analysis

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1 https://www.energy.ca.gov/publications/2023/senate-bill-846-load-shift-goal-report.

and public dialogue to explore additional opportunities and challenges raised to ensure DSGS effectively meets its goals.

ABSTRACT

These program guidelines for the Demand Side Grid Support (DSGS) Program establish the rules for the program, including eligibility requirements, participation process, and ~~incentive~~ participation options. Created by Assembly Bill (AB) 205 (Ting, Chapter 61, Statutes of 2022) and expanded by Assembly Bill 209 (Ting, Chapter 251, Statutes of 2022) as part of the Strategic Reliability Reserve, the DSGS Program provides ~~incentives~~ performance-based payments to reduce customer net-energy load during extreme events with upfront capacity commitments and per-unit reductions in net load.

Keywords: AB 205, AB 209, Strategic Reliability Reserve, DSGS, load reduction, extreme event

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What’s New in These Guidelines?

~~This section summarizes the changes in the proposed fourth edition of the Demand Side Grid Support (DSGS) guidelines as compared with the previous version, *DSGS Program Guidelines, Third Edition* (May 2024).~~

> ~~**Note:** This document includes all modifications contained in the *Proposed Demand Side Grid Support (DSGS) Program Guidelines, Fourth Edition*, published on March 6, 2025, but excludes PG&E distribution service customers from participation in Incentive Option 4.~~

~~**Chapter 1: Program Overview**~~

~~This chapter:~~

- ~~Updates and clarifies the summary of key program design elements.~~
- ~~Clarifies program background and purpose~~
- ~~Updates program budget based on the Budget Act of 2024.~~

~~**Chapter 2: Eligibility and Participation**~~

~~This chapter:~~

- ~~Makes clarifying and grammatical changes and updates section references.~~
- ~~Provides brief descriptions of the available DSGS incentive options.~~
- ~~Clarifies requirements for participants selecting different incentive options for each load reduction resource and specifies a load reduction resource cannot be enrolled in more than one incentive option.~~
- ~~Clarifies requirements and timeline for publicly owned utilities outside the California Independent System Operator (California ISO) balancing authority (BA) area to submit alternative dispatch requirements and associated performance measurement criteria to those described in the guidelines for any DSGS incentive option.~~
- ~~Requires DSGS providers to submit Incentive Option 1 enrolled participation reports before each program season.~~
- ~~Adds participant information to the enrolled participation reports for participants enrolled with an aggregator or directly with the CEC in Incentive Option 1.~~
- ~~Requires all Incentive Option 1 participants to provide notice and ramp time required to respond to a DSGS event.~~
- ~~Establishes enrollment and reporting requirements for the newly added Incentive Option 4.~~

- ~~Clarifies providers are responsible for certifying remote control capability of storage resources participating in Incentive Option 3.~~
- ~~Adds regular dispatch reports for Incentive Option 2 and performance reports for Incentive Options 3 and 4.~~

~~Chapter 3: Incentive Option 1: Emergency Dispatch~~

~~This chapter:~~

- ~~Clarifies that residential customers are not eligible to participate in Incentive Option 1.~~
- ~~Clarifies the definition of "combustion resources."~~
- ~~Clarifies the default process for calculating verified incremental load reduction.~~
- ~~Removes the one-time "controllable generation incentive" for fossil fuel-powered backup generators.~~

~~Chapter 4: Incentive Option 2: Incremental Market-Integrated Demand Response Capacity Pilot~~

~~This chapter:~~

- ~~Clarifies that Incentive Option 2 participants must be registered to an Option 2 provider.~~
- ~~Makes clarifying and grammatical changes.~~

~~Chapter 5: Incentive Option 3: Market-Aware Storage Virtual Power Plant Pilot~~

~~This chapter:~~

- ~~Updates the minimum aggregation size requirements for storage virtual power plants (VPPs).~~
- ~~Increases the maximum allowable discharge at a customer site during any hour of a program event.~~
- ~~Allows for dual participation in the DSGS Program and as a California ISO proxy demand response or reliability demand response resource for export-only portion of storage resources discharge.~~
- ~~Clarifies participation rules for providers that operate storage VPPs on behalf of partner companies.~~
- ~~Updates enrollment requirements for participants in Incentive Option 3.~~
- ~~Establishes day-ahead and day-of emergency triggers for Incentive Option 3 program events, where the former event is included in monthly demonstrated capacity but the latter event is not.~~

- ~~Requires storage VPP aggregators to notify the CEC in advance of conducting test events and allows VPP aggregators to conduct multiple test events per month, with only the most recent test event in the month being used in the calculation of demonstrated capacity.~~
- ~~Establishes the formula for calculating hourly discharge and demonstrated capacity for participants enrolled in a supply-side DR program and participating in DSGS with an export-only resource.~~
- ~~Specifies the timing and cadence of future updates to baselines used to calculate demonstrated capacity.~~

~~Chapter 6: Incentive Option 4: Emergency Load Flexibility Virtual Power Plant Pilot~~

~~This chapter:~~

1. ~~Establishes the eligibility, enrollment process, incentives, program availability and event triggers, and performance measurement method for a new Incentive Option 4: Emergency Load Flexibility Virtual Power Plant Pilot.~~
2. ~~Excludes PG&E distribution service customers from participation in DSGS Incentive Option 4 to address concerns raised about the potential overlap between the emergency focused Option 4 and PG&E's recently launched market-integrated Automated Response Technology (ART) Program (as both programs are targeted to smart devices), counted for resource adequacy, and the overlap possibly negatively impacting customer recruitment into ART.~~

~~Chapter 7: Program Payments~~

~~This chapter:~~

3. ~~Clarifies the types of administrative costs incurred by utilities and federal power marketing administrations in facilitating an aggregator's administration of the program and direct participation that are eligible for reimbursement.~~
4. ~~Clarifies applicable administrative costs incurred by utilities and federal power marketing administrations may be reimbursed directly to the utility or federal power marketing administration, or to the DSGS provider billed for direct costs.~~
5. ~~Changes the date by which Incentive Options 3 and 4 claims must be submitted to the CEC for review.~~
6. ~~Removes the participant-level information required for Incentive Option 3 claims that will already be provided in monthly performance reports or text event notifications.~~
7. ~~Makes clarifying and grammatical changes and updates section references.~~

8. ~~Clarifies that failure to meet the deadline to respond to questions and provide clarification or fix minor errors, discrepancies, or omissions in a claim package will result in the cancellation of a claim.~~

~~Chapter 8: Administration~~

~~This chapter:~~

9. ~~Makes clarifying changes and updates section references.~~

~~Glossary~~

~~This chapter:~~

10. ~~Clarifies the definitions for aggregator, behind the meter, California ISO, cogeneration, demand response, DSGS Program event, subcontract, subcontractor, and virtual power plant.~~
11. ~~Adds definitions for Agricultural and Pumping Interruptible Program, electric vehicle supply equipment, nameplate energy storage capacity, nameplate power rating, smart electrical panel, and virtual net metering.~~

This section summarizes the changes in the proposed fifth edition of the Demand Side Grid Support (DSGS) guidelines targeted for 2026 program season as compared with the previous version, DSGS Program Guidelines, Fourth Edition (April 2025).

Chapter 1: Program Overview

This chapter:

1. Establishes that Options 1 is suspended for the 2026 program year.
2. Includes updates on the program budget and restrictions on program spending in 2026.
3. Makes clarifying changes, including language to reflect that program options are participation options rather than incentive options.

Chapter 2: Eligibility and Participation

This chapter:

1. Provides examples of prohibited dual compensation.
2. Clarifies that load reduction resources at the same site may participate in different participation options under different providers.
3. Requires Option 3 participation reports to include number of inverters per site instead of batteries per site.

4. Clarifies that Option 3 providers attest to: having remote control of participant batteries, not dispatching for conflicting programs, and having no knowledge of customer enrollment in conflicting programs.
5. Makes clarifying changes, including language to reflect that program options are participation options rather than incentive options.

Chapter 3: Participation Option 1: Emergency Dispatch

This chapter:

1. Notes that Option 1 is suspended for the 2026 program year.
2. Makes clarifying changes, including language to reflect that program options are participation options rather than incentive options.

Chapter 4: Participation Option 2: Incremental Market-Integrated Demand Response Capacity Pilot

This chapter:

1. Establishes an enrollment cap for the 2026 program season and describes the mechanism to address over-subscription.
2. Removes the option for providers to request an interim season settlement payment.
3. Makes clarifying changes, including language to reflect that program options are participation options rather than incentive options.
4. Requires that battery storage participating in Option 2 have a permission-to-operate date on or before December 31, 2025.

Chapter 5: Participation Option 3: Market-Aware Storage Virtual Power Plant Pilot

This chapter:

1. Adds customer class to the definition of “aggregation”.
2. Updates participant enrollment information consistent with updated eligibility and baseline methodology.
3. Clarifies that payments are performance-based capacity payments and specifies that these capacity payments may be made from Distributed Electricity Backup Assets funds.
4. Sets total compensation amount available for Option 3 in 2026 and describes the mechanism to cap performance-based capacity payments for each provider.
5. Updates maximum event requirements to switch to a specific number of hours.

6. Establishes that the CEC may require Option 3 aggregators with large aggregations to conduct their test events in PG&E and Southern California territories on different days.
7. Requires a three-consecutive day test event in August.
8. Clarifies that subsequent energy emergency alerts do not affect the selection of day-of event hours.
9. Updates the baseline method to a measured baseline.
10. Makes clarifying changes, including language to reflect that program options are participation options rather than incentive options.
11. Requires that battery storage participating in Option 3 have a permission-to-operate date on or before December 31, 2025.
12. Updates the minimum aggregation size.

Chapter 6: Participation Option 4: Emergency Load Flexibility Virtual Power Plant Pilot

This chapter:

12. Provides a pathway for submitting other load reduction resources for consideration.
13. Clarifies that payments are performance-based capacity payments.
14. Requires new aggregations to enroll and begin participation at the beginning of the program season or at the beginning of the second quarter.
15. Establishes an enrollment cap for the 2026 program season and describes the mechanism to address over-subscription.
16. Clarifies the method for measuring performance.
17. Provides a description of method to calculate utility distribution company (UDC) planning temperature.
18. Updates the calculation of daily temperature average to align with the program's event window.
19. Provides description of method to calculate the temperature weights used for determining UDC composite temperature.
20. Makes clarifying changes, including language to reflect that program options are participation options rather than incentive options.
21. Updates the minimum aggregation size.
22. Requires that battery storage participating in Option 4 have a permission-to-operate date on or before December 31, 2025.

Chapter 7: Program Payments

This chapter:

1. Requires a provider's officer to sign attestations in claim forms.
2. Makes clarifying changes, including language to reflect that program options are participation options rather than incentive options.

Chapter 8: Administration

This chapter:

1. Adds more detail regarding the process for requesting records be designated confidential according to the CEC's regulations for confidential designation, Title 20, California Code of Regulations, Section 2505.
2. Clarifies that CEC is not obligated to provide funding or payments under the DSGS Program beyond CEC's authorized funding limitations.

Glossary

This chapter adds a definition of "holidays" for use in energy baseline calculations.

Appendix A

This chapter is added to provide detailed description of calculation methods referred to in Chapters 4 – 6, including funding and enrollment allocations for Options 2, 3, and 4 for the 2026 program season.

CHAPTER 1: Program Overview

A. Summary of Key Program Design Elements

Created by Assembly Bill (AB) 205 (Ting, Chapter 61, Statutes of 2022) as part of the Strategic Reliability Reserve, the Demand Side Grid Support (DSGS) Program compensates eligible customers for reductions in net load during extreme events (as defined in Public Resources Code [PRC] Section 25790.5[b]) achieved through reduced usage or use of backup generation or both.

The DSGS Program has four participation~~incentive~~ options. Participants can select different participation~~incentive~~ options for each eligible load reduction resource type. Participants may enroll with eligible DSGS providers or, in limited circumstances, directly with the CEC. The four ~~incentive~~ participation options include:

- Option 1: Emergency Dispatch
- Option 2: Market-Integrated Demand Response Incremental Capacity Pilot
- Option 3: Market-Aware Storage Virtual Power Plant Pilot
- Option 4: Emergency Load Flexibility Virtual Power Plant Pilot

Participation Option 1 is suspended for the 2026 program year due to the program's current budget constraints.

B. Background

AB 205, available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB205, requires the CEC to implement and administer the DSGS Program, codified under PRC Section 25792, to incentivize dispatchable customer load reduction and backup generation operation as on-call emergency supply and load reduction for the state's electrical grid during extreme events. Assembly Bill 209 (Ting, Chapter 251, Statutes of 2022), available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB209, expanded the eligibility of the DSGS Program to include all energy customers in the state, except those enrolled in demand response or emergency load-reduction programs offered by entities under the jurisdiction of the California Public Utilities Commission (CPUC). AB 209 also states that the CEC, in consultation with the CPUC, may adopt additional participation requirements or limitations.

The DSGS Program provides incentives to reduce customer net load during extreme events with performance-based ~~capacity~~ payments ~~and for per-unit reductions in net load~~. As part of the state's Strategic Reliability Reserve established in AB 205, the DSGS

Program aims to support electric grid reliability beyond normal planning standards by providing incremental load reduction during extreme events, such as heat waves.

Section 18 of AB 205 authorizes the CEC to adopt guidelines for the DSGS Program. Furthermore, PRC Section 25792(e) directs the CEC to develop guidelines to determine when to implement the program, including which resources are dispatched first to minimize local pollution and emissions of greenhouse gases.

C. Program Budget

DSGS Program funding is authorized under AB 205, AB 102 (Ting, Chapter 28, Statutes of 2023), AB 107 (Gabriel, Chapter 22, Statutes of 2024) and Senate Bill 108 (Wiener, Chapter 35, Statutes of 2024) with an overall budget of $109.5 million. Additional funding may become available for the DSGS Program through the 2026-2027 budget process.

Except for the 2026 program year, there~~There~~ is no specific restriction on annual spending or allotments for enrolled DSGS providers. ~~Incentive payment is available on a first-come, first-served basis.~~ The CEC will provide estimates and updates of DSGS Program expenditures and available funding annually once activity is reconciled.

CHAPTER 2: Eligibility and Participation

This chapter contains the program wide eligibility criteria and establishes the process for participating in the program options, including enrollment and reporting.

DSGS participation options are designed and intended to grow and deliver load reduction capacity that is incremental to resource adequacy and California ISO and CEC forecasts, while avoiding interference with resource adequacy or energy markets.

A. DSGS Program Eligibility

1. Eligible DSGS Providers

Eligible DSGS providers include:

a. Retail suppliers as defined in Public Utilities Code (PUC) Section 398.2.

b. Federal power marketing administrations.

c. Aggregators of customers.

i. Before enrolling customers in the service territory of a publicly owned electric utility (POU), aggregators of customers must notify the POU of their intent to enroll customers within the service territory of the utility by providing the information required in Section A.1.c.ii below and obtaining a written statement from each applicable POU that the POU:

- Does not object to the aggregator enrolling the POU's customers to participate in the DSGS Program.
- Will provide the aggregator the data necessary for the aggregator to administer the DSGS Program, as determined by the POU, subject to the aggregator (1) receiving authorization from participants and (2) entering into a data-sharing agreement with the POU, if required.
- Understands incurred costs associated with the DSGS Program pursuant to Chapter 7, Section B, are reimbursable.

Aggregators must provide the CEC a copy of this statement within five business days of receipt. POUs may establish terms and conditions for aggregators to enroll the POU's customers to participate in the DSGS Program, including protocols for communicating and coordinating with the POU regarding program events and the circumstances under which the POU may grant or revoke the aggregator's ability to enroll the POU's customers in the DSGS Program.

ii. Aggregators of bundled and unbundled customers must notify investor-owned utilities (IOUs) and community choice aggregators (CCAs) in writing of their intent to enroll customers within the service territory of the respective load-serving entity. The notice shall include:

- The aggregator's name.
- The DSGS participation~~incentive~~ option(s) the aggregator will offer to participants.
- A description of the types of customers (such as residential, commercial, industrial, and so forth) and load reduction resources the aggregator plans to enroll in each ~~incentive~~ participation option.

Aggregators must provide the CEC evidence of this notice within five business days of sending to the IOU or CCA.

~~Incentive~~ Participation Options 2, 3, and 4 include additional DSGS provider eligibility requirements described in Chapter 4, Section A, Chapter 5, Section A, and Chapter 6, Section A.

2. Eligible DSGS Participants

a. Eligible participants are:

   i. All customers of POUs.

   ii. All customers of federal power marketing administrations.

   iii. The following customers of CCAs, energy service providers, and electrical corporations:

   - Customers participating with backup generators.
   - Customers participating through ~~incentive~~ participation Option 2, Option 3 or Option 4 described in Chapter 4, Chapter 5, and Chapter 6, respectively.
   - Water agencies, which include water utilities, wastewater facilities, and irrigation districts.

   iv. All customers of tribal utilities.

b. Dual-compensation prohibition: A participant is not eligible to receive ~~incentives~~ compensation if the participant's load-reduction resource with the DSGS provider ~~is~~:

   i. Is ~~E~~enrolled in the Emergency Load Reduction Program or the Base Interruptible Program or the Agricultural Pump Interruptible Program.

   ii. Receiv~~ing~~es payment ~~or accounting~~ or compensation including, but not limited to, incentives, bill savings, bill credits, and other forms of compensation or credits, for the same reduction in use of electricity~~, including~~ or energy export, through any other utility, CCA, or state program, including retail tariffs, except critical peak pricing rate plans.

iii. If a~~A~~ cogeneration facility with a power purchase agreement.[2]

c. Eligibility to participate in both the DSGS Program and other utility, CCA, or state programs will be reevaluated each year and guidance may be updated to ensure participation in the DSGS Program is consistent with the dual-compensation prohibition described above.

d. DSGS providers may include additional eligibility requirements for their participants.

e. Customers must also meet the eligibility requirements specific to the ~~incentive~~ participation option in which they are enrolled, as described in Chapters 3–6.

B. DSGS ~~Incentive~~ Participation Options

The DSGS Program has four ~~incentive~~ participation options, which are described in Chapters 3–6.

i. Option 1: Emergency Dispatch offers energy and standby payments to nonresidential customers that reduce net load during program events triggered based on energy emergency alerts issued by a California balancing authority. Eligible technologies include combustion resources, subject to emergency proclamation, and clean, non-combustion resources.

ii. Option 2: Market-Integrated Demand Response Incremental Capacity Pilot offers a capacity payment based on demonstrated capacity by California Independent System Operator (California ISO) dispatched proxy demand resources that is incremental to existing resource adequacy commitments.

iii. Option 3: Market-Aware Storage Virtual Power Plant (VPP) Pilot offers a capacity payment for behind-the-meter storage VPPs based on demonstrated capacity. Program events are triggered based on day-ahead California ISO energy market prices exceeding a specified price threshold, but the VPP capacity is not actually bid into the energy market. An energy incentive is available for VPPs that respond to a day-of emergency.

iv. Option 4: Emergency Load Flexibility VPP Pilot offers capacity-based compensation for load reduction capacity committed by dispatchable VPPs composed of aggregated smart thermostat-controlled HVAC systems, electric water heaters, electric vehicle supply equipment (EVSE), stationary batteries, and residential "smart electrical panels." Program events are triggered based on energy emergency alerts issued by a California balancing authority.

Participation Option 1 is suspended for the 2026 program year due to budget constraints.

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2 If a participant has a power purchase agreement for a renewable generator at the same site as a cogeneration facility, but not one for the cogeneration facility, this does not make the participant ineligible to participate.

