DOCKETED

Docket Number:	22-RENEW-01
Project Title:	Reliability Reserve Incentive Programs
TN #:	250122
Document Title:	Generac Comments on Proposed DSGS Guidelines
Description:	Comments of Generac Power Systems
Filer:	Meredith Alexander
Organization:	Generac Power Systems
Submitter Role:	Public
Submission Date:	5/11/2023 4:41:02 PM
Docketed Date:	5/11/2023

Generac Power Systems
S45W29290 Highway 59
Waukesha, WI 53189

P: (262) 544-4811
W: www.Generac.com

May 11, 2023

California Energy Commission
Docket Unit, MS-4
715 P Street
Sacramento, CA
Via docket submission

Re: Docket No. 22-RENEW-01 - Reliability Reserve Incentive Programs - Comments on Proposed Draft Demand Side Grid Support (DSGS) Program Guidelines, Second Edition and April 26, 2023 Workshop on the DSGS Program

Dear Vice-Chair Gunda and Commission Staff,

Generac Power Systems (Generac) appreciates the opportunity to comment on the Draft Demand Side Grid Support (DSGS) Program Guidelines and respectfully submits the following comments on the proposed programs.[1]

California's electric grid is in an unprecedented position of resource scarcity. Capacity available to Load Serving Entities (LSEs) to contract for Resource Adequacy (RA) is at an all-time low, and capacity costs are at an all-time high.[2] There has been a 40% reduction in the availability of imported capacity in the last 4 years[3] -- all of which led the CA Legislature in 2022 to do something it had never done before: create new distributed energy resources programs funded by taxpayers through the budget process. The Legislature put its trust in the California Energy Commission (CEC) to develop new and innovative programs in a timely manner that could contribute to the immediate grid reliability challenges that California faces.

Generac Power Systems ("Generac") commends the CEC for their commitment of time and resources to develop an expanded DSGS program for Summer 2023. Overall, we find that certain program proposals will allow for new distributed resources to provide the grid much needed capacity, but most of this capacity would not be available until 2024. Generac is hopeful that we will be able to provide the grid with some much-needed capacity from certain commercial customers, particularly from water agencies in 2023— but will be constrained beyond that by the limitations of the overall program.

In these comments, Generac offers insights and recommendations that apply to the overall DSGS program framework as well as specific recommendations for each option.

---

[1] Note: page references throughout our comments refer to the Draft Second Edition DSGS Program Guidelines: 4/20/23

[2] Laura Shybut, Assembly Committee on Utilities and Energy, April 2023, AB 1373 Bill Analysis *available at* leginfo.legislature.ca.gov

[3] Source: publicly available RA market data, *available at* www.caiso.com

Summary of Comments on Program Options:

In addition to over-arching comments on DSGS guidelines, our comments focus on these key points for each program option:

- Option 1: The CEC should expedite this pathway for commercial customers, specifically water agencies. The CEC should expand option 1 to all residential IOU customers, rather than relying on only ELRP to realize energy savings for summer reliability and should consider improving the overall structure by including a capacity payment.
- Option 2: To be effective, the CEC must simplify this option to provide more revenue certainty and lower participation barriers.
- Option 3: With key modifications to incentive levels and structures, Option 3 presents an innovative pathway to unlock capacity from BTM batteries.
- Proposed Option 4: Using Option 3 as a template, the CEC should create a parallel program pathway for direct load control technologies including thermostats and water heaters that includes a capacity payment structure.

I. Overall Findings on the Proposed DSGS Program Guidelines

1. **<u>While Generac commends the CEC for creating program pathways for certain use cases, the program eligibility guidelines as proposed do not go far enough to unlock capacity from customers across California, especially residential customers.</u>**

We understand that there are many policy goals and considerations to balance, the ambition and scale of this proposed program does not reflect the funding and intent to include "all non-utility DR enrolled residential customers" set forth by the Legislature in AB 205 and AB 209 (*Committee on Budget, 2022)*, nor the coming threat to California's grid reliability that the Legislature directed the Commission to abate.

As created by, and given significant funding via, recent legislation, the DEBA and DSGS Programs present tremendous opportunities for investment decisions that improve reliability and foster the Distributed Energy Resources (DER) market across the state. AB205 (*Committee on Budget, 2022)* created both DSGS and DEBA and recognized "cost-effective demand response and efficiency" as a top priority in the loading order. Currently, DERs across California present thousands of untapped megawatts that have the potential to cost effectively provide reliability benefits now with low or zero emissions. Much of this potential exists in the homes of Californians; most of whom do not participate in demand response or emergency load reduction programs due to burdensome enrollment processes, lack of knowledge, or other barriers to access. Generac finds that these barriers are not adequately addressed in the DSGS guidelines as proposed (further elaborated in section 3). The CEC has an opportunity to engage thousands of California homes to improve reliability and visibility into load flexibility resources, maximize emissions reductions, and ensure equitable access to DER benefits.

The Legislature appropriated $295 Million and $700 Million over 5 years for the DSGS and DEBA programs, respectively. Based on the Governor's proposed budget, $95M of the DSGS fund and $100M of the DEBA fund will be spent in the 2023-24 budget year. Since a large portion of the budgets, especially the DSGS budget, is to be spent this year, it is crucial that the CEC sets strong precedents for these programs in line with their statutory intent and tied to real-world impact.

The Legislature intended for the DSGS program to be a statewide program that maximizes customer participation without dual enrollment. AB 205 specifically created the DSGS program, and provides that its purpose is 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. . . The commission shall allocate moneys to develop a new statewide program that provides incentives to reduce customer net load during extreme events with upfront capacity commitments and for per-unit reductions in net load."

Most notably, the Legislature modified the language of the DSGS program later in the session via AB 209, to specify that: "[e]ligible recipients may 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 Public Utilities Commission (CPUC)." Although the language allows for the addition of other "participation requirements or limitations," there is no ambiguity in the statutory intent of expanding eligibility to all residential customers that are not presently enrolled in existing utility programs overseen by the CPUC.

