| DOCKETED | |
|---|---|
| **Docket Number:** | 22-RENEW-01 |
| **Project Title:** | Reliability Reserve Incentive Programs |
| **TN #:** | 249330 |
| **Document Title:** | Sunrun and Leap Revised Proposal - DER Program Design |
| **Description:** | N/A |
| **Filer:** | Andrew Cole |
| **Organization:** | Leapfrog Power, Inc. |
| **Submitter Role:** | Applicant |
| **Submission Date:** | 3/17/2023 11:53:41 AM |
| **Docketed Date:** | 3/17/2023 |

# Joint Sunrun Leap Proposal - *Revised*

**March 17, 2023**

## Distributed Energy Resource Program Recommendations
## 22-RENEW-01

Sunrun, Inc. and Leap (hereafter "Joint Parties") respectfully submit revised recommendations for an effective DER program. These revised recommendations address feedback from California Energy Commission (CEC) staff and are intended to help guide the CEC as they review the Demand Side Grid Support (DSGS) program guidelines.

This proposal is based in part on the original DSGS guidelines that were issued in August of 2022 and make certain changes to facilitate more rapid deployment of demand side resources. These comments have been filed in the CEC's 22-RENEW-01 docket focused on "Reliability Reserve Incentive Programs". Our purpose is to clearly reflect necessary considerations and requirements to best harness demand side resources to the benefit of system reliability.

The Joint Parties currently have visibility into approximately 150 MWs of dispatchable demand response capacity across the IOU and POU territories that could be brought to the state ahead of summer 2023, as reflected in the following table.

| Technology | Asset Count | Capacity (MW) |
|---|---|---|
| Residential Energy Storage | 15,000 | 60 |
| Residential Electric Vehicles | 10,000 | 15 |
| Residential Air Conditioning | 50,000 | 50 |
| Commercial Air Conditioning | 1,000 | 20 |

Sunrun's portfolio and Leap's partner ecosystem - including such companies as Optiwatt (EVs) and Resideo (smart thermostats) contain thousands of assets that would be on boarded into this program. If implemented well, it is reasonable to expect that total potential is multiple hundreds of MWs for 2023. This would provide much needed firming capacity to the grid during extreme grid conditions as well as help address the evening ramp period. The table above shows the number of currently installed assets amongst the Joint Parties and their associated curtailable load that is currently not participating through any DR program in California. These are already developed, installed, and operating assets that are otherwise not being utilized for any grid services, and we’d expect the potential in the future to be significantly higher with additional time to recruit more partners and end customers.

The revised proposal below steps through the core elements of a successful DER program. The revision focuses on 1) coordination with utilities and CAISO to increase resource visibility, 2) pricing for 2-hour resources, 3) a comparison between the joint parties’ proposal and other current programs in California, 4) differentiation on performance evaluation and pricing structure between existing and new battery resources, 5) dispatch trigger price, and 6) dispatch windows.

It is worth noting that programs similar to DSGS have seen success in other parts of the country. For example, in Massachusetts, the “ConnectedSolutions” program is also a state level retail program that pays for peak reduction performance from customer devices, such as thermostats and batteries. ConnectedSolutions is wholesale market responsive but not integrated - it is leveraged by LSE’s, through program administrators and aggregators, to reduce wholesale market peaks and costs but does not act as supply nor bid into the wholesale market. The program dispatch attempts to hit the ISO-NE summertime peaks and lowers the capacity and energy costs for all ratepayers by doing so. ConnectedSolutions is statewide, across the Massachusetts IOU territories and is metered at the device level. The program runs through the state’s energy efficiency budgets and is widely supported by all stakeholders. It has a 5-year price lock. Similar to the interaction between DEBA as a storage deployment incentive and DSGS as a performance program, in Massachusetts customers who receive storage incentives must participate in peak / reduction reliability programs with ConnectedSolutions being the most popular option.