Participants may select a different ~~incentive~~ participation option for each load reduction resource enrolled with their provider, as long as each load-reduction resource has dedicated or distinctly identifiable metering. A load reduction resource cannot be enrolled in more than one ~~incentive~~ participation option. Different load reduction resources located at the same site may participate in different participation options under different providers. DSGS providers may limit which ~~incentive~~ participation options are available to their participants. All load reductions that would not have occurred in the absence of the DSGS Program, including those that result in negative load at the utility meter (that is, exports), are eligible for incentives.

~~Incentive~~ Participation Options 2, 3, and 4 are pilot ~~incentive~~ participation pathways intended to test new program designs. The CEC will prepare a report assessing the performance and cost-effectiveness of these pilots.

POUs outside the California ISO balancing area may develop alternative POU-specific "custom" dispatch requirements and associated performance measurement criteria to those described in Chapters 3–6 if the requirements are suitable to the operations of the applicable balancing authority and contribute to grid reliability within its balancing area. The alternative "custom" proposal may also include a different incentive structure, provided the total incentive rate is not higher than the incentives in Chapters 3–6. The POU "custom" proposal may allow the POU itself, third-party providers, or both to participate as DSGS providers.

POUs outside the California ISO wishing to submit "custom" proposals must submit a description of the proposed incentive structure, dispatch requirements, and performance measurement criteria to the CEC for approval. POUs outside the California ISO may submit a "custom" proposal at any time, but participants may not enroll to participate in the proposed incentive structure unless the CEC has approved the proposal.

C. DSGS Enrollment Process

1. DSGS Provider Enrollment Process

DSGS providers enroll in the program by electronically submitting an application to the CEC.

a. DSGS Provider Application Timing

Applications are accepted on an on-going~~, first-come, first-served~~ basis.

i. The date and time the CEC receives the electronically submitted complete application will establish the order in the queue for review of DSGS provider applications.

ii. The CEC will notify applicants if the application is incomplete. The applicant will have 10 business days to supplement the incomplete application. Failure to respond within the 10 business days will result in the cancellation of the application.

iii. The cancellation of an application does not preclude an applicant from reapplying.

b. DSGS Provider Application Package

Applicants to be DSGS providers must submit to the CEC the following information in a format provided by the CEC:

i. Legal name of the applicant

ii. Applicant's contact name, title, address, email address, and phone number

iii. Description of how applicant will verify which load-reduction resources are used by participants

iv. Description of how the applicant will verify participant eligibility prior to enrollment of participants

v. The DSGS participation~~incentive~~ options the applicant will offer to participants

vi. If offering ~~Incentive~~ Participation Option 1:

- Description of how the applicant will implement the dispatch loading order requirements described in Chapter 3, Section D
- Description of how the applicant will verify actual incremental load reduction amounts, including the DSGS provider's method for determining energy-use baselines and actual energy usage during a DSGS program event
- Indication of which administrative cost structure described in Chapter 7, Section B, the DSGS provider has chosen

vii. If offering ~~Incentive~~ Participation Option 2:

- Description of how the applicant meets the eligibility requirements specific to the ~~incentive~~ participation option and how the applicant plans to implement the program under the ~~incentive~~ participation option, including details on how the applicant will allocate incentives to participants
- California ISO Demand Response Provider ID (DRP ID) and an attestation that the DRP has active proxy demand resources (PDRs)

viii. If offering ~~Incentive~~ Participation Option 3:

- Description of how the applicant meets the eligibility requirements specific to the ~~incentive~~ participation option and the applicant's plans to implement the program under the ~~incentive~~ participation option, including plan to allocate incentives to participants
- Description of the applicant's plans to implement quality control on submetered charge and discharge data, including minimum standards for data completeness and quality

ix. If offering ~~Incentive~~ Participation Option 4:

- Description of how the applicant meets the eligibility requirements specific to the ~~incentive~~ participation option and the applicant's plans to implement the program under the ~~incentive~~ participation option, including plans to allocate incentives to participants

- Description of the applicant's plans to implement quality control on device-level load data or smart thermostat runtime data, including minimum standards for data completeness and quality

x. If the applicant is an aggregator of participants:

- A description of the types of customers (such as residential, commercial, industrial, and so forth) and load-reduction resources the applicant plans to enroll and the utility territories in which the DSGS provider plans to operate

xi. Payee data record (STD-204). If the designated payee has already submitted a complete STD-204 form with a prior reimbursement claim and has received a payment within the past year from the CEC, a new STD-204 is not needed.

xii. Verification in writing of the accuracy and completeness of the information submitted and agreement to the terms and conditions of the DSGS Program guidelines.

c. Application Review and Approval

The CEC will review applications to determine completeness and eligibility. After approving a complete DSGS provider application, the CEC will provide an electronic DSGS Program enrollment letter to the DSGS provider.

d. Withdrawal

A DSGS provider can voluntarily withdraw from the program, subject to applicable conditions specific to the ~~incentive~~ participation option, by notifying the CEC electronically in writing. Voluntary withdrawal from the program does not preclude the DSGS provider from reapplying in the future or from submitting a claim pursuant to Chapter 7 for program participation prior to withdrawal. Withdrawal from the program will result in the removal of all of the DSGS provider's enrolled participants from the program.

2. Participant Enrollment Process

a. How to Enroll

Except as outlined in the following paragraph, eligible participants must enroll to participate in the DSGS Program through a DSGS provider.

An eligible participant may enroll directly with the CEC only to participate under ~~Incentive~~ Participation Option 1 and only if enrollment through the participant's load-serving entity is not possible. For example, if the load-serving entity is not enrolled as a DSGS provider or is not offering DSGS Program participation for that type of customer or load reduction resource. A POU customer participant must obtain a written statement from its POU stating that the POU does not object to the participant enrolling directly in the DSGS Program. The CEC will work with the participant's load-serving entity, as appropriate, to confirm eligibility as soon as practicable.

The required application information for each ~~incentive~~ participation option is described in Chapters 3–6.

b. Withdrawal

A participant can voluntarily withdraw from the program by notifying the DSGS provider or the CEC if directly enrolled in the program. Voluntary withdrawal from the program does not preclude the participant from reapplying in the future or from submitting a claim pursuant to Chapter 7 for program participation prior to withdrawal.

D. DSGS Program Reporting

1. Enrolled Participation Reports

a. Initial Report Due Date

Within 10 business days of the DSGS provider's enrollment, or as soon as practicable, DSGS providers must submit to the CEC an initial report on enrolled participation with the information required in Sections 1.c, 1.d, and 1.e, as applicable.

b. Ongoing Reporting Due Dates

DSGS providers must submit to the CEC updated enrolled participation reports as detailed below. If a site is not included in a participation report, that site may not be included in performance calculations for the period that is covered by that participation report.

- ~~Incentive~~ Participation Option 1: No later than three business days before the first day of the program season (May–October) and within five business days after any changes to participants enrolled or expected load-reduction resources.
- ~~Incentive~~ Participation Option 2, Option 3, and Option 4: No later than three business days before the first day of each month for all enrollments effective the first calendar day of that month.

Only complete participation reports using the most recent report template version will be accepted. Reporting templates are available on the Resources page of the DSGS Program website at https://dsgs.olivineinc.com/resources/.

c. Participation Report for ~~Incentive~~ Participation Option 1

The initial report of the program season must include the following information on each participant enrolled under ~~Incentive~~ Participation Option 1, segmented by host utility and balancing authority, in a format provided by the CEC:

- Legal name of the participant
- Participant contact's name, title, email address, and phone number

- If the participant is enrolling with an aggregator or the CEC: applicable utility distribution company (UDC) and load-serving entity (LSE), customer identification number (such as service account identification number), phone number on file with the load-serving entity, or any other information necessary to verify participant eligibility with the load-serving entity, as appropriate.
- Information on the load-reduction resources the participant will use during a DSGS Program event, including:
  - Types of available resources, including the applicable loading order category (for example, demand response, renewable or zero-emission resource, near-zero-emission resource, biomethane or natural gas resource, or diesel backup generator or other conventional resource, or any combination of the above).
  - Address and customer identification number where the participant will deploy each resource.
  - Expected minimum and maximum load reduction amount (in kilowatts [kW]) for each resource.
  - Whether the resource may require a 202(c) emergency order pursuant to the Federal Power Act to participate in the DSGS Program.
  - If the resource is a backup generator, information on whether the backup generation is portable or stationary, rated horsepower, fuel type used, and federal emissions tier.
  - Notice time and ramp time required to respond to a DSGS event.

d. Participation Report for ~~Incentive~~ Participation Option 2

- California ISO Resource ID(s) for all resources under the aggregator enrolled in DSGS
- Number of end-use customers and customer class, sector, or load type of customers for each Resource ID
- Estimated incremental capacity not shown on any supply plan or other resource adequacy commitment

e. Participation Report for ~~Incentive~~ Participation Option 3

- Information on each participating site, including a unique identification number, partner company (if applicable), nominated duration (hours), customer class, utility service account number (for example, service agreement ID) or service account address or both, UDC, resource type (stationary default, stationary export-only, stationary VNEM, or EVSE), number of ~~batteries~~ inverters installed at each site, nameplate (~~i.e.~~that is, usable) battery system power rating (for nonvehicle behind-the-meter [BTM] storage) or nameplate discharge power rating for electric vehicle supply equipment (EVSE), and nameplate storage energy capacity (for stationary storage devices, in kWh)~~, and estimated full-duration event discharge (kWh)~~.

- ~~Indication~~ Attestation that the DSGS provider or its partner has remote control (for example, via Application Programming Interface (API) access) of each participant battery to dispatch the battery, is not dispatching the battery for a conflicting program, and has no knowledge or awareness that each customer is enrolled or participating in a conflicting program.
- ~~If claiming a baseline of zero (see Chapter 5, Section E): The permission-to-operate date, a field indicating the customer has attested that the relevant resource is not and will not receive Self-Generation Incentive Program (SGIP) funding, and both the service account address and service account number.~~

f. Participation Report for ~~Incentive~~ Participation Option 4

- The UDC service territory and device type for each aggregation participating in the DSGS Program. DSGS providers should submit no more than one entry for each combination of UDC and device type.
- Information on each participating device, including a unique identification number, device type, utility service account number (for example, service agreement ID) or service account address or both, UDC, and connected load estimate. The connected load estimate shall be entered as 2.5 kW for smart thermostats without direct load measurement or the estimated maximum instantaneous power draw of the device otherwise.
- Indication that the DSGS provider has remote control (for example, via API access) of each participant device to dispatch the device, is not dispatching the device for a conflicting program, and has no knowledge or awareness that each participant is enrolled or participating in a conflicting program.
- Indication that each participant device was not enrolled in a resource adequacy program in the 2024~~ or 2025~~–2026 calendar years.

2. Option 2 Dispatch Reports

Option 2 providers must submit to the CEC a monthly report summarizing the total expected energy (MWh) by Resource ID for each day and hour. Dispatch reports are due to the CEC 10 business days after the last day of the month in which dispatches occurred. If no eligible dispatches occured in the previous month, the report should indicate that no dispatches occured in the past month.

3. Option 3 Performance Reports

Within 15 business days after the start of the first month of participation and after the end of each month during the program season (May–October), Option 3 providers must submit to the CEC (a) submeter or inverter data in the specified format for the prior month for all sites participating in their aggregation that month and (b) electric utility meter data in 15-minute intervals for sites also enrolled in a supply-side demand response program and participating in DSGS with an export-only resource. Monthly performance reports are required for the CEC to accept a claim submission and complete settlement.

4. Option 4 Performance Reports

Within 10 business days after a program or test event occurs, Option 4 providers must submit participating device load or run-time data to the CEC in the specified format for all devices active in their aggregation.

5. Reports to the California Air Resources Board on Backup Generation

Within 10 business days after the end of each month in which a DSGS Program event occurred and the backup generator was dispatched, DSGS providers or participants participating in ~~Incentive~~Participation Option 1 shall provide to the CEC and the California Air Resources Board (CARB) the following information regarding backup generation participants used during a DSGS Program event, if any:

- The address or GPS coordinates where such backup generation occurred
- Information on whether the backup generation is portable or stationary
- The engine size, age, rated horsepower, and federal emissions tier for each generator dispatched under the program
- The type and amount of fuel used by each generator dispatched under the program
- The hours of operation on each day with a program event of each generator dispatched under the program

The CEC will not approve requests for incentive payments for backup generation until CARB receives the report associated with that backup generation for each month in which the backup generation participated.

DSGS providers must determine with their participants who is responsible for submitting the reports. Participants enrolled directly with the CEC are responsible for submitting the reports.

CHAPTER 3:
~~Incentive~~ Participation Option 1: Emergency Dispatch (Suspended)

Participation Option 1 is suspended for the 2026 program year due to budget constraints.

A. Participant Eligibility and Enrollment

Residential customers are not eligible to participate in ~~Incentive~~ Participation Option 1. Eligible participants must enroll to participate under ~~Incentive~~ Participation Option 1 by submitting to the DSGS provider, or the CEC if directly enrolling, all information listed in Chapter 2, Section D(1)(c). Additionally, the participant must verify in writing that:

- The participant meets the eligibility requirements of the DSGS Guidelines to the best of their knowledge.
- The participant will allow the CEC access to all documentation to verify compliance with the program.
- The information submitted is accurate and complete.
- The participant agrees to the terms and conditions of the program.

Participants may use behind-the-meter combustion or non-combustion resources. Combustion resources involve oxidizing fuel to produce energy. The fuel can be solid, liquid, or gas. Non-combustion resources eligible under Option 1 are those that can reduce electric load during emergency events without combustion.

Participants must also provide any other information the DSGS provider or CEC deems necessary.

B. Incentives

1. Energy Payment

Participants shall receive an energy payment at a rate of $2 per kWh of verified incremental load reduction provided during an Option 1 event (that is, dispatch period) as outlined in Chapter 3, Section D.

The default process for calculating the verified incremental load reduction achieved during an Option 1 event is as follows:

- Step 1: Calculate the energy baseline (EB) at the service account level. The EB will be calculated on an hourly basis using the average of the preceding similar days.[3] A service account must have at least 10 similar days of interval meter data available to have a valid baseline.
- Step 2: Calculate the day-of adjustment value (DOAV). A DOAV shall not be less than 0.60 or greater than 1.40. The DOAV is a ratio of (a) the average load of the first three hours of the four hours prior to the event to (b) the average load of the same hours from the days selected in accordance with Step 1 above. If either (a) or (b) are negative, the DOAV is 1.0.
- Step 3: Calculate the adjusted energy baseline (AEB). When the EB is greater than zero, a service account AEB for the event is calculated by multiplying the EB by the DOAV. If the EB is less than zero in an hour during the event, the AEB shall be equal to the EB (that is, DOAV treated as 1).
- Step 4: Calculate the incremental load reduction achieved during the event. The incremental load reduction for each hour of the event is the AEB minus the load measured during that hour. If this value is negative, the incremental load reduction in that hour shall be considered zero.

If the participant has a grid-connected device with export capability under the utility's interconnection agreement, the participant may choose to count exported energy, up to their export rating, in the incremental load reduction calculation. In that case, the baseline is modified to account for exported energy during non-event days and count exported energy in the incremental load reduction.

DSGS providers may propose an alternate method of calculating verified incremental load reduction in their application, subject to CEC approval, described in Chapter 2.C.1.

2. Standby Payment

Participants using combustion resources that provide a standby commitment identifying their available combustion capacity shall be eligible for a standby payment of $0.25 per kWh. Subsequent to a notice of a standby event described in Chapter 3, Section F, the participant shall receive the standby payment for each hour or portion thereof in which the combustion resource is not dispatched because:

i) The balancing authority did not issue an energy emergency alert (EEA) at the level at which the participant's resource may dispatch under Chapter 3, Section D.

ii) The Governor did not issue an emergency proclamation authorizing dispatch of backup generators.

iii) Or both i and ii.

3 The 10 nonexcluded weekdays will be selected for weekday events; for weekend and holiday events, the 4 nonexcluded weekend and holiday days will be selected.

The standby payment will be based on the standby commitment. If the actual average load reduction during the dispatch period is less than the standby commitment, the standby payment shall be prorated to reflect the actual average load reduction demonstrated by the resource.

The standby commitment requirements are detailed in Chapter 3, Section F.

3. Reimbursement for Increased Customer Demand Charges

Participants shall also be reimbursed for incremental increases in customer demand charges that result from participation in the program and are incurred during the billing period in which a DSGS Program event occurred, if any.

C. Program Events

To receive payment under ~~Incentive~~ Participation Option 1, participants shall dispatch enrolled resources to reduce electric load during Option 1 events called in response to EEAs issued by a California balancing authority during the following times:

- May 1 through October 31 each year ("program year")
- Seven days a week

EEA levels include, in ascending order of potential for grid emergency or emergency severity:

- EEA Watch.
- EEA 1.
- EEA 2.
- EEA 3.

All participants will be notified of Option 1 events called in response to EEAs issued by either their host balancing authority or the California ISO. Additionally, participants with non-combustion resources will be eligible for Option 1 incentives when dispatching in response to EEAs issued by a neighboring California balancing authority if requested or notified by that balancing authority and authorized to respond by the participant's host POU and balancing authority. If two or more California balancing authorities issue an EEA during the same time frame, participants shall prioritize providing load reduction to the balancing authority area in which the participant is located.

D. Dispatch Loading Order

In alignment with the state's climate and air quality goals, to the maximum extent feasible, the DSGS provider, or participants, shall dispatch load reduction resources for Option 1 events in the following order:

1. Demand response resources, including batteries
2. Renewable and zero-emission resources
3. Near-zero-emission resources
4. Biomethane and natural gas resources
5. Conventional diesel and gas resources

DSGS providers, or the CEC for direct participants, will dispatch participants with backup generators only if authorized under a state of emergency proclamation issued by the Governor. Participation in the program does not waive any air or operation permit requirements.

Participation in the program cannot extend the useful life of a resource in contravention of the state's climate and air quality goals.

E. Dispatch Period

The dispatch period for an Option 1 event shall be determined by the EEA level at which the participating resource may dispatch to reduce electric load and the time frames identified in the EEA notices issued by the applicable balancing authority. Option 1 events always start at the beginning of a complete hourly interval. If the start time identified in the EEA notice is not hour-aligned, the associated event start time is rounded to the nearest hour, with times ending in 30 minutes rounded to the next hour. If the end time identified in the EEA notice is not hour-aligned, the associated event end time is always rounded to the following hour.

Participants may dispatch non-combustion resources during Option 1 events called in response to an EEA or EEA Watch. Participants may dispatch combustion resources in response to an EEA 2 or higher if authorized to dispatch by an executive order issued by the Governor, unless authorized to dispatch at a lower EEA level in an executive order issued by the Governor. Participants that receive a controllable generation incentive described in Chapter 3.B.4 may not dispatch at an EEA level lower than EEA 2, regardless of any executive order. The CEC shall notify DSGS providers and direct participants participating with combustion resources of any change in the EEA level at which combustion resources may be dispatched.

F. Standby and Dispatch Notification Process

When a California balancing authority issues an EEA Watch or an EEA 1, DSGS providers, or the CEC for direct participants, shall notify all participants with non-combustion resources to dispatch during the dispatch period as described in Chapter 3, Section E, and notify all participants with combustion resources of a standby event and to be ready to potentially dispatch if a dispatch event is issued. DSGS providers, or the CEC for direct participants, shall determine from the participants the amount of incremental load reduction that will be available from non-combustion resources and would be available from combustion resources during each hour of the EEA Watch or EEA 1 time frame (standby commitment). Participants are not required to provide a standby commitment. Participants that choose to provide a standby commitment must provide a commitment in response to each standby event. Standby commitments are specific to a single standby event and are not carried over to subsequent standby events.