Generac urges the CEC to act with an exigency that recognizes California's reliability risks. Recent extreme events such as the September 2022 heatwave highlight the need to shore up emergency response capability. The response to this heatwave required "all hands on deck," including substantial voluntary reduction on the part of everyday Californians. As created and funded, DSGS could bring in as many Californians to respond to emergencies as possible while providing customer benefits that adequately recognize their contributions—but the current proposal will fall far short of this potential.

We find that the DSGS program, as proposed in the draft guidelines, is still not in line with clear legislative direction to provide additional capacity to the grid in times of stress.

A. <u>As proposed, DSGS will leave significant potential capacity out of the program.</u>

In taking a holistic view of the proposed DSGS guidelines, current emergency response programs, and demand response programs – there remains a significant gap between the potential capacity of residential customers in California and the realistic amount of capacity that can be tapped into by these programs. Significant eligibility and enrollment barriers put forth by the DSGS guidelines would severely inhibit this potential.

As proposed, Generac finds that it would be limited to providing only 4 MW to eligible POU customers from smart thermostats instead of 50 MW from all statewide eligible customers when its smart thermostat emergency grid reliability product is ready next summer. As discussed below, there is an additional 20 MW in available firm water heater capacity that will not be able to participate in DSGS programs as well. The revised guidelines do not expand the program to all customers not currently enrolled in an IOU DR program. Generac's recommendations throughout this document focus on lowering barriers to participation and in expanding program pathways, especially with regards to residential load-based technologies.

2. The DSGS and DEBA programs should be designed in tandem to create clear, near-term, and coordinated market-signals to maximize reliability investments.

After reviewing the proposed DSGS guidelines and learning that the Distributed Electricity Backup Assets (DEBA) guidelines will not be finalized concurrently, as an aggregator, we believe the two programs should be designed to work in tandem. The DSGS Program on its own is not enough to grow distributed energy resource (DER) and demand response (DR) capacity – especially at the proposed incentive levels and structures. The DEBA Program is necessary to provide upfront incentives to adequately incentivize the *addition* of clean, flexible, and reliable capacity onto the grid. Specifically, the DEBA incentive would significantly expedite deployment to the water agencies, as envisioned under "Option 1."

The DEBA Program can accelerate the effectiveness of the DSGS Program in the near-term with a relatively small amount of funding by providing upfront incentives for connectivity upgrades and DERMs technology. This would be especially effective for commercial customers with backup generation, such as water agencies. The CEC should explore this use case as an opportunity for DEBA in 2023. For water agencies, we estimate that the 2023 DSGS incentive payments would be sufficient to cover the costs of connectivity to increase the amount and speed of capacity available to the CEC from water agencies as long as they are called for at least 4 hours. DSGS payments on their own may not allow as sophisticated of connectivity or full "virtual power plant" aggregation of the resources, as these services would incur additional costs to the administrator or aggregator.

Providing DEBA incentives to water agencies, in addition to DSGS, would significantly accelerate deployment of the connectivity functions, as it would provide an upfront payment rather than requiring the customer to take on risk or the use of a separate financing mechanism. From Generac's perspective, the DEBA upfront incentive structure is better suited to support connectivity devices, and a very small allocation of the DEBA fund ($5M of the $700M) would significantly increase the speed of adoption of these programs across water agencies.

We recommend that the CEC work to align the timelines of DEBA and DSGS program development and implementation. Without understanding both programs concurrently, there is too much uncertainty for prospective providers and aggregators to innovate and realize effective business models that meet the goals of both programs.

3. Across all program options, the CEC should address key barriers to DER and demand flexibility deployment including a) energy-based payments, b) incentive levels and administrative structure, c) enrollment processes, and d) settlement processes.

Fundamentally, there are several barriers to DER and demand flexibility deployment that have historically inhibited growth in virtual power plant (VPP) capacity in CA:

a. Energy-based payments: programs that rely solely on energy-only based payments put all the risk on the customer, therefore most states have adopted capacity-based payments.
b. Incentive levels: despite the growing need for capacity, CA programs lag well below program payment levels in peer states.
c. Enrollment process: the current enrollment processes are onerous, bespoke, and slow.
d. Settlement process: settlement can only be done using aggregate load data or inverter data.

An overarching area of concern for Generac is that while the CEC is tasked with accelerating incremental deployment, the proposed DSGS guidelines do not seem to substantively address these barriers. We provide greater detail on each barrier below as well as provide recommendations for how the CEC could better address them within its guidelines.

a) <u>As compared to behavioral energy-based programs, advanced demand response capacity-based programs are more effective for reliability and more attractive to customers.</u>

At the recent workshop, CEC Staff implied that the Emergency Load Reduction Program (ELRP) is an effective alternative to the CEC incentivizing growth in distributed capacity statewide through DSGS. In our discussion of "Option 1" we lay out why ELRP falls far short of what CEC is capable of achieving through an expanded DSGS program for residential customers. Focusing on ELRP neglects the potential for firm, demand-side capacity, such as what can be delivered by smart thermostats, water heater controls, or EV chargers. Energy-based payments are by their nature highly variable due to differing dispatch behavior year-to-year. Without minimum compensation, all the revenue risk is on the customer. While this might be acceptable in cases where there is no upfront cost to enroll or enable participation, this is never the case for more advanced technology-enabled participation. Placing this risk on the customer or their aggregator will disincent residential or small business customers. For programs that require retrofit technologies (such as load controls or connectivity), capacity payments are more important. Energy only-payments also force aggregators to price in the cost of potential revenue exposure into their offerings.