DSGS providers and direct participants shall report to the CEC the amount of incremental load reduction committed to be available during the DSGS event time frame within one hour or as quickly as feasible after the balancing authority issues the EEA, but before the DSGS event hour to receive a standby payment for that hour. In the case of a sudden onset event, providers and direct participants shall report within one hour, recognizing that the event will have already started.

DSGS providers and direct participants shall provide to the CEC any updates to the standby commitments as soon as practicable.

DSGS providers, or the CEC for direct participants, shall notify participants to dispatch and reduce electric load during a dispatch period, as defined in Chapter 3, Section D.

CHAPTER 4: ~~Incentive~~ Participation Option 2: Market-Integrated Demand Response Incremental Capacity Pilot

A. Demand Response Provider Eligibility

A DSGS provider, or its authorized third party, is considered a demand response (DR) provider when administering ~~Incentive~~ Participation Option 2. Third-party DR aggregators and POUs are eligible to serve as DR providers. DR providers must be operating within the California ISO balancing authority area and must have at least one proxy demand resource (PDR) registered to participate under the incremental market-integrated DR capacity pathway.

B. Participant Enrollment and Eligibility

Eligible participants must be enrolled in a PDR participating in the California ISO energy market and registered to an Option 2 provider. DR providers must collect and retain participant information, which may be reviewed by the CEC in an audit, as described in Chapter ~~7~~8, Section D. Participants are not eligible to participate in Option 2 with battery storage unless the permission-to-operate date is on or before December 31, 2025.

C. Performance-Based Compensation~~Incentives~~

~~Incremental DR~~ Performance-based capacity ~~incentive~~ payments will be made to DR providers based on a PDR's demonstrated capacity in excess of its resource adequacy (RA) capacity commitments, if applicable. For example, if a DR provider has a PDR portfolio RA capacity commitment of 10 MW and demonstrates capacity of 12 MW, the incremental demonstrated capacity is 2 MW. DR providers shall allocate ~~incentive~~ the performance-based capacity payments between the DR provider and its PDR participants pursuant to the terms and conditions agreed upon by the DR provider and the participants. The ~~incremental~~ performance-based capacity ~~incentive~~ payment rates under Option 2 are summarized in Table 1.

Table 1: ~~Incremental~~ Capacity Prices by Month and Availability Requirement ($/MW-month)

Month	Every Day	Non-Holiday Weekdays
May	$9,000	$7,200
June	$9,300	$7,440
July	$16,800	$13,440
August	$18,000	$14,400
September	$19,200	$15,360

October	$10,500	$8,400
Season Total ($/MW)	**$82,800**	**$66,240**

Source: CEC staff

An additional 30 percent bonus shall be applied to the incremental capacity incentives for Program Years 2023, 2024, 2025, and 2026. Additional bonuses in future years may be provided at the CEC's discretion.

Incremental ~~D~~demonstrated ~~incremental~~ capacity shall be calculated and ~~incentive~~ performance-based capacity payments shall be disbursed following the season completion each program year.

In the 2026 program season, $1 million is available for funding Option 2 performance-based capacity payments across all Option 2 participating providers. If additional funding becomes available through the 2026-27 budget process, up to $3 million is available for Option 2. Available Option 2 funds shall be allocated to each participating provider based on the method described in Appendix A. Any funds remaining after the end-of-season allocations may be reallocated to the 2026 funding pool for Option 3.~~After August 31 of each program year, DR providers may request one additional interim calculation of demonstrated incremental capacity and incentive disbursement before the completion of the program year. If requested, the CEC shall calculate the season-to-date incremental capacity value of the aggregator and provide the aggregator the associated incentive payment for the completed months. This interim incentive payment shall be deducted from the total incentive payment made at the end of the season.~~

D. Program Events

Incremental ~~D~~demonstrated capacity (defined in the following section) will be calculated based on resource availability and performance during a defined availability window. A PDR ~~aggregation~~ may participate on non-holiday weekdays only, or all days including weekends and holidays for a higher incentive level (Table 1). To receive ~~incentives~~ payments for incremental capacity demonstrated under Option 2, the PDR must have capacity bid at a price no greater than $600/MWh (or self-scheduled) in the day-ahead market for at least three consecutive hours between 4:00 p.m. and 10:00 p.m. For a PDR with a capacity obligation on a monthly RA showing, the RA availability and bidding rules take precedence over DSGS.[4]

Unlike the must-offer obligation under the RA program, DSGS does not require offering any minimum amount (MW). Instead, the DR provider may determine the appropriate amount to offer; this amount may factor into demonstrated capacity if dispatched. If the DR provider does not bid (or self-schedule) during these hours, a value of zero will be entered into the performance calculation described in the following section.

4 Resource adequacy resources generally have a 24x7 must-offer obligation, unless otherwise specified by the California ISO tariff.

E. Measuring Performance

Under Option 2, incremental demonstrated ~~incremental~~ capacity is calculated using the following method. The CEC shall allow DR providers to measure PDR capacity at the Resource ID or Sub-LAP level. The CEC may grant DR providers the ability to create aggregations of Resource IDs with similar characteristics and in the same Sub-LAP. The unit of analysis for these metrics is an "aggregation," which may consist of a single Resource ID for resource-level analysis or multiple Resource IDs for Sub-LAP or custom aggregations.

1. Calculate Aggregation-Level Input Values

DSGS capacity measurement relies on the data streams listed below, each of which must be aggregated to the hourly level. These data streams and the aggregation required for each include the following:

- **Offer:** The offer value is the real-time bid quantity at a price no greater than $600/MWh plus self-schedules (MW) in the real-time market during each hour. The offer value for aggregation *a* (consisting of *n* Resource IDs *r,* where n≥1) in each interval (date d, hour *h*) is defined as:

$$Offer_{a,d,h} = \sum_{r=1}^{n} RTM\_BID\_QUANTITY_{r,d,h} + RTM\_SELFCHEDMW_{r,d,h}$$

  where RTM_BID_QUANTITY refers to the bid quantity at a price of ≤$600/MWh. Offer values of zero will be excluded from analysis unless the sub-LAP DAM LMP ≥$600, such that resources that have no schedules when the price cap is reached receive an offer value of zero.

- **Demand response energy measurement (DREM):** DREM is the delivered energy value (MWh) determined through California ISO settlement processes. The DREM value for aggregation *a* (consisting of *n* Resource IDs *r,* where n≥1) on day *d* in hour *h* over the twelve 5-minute intervals *i* is defined as:

$$DREM_{a,d,h} = \sum_{r=1}^{n} \sum_{i=1}^{12} DREM_{r,d,h,i}$$

- **Total expected energy (TEE):** TEE is the total amount of energy (MWh) a Resource ID is expected to deliver in the California ISO based on its real-time market schedules. The TEE value for aggregation *a* (consisting of *n* Resource IDs *r,* where n≥1) on date *d* in hour *h* over the twelve 5-minute intervals *i* is defined as:

$$TEE_{a,d,h} = \sum_{r=1}^{n} \sum_{i=1}^{12} EXP\_ENRGY\_QUANTITY_{r,d,h,i}$$

- **Temperature:** Temperature is defined on a daily basis based on the number of participating customers. This temperature metric is the average of daily high (TMax) and low (TMin) averaged across all dispatched customers on a given day. The daily high and low temperatures for a given customer will be taken from the closest weather station to the ZIP code of the customer with available data, such as those identified in the California ISO "NOAA Station to Zip Mapping" file.[5] The temperature ("Temp") value for aggregation *a* (which may consist of one or more Resource IDs within a single sub-LAP) on date *d* is defined as:

$$\mathrm{Temp}_{a,d} = \frac{\sum_{c=1}^{n} \frac{1}{2}\left(\mathrm{TMax}_{c,d} + \mathrm{TMin}_{c,d}\right)}{n}$$

  where *c* is the index for customers dispatched on date *d* and *n* is the number of participating customers.

  Equivalently, this value can be determined from counts of customers by ZIP code *z*:

$$Temp_{a,d} = \frac{\sum_{z=1}^{m} \frac{n_{z,d}}{2}\left(TMax_{z,d} + TMin_{z,d}\right)}{\sum_{z=1}^{m} n_{z,d}}$$

  where *m* is the number of ZIP codes and *n* is the number of dispatched customers in each ZIP code.

2. Individual Settled Load Impacts Are Calculated and Adjusted Relative to Bids

Hourly load impacts determined by California ISO settlement are adjusted relative to the amount offered, and dispatched according to the following definition of bid-normalized load impacts (BNLI) on date *d* and hour *h*:

$$BNLI_{a,d,h} = Max\left(Offer_{a,d,h}\left(\frac{Min\left(DREM_{a,d,h}, TEE_{a,d,h}\right)}{TEE_{a,d,h}}\right), DREM_{a,d,h}\right)$$

where $Offer$, $DREM$, and TEE are the hourly resource or aggregational values as defined above. BNLI will only be calculated if Offer > 0 or if the sub-LAP LMP ≥$600, such that resources that have no schedules when the bid cap is reached receive a

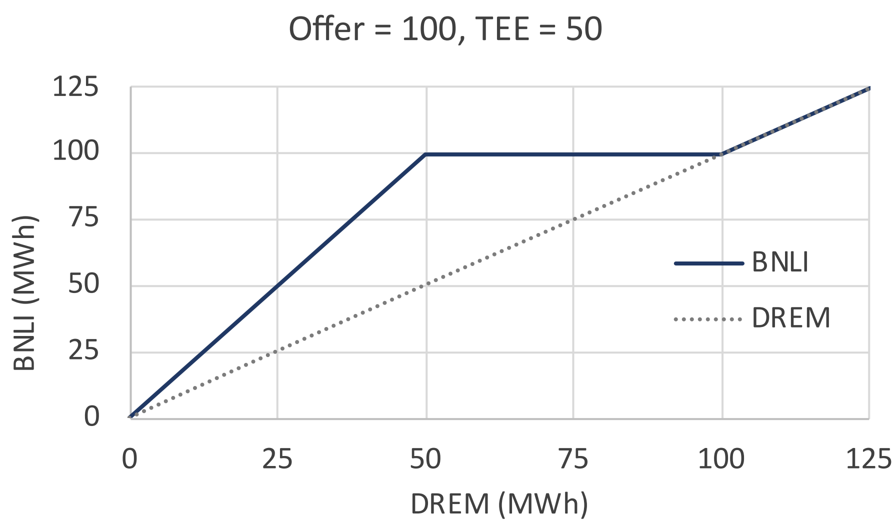
5 California Independent System Operator. December 17, 2019. "NOAA Station to Zip Matching," http://www.caiso.com/Documents/NOAA-Station-to-Zip-Mapping.xlsx.

BNLI value of zero. If TEE < 0.2*Offer in an hour, the event shall also be omitted from the calculation of demonstrated capacity.

Intervals in which a DR resource does not bid in the day-ahead market as required by the RA program or DSGS will be assigned a bid-normalized load-impact value of zero. The hours the resource would have bid under an RA or DSGS obligation will be assumed to be the hours within the availability window with the highest consecutive day-ahead locational marginal price (LMPs).

Figure 1 illustrates bid-normalized load impacts as a function of actual DREM when the offer value is greater than TEE. When TEE is greater than or equal to offer, for example because the resource received a dispatch on bid amounts above $600/MWh, BNLI will always be equal to DREM.

Figure 1: Example BNLI for Offer = 100 MWh and TEE = 50 MWh



Source: CEC staff analysis

3. Load Impact Temperature Models

DR providers may elect to apply a weather-sensitive or non-weather-sensitive demonstrated capacity calculation method for each aggregation in their portfolio. For weather-sensitive aggregations, a weighted least-squares linear regression models bid-normalized load impacts as a function of temperature. For non-weather-sensitive resources, capacity is defined as the mean LMP-weighted bid-normalized load impacts.

For weather-sensitive aggregations, the load impact regression model specification takes the following form:

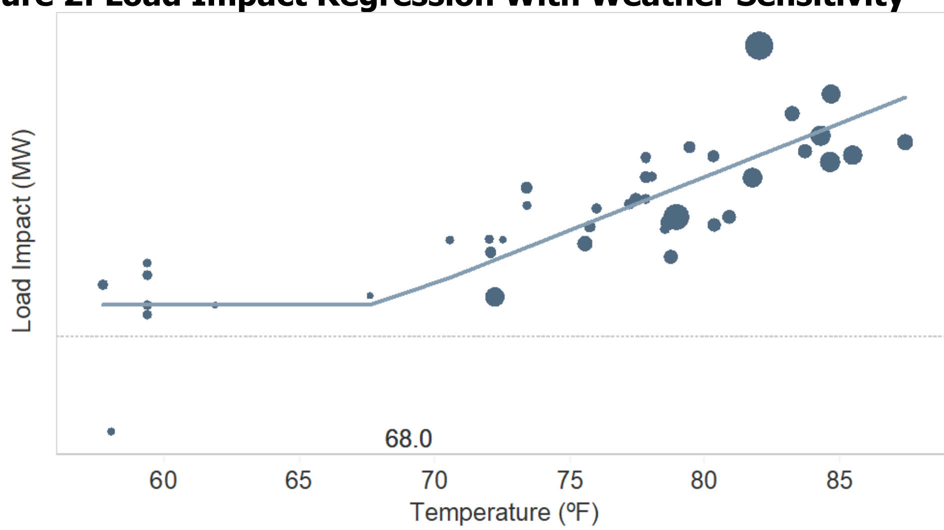
$$\text{BNLI} = a + b^{*}\max(\text{Temp}, C) + e$$

where BNLI is the estimated bid-normalized load impact value (MWh) in each hour, *a* is the model intercept value, *b* is a term reflecting sensitivity to hot weather, Temp is the average of daily high and low temperature (ºF) for a representative sub-LAP weather station, *C* is a change point between regions under which the resource does and does not show weather sensitivity, and *e* is an error term. Change point *C* will be determined by testing values across the range of temperatures in the data in increments of 2ºF and selecting the change point with the highest corresponding R^2 value.

The regression is weighted by day-ahead LMP for the sub-load aggregation point (sub-LAP). Temperature is the average of daily high and low for a representative weather station for each sub-LAP.

Figure 2 shows the load impact regression for a sample resource with a changepoint at 68ºF, with LMP represented by point size.

Figure 2: Load Impact Regression With Weather Sensitivity



Source: CEC staff analysis

For non-weather-sensitive resources, the LMP-weighted mean bid-normalized load impact is calculated according to the following formula:

$$Capacity_a = \frac{sum(BNLI_{a,d,h} LMP_{a,d,h})}{sum(LMP_{a,d,h})}$$

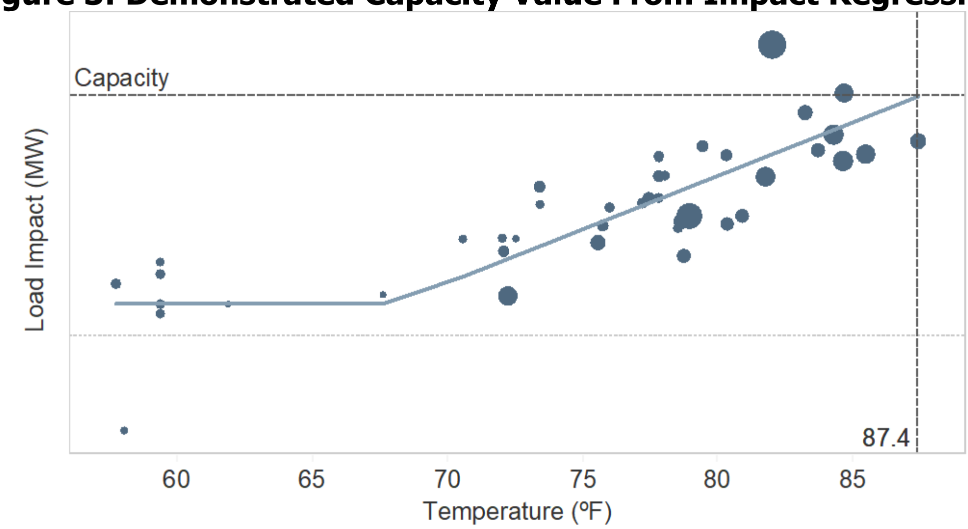
Where $BNLI_{a,d,h}$ is the bid-normalized load impact and $LMP_{a,d,h}$ is the sub-LAP day-ahead LMP for aggregation *a* on date *d* and hour *h.*

DR providers bear the responsibility to develop sufficient dispatches to calculate a demonstrated capacity value through the regression model or weighted average. Each DR aggregation must receive at least one dispatch resulting in a BNLI value per month from July through September and one BNLI value per month on average to be awarded a demonstrated capacity value for the season. In the case of a single dispatch for participation in a single month, the non-weather-sensitive capacity formula shall be applied. Regardless of participation duration, each aggregation must receive at least one dispatch resulting in three consecutive BNLI values. The three-hour minimum dispatch requirement is waived for participation in 2024.

4. Determine Demonstrated Capacity From Load-Impact Models

For weather-sensitive resources, the seasonal demonstrated capacity is defined as the value of the regression model at the maximum temperature (as previously defined) for which the resource had a dispatch event during the program year. Figure 3 illustrates the demonstrated capacity derived from the highest dispatch event temperature of 87.4ºF.

Figure 3: Demonstrated Capacity Value From Impact Regression



Source: CEC staff analysis

For non-weather-sensitive resources, demonstrated capacity is calculated directly in the previous step.

5. Calculate Incremental Demonstrated Capacity Relative to Resource Adequacy Obligation

Sum a DR provider's capacity obligations included in month-ahead RA showings across all California ISO LSEs by month. The month with the highest total RA capacity showing is considered the reference RA obligation. Sum all resource-level demonstrated capacity values from above and subtract the reference RA obligation. Any positive difference is the incremental demonstrated capacity.

Payment to each DR provider shall be made for this incremental capacity for all program months the provider participated in at the rates enumerated in Table 1.

F. Data Requirements

By participating in Option 2, DR providers authorize the California ISO to transmit resource-level data required to calculate demonstrated capacity to the CEC. These data streams include:

- **Real-time market bids and self-schedules** (in MWh) by Resource ID.
- **Total expected energy** (TEE, in MWh) by Resource ID.
- **Demand response energy measurement** (DREM, in MWh) by Resource ID.

CHAPTER 5: ~~Incentive~~ Participation Option 3: Market-Aware Storage Virtual Power Plant Pilot

A. Aggregator and Participant Eligibility

A DSGS provider, or its authorized third party, is considered a storage virtual power plant (VPP) aggregator when administering ~~Incentive~~ Participation Option 3. Third-party battery providers, including third-party vehicle-to-load or grid (V2X) service providers, POUs, and CCAs, are eligible to serve as storage VPP aggregators. POUs and CCAs may serve only customers for which they serve as the LSE or retail provider.

A VPP shall consist of behind-the-meter (BTM) battery storage, which may include stand-alone batteries and batteries paired with solar systems or battery-electric vehicles (EVs) with bidirectional charging capability. A VPP may include residential (bundled or unbundled), nonresidential (bundled or unbundled) customers, or both.

To be eligible to serve as a storage VPP aggregator of ~~Incentive~~ Participation Option 3, the storage VPP aggregator must:

1. Receive authorization from participants allowing for the use of their device for DSGS Program participation.
2. Send dispatch signals to or directly control individual batteries.
3. Collect and provide hourly or sub-hourly charge/discharge interval data from a battery inverter or submeter to the CEC.
4. Comply with the participants' utility interconnection agreements (for example, a Rule 21 tariff). Dispatch in violation of an interconnection agreement is not eligible for ~~incentive~~ performance-based capacity payments.
5. Aggregate a total minimum nameplate power rating of 300 KW per aggregation for stationary storage assets and a total minimum nameplate power rating of 50 KW per aggregation for EVSEs~~either (a) a total minimum nameplate power rating of 400 kW across all utility service territories and resource durations, (b) at least one aggregation with a total minimum nameplate power rating of 200 kW, or (c) at least three aggregations with a total minimum nameplate power rating of 100 kW each~~. For stationary storage assets, the total nameplate power rating is determined by summing the nameplate continuous power rating (kW) from the specification sheets of the individual storage devices comprising the aggregation. For aggregations of EVs, the total nameplate power rating is determined by summing the discharge power rating (kW) from the specification sheets of the EVSE used by individual vehicle operators.

At a minimum, each customer site participating in a market-aware storage VPP must:

1. Have an operational stationary battery system or an EV with bidirectional EVSE capable of discharging at least 1 kW for at least two hours during a program event.
2. Provide no more than 2,000 kW discharge during any hour of a program event.[6]
3. Have permission from the host utility to operate the battery system or bidirectional EVSE ~~from the host utility~~ in parallel to the utility's grid (for example, under a Rule 21 tariff) and operate in a manner compliant with existing rules and tariffs applicable to the site. The permission-to-operate date must be on or before December 31, 2025. UL 1741-SB listing of bidirectional chargers is not required for participation in a DSGS VPP.
4. Not be participating in a California ISO proxy demand resource (PDR) or reliability demand response resource (RDRR) unless either:
    a. The participant's customer energy baseline reflects total gross consumption (that is, consumption independent of any energy produced or consumed by behind-the-meter battery storage) consistent with California ISO tariff Section 4.13.4, or
    b. The participant is enrolled in DSGS with a stationary export-only ~~DSGS~~ resource, as described in Section E.

If a participant is identified as participating in a conflicting program, the participant's DSGS provider will be notified, and the participant shall be suspended from participation indefinitely until the conflict is resolved.

A DSGS provider serving as a storage VPP aggregator for more than one partner company may consider each partner company's battery aggregation to be separate and distinct VPPs that will be measured and compensated independently. In this case, the storage VPP aggregator must submit separate entries for each partner's aggregation and identify the partner for each participating site in the enrolled participation report. Each partner must be able to meet all other aggregator requirements, such as the minimum aggregate nameplate power.

At a minimum, to participate under Option 3 as a storage VPP, each aggregation must:

- Consist of customer sites located within the same UDC service territory and, if applicable, associated with the same partner company and same customer class.
- Consist of storage assets of the same device type (stationary storage or EVSE).
- Consist of storage assets nominated for the same duration (number of hours, see following section for details).

B. Participant Enrollment

Storage VPP aggregators must collect and maintain the following information to enroll eligible participants under ~~Incentive~~ Participation Option 3:

6 A customer site may participate with a stationary battery system capable of discharging greater than or equal to 2,000 kW but only incremental discharge up to 2,000 kW during a given event hour shall be counted toward performance.

- Legal name of the participant or name on the utility bill at the participating site
- If contact name is different from above, primary contact's name and, if available, title
- Email address and phone number of participant or primary contact
- Service account address, service account or agreement identification number (SAID), or both
- Service account UDC
- Indication of whether the service account is non-residential or residential.
- Indication of whether the participating resource type is stationary default, stationary export-only, stationary VNEM, or bi-directional EVSE
- Authorization from the participant allowing for the use of their device charge and discharge data for purposes of program participation
- Acknowledgement and agreement from the participant that:
  - The participant meets the eligibility requirements of the DSGS Guidelines and is not enrolled or participating in a conflicting program to the best of their knowledge.
  - The participant will allow the CEC access to all documentation to verify compliance with the program and program performance.
  - The information submitted is accurate and complete.
  - The participant agrees to the terms and conditions of the program.
- ~~If claiming a baseline of zero (Chapter 5., Section E):~~
  - ~~Permission to operate date~~
  - ~~Indication the participant has not received and will not apply for SGIP incentives~~
  - ~~Both service account address and SAID~~
- Any other information the storage VPP aggregator deems necessary

Participant enrollment information may be reviewed by the CEC in an audit as described in Chapter 8, Section D.

C. ~~Incentives~~Performance-Based Compensation

~~Incentive~~ Performance-based capacity payments shall be made to storage VPP aggregators based on the demonstrated capacity of a VPP during market-aware VPP events as calculated in Section E, below. Storage VPP aggregators shall allocate ~~incentive~~ the payments between the storage VPP aggregator and ~~its~~ their customer participants pursuant to the terms and conditions agreed to between the storage VPP aggregator and participant.

Different levels of ~~incentives~~ capacity prices for demonstrated capacity (kW) are available for VPPs of varying durations (hours). Storage VPP aggregators shall be eligible for a payment for demonstrated capacity of a VPP at the rates defined in Table 2 based on the capacity (kW) and discharge duration (hours) demonstrated by the storage VPP ~~aggregator~~ aggregation in each month.

Table 2: Storage VPP Capacity Prices ($/kW-month)

Month	4-Hour	3-Hour	2-Hour
May	$9.00	$8.10	$6.75
June	$9.30	$8.37	$6.98
July	$16.80	$15.12	$12.60
August	$18.00	$16.20	$13.50
September	$19.20	$17.28	$14.40
October	$10.50	$9.45	$7.88
Annual Total ($/kW)	**$82.80**	**$74.52**	**$62.10**

Source: CEC staff analysis

An additional 30 percent bonus shall be applied to all capacity ~~incentives~~ prices for Program Years 2025 and 2026. Additional bonuses in future years may be provided at the CEC's discretion.

In the 2026 program season, $21.05 million is available to fund Option 3 performance-based capacity payments. If additional funding becomes available through the 2026-2027 budget process, up to $42.7 million is available for Option 3. The available Option 3 fund will be subdivided into separate funding set asides for residential and non-residential customer class aggregations based on the ratio of the total compensation for each class in October 2025 (as determined in the Option 3 Compensation Allocation Method described in Appendix A). Participation in 2026 season is limited to storage VPP aggregators that participated in October 2025.

With the available funds for each customer class, the maximum performance-based capacity payment to each eligible participating storage VPP aggregator (with aggregations associated with that customer class) for the 2026 season shall be determined as described in Option 3 Compensation Allocation Method in Appendix A.

D. Program Events

Option 3 program events may occur only during the following times:

- **Daily availability:** Starting no earlier than 4:00 p.m. and ending no later than 9:00 p.m.
- **Weekly availability:** Seven days a week.
- **Maximum events:** 60 day-ahead event~~s~~ hours per program year (May–October), ~~including~~ plus ~~up to one~~ monthly test events as applicable ~~per month~~ in the absence of ~~a~~ suitable full-duration events. Participation in more than ~~35 events~~60 day-ahead event hours is optional but may be used to increase demonstrated capacity. If the day-ahead events called in a month bring the total for a given ~~resource~~ aggregation to more than ~~35 events~~60 event hours for that program year, the event~~s~~ hours in the

month with the highest performance shall be included in the ~~35-event~~60 event hour maximum and used to determine the aggregation's demonstrated capacity in that month.

- **Minimum events:** One full duration event per month is required for all participating aggregations. Storage VPP aggregations that have reached the maximum event~~s~~ hours per season must still participate in at least one full-~~resource~~ duration event in each month. In the absence of a full-duration DSGS Program non-test event, a full duration ~~test~~ event must be ~~called~~ enabled by the storage VPP aggregator (see Test Events below). This requirement supersedes the maximum event hours threshold.
- **Exceptions:** An event hour may be discarded from the performance calculation at the discretion of the storage VPP aggregator if customers representing 10 percent or more of the nameplate power rating of the aggregation lose power on an event day before or during the event.
- **Day-Ahead Events**: A day-ahead storage VPP event is triggered within the hours that meet either of two criteria within program hours. These criteria are:
  - **A. Absolute Price Trigger:** The hourly locational marginal price (LMP)~~LMP~~ must be greater than or equal to $200/MWh.

    Option 3 VPP events will only be called for consecutive hours. If multiple hours within the program window meet the ~~absolute price trigger~~Absolute Price Trigger but are not consecutive, the hour, or hours, in between shall also be considered to meet this criterion.
  - **B. Day-Ahead Emergency Trigger:** If an EEA Watch or above is called for the following day by the host BA, the emergency trigger shall take effect beginning at 4:00 p.m. and lasting until 9:00 p.m.

  If no hours within the program window meet either criterion, no day-ahead event shall be called.

  For all ~~resources~~aggregations, hourly price is defined as the California ISO day-ahead hourly ~~locational marginal price (LMP)~~LMP for the default load aggregation point (DLAP) of the ~~VPP's~~ aggregations' host UDC, or the trading hub of the host UDC if a DLAP is not available.[7]

  ~~If no hours within the program window meet either criterion, no day-ahead event shall be called.~~

  A~~n~~ program event may last from one hour to the maximum discharge~~resource~~ duration of a VPP aggregation. If the number of hours ~~where the day-ahead LMP ≥$200/MWh~~ meeting the Absolute Price Trigger exceeds the nominated capacity duration, only those consecutive hours with the highest mean ~~LMP~~ hourly price shall be considered event hours. If the highest mean consecutive hourly price applies to

7 The UDCs and corresponding aggregate pricing node IDs are Pacific Gas and Electric ("DLAP_PGAE-APND"), Southern California Edison ("DLAP_SCE-APND"), San Diego Gas & Electric ("DLAP_SDGE-APND"), and the POUs of Anaheim, Azusa, Banning, Pasadena, Riverside, and Vernon (SP15, "TH_SP15_GEN-APND").

more than one set of hours (that is, if there is a tie), the event will be the first (that is, earliest) set of hours meeting these conditions.

For example, if an event is price triggered~~ by price~~, the performance of a 3-hour VPP ~~resource~~ aggregation will be measured over the three highest-priced consecutive hours that meet ~~or exceed $200/MWh~~ the Absolute Price Trigger during the 4:00 p.m.–9:00 p.m. program window. If more than three hours meet or exceed ~~$200/MWh~~the Absolute Price Trigger during this window on a given day, only the three highest-priced consecutive hours will count toward performance. If fewer than three hours meet ~~or exceed $200/Mwh~~the Absolute Price Trigger, only those hours will count toward performance.

- **Test Events:** In the absence of a full-duration~~,~~ day-ahead storage VPP event during a participation month, a storage VPP aggregator must define a full-duration test event per aggregation to substantiate its demonstrated capacity value. The test hours must occur during hours with the highest consecutive hourly ~~LMPs~~ price within the program hours and last for the duration of the capacity commitment. VPP aggregators must notify the CEC of planned test events no later than 3:00 p.m. on the day preceding the planned test event. The storage VPP aggregator must provide the CEC with the hours of the planned test event, the UDC service territory, and nominated duration of the storage VPP(s) that will participate in the test event.

  To mitigate potential system impacts, the CEC, in consultation with the California ISO, may require storage VPP aggregators with large aggregations to conduct test events for the PG&E UDC service territory and the Southern California UDC service territories (SCE and SDG&E) on different days.

  Test events may coincide with a shorter duration price-triggered storage VPP event. If all storage VPP events called during a month are shorter than the ~~resource~~ discharge duration of a VPP aggregation, a provider may extend an event with test hours to reach the ~~VPP's~~ aggregation's full ~~resource~~ discharge duration. In this case, both day-ahead event hours and test hours will be used in the capacity calculation.

  A storage VPP aggregator may conduct multiple test events ~~per~~ in a month (except in August) per aggregation, but only the most recent test event will be used in the calculation of demonstrated capacity for that month. ~~Test events included in the demonstrated capacity calculation count toward the maximum number of events.~~

  In August, in the absence of three consecutive full duration day-ahead events, the storage VPP aggregator must call a full-duration test event on three consecutive days, subject to other requirements described above. The storage VPP aggregator must notify the CEC of the planned three-day testing no later than 3:00 p.m. on the day preceding the first day of the three-day test. The three-day test cannot be repeated. Performance results of all test events, along with any day-ahead events, will be counted in August's demonstrated capacity calculation.

- **Day-of Events:** If an EEA Watch or above is issued for the same day by the host BA, the emergency trigger shall take effect at the later of the notice issued time rounded to the nearest hour, the notice start time rounded to the nearest hour, and 4:00 p.m., and last no later than 9:00 p.m. Day-of event triggers shall not change day-ahead event hours. If a day-of Event is called following a partial-duration day-ahead event, the day-of event hours must be consecutive with the day-ahead event hours. Subject to this constraint, only the consecutive hours of the ~~resource~~ discharge duration with the highest mean LMP shall be considered event hours, with ties in LMP going to the earlier set of hours. Following the issuance of the first (earliest) day-of EEA Watch or above, the issuance of any subsequent day-of EEAs on the same day shall not supersede or change the day-of event hours.

Day-of event hours shall not be included in the demonstrated capacity calculation described in Section E.4 below and the VPPs dispatching during the event will be compensated at a rate of $1 per kWh of net discharge. Day-ahead event hours, including test event hours, are not considered day-of event hours.

E. Measuring Performance

1. Hourly Discharge

Except as provided below, hourly ~~battery~~ discharge shall be measured at the submeter~~,~~ or inverter associated with the participating battery~~,~~ or EVSE, regardless of whether the energy serves BTM load or is exported to the grid.

Hourly Discharge for an aggregation *a* is the total discharge across all resources *r* in the aggregation, during hour *h* of day *d:*

$$Discharge_{a,d,h} = \text{sum}(Discharge_{r,d,h})$$

Any charging of the battery system is considered the negative of discharge in the calculation.

If the participant is also enrolled in a supply-side DR program and participating in DSGS with a stationary export-only resource, then only the discharge exported to the distribution grid shall be attributable to the DSGS program using the following formula:

$$Discharge_{r,h} = |\min(load_{r,h}, 0)|$$

Where $load_{r,h}$ is the hourly load (kWh) from the electric utility meter at the customer site with the resource *r* in hour *h*. That is, for DR-enrolled customers, discharge is the absolute value of any negative load during a DSGS event hour.

2. ~~Prescriptive Baseline~~Net Discharge

For Option 3 events, hourly Net Discharge (*NetDischarge*) of an aggregation in each event hour shall be determined by subtracting the aggregation's hourly Discharge

(*Discharge*) from the applicable hourly Measured Baseline (*MBaseline*) as defined in Section E.3 below:

$$NetDischarge_{a,h} = Discharge_{a,h} - MBaseline_{a,h}$$

The formula for *NetDischarge* is the same for both day-ahead and day-of events.

~~For default and VNEM stationary battery resources receiving self-generation incentive program (SGIP) funding or with a host utility permission-to-operate date before July 1, 2023, an hourly prescriptive baseline shall be applied to battery discharge:~~

1. ~~**Residential (including all VNEM):** 0.074*NCapacity*kWh~~ $\cancel{0.074 NCapacity_{kWh}}$
2. ~~**Nonresidential:**~~ $\cancel{0.028 NCapacity_{kWh}}$

~~Where~~ $\cancel{NCapacity_{kWh}}$ ~~is the nameplate energy storage capacity (kWh) of the battery as defined on the specification sheet for the battery. The resulting baseline value is in kWh per hour.~~

~~For all other batteries, including EVs and stationary export-only, the baseline is defined as zero kWh per hour.~~

~~Beginning in the 2026 program season, baselines shall be applied to all resources participating in DSGS Option 3. For the 2026 season and every two years thereafter, the CEC may update the baselines, as appropriate, to accurately reflect the incrementality of DSGS storage VPP's contribution relative to load forecasts based on CEC's analysis of the VPP performance and other relevant considerations.~~

3. ~~Net Discharge~~Measured Baseline

~~Net discharge for an aggregation is equal to discharge minus the baseline in each event hour, which may be zero for resources meeting the criteria listed above. Net discharge (kWh) in hour *h* is calculated as the difference between the battery discharge and baseline values across all resources *r*.~~

$$\cancel{NetDischarge_{h} = \text{sum}(Discharge_{r,h} - Baseline_{r,h})}$$

~~Any charging of the battery system is considered the negative of discharge in the calculation. The formula for net discharge is the same for both day-ahead and day-of events.~~

The Measured Baseline (*MBaseline*) will be established per a 10-in-10 (weekday) or 5-in-5 (weekend/holiday) day-matching non-event-day baseline.

The process for calculating the Measured Baseline for aggregation *a* in hour *h* is as follows:

- Step 1: For event *e* of aggregation *a,* identify the *m* preceding eligible baseline days, where *m* is 10 for a weekday non-holiday event and 5 for a weekend/holiday event. A day is eligible for baseline selection if all the following conditions are met:

- It is a similar day type to the event day (either weekday non-holiday or weekend/holiday)
- There was no Option 3 event of any kind for that aggregation on the day
- The day is no more than 30 calendar days before the event date

- Step 2: Out of the *m* eligible baseline days, select the *n* days with the highest hourly Discharge for the aggregation *a* during hour *h*, where *n* is 10 for a weekday non-holiday event and 5 for a weekend/holiday event. These are the *n* baseline days to be used in the next step.
- Step 3: For each event hour *h* of event *e*, calculate the average hourly *Discharge* across the *n* selected baseline days (*d*) for aggregation *a* to determine the hourly *MBaseline*:

$$MBaseline_{a,e,h} = \text{sum}(Discharge_{a,d,h})/n$$

Additional notes related to baseline determination:

1. There is no day-of adjustment applied to the baseline.
2. Submeter data is required for all participating resources for the months of their participation *and the month immediately preceding* a resource's first participation month.
3. CEC staff may audit the integrity of an aggregation's baseline by comparing the *MBaseline* computed in Step 3 above for an event in a given month with alternative *MBaseline* computed for other similar *n* days in the month. If the alternative *MBaseline* exceeds the Step 3 *MBaseline* by 10% or more, the aggregation will be excluded from receiving compensation in that month.
4. An aggregator could 1) switch to using an alternate shorter baseline, 5-in-10 (weekday) and 3-in-5 (weekend/holiday), and 2) avoid the CEC baseline audit, by electing to have CEC call the test events for their aggregations. The election must be made prior to the start of the program season, and the election cannot be changed during the season.
5. For EVSE resources, the Measured Baseline is defined as zero kWh per hour.

4. Demonstrated Capacity

Demonstrated capacity for an aggregation *a* in a participation month *m* ($DCapacity_{\cancel{m}a,m}$) shall be defined as the weighted average ~~net~~ of hourly Net ~~D~~Ddischarge ~~(kWh) per~~ across all event hours in the month, where the weights are given by the relevant hourly price (*LMP*) across all day-ahead storage VPP event hours (including test event hours, where ~~appropriate~~applicable), as summarized below:

$$DCapacity_{a,m} = \text{sum}(NetDischarge_{a,m,h} * LMP_h)/\text{sum}(LMP_h)$$

Where LMP_h is the day-ahead LMP in hour *h.*

Any ~~VPP~~ aggregation that shows a demonstrated capacity at or below zero in a month will not be eligible for compensation for that month.