While we discuss the benefits of proposed Option 1 below, we emphasize in our proposed "Option 4" that we believe a statewide program providing capacity payments not just to storage resources, but also to load-based resources would be more effective. Significant potential for firm, reliable capacity from advanced demand response assets will be missed by programs like ELRP, or CEC's proposed option 1 .

b) <u>The CEC should increase incentive levels across proposed options to adequately incentivize resources, and should increase flexibility in administrative payment structures to make these options viable for prospective DSGS providers and customers.</u>

To increase the viability of the entire program, our comments recommend improvements including incentive structures and payment structures. If this cannot be done by the CEC now, the CEC should revisit the program in the fall of 2023 and re-consider a simplified statewide DER program. Overall, the payment structure proposed for DSGS providers and aggregators poses a market barrier that will restrict the ability of aggregators to craft creative incentive offerings for customers. Across the board—incentive levels are not sufficient to accelerate the deployment of DERs for emergency capacity response or justify the high transaction costs of enrolling residential customers.

Despite an urgent need for capacity, DSGS incentive levels are too low both in comparison to other states and with respect to established avoided cost methodologies in California. Participation often requires costly equipment that can take years to pay off; having low and uncertain incentive structures does little to motivate customer adoption. The table below demonstrates different storage incentive programs around the country:

Table 1. Storage Incentive Benchmarking (based on market rate residential 5kW/18kWh battery, 3hr nomination, 10% discount rate)[4]

Program	Upfront Payment ($/kWh)	Upfront Payment ($/kW)	Capacity Payment ($/kw-yr)	Energy Payment ($/kWh)	5-yr Levelized Cost ($/kW-yr)
CT-ESS[5]	$200	$0	$225	$0.00	$315
Connected Solutions (RI)[6]	$0	$0	$400	$0.00	$303
ComEd[7]	$300	$0	$0	$0.00	$216
HECO Battery Bonus[8]	$0	$850	$60	$0.00	$215
Connected Solutions (MA)[9]	$0	$0	$225	$0.00	$171
GMP BYOD[10]	$0	$850	$0	$0.00	$170
Xcel Battery Connect[11]	$0	$500	$20	$0.00	$115
HECO BYOD (proposed)[12]	$0	$500	$60	$0.00	$145

[4] In order to provide a common point of reference, we calculated 5-yr levelized costs for a standard battery size (in this case, modeled as Generac's PWRcell M6 unit) for a market rate (non-LMI) residential customer with no locational incentive adders. For ELRP, we assume 30 hrs of dispatch per year, consistent with historical dispatch trends.
[5] https://energystoragect.com/homeowner-faq/
[6] https://www.rienergy.com/RI-Home/ConnectedSolutions/BatteryProgram
[7] https://www.comed.com/SmartEnergy/MyGreenPowerConnection/Pages/SolarRebates.aspx
[8] https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/battery-bonus
[9] https://www.masssave.com/residential/rebates-and-incentives/connectedsolutions-batteries
[10] https://greenmountainpower.com/rebates-programs/home-energy-storage/bring-your-own-device/
[11] https://nm.my.xcelenergy.com/s/renewable/battery-connect
[12] https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A22K01A83518A00217

RMP-UT WattSmart[13]	$0	$400	$15	$0.00	$91
DSGS Option 3 (proposed)	$0	$0	$75	$0.00	$56
ELRP	$0	$0	$0	$2.00	$45

As demonstrated above, even if the proposed DSGS guidelines go into effect, California's incentives will lag behind nearly a dozen programs in mature markets. If the CEC is looking to provide an incentive to drive greater adoption of storage providing dispatchable capacity to the grid, then it should look to benchmark itself against successful programs seen in Hawaii or New England.

We recognize that there is a need to index incentive against to CA-specific values as opposed to simply borrowing values from peer programs. A good point of reference would be the Avoided Cost Calculator's avoided capacity cost component. The most currently 2022 ACC Capacity Avoided Cost provides a nominal avoided capacity cost of $165/kW-yr in 2023, climbing to $257/kW-yr in 2024. Given that the benchmark resource is a 4-hr utility-scale battery, this is an appropriate benchmark for incentives for a 4-hr BTM battery.

For aggregators and administrators, the proposed payment structure requires clarification and should be revised to provide flexibility for aggregators. The draft guidance is unclear regarding what and how aggregator costs can be recovered – more guidance is needed on this point. Administrative costs are offered under two structural options (p.17). The guidelines could be interpreted to say that DSSG providers must choose either 10% of incentives or 10% of costs when administering a program. This is too rigid, as the logical choice may vary from program to program. Further, the prescriptive nature of the payment guidelines will make it very difficult for aggregators to create structures that may motivate customers to participate (e.g., sign-up incentives), thus potentially limiting customer enrollment.

We agree with CALSSA's comment regarding compensation and reimbursement and emphasize that all aggregators should be able to allocate incentive payments between the aggregator and its customers pursuant to an agreement reached between them. The final guidelines should state that VPP aggregators serving as DSGS providers shall pay the appropriate portion of eligible incentive amounts to their participating customers pursuant to an agreement between participant and provider.

c) <u>The CEC should streamline enrollment requirements and allow DSGS providers more discretion over customer enrollment.</u>

The enrollment processes proposed for both DSGS providers and customers are too onerous and will result in high barriers for enrollment and long lag times between application and approval. For providers, the CEC should provide more clarification and guardrails on the IOU notification and CCA permission process to reduce the burden on DSGS providers. Further, the CEC should allow DSGS providers and aggregators more discretion over customer enrollment.

[13] https://www.rockymountainpower.net/savings-energy-choices/wattsmart-battery-program.html

Generac Power Systems
S45W29290 Highway 59
Waukesha, WI 53189

P: (262) 544-4811
W: www.Generac.com

As noted in previously filed comments, the enrollment process currently used for market-integrated demand response is far too onerous for residential customers. The "click through" process currently in place for market-integrated DR requires multiple steps in the customer journey, including providing account number and waiting for the utility to verify no issues with dual enrollment. This has a disproportionate impact on "low engagement" customers, such as residential customers who are not making a large purchasing decision (such as installing solar or a battery).