CHAPTER 6: ~~Incentive~~Participation Option 4: Emergency Load Flexibility Virtual Power Plant Pilot

A. Aggregator and Participant Eligibility

A DSGS provider, or its authorized third party, is considered a load flexibility virtual power plant (VPP) aggregator when administering ~~Incentive~~Participation Option 4. Third-party load flexibility providers, POUs, and CCAs are eligible to serve as load flexibility VPP aggregators. POUs and CCAs may serve only customers for which they serve as the LSE or retail provider.

A load flexibility VPP shall consist of eligible dispatchable equipment types listed below:

- Weather-sensitive resources:
  - smart thermostats with runtime monitoring capability controlling air conditioning units, including heat pumps, without load monitoring capability, or
  - smart thermostat with load monitoring capability ~~-~~controlling~~ed~~ air conditioning units, including heat pumps, ~~with load monitoring capability~~.~~,~~
- Non-weather-sensitive resources:
  - heat pump water heaters,
  - electric resistance water heaters,
  - electric vehicle supply equipment (EVSE),
  - stationary BTM batteries with a permission-to-operate date on or before December 31, 2025, or
  - residential smart electrical panels (also known as circuit breaker box or service panel).

VPP aggregators may submit proposals to the CEC for approval to qualify other load flexibility dispatchable resources as eligible for participation in Option 4. Proposals must include a description of 1) the resource, 2) how the resource will be dispatched to provide load reduction incremental to resource adequacy during a program event, 3) how the device load will be monitored, 4) how the committed capacity nominations will be determined, and 5) barriers impeding the proposed aggregation from participating in other existing programs (such as time-of-use and resource adequacy qualified demand response) for encouraging load reduction.

A load flexibility VPP may include dispatchable devices located at residential (bundled or unbundled), nonresidential (bundled or unbundled) customer sites, or both.

To be eligible to serve as a load flexibility VPP aggregator of ~~Incentive~~Participation Option 4, the load flexibility VPP aggregator must:

1. Receive authorization from participants allowing for the use of their device for program participation.
2. Send dispatch signals to or directly control individual devices participating in the load flexibility VPP.
3. Collect and provide 15-minute or 5-minute load data from a smart thermostat-controlled HVAC system, or other eligible device, to the CEC. If HVAC load data is unavailable, then the HVAC runtime data from a smart thermostat can be provided as an alternative.
4. Aggregate ~~at~~ a minimum of 100 kW of load reduction per aggregation (50 kW for EVSEs).~~:~~
    - ~~200 kW across all aggregations, or~~
    - ~~100 kW in at least one single aggregation, or~~
    - ~~50 kW in at least 3 aggregations~~

At a minimum, each participating site in a load flexibility VPP must:

- Have an operational ~~HVAC system, electric water heater, EVSE, stationary battery, or smart electrical panel~~eligible equipment device capable of reducing net load in response to a dispatch signal by the VPP aggregator by changing device operational mode, temperature setpoint, or other method. Device operational changes through behavioral actions are not eligible.
- Not be participating in a California ISO PDR or RDRR~~,~~ or registered in the California ISO DRRS.
- Not be a distribution service customer of Pacific Gas and Electric Company (PG&E).

If a participant is identified as participating in a conflicting program, the participant's DSGS provider will be notified, and the participant shall be suspended from participation indefinitely until the conflict is resolved.

Each load flexibility aggregation must consist of a single device technology type and customer sites located within the same UDC service territory.

B. Participant Enrollment

Load flexibility VPP aggregators must collect and maintain the following information to enroll eligible participants and their devices under ~~Incentive~~ Participation Option 4:

- Name of the participant
- Address at which the device is installed
- UDC for the above address
- Eligible equipment type for the device~~Indication of whether the device is a smart thermostat, air conditioning unit (or heat pump), electric resistance water heater, heat pump water heater, EVSE, stationary battery, or smart electrical panel~~

- Authorization from the participant allowing for the use of their device load or runtime data for purposes of program participation
- Acknowledgement and agreement from the participant that the information submitted is accurate and complete.
- Any other information the load flexibility VPP aggregator deems necessary

Participant enrollment information may be reviewed by the CEC in an audit as in Chapter 8, Section D.

C. ~~Incentives~~ Performance-Based Compensation

Load flexibility performance-based monthly capacity ~~incentive~~ payments will be made to load flexibility VPP aggregators based on the performance of each aggregation relative to its monthly committed capacity nomination (see Committed Capacity Nomination below). The monthly ~~incentive rates~~capacity prices ~~for~~ applicable to the payments for the monthly demonstrated capacity (performance) achieved by load flexibility ~~VPPs~~ aggregations are summarized in Table 3.

Table 3: Load Flexibility VPP ~~Demonstrated~~ Capacity Prices ~~Incentive Rates by Month~~

Month	$/kW-month
May	$5.86
June	$7.10
July	$9.79
August	$13.42
September	$15.41
October	$9.00
Season Total	**$60.58 / kW-yr**

Source: CEC staff

Load flexibility VPP aggregators shall allocate ~~incentive~~ the performance payments between the aggregator and its participants pursuant to the terms and conditions agreed to between the aggregator and participant.

The final ~~incentive~~ monthly performance payment of the season shall be adjusted relative to the total ~~incentive~~ compensation associated with the ~~minimum~~ committed capacity nomination based on VPP performance during program events (see Section E.3).

D. Committed Capacity Nomination

Monthly committed capacity nominations are composed of two parts: (1) per-device average load reduction commitment and (2) device enrollment. Per device load reduction commitments are submitted for each program season, and device enrollments are submitted and updated monthly.

No later than three business days before the first month of program participation in a UDC, each load flexibility VPP aggregator shall submit per-device average load reduction commitment nomination for each month. For a weather-sensitive ~~resource~~ aggregation~~s~~, this nomination estimate shall reflect the weather-normalized load reduction capability, or per device average load reduction capability at the planning temperature *TPlan* for the applicable UDC service territory, as defined in Section F.2 (Performance Evaluation).

No later than three business days ahead of the first day of each participation month, a load flexibility VPP aggregator shall submit the number of devices enrolled for each ~~VPP~~ aggregation. The total committed capacity nomination for that month is the product of the nominated per-device average load reduction commitment and monthly device enrollment. The nominated committed capacity ~~incentive~~ compensation is the product of the total committed capacity nomination and the ~~incentive amount~~ applicable capacity price for that month. The CEC shall set aside funds for each load flexibility VPP aggregator in an amount equal to 120 percent of the nominated committed capacity ~~incentive~~compensation.

For the 2026 program season, Option 4 total committed capacity is limited to 75 MW (MaxCC) of committed capacity each month across all participating aggregators. If additional funding becomes available through the 2026-2027 budget process, the Option 4 MaxCC of committed capacity each month in the second quarter of the season will increase to 100 MW. In case the total nominated committed capacity in a month exceeds MaxCC, the CEC will allocate the available capacity to the participating providers as described in Appendix A. Any funds remaining after the end of season compensation payout may be reallocated to the 2026 funding pool for Option 3.

E. Program Events

Option 4 load flexibility VPP events may occur only during the following times:

- **Daily availability:** Starting no earlier than 4:00 p.m. and ending no later than 10:00 p.m.
- **Weekly availability:** Seven days a week.
- ~~**Minimum response time:** 20 minutes.~~
- **Maximum events:** Option 4 events are capped at cumulative 60 hours per program season (May–October). Participation in events beyond 60 hours is optional but may be used to increase demonstrated capacity. If the events called in a month bring~~s~~ the total for a given ~~resource~~ aggregation to more than 60 hours for ~~that~~ the program year, the event hours with the highest performance shall be included in the 60-hour maximum and used to determine the aggregation's demonstrated capacity for that month.

  Option 4 events are capped at 3 events in any 7-day period. If an event ~~is triggered~~occurs in excess of this limit, the event will be excluded from calculation of the Performance-Adjusted Capacity Payment in Section F.3, but providers shall be eligible for energy payments for that event at the rate of $1/kWh of load reduction during core hours and $0.50/kWh during shoulder hours (see "Event Trigger" below).

- **Minimum events:** ~~Two events per program season are required for participating load flexibility VPPs, with o~~One event per program quarter is required for participating load flexibility VPPs (aggregations), where the months of May through July constitute the first program quarter and the months of August through October constitute the second program quarter. A load flexibility aggregator must begin initial participation by May 1 to participate in the first program quarter and by August 1 to participate in the second program quarter.
- **Event trigger:** A load flexibility VPP event shall occur on each day for which the host BA issues an EEA or EEA Watch ("EEA Watch+" or "emergency trigger"), subject to the maximum event limit (above).
- **Test events:** In the absence of a load flexibility VPP ~~EEA Watch+~~emergency-triggered event in each of the 3-month ~~periods~~ program quarters defined above, the VPP must respond to ~~at~~ a CEC-~~-~~initiated test event per ~~period~~ quarter to meet the minimum event requirement. The test hours shall be consistent with the event hour selection criteria defined below. The CEC shall make reasonable efforts to align test events with high-need days in coordination with the California ISO and to avoid test events if an emergency-triggered event is likely. However, it is possible that an emergency-triggered event may occur later in a month in which a CEC-initiated test event has already occurred. In this case, the VPP's performance in both events will be counted in determining the ~~overall~~ VPP's performance in that month.
- **Event hour selection:** Load flexibility VPP events shall consist of up to two hours of "core" event hours and up to two hours of "shoulder" event hours, in 15-minute increments.

  In general, the core intervals target the "peak price hours," defined as the two consecutive hours in the daily availability window with the highest mean ~~energy~~ hourly price. For all ~~resources~~aggregations, ~~energy~~ hourly price refers to the California ISO day-ahead energy market hourly LMP for the default load aggregation point (DLAP) of the host UDC, or the trading hub of the host UDC if a DLAP is not available.[8] If the highest mean ~~consecutive~~ hourly price applies to more than one set of consecutive hours (that is, if there is a tie), the core hours shall begin with the earliest set of consecutive hours ~~meeting these conditions~~with the highest mean hourly price.

  The shoulder intervals target~~s~~ the hour immediately preceding and hour following the core hours.

  ~~However, b~~Both core hours and shoulder hours may be shifted or shortened in 15-minute increments to conform to the daily availability window and minimum response time (above). The subsections below detail how core and shoulder hours may be adjusted depending on the notice issued time relative to the start of the peak price hours.

8 The UDCs and corresponding aggregate pricing node IDs are Pacific Gas and Electric ("DLAP_PGAE-APND"), Southern California Edison ("DLAP_SCE-APND"), San Diego Gas & Electric ("DLAP_SDGE-APND"), and the POUs of Anaheim, Azusa, Banning, Pasadena, Riverside, and Vernon (SP15, "TH_SP15_GEN-APND").

- **Advanced-Notice Events:** An Advanced-Notice Event is triggered by an EEA Watch+ notice issued at least 1 hour and 20 minutes ahead of the peak price hours start time. In Advanced-Notice Events, both core and shoulder intervals are hour-aligned. The core intervals are the peak price hours and the shoulder intervals are the hours immediately preceding and following the peak price hours, unless outside the availability window.
- **Short-Notice Events:** A Short-Notice Event is triggered by an EEA Watch+ notice issued more than 20 minutes but less than 1 hour and 20 minutes ahead of the peak price hours start time. Short-Notice Event core intervals are ~~the peak price hours and are~~ hour-aligned. The shoulder intervals are the 15-minute intervals preceding the peak price hours start time and at least 20 minutes from the EEA Watch+ notice issued time, and four intervals immediately following the event, unless outside the availability window.
- **Real-Time Events:** A Real-Time Event is triggered by an EEA Watch+ notice issued less than 20 minutes before the peak price hours start time, including notices issued during or after the peak price hours. Only during Real-Time Events may core intervals ~~not~~ be not hour-aligned. Real-Time Event core intervals shall take effect beginning the first 15-minute interval at least 20 minutes from ~~the announcement of~~ the EEA Watch+ notice issued time. The core intervals shall last for two hours or until 10:00 p.m., whichever is earlier. The shoulder intervals are the four 15-minute intervals immediately following the event, unless outside the availability window. If no EEA Watch+ is issued by 8:40 p.m., no emergency-triggered event shall be called.

- **Event Cancellation:** A load flexibility VPP event shall be cancelled if the host BA issues a cancellation of all applicable EEA Watch+ notices at least 20 minutes before the beginning of the first scheduled shoulder interval. (Real-time events are always initiated within 80 minutes of the highest LMP hours and start with core intervals. These events cannot be cancelled.)

F. Measuring Performance

Option 4 load flexibility VPP devices (or resources) will be aggregated to the UDC territory for IOUs, trading hub for California ISO-integrated POUs, or BA area for non-California ISO POUs, collectively referred to as "territory."

1. ~~Load Impact~~ Increment Load Reduction Measurement

a. Non-Weather-Sensitive Resources

Load impacts, or incremental load reduction, of non-weather-sensitive resources~~, including electric water heaters, EVSE, and stationary batteries,~~ shall be measured relative to a 10-in-10 or 4-in-4 day-matching non-event-day energy baseline consisting of the average ~~15-minute~~ load during a 15-minute measurement interval in the 10 preceding non-holiday weekdays or ~~four~~ 4 preceding weekend/holiday days matching the event day type.

Load for aggregation *a* is the total load across all devices *r* during the 15-minute interval *i* of day *d*:

$$Load_{a,d,i} = \text{sum}(Load_{r,d,i})$$

The energy baseline (*Baseline*) for aggregation *a* during the measurement interval *i* of event day *e* is the average aggregate load (*Load*) in that interval across the *n* (10 or 4) similar non-event days *d:*[9]

$$Baseline_{a,e,i} = \text{sum}(Load_{a,d,i})/n$$

~~Load impacts~~ Incremental load reduction (*ILR*) for aggregation *a* during event interval *i* of event day *e* ~~are~~ is defined as the aggregation's baseline load value minus the aggregation's observed load for that event interval:

$$\cancel{LoadImpact_a}ILR_{a,e,i} = Baseline_{a,e,i} - Load_{a,e,i}$$

A ~~result of~~ negative load impact (*ILR*) result implies that the aggregation's ~~increased~~ load increased during the event interval relative to the aggregation's baseline load level.

b. Weather-Sensitive Resources

Incremental Load Reduction

Load impacts, or incremental load reduction, of weather-sensitive resources~~, including smart thermostats, smart electrical panels, and other HVAC devices,~~ shall be calculated using a 4-day weather-matching baseline with a 28-day lookback period and day-of adjustment applied. The baseline shall be applied to ~~power draw~~the resource's load if available, or compressor runtime if not. Runtime-based estimates of compressor load shall use an assumed connected load of 2.5 kW for full or high speed and 1.25 kW for partial or low speed compressor. For example, on a multi-stage AC compressor, full or high speed would be the mode controlled by the Y2 wire and partial or low would be controlled by Y1. A single-stage compressor would be controlled only by any of Y, Y1, or Y2.

The process for calculating the aggregation's estimated ~~load impact~~incremental load reduction is as follows:

- Step 0: If the load of the device is directly measured and recorded, skip this step. Otherwise, calculate the device's ~~interval~~ estimated load during a measurement interval using the assumptions described above. For example, if in a 15-minute measurement interval the compressor runs for 6 minutes on high and 3 minutes on low, the ~~assumed~~ estimated load during the interval is 2.5kW*0.1h + 1.25kW*0.05h = 0.25kWh + 0.0625kWh = 0.3125 kWh. The aggregation's estimated load in that interval is the sum of the estimated load in that interval of all devices in the aggregation.

9 The 10 nonexcluded weekdays will be selected for weekday events; for weekend and holiday events, the 4 nonexcluded weekend and holiday days will be selected.

- Step 1: Calculate the energy baseline (EB) and the event day aggregate load of an aggregation. Identify the four ~~of the 28 preceding~~ similar~~,~~ non-event days (from the preceding 28-day lookback period) with the ~~closest composite~~ daily average temperature (T*DAv*, as defined ~~in the following~~ further below in this section) closest to the event day average temperature (T*DAvE*). If the 28-day lookback period does not include four similar non-event days, extend the lookback period until four such days are included. The four selected similar days are referred to as the aggregation's "baseline days". Sum the device's actual load, or estimated load~~,~~ for a measurement interval across all devices in ~~each load flexibility VPP~~the aggregation; do this separately for both event days and baseline ~~non-event~~ days.

  The EB of the aggregation during a measurement interval is the average aggregate load in the interval across the selected baseline ~~for the interval on the non-event~~ days. The sum of the device load, during a measurement interval in the event day, across all devices in the aggregation, is the aggregation's event day aggregate load in that interval.

- Step 2: Calculate the day-of adjustment value (DOAV) for each baseline day. A DOAV shall not be less than 0.60 or greater than 1.40. The DOAV is a ratio of (a) the aggregation's average load ~~of~~ across the first 12 measurement intervals of the 16 intervals prior to the start of the event (including core and shoulder ~~intervals~~hours) to (b) the aggregation's average load ~~of~~ across the same intervals from the baseline day~~s~~ selected in accordance with Step 1 above. If either (a) or (b) are zero, the DOAV is 1.0.
- Step 3: Calculate the adjusted energy baseline (AEB). When the EB is greater than zero, the AEB for a ~~DSGS~~ load flexibility VPP event is calculated by multiplying the EB by the DOAV. If the EB is less than zero in an interval, the AEB shall be equal to the EB (that is, DOAV treated as 1).
- Step 4: Calculate the aggregate incremental load reduction (*ILR*) during each event interval. The aggregation's incremental load reduction (*ILR*) for each interval is the AEB minus the event day aggregate load in that interval.

$$ILR_{a,e,i} = AEB_{a,e,i} - Load_{a,e,i}$$

Daily Average Temperature

~~Temperature for each territory is defined as a composite of the average of daily high and daily low temperatures from one or more California Measurement Advisory Council (CALMAC) weather stations.[10] The composite temperature (*TComp*) for utility territory *u* on date *d* is the weighted average of the average of daily high (*Tmax*) and daily low (*Tmin*) for all weather stations, using weights *W* for territory *u* from the stations *s* from Table 4 below:~~The daily average temperature T*DAv* (referenced in Step 1 above) for each UDC territory is defined as the UDC-wide composite daily average of the high and low temperatures between the hours of 4:00 p.m.–10:00 p.m. across one or more California

Measurement Advisory Council (CALMAC) weather stations within the UDC territory.[10]

The UDC-wide composite daily average temperature (*TDAv*) for UDC territory *u* on date *d* is the weighted average of the daily average of a weather station's high (*Tmax*) and low (*Tmin*) temperatures (in the hours between 4:00 p.m.–10:00 p.m.) across all stations, using temperature weight *W* for each station *s* in the UDC territory:

$$TDAv\cancel{Comp}_{u,d} = \text{sum}((TMax_{s,d} + TMin_{s,d})/2 * W_{u,s})$$

The temperature weights applicable to stations in a UDC territory are determined by CEC at the end of the season based on the method described in Appendix A. Station selection is contingent on availability of sufficient CALMAC weather data. UDC temperature weights may be updated if specific stations need to be excluded due to insufficient weather data for the program season. If the UDC temperature weights need to be updated, the CEC will update the values at the end of the program season and post the values on the Resources page of the DSGS Program website at https://dsgs.olivineinc.com/resources/. For reference, below is a table of UDC temperature weights for various stations as calculated at the end of 2025.

10 CALMAC. "California Weather Files," https://www.calmac.org/weather.asp.

Table 4: Temperature Weights at UDC Stations[11]

STATION	PG&E	SCE	SDG&E	PASADENA
BAKERSFIELD-MEADOWS-FLD	-	0.092	-	-
BLUE-CANYON-AP	0.233	-	-	-
BURBANK-GLNDLE-PASAD-AP	-	-	-	1
CORONA-MUNI-AP	-	-	0.127	-
LEMOORE-REEVES-NAS	0.198	-	-	-
LONG-BEACH-DAUGHERTY-FLD	-	0.010	-	-
LOS-ALAMITOS-AAF	-	0.091	-	-
LOS-ANGELES-IAP	-	0.372	-	-
MERCED-MUNI-MACREADY	0.016	-	-	-
OCEANSIDE-MUNI-AP	-	-	0.348	-
PLACERVILLE-AP	0.180	-	-	-
SAN-BERNARDINO-IAP	-	0.327	-	-
SAN-DIEGO-NORTH-ISLAND-NAS	-	-	0.381	-
SAN-JOSE-REID-HILLV	0.237	-	-	-
SANDBERG	-	0.108	-	-
SANTA-ANA-JOHN-WAYNE-AP	-	-	0.144	-
STOCKTON-METRO-AP	0.136	-	-	-

Source: CEC Staff

11 Table may be updated at the end of the program season depending on availability of weather station data.

~~**Table 5**: UDC Temperature Weights~~

~~**STATION**~~	~~**SCE**~~	~~**SDG&E**~~
~~**BISHOP-AP**~~	~~–~~	~~–~~
~~**EL-MONTE**~~	~~0.143~~	~~–~~
~~**FRESNO-YOSEMITE-IAP**~~	~~–~~	~~–~~
~~**FULLERTON-MUNI-AP**~~	~~0.302~~	~~–~~
~~**LA-VERNE-BRACKETT**~~	~~0.080~~	~~–~~
~~**LIVERMORE-MUNI-AP**~~	~~–~~	~~–~~
~~**MERCED-CASTLE-AFB**~~	~~–~~	~~–~~
~~**MODESTO-CITY-CO-AP**~~	~~–~~	~~–~~
~~**OCEANSIDE-MUNI-AP**~~	~~–~~	~~0.306~~
~~**ONTARIO-IAP**~~	~~0.059~~	~~–~~
~~**PALMDALE-AP**~~	~~0.100~~	~~–~~
~~**PLACERVILLE-AP**~~	~~–~~	~~–~~
~~**RED-BLUFF-MUNI-AP**~~	~~–~~	~~–~~
~~**RIVERSIDE-MARCH-AFB**~~	~~0.244~~	~~–~~
~~**SACRAMENTO-EXECUTIVE-AP**~~	~~–~~	~~–~~
~~**SAN-DIEGO-GILLESPIE**~~	~~–~~	~~0.694~~
~~**SAN-JOSE-IAP**~~	~~–~~	~~–~~
~~**SANDBERG**~~	~~0.072~~	~~–~~
~~**UKIAH-MUNI-AP**~~	~~–~~	~~–~~

~~**Weights represent the relative magnitude of coefficients from an elastic net regression of CalMAC weather station cooling degree days (reference composite temperature = 66ºF) on UDC TAC area daily peak load. Model reflects the highest penalty parameter value within one standard error of the minimum error.**~~

~~Source: CEC staff.~~

2. Performance Evaluation

A l~~L~~oad flexibility VPP's (aggregation's) measured load impacts shall be compared against the weather-normalized capacity~~capability~~ (WNC) for each event to determine performance and the final ~~incentive~~ compensation amount.

For non-weather-sensitive resources, WNC is equal to nominated committed capacity.

For weather-sensitive resources, WNC represents the weather-dependent derated of the aggregation's committed capacity ~~load reductions~~ (which should reflect the aggregation's ~~resource~~ load reduction capability~~ies~~ expected at the planning ~~composite~~ temperature~~s~~ T*Plan* of the applicable UDC territory) and determined as described further below in this section.

The planning temperature (*TPlan*) is a single value determined by CEC for each UDC for the program season and may be subject to change depending on station selection and new program season data availability.[12] Planning temperatures in recent years are provided for reference below in Table 5~~. Peak composite temperatures in recent years are provided for reference.~~

Table 6: UDC Planning Temperatures[13]

UDC	2021	2022	2023	2024	2025	2026
PG&E	87.9	94.5	86.4	90.4	85.2	90.5
PASADENA	88.6	98.4	88.1	101.1	89.5	99.7
SCE	82.5	88.4	83.0	87.5	83.1	88.4
SDGE	75.3	85.7	76.4	81.2	76.3	83.4

Source: CEC Staff

~~**Table 7: UDC Planning and Historical Peak Composite Temperatures Planning**~~

~~UDC~~	~~TEMP (ºF)~~	~~2020~~	~~2021~~	~~2022~~	~~2023~~	~~2024~~
~~SCE~~	~~91.3~~	~~92.9~~	~~84.4~~	~~92.6~~	~~85.3~~	~~92.1~~
~~SDG&E~~	~~87.0~~	~~87.4~~	~~80.2~~	~~86.2~~	~~80.3~~	~~89.2~~

The WNC of a weather-sensitive aggregation ($WNC_{u,d}$) in utility territory u in month m on date d is a function of nominated committed capacity (*Nominated*), utility-specific daily average temperature (as defined before) on the event day ~~composite temperature~~ ($TDAvE\cancel{EComp}$), and the utility-specific planning temperature ~~as defined above~~ ($TPlan$), as defined in Table 6.

Table 8: Weather-Normalized Capacity~~Capability~~ Formula

TEMPERATURE	WEATHER-NORMALIZED CAPACITY~~CAPABILITY~~ ($WNC_{\cancel{u,D}u,d}$)
$TDAvE\cancel{EComp}_{u,d} \leq 66$	0
$66 < TDAvE\cancel{EComp}_{u,d} < TPlan_u$	$Nominated_{u,m} * (TDAvE\cancel{EComp}_{u,d} - 66) / (TPlan_u - 66)$
$TDAvE\cancel{EComp}_{u,d} \geq TPlan_u$	$Nominated_{u,m}$

Source: CEC Staff

For example, an aggregation of 4,000~~2,000~~ smart thermostats with an average load reduction commitment of 0.5 kW per device equates to a nominated committed capacity of 2~~1~~ MW in 2025. If this aggregation is in the SDG&E service territory, that

12 A description of the method for calculating the planning temperature is available in Appendix A.

13 The table may be updated at the end of the program season depending on the available station weather data.

capacity commitment value would represent the expected load reduction potential at ~~the~~ SDG&E's 2025 planning temperature of 76.3ºF~~87ºF.~~ Below this level, the weather-normalized ~~capability~~ capacity of the aggregation would decrease until it reaches zero at 66ºF, as shown in Figure 4.

~~Figure 4: Weather-Normalized Capability Profile for SDG&E Aggregation (Planning Temperature = 87ºF) With 1 MW Capacity Nomination~~

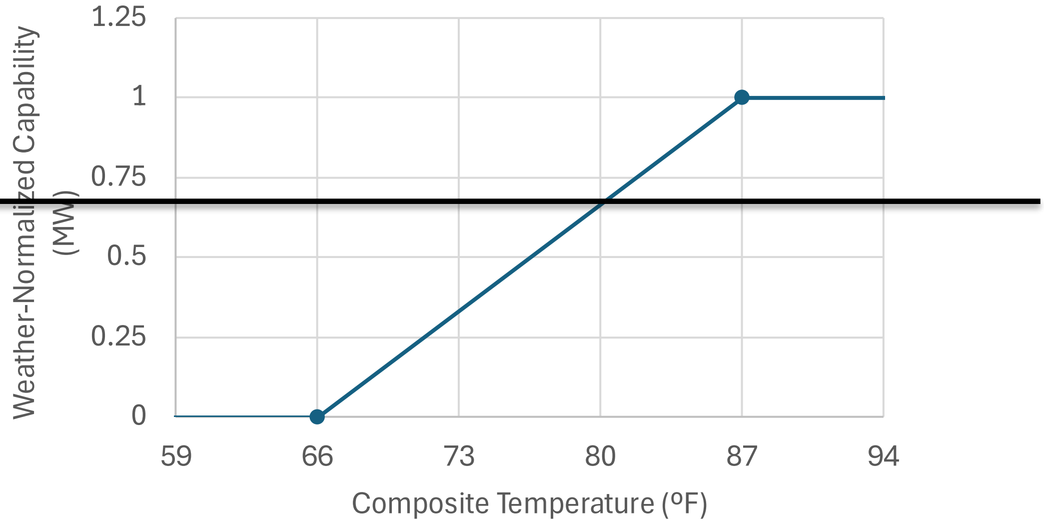
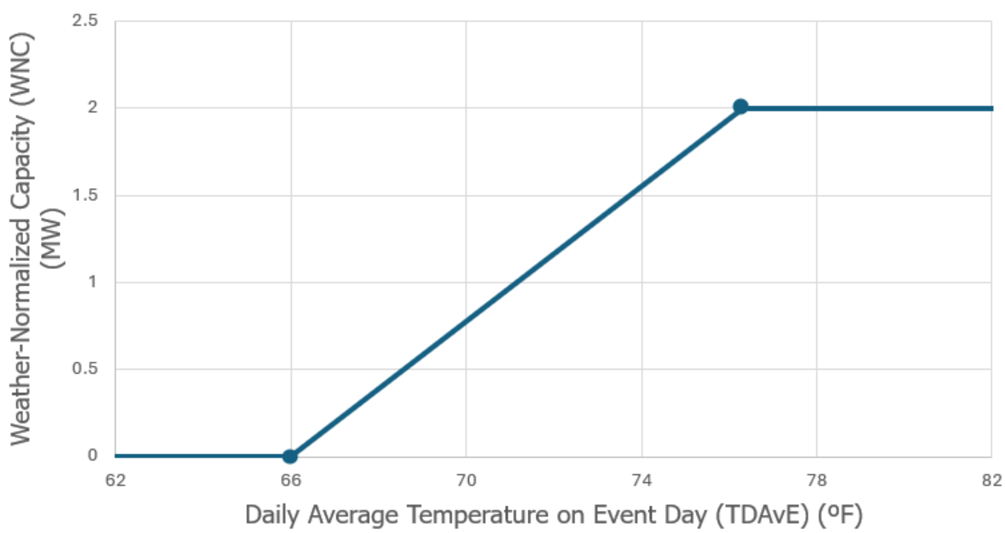


Figure 5: Weather-Normalized Capacity Profile for an Aggregation in SDG&E



Source: CEC staff

Each aggregation ~~*u*~~*a* will be assigned a P~~p~~erformance score (~~*Performance*~~) of incremental load reduction (*ILR*) as a weighted percentage of WNC during each event interval *e* for the day *d* in utility *u*, using day-ahead *LMP*:

~~$Performance_u = \text{sum}(ILR_{u,d,e} * LMP_{u,d,e} * (1 - 0.5*Shoulder_{u,d,e}))/ \text{sum}(WNC_{u,d} * LMP_{u,d,e} * (1 - 0.5*Shoulder_{u,d,e}))$~~

$$P_a = \text{sum}(ILR_{a,d,e} * LMP_{u,d,e} * (1 - 0.5*Shoulder_{a,d,e}))/ \text{sum}(WNC_{u,a,d} * LMP_{u,d,e} * (1 - 0.5*Shoulder_{a,d,e}))$$

Where *Shoulder* is 1 if the interval *e* is a shoulder interval and 0 if it is a core interval. In the case where WNC is 0, P is assigned a value of 1 if the numerator is positive, and 0 if the numerator is negative.

3. Performance-Adjusted ~~Incentive Payment~~Compensation

In months with one or more load flex VPP events, the total ~~incentive payment~~ compensation for an aggregation shall be adjusted ~~relative to~~ based on its overall performance in the month relative to the committed capacity according to the Adjusted Capacity Payment S~~s~~chedule summarized in Table 7.

Overperformance shall be compensated up to 120 percent of nominated committed capacity, and ~~incentives~~ funding for 120 percent of nominated committed capacity shall be set aside, subject to the availability of funds at time of nomination.

Compensation for performance below 100 percent of nominated committed capacity shall be reduced (derated) by two times the percentage shortfall below 100 percent until the performance-adjusted ~~payment~~ compensation reaches zero as performance declines to 50 percent of nominated committed capacity.

For performance below 50 percent of nominated committed capacity, an additional 50 percent of the full nominated committed capacity ~~incentive~~ compensation amount in that month shall be deducted (penalty) from other ~~load flexibility VPP incentives~~ compensation earned by the provider for the load flexibility VPP (aggregation) in other months of the program year.

Table 9: Performance-Adjusted ~~Incentive~~ Capacity Payment Schedule

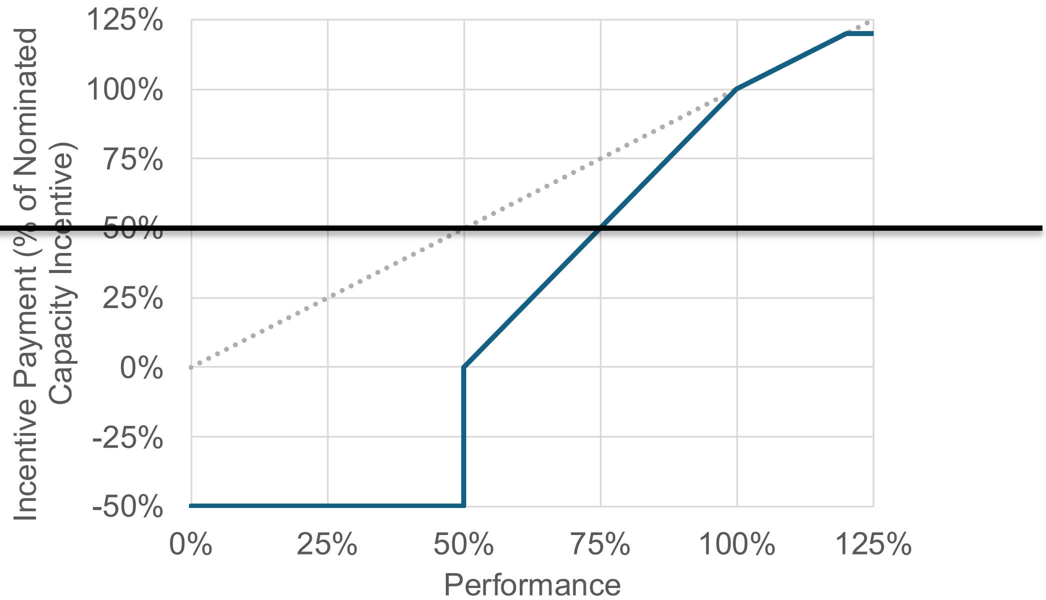
	PERFORMANCE SCORE (*P*)	**~~INCENTIVE~~ PERFORMANCE-ADJUSTED CAPACITY PAYMENT ~~(% OF NOMINATED CAPACITY INCENTIVE)~~**
OVERPERFORMANCE	$P > 120\%$	120%
PRO-RATA	$100\% \le P < 120\%$	P
DERATED	$50\% \le P < 100\%$	$100\% - 2(100\% - P)$
PENALTY	$P < 50\%$	-50%

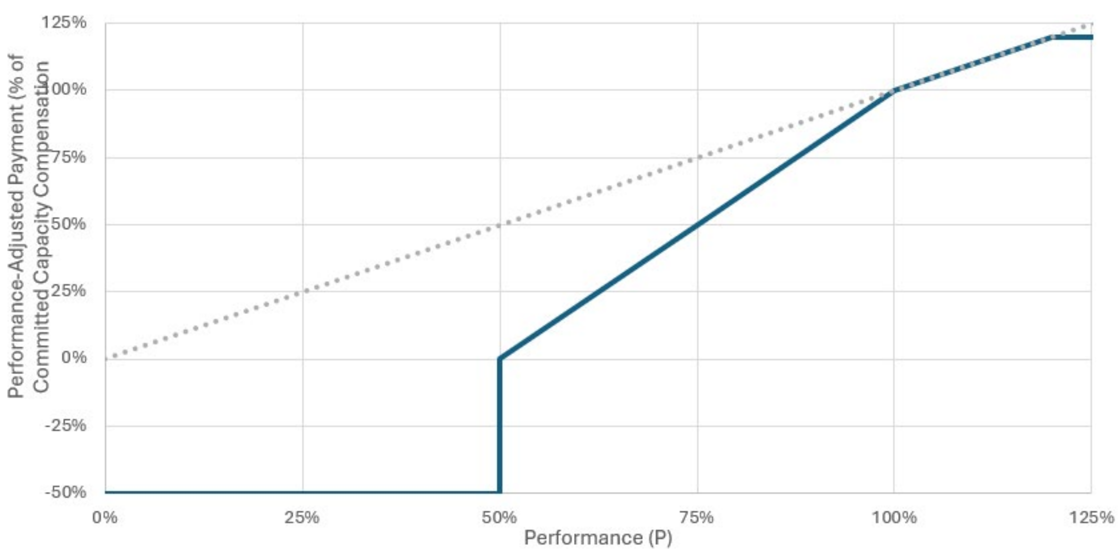
Source: CEC staff

Where the adjusted capacity-payment is shown as a percent (%) of the full nominated committed capacity compensation amount.

The performance-adjusted payment schedule in each month is illustrated in Figure 5.

Figure 6: Performance-Adjusted ~~Incentive~~ Payment Illustration





Source: CEC staff

Additional payment terms:

1. In months without load flex VPP events, DSGS providers shall receive a performance-adjusted payment corresponding to 100% performance ~~of 100 percent of nominated capacity~~.
2. ~~A load flexibility aggregator may begin initial participation after May 1. However, if no events (including test events) occur in the program quarter after the aggregator begins participation, then the payment for the months in the program quarter that participation began is set to zero.~~

3. If the cumulative ~~incentive~~ performance-adjusted payment across all months in the program season is a negative quantity, the seasonal payment to the aggregator is set to zero.
4. If the load flexibility aggregator withdraws from the program during the season, the seasonal payment is set to zero, even if the aggregator's VPP performed during an event prior to the withdrawal.
5. Any funds remaining in the load flexibility aggregator's set aside for compensation after calculating the ~~incentive~~ performance payments will be released from the set aside.

CHAPTER 7: Program Payments

This chapter identifies the information and steps to receive administrative costs and incentive payments.

A. Incentive Payments

DSGS providers shall pay eligible incentive amounts under ~~Incentive~~ Participation Option 1 directly to their participants and submit to the CEC claims for administrative costs and incentive payments. Participants enrolled directly with the CEC shall submit to the CEC claims for incentive payments. DSGS providers shall submit to the CEC claims for incentive payments under ~~Incentive~~ Participation Options 2, 3, and 4 and shall allocate incentive payments between the DSGS provider and its participants pursuant to the terms and conditions agreed to between the DSGS provider and participant.

B. Administrative Costs

1. The CEC shall reimburse each DSGS provider for up to $1 million per year in administrative costs associated with implementing ~~Incentive~~ Participation Option 1. The DSGS provider shall select one of the following administrative cost structures:
   a. Actual incremental costs incurred in administering ~~Incentive~~ Participation Option 1, such as costs derived from employee timesheets or invoices from third-party contractors, pending specified conditions, and for indirect/overhead costs (not to exceed 10 percent of actual incremental costs or a federally approved indirect rate from a federal agency as evidenced by an approval letter).
   b. Ten percent of incentive payments provided to participants under Participation~~Incentive~~ Option 1, or if an electrical corporation, 5 percent of incentive payments provided to participants under Participation~~Incentive~~ Option 1.
2. The CEC shall also reimburse for the following actual costs incurred by utilities and federal power marketing administrations in facilitating an aggregator's administration of the program in the utility's service territory and a direct participant's participation in the program:
   a. Costs incurred to verify customers are eligible to enroll in the program.
   b. Costs incurred to provide customer data necessary for program enrollment and incentive claims.