Every additional administrative step reduces the number of participants in a program. A white paper by EnergyHUB[14] illustrated this issue, comparing the DRAM participation process to ERCOT, where the process is much more seamless and does not require a utility account number. The table below shows how customers drop off at each step in that process.

Table 2. EnergyHUB Comparison of CA and TX Enrollment Processes

ERCOT and TDSP programs 2015		California DRAM 2016 (PG&#)	
Customer receives program offer	100%	Customer receives program offer	100%
Customer agrees to participate in program (no service account number required)	55%	Customer agrees to participate in program and provides service account number	9%
		Customer completes CISR-DRP form on third party site	5%
Customer is accepted into program	42%	Customer is accepted into program	3%

Generac runs similar programs across the country, and these findings on enrollment strongly resonate with our own experience recruiting customers into programs across our fleet of thermostats, generators, water heating controls, and energy storage.

The CEC can improve the outcomes of DSGS by simplifying the enrollment process for DSGS participants. If the CEC's goal is to accelerate enrollment in programs, putting more control of that process in the hands of technology providers will go a long way. The CEC could enable a simple address lookup process administered at the state level similar to what has been implemented by ERCOT and allow each provider or aggregator to manage the terms and conditions through their own process. If the results in Texas are any indication, this could increase participation by at least a factor of ten.

[14] See: https://415845.fs1.hubspotusercontent-na1.net/hubfs/415845/W.hite%20papers%20(2021)/EnergyHub_OptimizingEnrollmentProcess_Whitepaper_2021.pdf

d) <u>The CEC should simplify settlement for all DSGS program options by allowing device-level telemetry.</u>

Currently, all settlement for storage resources requires aggregate load data or meter data, making it difficult for load-based resources to participate. As outlined in Generac's previous DEBA/DSGS program proposal submitted into this docket, we believe another key to opening participation is to allow DR/DER resources to participate using device level telemetry for settlement (specifically in a new DSGS Option 4, outlined later in the document). Device-level telemetry allows for better fidelity for devices such as water heater controls and smart thermostats and reduces the need for onerous data transfer authorization with the utilities. In many cases, connected devices can provide more accurate, granular, and end-use specific data than can be provided by whole-home advanced metering (AMI). For instance, our water heater controllers collect real-time energy data at one-minute intervals at the device level.

There has long been precedent for using end-use data for measurement and verification (M&V) of demand response impacts, both within markets and utility programs. For instance, FERC's M&V[15] guide cites this as a common use case where two-way communicating devices are present. Further, several utility programs across the country including in Massachusetts, Colorado, New Mexico, Ohio, and Texas use smart thermostat telemetry to quantify energy impacts.[16] There is also a corollary within the CEC's own draft guidelines: Option 3 allows for baselining based on inverter-level measurements. We strongly recommend that for all options that allow load-based participation, that device-level measurement is allowed for settlement.

II. Comments on Option 1

1. <u>For commercial customers and specifically water agencies, Option 1 presents a viable pathway to unlock existing available capacity to support the grid during emergency conditions, but it must be approved immediately to be available for Summer 2023.</u>

Generac commends the CEC for recognizing the essential role of water agencies in emergency capacity response and urges the CEC to prioritize making this option available as soon as possible. If the guidelines for only water agencies/ other commercial customers could be adopted immediately, it *might* be possible to enroll customers before the peak summer demand periods (August and September), but the CEC needs to act immediately. We recommend the CEC separate the guidelines for this program from the rest of DSGS and request Commission approval ASAP so that thousands of water & wastewater facilities can be enrolled quickly. These agencies have backup generation ranging in sizes up to 3.25MW. Manually dispatching these resources, as was done last year, is time and resource intensive. Therefore, DSGS incentives will lead to much greater resource efficiency and increased participation from water agencies.

[15] See: https://www.ferc.gov/sites/default/files/2020-04/napdr-mv.pdf

[16] See Xcel Energy New Mexico's Saver Stat Program, Xcel Energy Colorado's Smart Thermostat Pilot Program, National Grid's Connected Solutions Program, CPS Energy's Rush Hour Rewards Pilot Program, and Vectren's Residential Smart Thermostat Pilot Program.

This year, it could be possible to deploy cloud-based IoT monitoring and control solution for real-tie generator access to aggregators. Next year, Generac hopes to deploy battery systems alongside generators to reduce carbon emissions for short duration events and provide municipalities with more efficiency and compensation. As stated in our introductory comments, much more will be possible if DSGS payments are supported by DEBA incentives.

Existing municipal water and wastewater infrastructure offers clear opportunities to meet DSGS program goals, with several unique aspects:

- Significant Existing Back-up Capacity: virtually all water / wastewater infrastructure is supported by emergency (full) back-up power generation.
- Broad Reach: wide geographic distribution to all regions of CA to target specific locations during events (both large and small municipalities).
- Uniform Application Deployment: CEC programs to utilize this infrastructure can be defined and applied consistently across these sites to maximize the speed of deployment (and access to the capacity).
- Ideal Sites for Clean Energy Transition: targeting new programs for these agencies will provide immediate and broad-reaching impacts to CA. Many of these agencies are the largest energy users on their local distribution grid.

A. <u>The CEC should increase flexibility in payment structure and provide necessary clarifications on eligible payments.</u>

Generac finds that this program option could be greatly improved with increased flexibility in the payment structure for aggregators. More flexibility could allow aggregators to quickly deploy connectivity upgrades and increase participant enrollment. This option could also be greatly improved with a tandem DEBA pathway that would provide upfront payments for connectivity upgrades. A very small allocation of the DEBA fund ($5M of the $700M) would significantly accelerate access to capacity from water agencies (CEC realized 150 MW of capacity from water agencies in September 2022 emergency conditions).