   These costs may be reimbursed directly to the utility or federal power marketing administration, or to the DSGS provider billed for direct costs. Each utility and federal power marketing administration is limited to reimbursement of up to $250,000 each year in actual incremental costs.

C. Process for Requesting Administrative Costs and Incentive Payments

1. Claim Timing

The CEC shall accept and review claims for administrative costs and incentive payments on a first-come, first-served basis.

a. Participation~~Incentive~~ Option 3 and Participation~~Incentive~~ Option 4 claims must be submitted for review by the last business day of November of the same calendar year in which the program season occurred. All other claims must be submitted by the last business day of February of the following calendar year. The date and time of the electronically submitted completed claim will establish the order in the queue for review of claims. DSGS providers will not be penalized for late claim submissions if the CEC has an outstanding data request necessary to submit a claim.

b. The CEC shall notify claimants if claim packages are incomplete. The claimant shall supplement the incomplete claim within 10 business days. Failure to respond within the 10 business days will result in the cancellation of the claim.

c. The cancellation of a claim does not preclude a claimant from resubmitting a claim, but the date and time of the electronic resubmission will determine the order of review of the claim. The claimant must explain the changes in the re-submitted claim and how the issues for the initial rejection are addressed.

2. Claim Packages

a. DSGS Provider Claim Package

DSGS providers must include the following items:

i. The following information in a format provided by the CEC:

- Reporting period
- DSGS provider name
- DSGS provider's contact name, title, email address, and phone number
- For each participant with resources enrolled in Participation~~Incentive~~ Option 1:
    - Participant name
    - Type of resources dispatched, including the applicable loading order category (for example, demand response or efficiency resource, renewable or zero-emission resources, near-zero-emission resource, biomethane or natural gas resource, or diesel backup generator or other conventional resource, or any combination of the above)
    - Address where each resource is located and customer identification number (both must match the information provided in the participation reports)

- Verified incremental load reduction (kWh) delivered to the grid each hour of each dispatch period during the reporting period
- Eligible standby commitment amount (in kWh) each hour during the reporting period, as described in Chapter 3
- Amount of incremental increases in customer demand charges that result from participation in the program during the billing period in which a DSGS Program event occurred, if any, and supporting documentation
- Documentation demonstrating load-reduction activities, such as meter data and supporting calculations showing how the claimant calculated the baseline and load-reduction amount.

- For participation under Participation~~Incentive~~ Option 2, if requested by the CEC:
  - Real-time market bids and self-schedules (in kWh) by Resource ID
  - Total expected energy (TEE, in kWh) by Resource ID
  - Demand response energy measurement (DREM, in kWh) by Resource ID
  - Customer-weighted average of daily high and low temperature by dispatch event

ii. For administration of Participation~~Incentive~~ Option 1, amount of administrative costs being claimed based on the selected administrative cost reimbursement structure described in Chapter 7, Section B.1. Claims seeking reimbursement based on incremental administrative costs must provide supporting documentation.

iii. Payee data record (STD-204). If the designated payee has already submitted a complete STD-204 form with a prior reimbursement claim and has received a payment within the past year from the CEC, a new STD-204 is not needed.

iv. Attestation, submitted by an officer under penalty of perjury, that the requested payment will reimburse eligible incentive payments and administrative costs and that the information submitted is complete and accurate.

b. Direct Participant Claim Package

Participants enrolled directly with the CEC must provide the following items:

i. The following information in a format provided by the CEC:
   - Reporting period
   - Participant name
   - Participant’s contact name, title, email address, and phone number
   - For each load-reduction resource:
     - Load-serving entity for the resource

        - Type of resource, including the applicable loading order category (for example, demand response or efficiency resource, renewable or zero-emission resources, near-zero-emission resource, biomethane or natural gas resource, or diesel backup generator or other conventional resource, or any combination of the above)
        - Address where the resource is located
        - Eligible standby (in kWh) each hour during the reporting period, as described in Chapter 3
        - If claiming the one-time controllable generation incentive described in Chapter 3, Section C.4, kW or HP as defined on the specification sheet of the generator and supporting documentation.
        - Interval meter data (or if IOU customer, authorize data sharing with DSGS admin) or other documentation evidencing load-reduction activities if interval meter data are not available.
    - Amount of incremental increases in customer demand charges that result from participation in the program during the billing period in which a DSGS Program event occurred, if any, and supporting documentation

ii. Payee data record (STD-204). If the designated payee has already submitted a complete STD-204 form with a prior reimbursement claim and has received a payment within the past year from the CEC, a new STD-204 is not needed.

iii. Attestation, submitted by an officer under penalty of perjury, that the requested payment will reimburse eligible incentive payments and to the information submitted is complete and accurate.

c. Utility and Federal Power Marketing Administration Claim Package for Administrative Cost

Utilities and federal power marketing administrations claiming incremental costs pursuant to Chapter 7, Section B.2, must provide the following items:

i. Reporting period

ii. Utility or federal power marketing administration name

iii. Contact person’s name, title, email address, and phone number

iv. Amount of administrative costs being claimed

v. Documentation evidencing claimed administrative costs

vi. Payee data record (STD-204). If the designated payee has already submitted a complete STD-204 form with a prior reimbursement claim and has received a payment within the past year from the CEC, a new STD-204 is not needed.

vii. Verification in writing that:

- The payment will reimburse eligible administrative costs.

- The utility or federal power marketing administration is not receiving compensation from another source for the administrative costs included in the claim.
- The information submitted is accurate and complete.
- The utility or federal power marketing administration agrees to the requirements of the terms listed in Chapter 7, Section S.

3. Claim Review and Approval

If, during the claim review, a complete and timely submitted claim package is found to contain minor errors, discrepancies, or omissions, the CEC will request clarification from the claimant. The claimant will be responsible for providing all information requested by the CEC to process the request. The CEC may impose a reasonable deadline for claimants to respond to and provide any information requested under this section. Failure to respond by the deadline provided will result in the cancellation of the claim.

If a claimed cost in the claim package is found to be ineligible for reimbursement, the CEC will not approve the claimed cost.

Payment of approved eligible incentive payments and administrative costs reimbursements will be made to the payee according to the Payee Data Record (STD-204).

CHAPTER 8: Administration

A. Effective Date of Guidelines

This edition of the DSGS Program Guidelines will take effect immediately upon approval at a CEC business meeting. The CEC will post the adopted DSGS Program Guidelines on its website, available at https://www.energy.ca.gov/programs-and-topics/programs/demand-side-grid-support-program.

Applicants and interested persons may also obtain the program guidelines by contacting DSGS@energy.ca.gov.

B. Compliance and Verification

As a condition of receiving a DSGS incentive, DSGS providers and participants must agree to provide the CEC with access to relevant documents to verify load-reduction activities and confirm that funding is being used to reimburse eligible administrative costs and incentive payments as directed by DSGS Program Guidelines. CEC staff, and its agents, may take various steps, as needed, to ensure compliance with program requirements.

DSGS providers and participants must agree to provide information, access to participant application records, and documentation evidencing load-reduction activities as reasonably requested by CEC staff, or its agent, to verify eligibility for DSGS incentives. These steps may include:

1. Requesting relevant documents or other materials from the DSGS provider or participant.
2. Contacting the participant or its retail supplier.
3. Contacting the California ISO or applicable balancing authority.
4. Performing an audit, as discussed below in Section E.

C. Enforcement

In addition to any other rights the CEC has, the CEC may take any of the following actions necessary to enforce the CEC's rights and program requirements. By applying for funds under this program, DSGS providers and participants agree that any effort to enforce this funding arrangement in court shall have the venue in Sacramento County, and this funding arrangement shall be interpreted in accordance with and governed in all respects by California law.

1. Recovery of Overpayment

In addition to all rights and remedies available to the CEC, the CEC may direct its chief counsel to commence formal legal action against any current or former DSGS provider or participant to recover any portion of an incentive or administrative payment, and any other amounts due under the law, that the CEC's executive director determines the

DSGS provider or participant or former DSGS provider or participant was not otherwise entitled to receive.

2. Fraud and Misrepresentation

The executive director may initiate an investigation of any current or former DSGS provider, participant, or applicant that the executive director has reason to believe may have misstated, falsified, or misrepresented information in submitting an application, reimbursement request, or any reporting or other information required under the program. Based on the results of the investigation, the executive director may take any action deemed appropriate, including, but not limited to, removal from the program and recovery of any overpayment, and, with the concurrence of the CEC, recommending the Attorney General initiate an investigation and prosecution under Government Code Section 12650, et seq., or other provisions of law.

3. Noncompliance With Guidelines

The CEC may seek remedies for noncompliance with guideline requirements and terms, including, but not limited to, termination of enrollment, withholding requested payments, recovery of funds, or any other administrative or civil action.

Without limiting any of its other remedies, the CEC may, for eligible DSGS provider's, participant's, or applicant's noncompliance with any guideline requirement, withhold future reimbursement payments, demand and be entitled to repayment of past reimbursements, and suspend or cancel the DSGS provider's or participant's enrollment.

D. Audits

DSGS providers and participants shall keep separate, complete, and correct accounting of the costs involved in participating in this program, as applicable. The CEC, the Bureau of State Audits, or their authorized agents may audit any applicant or participant to verify compliance with all program requirements, including the accuracy of any information included as part of the application, reimbursement claim, or report required under these guidelines. As part of an audit, a DSGS provider or participant may be required to provide the CEC or its authorized agents with all information and records necessary to verify the accuracy of any information included in the DSGS provider's or participant's application, reimbursement claims, or reports. A DSGS provider or participant may also be required to open its business records for on-site inspections and audit by the CEC or its authorized agents to verify the accuracy of any information included therein. An audit may be performed at any time within five years after payment by the CEC of the DSGS provider's or participant's final claim payment.

If an audit finds that a DSGS provider or participant has incorrectly stated or falsified information included on the DSGS provider's or participant's application, claims, or reports, the CEC shall notify the DSGS provider or participant of its findings in writing within 30 days of completing the audit. Based on the audit results and without limiting any of CEC's other rights, a DSGS provider or participant may be required to refund all or a portion of the DSGS claim payments it has received. In addition, the DSGS provider's or participant's enrollment may be terminated and enforcement actions initiated following Section D of Chapter 8: Administration.

E. Authorized Third Parties

Authorized third parties may complete applications on behalf of an eligible DSGS provider but may not sign attestations on their behalf. A letter of authorization from the DSGS provider specifying any authority or responsibility delegated to the third party is required as part of the application package.

F. Records Retention: Use and Disclosure of Information and Records and Confidentiality

Any entity receiving a DSGS payment from the CEC must retain all records required to be submitted to the CEC for a period of five years after the date the project receives its final, or most recent, incentive payment from the CEC. Unless an applicable exception or exemption to public disclosure applies, all documents submitted to the CEC or its technical assistance providers, including as part of any audit, are considered public records subject to disclosure under the California Public Records Act. The CEC or other state agencies may also use any of these documents or information for any purpose, including to determine eligibility and compliance with the DSGS Program, applicable law, or a particular guideline document; evaluate related or relevant programs or program elements; or prepare reports. These documents and information include, but are not limited to, applications, invoices, and any documentation submitted in support of the applications; all incentive deliverables; and documents prepared for other reporting requirements.

If the CEC requires a DSGS provider or participant to provide copies of records that the DSGS provider or participant believes contain confidential, proprietary, or any other information entitled to protection under the California Public Records Act or other law, the DSGS provider or participant may request that such records be designated confidential according to the CEC's regulations for confidential designation, Title 20, California Code of Regulations, Section 2505. If the DSGS provider or participant believes that the record should not be disclosed because it contains trade secrets or its disclosure would otherwise cause loss of a competitive advantage, the application for confidential designation shall also state the specific nature of that advantage and how it would be lost, including the value of the information to the applicant, and the ease or difficulty with which the information could be legitimately acquired or duplicated by others.~~may~~ If the confidential information within a document can be redacted without removing the portion of the record that is required for verification of compliance with these guidelines, the DSGS provider or participant shall submit versions of documents with the confidential information masked or redacted rather than requesting confidential designation. Questions regarding whether redactions may inhibit verification of compliance with these guidelines should be submitted to CEC staff with sufficient time to resolve the question before reimbursement.

DSGS providers and participants considering confidentiality should note that DSGS funds are subject to information disclosure requirements to ensure transparency. Information concerning the identity of DSGS providers and participants and the amounts provided are public information and will be published in CEC reports and disclosed in response to requests filed under the California Public Records Act. This information, as well as other public information, may also be disclosed through the CEC's website, another State of California agency website, or through other means. The CEC will not disclose information in a manner that is otherwise protected by the Public Records Act, including qualifying trade secrets or confidential or privileged information, including energy use.

In addition to any other disclosure requirements under the law, the CEC can disclose confidential information and records to other governmental entities, including other local, state, or federal agencies that are funding eligible projects, and law enforcement authorities for civil and criminal investigation and enforcement.

G. Nondiscrimination Statement of Compliance

While participating in the DSGS Program, DSGS providers, DSGS participants, and subcontractors will not unlawfully discriminate, harass, or allow harassment against any employee or applicant for employment because of any of the following:

- Sex
- Sexual orientation
- Race
- Color
- Ancestry
- Religious creed
- National origin
- Physical disability (including HIV and AIDS)
- Mental disability
- Medical condition
- Age
- Genetic information
- Gender
- Gender identity
- Gender expression
- Military and veterans status
- Marital status
- Denial of family care leave

DSGS providers, DSGS participants, and subcontractors will ensure that the evaluation and treatment of their employees and applicants for employment are free from such discrimination and harassment.

DSGS providers, DSGS participants, and subcontractors shall comply with the provisions of the Fair Employment and Housing Act (Government Code Sections 12990 et seq.) and the applicable regulations promulgated thereunder (California Code of Regulations, Title 2, Section 11000 et seq.). The applicable regulations of the Fair Employment and Housing Commission implementing Government Code Section 12990 (a-f), set forth in Chapter 5 of Division 4.1 of Title 2 of the California Code of Regulations, are incorporated into these guidelines by reference and made a part of it as if set forth in full. The DSGS provider, DSGS participants, and subcontractors will give written notice of their obligations under this section to labor organizations with which they have a collective bargaining or other agreement.

DSGS providers shall include and shall ensure all subcontractors include the nondiscrimination and compliance provisions in this section in all subcontracts under this program.

H. Drug-Free Workplace Certification

By participating in the DSGS Program, the DSGS provider certifies under penalty of perjury under the laws of the State of California that it will comply with the requirements of the Drug-Free Workplace Act of 1990 (Government Code Section 8350 et seq.) and will provide a drug-free workplace by taking the following actions:

1. Publish a statement notifying employees that unlawful manufacture, distribution, dispensation, possession, or use of a controlled substance is prohibited and specifying actions to be taken against employees for violations as required by Government Code Section 8355(a).
2. Establish a Drug-Free Awareness Program as required by Government Code Section 8355(b) to inform employees about:
   - The dangers of drug abuse in the workplace.
   - The person’s or organization’s policy of maintaining a drug-free workplace.
   - Any available counseling, rehabilitation, and employee assistance programs.
   - Penalties that may be imposed upon employees for drug abuse violations.
3. Provide, as required by Government Code Section 8355(c), that every employee who works on the proposed project:
   - Will receive a copy of the company's drug-free policy statement.
   - Will agree to abide by the terms of the company's statement as a condition of employment on the project.

In addition to any other rights and remedies available to the CEC, failure to comply with these requirements may result in suspension of payments under the DSGS Program or termination of participation, and the DSGS provider may be ineligible for any future state awards if the CEC determines that any of the following has occurred: (1) the DSGS provider has made false certification or (2) violates the certification by failing to carry out the requirements as noted above.

I. Americans With Disabilities Act

By participating in the DSGS Program, the DSGS provider assures the CEC that it complies with the Americans with Disabilities Act (ADA) of 1990 (42 U.S.C. Section 12101, et seq.), which prohibits discrimination on the basis of disability, as well as applicable regulations and guidelines issued pursuant to the ADA.

J. Air or Water Pollution Violation

This term applies to DSGS providers receiving more than $10,000. Under state laws, DSGS providers shall not be (1) in violation of any order or resolution not subject to review promulgated by the California Air Resources Board or an air pollution control district, (2) subject to cease and desist order not subject to review issued under Section 13301 of the Water Code for violation of waste discharge requirements or discharge prohibitions, or (3) finally determined to be in violation of provisions of federal law relating to air or water pollution.

K. Prompt Payment

Payment will be made in accordance with the Prompt Payment Act, Government Code Chapter 4.5, commencing with Section 927, which requires payment of properly submitted, undisputed invoices within 45 days of receipt or the automatic calculation and payment of appropriate late payment penalties when applicable.

<u>The CEC’s financial obligations under these guidelines are strictly limited to the amounts expressly appropriated and legally available for the purposes of the DSGS program. The CEC has no obligation to provide funding or payments for DSGS providers’ or participants’ activities that exceed the CEC’s authorized funding limitations.</u>

L. Amendments

No amendment or variation of the terms of the agreement between the CEC and DSGS providers shall be valid unless made in writing, signed by the parties, and approved as required. No oral understanding or agreement not incorporated in the agreement is binding on any of the parties.

M. Termination Without Cause

The CEC may terminate agreements with a DSGS provider without cause upon giving written notice. In this event, the DSGS provider will use all reasonable efforts to mitigate its expenses and obligations.

N. Public Works

If a DSGS provider engages in public works or has subcontractors or DSGS participants engage in public works under this program, the DSGS provider shall comply with all applicable public works laws (for example, Labor Code Section 1720 et seq.), a requirement of which is to pay prevailing wages. If an entity engages in public works, then it is subject to compliance monitoring and enforcement by the Department of Industrial Relations.

O. Independent Capacity

In their performance under this program, DSGS providers, DSGS participants, and subcontractors and their respective agents and employees will act in an independent capacity and not as officers, employees, or agents of the CEC or the State of California.

P. Third-Party Beneficiary

DSGS providers shall ensure every subcontract and agreement with DSGS participants under this program includes a provision indicating the CEC is a third-party beneficiary to the agreement.

Q. Travel and Per Diem

1. Any travel for which DSGS providers and subcontractors want to be reimbursed must be preapproved in writing by the CEC before such costs are incurred.
2. The CEC shall only pay travel and per diem up to, but not to exceed, the rates allowed for unrepresented state employees. Current allowable travel reimbursement rates can be obtained from the CEC at http://www.energy.ca.gov/contracts/TRAVEL_PER_DIEM.PDF.
3. DSGS providers and their subcontractors shall not invoice for or spend, and the CEC shall not pay, any CEC funds for food or beverages other than for allowable per diem charges. DSGS providers and their subcontractors are responsible for any amounts more than this allowed amount.
4. DSGS providers and their subcontractors shall not invoice for or spend, and the CEC shall not pay, any CEC funds for alcohol or travel and meals for non-DSGS, entertainment, or public relations purposes.
5. DSGS providers shall not allow subcontractors to invoice for, and the CEC shall not pay, any funds for a profit amount greater than 10 percent.

R. Flow-Down Requirements

DSGS providers shall flow down in their agreements with subcontractors and DSGS direct participants and shall ensure subcontractors flow down in their subcontracts, the requirements in the following terms:

- Compliance and Verification (Chapter 8, Section C)
- Enforcement (Chapter 8, Section D)
- Audits (Chapter 8, Section E)
- Records Retention (Chapter 8, Section G)

- Nondiscrimination Statement of Compliance (Chapter 8, Section H)
- Drug-Free Workplace Certification (Chapter 8, Section I)
- Americans With Disabilities Act (Chapter 8, Section J)
- Air and Water Pollution Violation (Chapter 8, Section K)
- Prompt Payment (Chapter 8, Section L)
- Public Works (Chapter 8, Section O)
- Third-Party Beneficiary (Chapter 8, Section Q)
- Travel and Per Diem (Chapter 8, Section R)
- Flow-Down Requirements (Chapter 8, Section S, this section)
- Survival of Terms (Chapter 8, Section V)
- A provision indicating the person or entity agrees to comply with all applicable laws and DSGS Program requirements.

S. Severability

If any provision of these guidelines is unenforceable or held to be unenforceable, all other provisions of these guidelines will remain in full force and effect.

T. Waiver

No waiver of any breach of these guidelines constitutes waiver of any other breach. All remedies in these guidelines will be taken and construed as cumulative, meaning in addition to every other remedy provided in the guidelines or by law.

U. Survival of Terms

Certain provisions will survive the withdrawal of a DSGS provider or participant from the program for any reason. The provisions include, but are not limited to:

- Program Payments (Chapter 7).
- Compliance and Verification (Chapter 8, Section C).
- Enforcement (Chapter 8, Section D).
- Audits (Chapter 8, Section E).
- Records Retention: Use and Disclosure of Information and Records and Confidentiality (Chapter 8, Section G).
- Public Works (Chapter 8, Section O).
- Third-Party Beneficiary (Chapter 8, Section Q).
- Severability (Chapter 8, Section T).
- Waiver (Chapter 8, Section U).
- CEC's financial Survival of Terms (Chapter 8, Section V, this section).

Reference Documents

Assembly Bill 205 (Committee on budget, Stats. 2022, Ch. 61)
https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB205

Assembly Bill 209 (Committee on budget, Stats 2022, Ch. 251)
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB209

California ISO Emergency Notifications Fact Sheet
http://www.caiso.com/Documents/Emergency-Notifications-Fact-Sheet.pdf

North American Electric Reliability Corporation Reliability Standard EOP-011-1
https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

GLOSSARY

Key Words and Terms

Word/Term	Definition
Aggregator	An entity that dispatches behind-the-meter load reduction or battery storage or EV supply equipment of multiple customers in a coordinated manner in response to a signal for the benefit of from a load-serving entity, utility or balancing authority.
Agricultural and Pumping Interruptible Program	A demand response program in Southern California Edison's (SCE) territory that offers monthly bill credits to businesses that agree to temporarily interrupt their electricity service during peak energy demand.
Balancing authority area	A balancing authority area means the collection of generation, transmission, and loads within the metered boundaries of the area within which the balancing authority maintains the electrical load-resource balance (Public Utilities Code Section 399.12[c]).
Base Interruptible Program (BIP)	A program created by the CPUC and managed by the state's IOUs that pays customers to reduce their electricity use during electrical grid emergencies.
Behind the Meter (BTM)	Refers to energy resources located on the customer's side of the utility meter, including resources connected to a dedicated net generation output meter (NGOM) and participating in virtual net metering (VNEM)
Balancing Authority	An entity that manages the operation of the electric power system within a specific geographic area. The goals of a balancing authority are to maintain balance between power demand and supply and to sustain safe and reliable operation of the power system.
California Independent System Operator (California ISO)	A balancing authority serving most of California. California ISO oversees the operation of California's bulk electric power system, transmission lines, and electricity markets.

California Public Utilities Commission (PUC)	The California Public Utilities Commission is the state agency charged with regulating privately owned utilities (electric, natural gas, telecommunications, water), railroad, rail transit, and passenger transportation companies.
California Energy Commission (CEC)	State Energy Resources Conservation and Development Commission, commonly called the California Energy Commission, the Energy Commission, or the CEC. The state's primary energy policy and planning agency. The agency was established by the California Legislature through the Warren-Alquist Act in 1974. It has seven core responsibilities: (1) Developing renewable energy (2) Transforming transportation (3) Increasing energy efficiency (4) Investing in energy innovation (5) Advancing state energy policy (6) Certifying thermal power plants (7) Preparing for energy emergencies This term also includes any entity the CEC has contracted with to implement all or part of this program.
Cogeneration	The simultaneous production of electricity and heat, where the latter is used for a useful function to improve overall efficiency of the system.
Community choice aggregator	Community choice aggregator means any of the following entities, if that entity is not within the jurisdiction of a local publicly owned electric utility, that provided electrical service as of January 1, 2003: (a) Any city, county, or city and county whose governing board elects to combine the loads of its residents, businesses, and municipal facilities in a communitywide electricity buyers' program. (b) Any group of cities, counties, or cities and counties whose governing boards have elected to combine the loads of their programs, through the formation of a joint powers agency established under Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code. (c) The Kings River Conservation District, the Sonoma County Water Agency, and any California public agency possessing statutory authority to generate and deliver electricity at retail within its designated jurisdiction, provided the entity may only

	combine the loads of residences, businesses, and governmental facilities of cities and counties within, or contiguous to, its jurisdiction that have, by resolution exercised pursuant to paragraph (12) of subdivision (c) of Section 366.2, requested the agency to implement a community choice aggregation program. (Public Utilities Code Section 331.1.)
Customer(s)	A utility service account representing a home, business, or other entity.
Demand Response	Customers make temporary or recurring changes in their energy consumption profile (typically reduce or shift net demand) in response to grid or price signals to provide grid services in exchange for incentives or compensation from an energy service provider, utility, or California ISO.
DSGS Program event	DSGS Program events include the dispatch periods described in the DSGS Guidelines for the various participation~~incentive~~ options to prompt enrolled devices to reduce demand or increase supply to reduce stress on the power grid.
DSGS provider	A retail supplier as defined in Public Utilities Code Section 398.2, federal power marketing administrations, and aggregators of customers enrolled with the CEC to administer the DSGS Program for participants.
EEA Watch	An Energy Emergency Alert Watch issued by the California ISO when analysis shows all available resources are committed or forecasted to be in use, and energy deficiencies are expected. Market participants are encouraged to offer supplemental energy (California ISO Emergency Notifications Fact Sheet, https://www.caiso.com/documents/emergency-notifications-fact-sheet.pdf).
EEA 1	An Energy Emergency Alert 1 as defined in the North American Electric Reliability Corporation's Reliability Standard EOP-011-1. A balancing authority issues an EEA 1 when it is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required contingency reserves.
EEA 2	An Energy Emergency Alert 2 as defined in the North American Electric Reliability Corporation's Reliability Standard EOP-011-1. A balancing authority issues an EEA 2 when it is no longer able to provide its expected energy requirements and is energy deficient.

EEA 3	An Energy Emergency Alert 3 as defined in the North American Electric Reliability Corporation's Reliability Standard EOP-011-1. An energy deficient balancing authority issues an EEA 3 when it is unable to meet minimum contingency reserve requirements.
Electric Vehicle Supply Equipment (EVSE)	The equipment that connects an electric vehicle (EV) to a power source to charge its battery.
Emergency Load Reduction Program (ELRP)	A program created by the CPUC in Decision 21-03-056 and managed by the state's IOUs to pay electricity consumers for reducing energy consumption or increasing electricity supply during electrical grid emergencies.
Energy Baseline	An estimate of typical energy demand for a given customer during a DR event, usually based on historical behavior of that resource.
Extreme event	An extreme event is defined in Public Resources Code Section 25790.5(b) to mean either of the following: (a) An event occurring at a time and place in which weather, climate, or environmental conditions, including temperature, precipitation, drought, fire, or flooding, present a level of risk that would constitute or exceed a one-in-ten event, as referred to by the North American Electric Reliability Corporation, including when forecast in advance by a load-serving entity or local publicly owned electric utility. (b) An event where emergency measures are taken by a California balancing authority, including when forecast in advance by the California balancing authority.
<u>Holiday</u>	<u>For defining "weekend/holiday" days for day-matching energy baseline calculations, the following are considered holidays: Memorial Day, Independence Day (Observed), and Labor Day.</u>
Investor-owned utility (IOU)	As used in this document, investor-owned utilities include Pacific Gas and Electric Company (PG&E), Southern California Edison, and San Diego Gas & Electric Company (SDG&E).
Load reduction	A decrease in electric demand as measured at a customer site relative to a counterfactual baseline. Load reductions include behind-the-meter generation or storage discharge that result in negative demand (that is, exports) except where otherwise prohibited.

Load-serving entity	An electric customer's retail supplier or federal power marketing administration.
Local publicly owned electric utility (POU)	Local publicly owned electric utility means a municipality or municipal corporation operating as a "public utility" furnishing electric service as provided in Section 10001, a municipal utility district furnishing electric service formed pursuant to Division 6 (commencing with Section 11501), a public utility district furnishing electric services formed pursuant to the Public Utility District Act set forth in Division 7 (commencing with Section 15501), an irrigation district furnishing electric services formed pursuant to the Irrigation District Law set forth in Division 11 (commencing with Section 20500) of the Water Code, or a joint powers authority that includes one or more of these agencies and that owns generation or transmission facilities, or furnishes electric services over its own or its member's electric distribution system (Public Utility Code Section 224.3).
Locational Marginal Price (LMP)	The marginal price for energy at the location where the energy is delivered or received and is based on forecasted system conditions and the latest approved real-time security constrained economic dispatch program solution. LMP is expressed in dollars per megawatt-hour ($/MWh). LMP is a pricing approach that addresses Transmission System congestion and loss costs, as well as energy costs.
Nameplate Energy Storage Capacity	The manufacturer's published maximum usable energy storage capacity (kWh) for a given energy storage product.
Nameplate Power Rating	The manufacturer's published theoretical maximum discharge power (kW) for a given energy storage product.
Participant	An energy customer that has enrolled in the DSGS Program
Proxy Demand Resource (PDR)	Economic demand response composed of a load or aggregation of loads that bid into the California ISO market under normal operating conditions.
Rule 21	CPUC Electric Rule 21 is a tariff that describes the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system.
Self-Generation Incentive Program (SGIP)	Administered by the CPUC, the Self-Generation Incentive Program (SGIP) provides incentives to support existing, new, and emerging distributed energy resources. SGIP provides

	rebates for qualifying distributed energy systems installed on the customer's side of the utility meter. Qualifying technologies include wind turbines, waste heat-to-power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems.
Smart Electrical Panel	An electrical panel with a communication link that enables remote monitoring and dispatch control of devices connected to the panel.
Strategic Reliability Reserve (SRR)	A state program that provides funding to secure conventional generation, efficiency upgrades at existing natural gas plants, demand response, distributed generation, and long-duration storage. The SRR consists of three programs, two of which are administered by the CEC, and one is administered by the Department of Water Resources.
Subcontract	An executed contract between a DSGS provider and a person or entity assisting the DSGS provider in fulfilling the requirements of this program that is not a DSGS participant.
Subcontractor	A person or entity that executes a subcontract with a DSGS provider.
Virtual Net Metering (VNEM)	A system where customers receive credit on their electricity bills for power generated from a solar-plus-storage system that is not installed on their home. For example, the benefits of a solar-plus-storage system can be shared by multiple tenants in a multifamily residential building.
Virtual Power Plant (VPP)	A network of behind-the-meter customer operated distributed energy resource (DER) devices that respond to a grid signal to benefit the electric grid.

APPENDIX A: Participation Options 2, 3 and 4 – Selected Topics

A. Option 2 Compensation Allocation Method

Available Option 2 funds for 2026 season shall be allocated to each participating provider based on their CEC-validated cumulative performance-based capacity compensation in the 2026 program season, up to their pro-rata share of the total *uncapped* compensation across all participating Option 2 providers in the season.

B. Option 3 Compensation Allocation Method

With the available funds for each customer class, the performance-based capacity payment to each eligible participating storage VPP aggregator (with aggregations associated with that customer class) for the 2026 season shall be determined as described below:

1. The available funds shall be allocated at the end of the 2026 program season (Round 1 funding allocation) to each aggregator based on their CEC-validated cumulative performance-based capacity compensation in the 2026 program season, up to their pro-rata share of the total compensation for Option 3 in October 2025. The October 2025 total compensation is the sum of the per aggregator compensation that the aggregators would have earned in October 2025 based on their demonstrated capacity relative to a measured baseline,[14] as determined by the CEC using the available existing performance data for that month.
2. For each aggregator, the CEC will disclose their October 2025 pro-rata share applicable to their customer-class specific available fund in 2026, prior to the start of the 2026 program season.
3. To the extent that some aggregators' cumulative performance-based capacity compensation for the 2026 season is less than their Round 1 pro-rata share described above, the remaining funds will be pooled and re-allocated to aggregators (Round 2 funding allocation) whose total 2026 compensation exceeded their October 2025 pro-rata share in Round 1. The Round 2 allocation to the eligible providers shall be based on their CEC-validated cumulative performance-based capacity compensation in the 2026 program season, up to their *revised* pro-rata share for Round 2 – that is, based

14 The measured baseline is based on averaging the hourly aggregated discharge of an aggregation across all non-event days in the month for a given event hour and day type.

on their share of the October 2025 total compensation associated with only the Round 2 aggregators.

4. Any remaining funds in the customer class specific fund shall be allocated to the providers with aggregations participating in the other customer class, using the Round 1 & 2 processes described above.

Below is an example of the Option 3 allocation method. Assume five providers and a total of $40 million available for residential aggregations:

Round 1:

Table 10: Example Round 1 Option 3 Compensation Allocation

Provider	**October 2025 Pro-Rata Share (Residential)**	**Max 2026 Round 1 Payment ($M)**	**Uncapped 2026 Performance Payment**	**Round 1 Payment Allocation**
Provider 1	35%	$14	$20	$14
Provider 2	25%	$10	$12	$10
Provider 3	15%	$6	$3	$3
Provider 4	15%	$6	$4	$4
Provider 5	10%	$4	$5	$4
Total	100%	$40	$44	$35

Source: CEC staff

Round 2:

Table 11: Example Round 2 Option 3 Compensation Allocation

Provider	**October 2025 Revised Pro-Rata Share (Residential)**	**Max 2026 Payment ($M) after Round 1 (Total $5M Available)**	**Remaining Uncapped 2026 Performance Payment**	**Round 2 Payment Allocation**
Provider 1	50%	$2.50	$6	$2.50
Provider 2	36%	$1.79	$2	$1.79
Provider 5	14%	$0.71	$1	$0.71
Total	100%	$5	$9	$5

Source: CEC staff

Total compensation paid:

Table 12: Example Total Compensation Paid for Option 3

Provider	Uncapped 2026 Performance Payment	Round 1 Payment Allocation	Round 2 Payment Allocation	Total Payment
Provider 1	$20	$14	$2.50	$16.5
Provider 2	$12	$10	$1.79	$11.79
Provider 3	$3	$3	$0	$3
Provider 4	$4	$4	$0	$4
Provider 5	$5	$4	$0.71	$4.71
Total	$44	$35	$5	$40

Source: CEC staff

C. Option 4 Capacity Allocation Method

If the total offered nominated committed capacity (ONCC) across all aggregators (providers) participating in Option 4 exceeds MaxCC specified in Chapter 6, the CEC will allocate the available capacity to the participating providers as described below.

For each month, the allocation process involves multiple rounds to fully allocate the MaxCC among the participating providers, with P_0 representing the number of participating providers:

Round 1

- All providers (P_1) with offered nominated committed capacity (ONCCs) less than or equal to the Available Capacity Per Provider in Round 1 (R1ACPP), where R1ACPP = MaxCC/P_0, are allocated nominated committed capacities (NCCs) equal to their ONCCs, resulting in total committed capacity at the end of Round 1 (referred to as R_1CC, where R_1CC = sum of NCCs across the P_1 providers).
- All remaining providers (P_0-P_1) with ONCCs greater than R1ACPP continue to Round 2.

Round 2

- All providers (P_2) with offered nominated committed capacity (ONCCs) less than or equal to the Available Capacity Per Provider in Round 2 (R2ACPP), where R2ACPP = (MaxCC-R_1CC)/(P_0-P_1) are allocated nominated committed capacities (NCCs) equal to their ONCCs, resulting in total committed capacity at the end of Round 2 (referred to as R_2CC, where R_2CC = sum of NCCs across the P_2 providers).
- All remaining providers (P_0-P_1-P_2) with ONCCs greater than R2ACPP continue to the next Round.

Round X (final)

- The steps in Round 2 are repeated in additional Rounds as needed, until only the providers (P_0-P_1-…-P_{X-1}) with ONCCs greater than Available Capacity Per Provider in Round X (RXACPP), where RXACPP = (MaxCC-R_1CC–R_2CC - … -R_{X-1}CC)/(P_0-P_1-…-P_{X-1}) remain. These providers are allocated nominated committed capacities (NCCs) equal to RXACPP.

Example:

MaxCC is 100 MW. There are three participating providers (P_0=3) and their NCCs are 30, 40, and 50 MWs, respectively.

Round 1: One provider (P_1=1) has ONCC less than R1ACPP = MaxCC/P_0 = 100 MW/3 = 33.33 MW. That provider is allocated NCC equal to their ONCC = 30 MW, resulting in total committed capacity at the end of Round 1 (R_1CC), where R_1CC = sum of NCCs across P_1 = 30 MW.

The remaining providers (P_0-P_1 = 3-1 = 2) with NCCs (40 and 50 MWs) continue to Round 2.

Round 2 (final): The providers in this round all have NCCs that exceed R2ACPP = (MaxCC-R_1CC)/(P_0-P_1) = (100 MW – 30 MW)/2 = 35 MW. They are each allocated NCCs equal to R2ACPP = 35 MW.

The total MaxCC of 100 MW is now fully allocated to the three providers: 30, 35, and 35 MWs, respectively.

D. Temperature Weights (Option 4)

The temperature weights applicable to stations in a UDC territory will be determined by CEC at the end of the season as follows:

- Step 1: From the available CALMAC weather stations, match each station's zip code with the corresponding UDC service area.
- Step 2: Filter for stations with complete weather data during the program season in the last 10 years; exclude stations with incomplete data.
- Step 3: Use the historical temperature data from the filtered stations as independent variables in a Least Absolute Shrinkage and Selection Operator (LASSO) regression model, with historical California ISO daily peak load between 4:00 p.m.–10:00 p.m. from May through October of last 10 years as the dependent variable. The regression estimates the relationship between cooling degree days (with a reference temperature

of 66°F)[15] from each CALMAC weather station and UDC TAC area daily peak load. The resulting coefficients for each weather station represent the UDC temperature weights, indicating each station's relative contribution to explaining historical peak load variation.

E. Planning Temperature (Option 4)

The planning temperature is a UDC-wide composite temperature value fixed for the programming season and is determined by CEC as follows:

- Step 1: Utilizing the same set of historical data of last 10 years from 4-10 PM window used to generate the UDC temperature weights above (and in Table 4), calculate the annual composite peak temperature for the UDC as a weighted average of the peak temperature across all weather stations in the UDC, using temperature weights associated with the stations.
- Step 2: Fit a Gumbel extreme value distribution per UDC territory to the UDC's composite peak temperatures over the last 10 years using a 4-year return level. The resulting temperature value is the UDC's T*Plan* for the program season.

15 Using a temperature of 65 or 66° F is a standard reference temperature used in California utility load analysis, representing the threshold above which cooling demand begins to significantly impact electric load.