We request clarification on the provision of “no payment for the same reduction” and how this would apply to commercial customers currently enrolled in a utility DR program, specifically: who could provide additional load reduction under DSGS due to a having an on-site generator? The guidelines need to be clarified between the load and the customer. We believe CEC’s intent is to allow for incentives for incremental load at a commercial facility, and we ask for the guidelines to be re-drafted to confirm this point. The guidelines also need clarification regarding how a “resource” will be defined: is it the “widget” or the integrated DERs at a customers’ facility?

2. **For residential customers, Option 1 excludes large segments of the market that have valuable and untapped DER capacity from participating and contributing to needed reliability solutions from both smart water heaters and smart thermostats.**

The CEC should expand and improve Option 1 in terms of scale and ambition to reflect legislative intent and the present reality that our electric grid is likely to experience more grid emergencies and near emergencies in 2023, due to a continued shortfall of available capacity and due to the realities of climate change. As currently structured, the CEC is deferring to the IOU's ELRP program as the reason why DSGS cannot be offered to all Californians. This understates the value to the grid of avoiding a blackout which is higher than the incentive currently offered by ELRP. ELRP enrollment is also burdensome and complicated. The CEC could provide an additional, limited time, bonus payment to ELRP customers, and could allow non-ELRP participants to enroll in statewide programs run by 3rd party aggregators. Not only are these options available to the CEC, but the legislation creating DSGS requires nothing less.

The CEC should prioritize enrolling capacity from thermostats and smart water heater controls as strong applications for emergency demand response – these are customers and DER assets that do not necessarily want to participate in a more traditional DR program, but are likely happy and able to respond in an emergency, especially if that response is controlled automatically by a company they trust. By excluding IOU customers from Option 1 and limiting it to an ELRP-like structure, the CEC is unnecessarily reducing the amount of capacity available for emergency response. For ecobee smart thermostats, this results in a reduction of potential capacity response from 50 MW statewide to only 4 MW in POU territory. The likelihood of unlocking this 4MW is diminished by the need to receive approval from the POU governing boards to run a program in their territories.

Overall, we recommend two potential pathways for the CEC to consider: one, expand and improve option 1 for all residential customers so that it could capture more capacity from less-expensive existing technologies (like smart-thermostats), or two, to build a new option that parallels option 3 by including a capacity payment, and therefore would capture more advanced technologies. This would be more effective, but at a minimum we recommend at least improving on Option 1 as we discuss here.

A. ELRP will not be sufficient to provide meaningful capacity to the grid during summer grid events.

We do not believe that residential IOU customers will contribute significantly to grid resiliency by participating in ELRP because the ELRP program is not designed to allow smart thermostat automation technology to achieve scale. First, it is a behavioral program, not an automated load control program. Second, ELRP payments are quite low, presumably driven by their loose participation requirements and non-firm commitments. Focusing on ELRP neglects the potential for firm, demand-side capacity, such as what can be delivered by smart thermostats, water heater controls, or EV chargers. Presuming ELRP is sufficient for these resources undervalues the resource that direct load control provides. The CEC should focus efforts on advanced/automated demand response capacity-based programs rather than behavioral energy-based programs similar to ELRP (as presented in Option 1), as advanced DR capacity-based programs are more effective for reliability and attractive to customers.

There are two ELRP participation categories in which smart thermostats could ostensibly participate, but these leave dozens of MW on the table. One of these categories is ELRP A6 – Residential customers. However, the required response from this participation category to a flex alert is behavioral, not automatic, meaning that customers must be willing and available to manually adjust a thermostat in response to a flex alert rather than allow their smart device to respond automatically. Our experience with a 2020 SDG&E grid resiliency pilot showed that automated responses to flex alert delivered significantly more capacity than the existing behavioral one.

The other potential category is ELRP B1 – Third party DR Providers. This category is defined as a market-integrated proxy demand resource, and it is well known that market registration represents a burden on the customer that the vast majority – 97% in one ecobee pilot – will never take on. Ecobee has found that free devices coupled with generous cash incentives are still not enough to persuade customers to struggle through the Share My Data Process. Therefore, neither DSGS option 1 nor the ELRP are sufficient to allow smart thermostats to provide emergency grid resources at scale. This is a major missed opportunity to support the grid.

B. <u>An improved Option 1 could capture additional capacity from smart-water-heater controls.</u>

Generac previously proposed to the CEC an automatic water-heater control program for grid resiliency, which if deployed statewide in 2024 would offer 20MW of grid resiliency assets. Our proposed Water Heater Market Transformation program would remove the barriers noted above by moving upstream to transform how electric water heaters are delivered to Californians. The need for flexible electric water heating is only increasing as California seeks to electrify end uses and regional demonstrations have shown that large scale efforts can achieve cost-effective flexibility at scale.[17]

Generac would coordinate with water heater manufacturers to deploy our low-cost controllers as a default on all the units sold in California, with the end goal being the conversion of water heaters into a network of dispatchable thermal energy storage devices that can contribute significant incremental capacity in support of California's grid. We have explored this concept with all major manufacturers and they have significant interest, provided the scale that CEC could provide to a program. However, given the enrollment barriers this type of offering would be untenable under the construct proposed within Options 1 or 2.

The initial growth in ELRP was likely due to a combination of low-effort behavioral interventions and existing high-engagement customers. This low-hanging fruit is often seen in behavioral programs at their initial launch, but it rarely results in sustained growth. For instance, the most robust comparison would be Baltimore Gas and Electric's behavioral portfolio, which most notable included an opt-out peak time rebate of $1.25/kWh to its roughly 1.1 million residential customers. According to annual program

[1] Bonneville Power Administration, *CTA-2045 Water Heater Demonstration Report Including a Business Case for CTA-2045 Market Transformation* (2018) https://neea.org/img/documents/CTA2045-Water-Heater-Demonstration-report.pdf

reporting, this portfolio is down to 125 MW in 2021 from a peak of 336 MW in 2016.[13] While these programs can be helpful in engaging customers in the near term, they need to be coupled with firm capacity-based programs in order to build a sustainable portfolio demand-side resources.

C. Other recommendations to smooth implementation of Option 1

Not having a real option for residential customers to participate in Option 1 is especially disappointing because, as discussed below, while residential IOU customers can technically participate in Option 2 and Option 3, Option 2 presents very high barriers to entry for both providers and participants and Option 3 as proposed is not applicable to smart thermostat and water heater customers. Simplified customer enrollment is a *pre-requisite* to unlocking new capacity from Californian's thermostats and water-heaters. Additionally, the CEC should also provide some oversight or appeals process in allowing CCAs to have discretion on granting permission to DSGS providers in their territory.

The CEC should be ambitious in considering DSGS a necessary bridge to future program design, and a sandbox for DER reliability solutions, while acknowledging that some pathways may not continue long-term (a role for utility programs) but will yield useful learnings and immediate impact regardless. Specifically, we think the CEC should consider piloting statewide pathways to access reliability benefits from smart home technologies, including water heaters and thermostats.

III. Comments on Option 2

1. Option 2 does not provide a seemingly viable pathway for significant participation due to its complexity and revenue unpredictability for aggregators.

We do not believe that Option 2 provides a viable pathway for most prospective DSGS providers to invest in the necessary technology and software and to enroll participants, due to its high complexity and the inability to predict expected revenue reliably. Therefore, we believe Option 2 offers little incremental value relative to Options 1 and 3. The barriers to entry for Option 2 are also significant for both providers and participants. For providers that do not currently have market-integrated products, CAISO registration itself is one such barrier.

Option 2 appears to presume that the barrier to greater enrollment is simply that existing aggregator bids are too small, when in fact the issue is high barriers to enrollment and scale. To materially accelerate deployment, the CEC should change the participation model, enrollment process, and incentive structure to better align to the needs of the market.

A. Customer enrollment requirements will pose a significant barrier.

Market integration of residential customers under the current draft guidelines for Option 2 will likely require a customer enrollment process (the "click-through" process) that has been shown to significantly decrease residential customer participation, as discussed previously. Generac/ecobee's national expertise has shown us that the vast majority of residential customers – in most cases, more than 90% of potential enrollees -- fail to enroll in programs that require any information not already committed to memory. This includes data such as their utility account number as required in the draft guidelines for participation under Option 2.

In order to provide maximum grid benefits under DSGS on a statewide basis, we believe that customers instead should be enrolled through their utility directly, opting in through the acceptance of terms that would allow providers, such as ecobee, to participate on their behalf.

Due to multiple barriers, it is likely that only providers that currently have market-integrated customers will be able to participate in Option 2—meaning the likely incremental capacity that DSGS may realize to support the grid from new residential customers under Option 2 will be low overall. <u>Providers will struggle to determine approximate values of "incremental DR capacity" in advance.</u>

We have concluded that the proposed structure is extremely complex and of questionable practical value. More specifically, the structure of "demonstrated capacity" in excess of "reference RA obligation (under Proxy Demand Resource or PDR)" and the resulting "incremental DR capacity" eligible for DSGS incentives, is highly complex and the reasoning for that complexity is not apparent. We echo the comments of others in seeking clarity on the following points:

1) How can a provider (or aggregator) determine approximate values of "incremental DR capacity" in advance? An aggregator would need to know this to justify the investments needed to participate in the market.

Without understanding this, it is hard to imagine why a provider wouldn't just choose to add this incremental DR capacity directly into its existing PDR capacity. If a provider could do that rather than participate in DSGS, then what does the value of the DSGS incentives represent? Is the true value of the resource simply the difference between: (a) treating added DR capacity as DSGS incremental DR capacity; vs. (b) treating added capacity as additional PDR capacity?

2. <u>Due to uncertainty and complexities of potential revenue for Option 2, we recommend alternative approaches to market-based incremental DR under DSGS.</u>

The proposed methodology to calculate performance is highly complex and will make it challenging for providers to estimate revenues in advance reliably. Providers may not be able to provide guarantees or even simple estimates to potential customers —a major enrollment barrier. Option 2 should be reconsidered and simplified in view of the barriers, value uncertainties, and inability to project incremental capacity. While we appreciate the work that CAISO and CEC have put into developing Option 2, we hope CEC will recognize that given importance of further growing market-based DR in the state, Option 2 is not ready for implementation.

Special emphasis should be given to (a) productive ways to aggregate large numbers of residential customers, including IOU residential customers, within market-based DR frameworks, while ensuring low hurdles to enrollment; (b) providing smooth on-ramps for providers who do not currently have market-integrated customers; (c) providing much more certainty in terms of both minimum and typical revenue streams; and (d) avoiding the need to force aggregators to create artificial distinctions (and/or choose) between developing "PDR resources" and developing "incremental DR resources for DSGS beyond PDR resources."

Generac recommends that CEC dedicate resources to further develop Option 2, including developing the necessary administrative, data, and customer enrollment and registration infrastructure that would create a level playing field and lower barriers to entry for the many different types of aggregators. Generac, and other could bring greater market-based DR resources to bear in the state, and find practical approaches to including large numbers of residential customers as program participants.

IV. Comments on Option 3

1. With key clarifications and modifications, Option 3 presents a promising pathway to leverage the capability of behind-the-meter (BTM) storage for reliability benefits.

Generac appreciates the CEC's recognition of potential of BTM storage as demonstrated in Option 3. We specifically commend the CEC's responsiveness to stakeholders in recognizing the need for firm capacity payments and device-level telemetry for settlement. The structure of this option presents an innovative pathway for compensating BTM storage. With some adjustments, we believe this proposal could lead to an effective statewide program to maximize the effectiveness of BTM storage to support the grid.

2. **The proposed incentive levels should be increased to adequately incentivize customers to invest in storage resources.**

As proposed, incentive levels (indicated on p.16) are too low to adequately incentivize the customer when they are deciding whether to invest in storage resources in the first place. Other jurisdictions are paying much higher incentive levels, as we shared above. If considered on a levelized $/kW-year basis, DSGS incentive levels for a 3-hour duration are $56/kW-year, whereas incentives in other jurisdictions are in the $100-300/kW-year range. Annual incentives of less than $100 dollars/kW-year should not be expected to appreciably change investment decisions for storage systems costing $15k and upwards.

Further, we urge the CEC to confirm that incentive payments are independent of the number of events—so that they depend only on the capacity and duration demonstrated during each month, as determined by the submeter or inverter-level measured battery discharge data provided by the provider to the CEC during all events in a given month.

3. When setting incentive levels, the CEC should clarify and acknowledge anticipated interactions between DSGS Option 3 participation and NEM 3.0 bill impacts.

Currently, the incentive levels do not adequately compensate for lost opportunity value of NEM 3.0 exports during all hours. The proposed guidelines are unclear as to whether a participant will still get NEM 3.0 export credit during event hours. We assume this will be the case, but we ask the CEC to provide written clarification. If NEM export credit is lost during event hours, customers will have virtually no motivation to participate in DSGS as currently proposed based on our analysis.

Even if customers keep their NEM 3.0 export credit during event hours, there can be a substantial opportunity cost of not capturing high NEM 3.0 Avoided Cost Calculator (ACC) export values in the process of responding to DSGS events. For example, a DSGS event from 4-6pm could preclude the use of the storage during 6-8pm when ACC values might be very high. We have calculated that for a typical storage product (assuming capacity of 12 kWh being used for 10,000 kWh per year, and with 30-35 DSGS events during the months of August and September) when ACC values can be particularly high, this opportunity cost is on the order of $500/year. Therefore, this opportunity cost could completely negate the value of DSGS incentives.

Relatedly, we are concerned about potential bill impacts to customers from participating in these programs. In CA, with the introduction of NEM 3.0, customers are expected to largely utilize their batteries for self-consumption (offset consumption is compensated at full retail, while export is compensated at the avoided cost rate). While we appreciate consideration given to demand charge impacts in the Option 1 proposal, we did not see any mention of how bill impacts due to export compensation or demand charges in Option 3. Absent any consideration, this leaves customers exposed to large bill impacts from dispatch where export compensation is below the retail rate and/or dispatch results in demand charge impacts.

We conclude that additional incentives are required, such as "true-up" payments between ACC and retail rates that would compensate for lost NEM 3.0 ACC export revenue, or supplemental energy payments in addition to DSGS per-kW payments. Alternatively, CEC should amend the guidelines to reduce the maximum number of DSGS events during the months of August and September when ACC evening rates can be particularly high, limit the total number of dispatches, or constrain them to periods when the export rate likely exceeds retail compensation.

4. **<u>The relative price trigger adds unnecessary complexity and uncertainty.</u>**

The relative price trigger adds unnecessary complexity to both the dispatch protocol and to the determination of the full value of Option 3 to a provider and to participants. When dispatching the resource for DSGS, a provider must decide if that dispatch creates more value than using the storage resource to offset load given prevailing retail rates, avoided cost (ACC) for exports, and state-of-charge conditions, and that decision becomes even more complicated with the inclusion of the relative price trigger. As the overall DSGS program is just starting, it should start as simply as possible.

If the relative price trigger provision is retained, then the language defining this trigger should be clarified so there is no room for misinterpretation. We interpret the criteria as follows, using the following examples. We request that the CEC confirm these examples, and our interpretations of the guidelines contained therein, and clarify any ambiguities:

i. If the day-ahead LMP for a 5-hour period was $200, $250, $200, $250, and $200, and there is a 3-hour capacity commitment, then the event hours would be Hours 2-4 because the mean value of these three hours is higher than the mean value of any other three consecutive hours during the 5-hour period. However, if there is a 2-hour capacity commitment, then who would determine whether the event hours are Hours 1-2, 2-3, 3-4, or 4-5, all of which have the same mean value?

Generac Power Systems
S45W29290 Highway 59
Waukesha, WI 53189

P: (262) 544-4811
W: www.Generac.com

ii. If the day-ahead LMP for a 5-hour period was $200, $190, $190, $190, $200, then would only Hour 1 or Hour 5 be considered event hours even with a 3-hour capacity commitment? So only one hour would qualify for DSGS incentives? Or would three hours still qualify, either Hours 1-3 or Hours 3-5? And again, who would decide which of these two periods would be the qualifying event hours?

5. <u>The aggregated BTM storage capacity requirement should be adjusted.</u>

Regarding the requirement that all VPP aggregation sites be located within the same utility service territory (p.16), 100 kW is more appropriate as a minimum aggregated BTM storage capacity size for two reasons. First, a 100kW minimum is also the aggregation limit used by CAISO. Second, from Generac's perspective, a material portion of the existing storage resources that we could dispatch under DSGS would be sidelined by the 500 kW per service territory requirement.

As an alternative, the 500kW minimum aggregated BTM storage capacity of the VPP should be allowed as the minimum when aggregated across all utility service territories in the state.

6. **<u>Clarify program daily availability hours.</u>**

The CEC should clarify whether the daily availability is 4-10pm or 4-9pm (pp. 17-18). The proposed guidelines appear to be internally inconsistent.[18] 9pm is a more appropriate end-time for the program window, given that 9pm aligns administratively with the TOU and DRAM windows. With a mismatch of the time windows between TOU and DSGS, providers will likely need to remain within the 4-9pm window for DSGS regardless and may more often need to default to TOU in order to be able to provide more certainty to customers and participants. In addition, we do not believe that there are many instances of high prices in the 9-10pm period.

7. <u>Remove additional hurdles to customer enrollment.</u>

The draft DSGS Guidelines mandate provision of the following: Utility identification number (service account ID), Permission to Operate (PTO) date, and verifying/providing Rule 21 compliance (p.5). The customer enrollment hurdles become much more arduous under Option 3 if the customer must provide the utility identification number and PTO date to the provider. Option 3 can apply to customers who are not currently enrolled in any type of program and experience has shown that even the simple provision of this number deters many would-be participants in view of the limited benefits offered. Obtaining the PTO date, as well as verifying and providing Rule 21 compliance, may require identifying and going back to the original installer. This can put certain providers (such as OEMs) at a competitive disadvantage and unduly favor large vertically integrated installers at the expense of smaller installers and innovative aggregation models.

[18] page 17 of the Proposed Guidelines provide for a 10pm ending but page 18 says 9pm.

Finally, Generac seeks clarification on whether a standardized Customer Agreement Form be provided by CEC, or will providers be free to develop their own forms? Generac encourages the CEC to allow the second option.

V. The CEC should create a new program offering – Option 4, parallel to Option 3 for additional distributed resources

As stated earlier, we appreciate the recognition that the CEC is giving to BTM storage in Option 3, recognizing the need for firm capacity payments and device-level telemetry for settlement. This capacity-based model could and should be extended to direct load control devices, such as smart thermostats, water heater controls, and EV charging. We propose, along with CEDMC and AEU that the CEC consider an Option 4, modeled after Option 3, that provides capacity payments to incremental load-based resources.

There is strong evidence from decades of programs both with utilities and in wholesale markets that direct load control assets can provide firm capacity to the grid. Despite the well documented capacity value of these resources, under the proposed framework the only statewide offering available to them would be participation in Option 1 (or its equivalent ELRP at the IOUs), which only provides non-firm emergency energy payments. Adopting a capacity-based approach would provide the incentive needed to drive new and broader deployment of grid interactive technologies; particularly important with mounting electrification of buildings and transportation. Further, expanding market-aware but not yet market-integrated options will have the benefit of providing learnings and acclimating customers to having market-responsive devices and appliances for real-time pricing uptake in 2026.

1. <u>Create a new option that broadly follows the structure of Option 3 with market-aware capacity payments.</u>

An Option 4 could broadly follow the structure of Option 3, using a capacity payment weighted to LMP and indexed based on the number of hours available. Smart thermostats, and later other devices, can be aggregated into a VPP as alluded to by the proposed Option 3. They are dispatchable in 2- and 4-hour increments with day-ahead notice and predictable capacity delivery.

Providing capacity-payments would improve upon Option 1 by providing greater revenue certainty to participants (to justify the incremental cost of more advanced technology) and more accurately value the standby service these firm capacity resources provide. It would also help to streamline statewide deployment, with a common structure across utility service areas. Programs like the ConnectedSolutions program in New England have been so successful due to the consistent, capacity-based structure, which allows solution providers and aggregators to communicate the value of participation more seamlessly to customers.

2. **<u>Allow settlement with device-level telemetry for direct load control technologies</u>**.

Baselining could be done based on device-level telemetry to ensure that specific impacts are well captured. The CEC should recognize, for example, smart thermostat runtime data as a reliable method to quantify energy impacts. Several utility programs across the country including in Massachusetts, Colorado, New Mexico, Ohio, and Texas already use smart thermostat telemetry to quantify these impacts.[19] Device-level telemetry allows for better fidelity for devices such as water heater controls and smart thermostats and reduces the need for onerous data transfer authorization with the utilities. In many cases, connected devices can provide more accurate, granular, and end-use specific data than can be provided by whole-home advanced metering (AMI). For instance, our water heater controllers collect real-time energy data at one-minute intervals at the device level. The only areas that may need to be revisited would be around number of dispatches, perhaps providing different tiers of participation (e.g. < 20 dispatches/yr, 20-50, >100). Baselines should always be calculated against non-event days for proper measurement.

We strongly believe that this program structure would drive greater participation with existing devices as well as, critically, driving incremental adoption of new grid-interactive devices. By building off the proposal already developed in Option 3, we hope that this would not present an undue burden to CEC staff as they look to launch for this summer.

VI. Conclusion

Grid stressors that were once considered unprecedented are now predictable emergencies. In preparing for 2023 and onward, the Legislature created this statewide taxpayer funded program through DSGS and DEBA and has given the CEC the opportunity to find creative ways to shore up our grid to adapt to increasing levels of resource scarcity.

Generac has reliably been installing backup energy capacity to households and businesses for decades. Providing responsive energy capacity is what we have always done. The CEC can use DSGS and DEBA to leverage households and commercial operations in a statewide "coming together" to support the electrical grid in times of emergency, but we cannot count on individuals to do it on their own and we cannot continue to use emergency tools like "amber alert" messages. These tactics should not be necessary when the state has so much potential emergency capacity behind-the-meter. DSGS, implemented well, will ensure that not only the grid remains sound, but also that participants are compensated appropriately. By decreasing enrollment barriers, increasing incentive levels, and broadening enrollment options, we believe that DSGS will have a keystone role in maintaining grid reliability and can represent a huge success for the CEC.

Thank you for your review and consideration of our extensive comments, which we intend only to strengthen the effectiveness of DSGS for the benefit of California's grid and for all Californians who rely on it. We look forward to continuing to work with your Staff as you refine DSGS and create options for all Californians to participate meaningfully during grid emergencies.

[19] See Xcel Energy New Mexico's Saver Stat Program, Xcel Energy Colorado's Smart Thermostat Pilot Program, National Grid's Connected Solutions Program, CPS Energy's Rush Hour Rewards Pilot Program, and Vectren's Residential Smart Thermostat Pilot Program.

Sincerely,

Anne E. Hoskins

Anne Hoskins
Senior Vice President
Policy and Market Development, Energy Technology
Generac Power Systems, Inc.