## I. Third Party Aggregators as Direct Providers

Third party aggregators reliably provide demand response capacity services to utilities and the wholesale market today, and are well positioned to continue this direct provider model via DSGS. This is a role that DR providers are already fulfilling, and indeed third party developed demand response has been the fastest source of DR growth in California in recent years. The CEC’s original DSGS guidelines recommended that LSEs, many of whom have not done this before, would serve as the sole providers and administrators. The Joint Parties strongly recommend that third party aggregators be allowed to be Program Providers as they will be able to develop and bring DR resources to bear in time for the stressed grid conditions of Q3 2023.

This could work in practice similar to how third party aggregators currently participate in the ELRP. Third party aggregators must accept the Terms and Conditions of the program prior to submitting invoices for settlement. For the proposed DSGS program discussed here, the CEC can develop the T&Cs that describe the program in full, including enrollment, dispatching, performance calculation, and finally settlement. Any third party aggregator that intends to participate in the program must accept those T&Cs prior to participation. Whereas the ELRP agreement is between the DRP and the IOU, for the DSGS program the agreement would be between the 3rd party aggregator and the CEC.

## II. **Customer Eligibility**

The CEC already has precedent for this during the September 2022 heatwave when it issued the *Guideline Advisory - Demand Side Grid Support Program.* The Advisory states “aggregators of customers may participate in the DSGS Program as DSGS providers.” It also states: “If AB 209 (Ting, Statutes of 2022) is enacted into law, the DSGS Program will immediately be opened to community choice aggregators and specific customers in investor-owned utility territories, except those that are enrolled in demand response or emergency load reduction programs offered by entities under the jurisdiction of the Public Utilities Commission.”

The Joint Parties support that customers in IOU territories who are not actively participating in an emergency load reduction or market integrated program should be eligible to participate in the DSGS program for 2023 and beyond. The Joint Parties estimate that of the 145 MW of potential load curtailment they have visibility into for summer 2023, 90% of that is located in IOU territories and not wholesale market integrated. While it is true that there is already a participation pathway through the ELRP or direct market participation in IOU territories, there remains a significant number of potential assets that are not currently utilized. This is due to the difficulties of the ShareMyData process that lead to significant attrition for market integrated DR, as well as the ELRP not being a good fit for all remaining assets. Notably the ELRP is an energy based program as opposed to a capacity based program. The intrinsic uncertainty in revenue with an energy only program makes it difficult to sell the program to end customers and recruit them.

The Joint Parties support a similar dual participation restriction. Any assets that are enrolled in a demand response or emergency load reduction program are not permitted to participate, which we discuss in further detail later in these comments. Any customers that may be eligible for one of those programs, but are not participating, would be eligible to participate in the structure we recommend here. This would allow the tens of thousands of assets that the Joint Parties already have engaged in grid services, but who cannot complete the cumbersome authorization and enrollment process required for wholesale market integration, to still provide crucial demand flexibility to the state. Nothing in these comments nor the CEC’s processes will modify the CAISO’s requirements for wholesale market integrated resources. In fact, this proposal does not recommend any energy payment, market or program participation and is otherwise consistent with existing policy.

## III. **Customer Enrollment, Customer Terms, Dual Participation, and Data Requirements**

We share the CEC’s goal of increasing the amount of capacity providing on-going and peak load reductions to support low-cost, resilient operations of the California electric grid. In order to accomplish this goal and to ensure there is no double counting of participants, we focus on several key administrative components: the customer enrollment process, ensuring adequate customer protections, preventing dual participation, and the required data for participation and settlement.

**Enrollment:**
Current customer enrollment processes, for wholesale market integrated resources in particular, are overly onerous and even with significant streamlining have proven a significant barrier to enabling mass participation. The difficulty of the current authorization process for the wholesale market results in far fewer customers signing up for programs to provide capacity and energy, thus leaving significant value unrealized - we see participation rates as low as 2% from some customer bases with most of the customer drop out occurring at the customer authorization stage within the Share My Data (SMD) process which requires customers to 1) go through a completely separate process outside of aggregator's enrollment campaign , 2) use utility credentials to log into the SMD portal to authorize. To help address the substantial attrition we see in the enrollment process and bring all the resources available online, we propose that 3rd party aggregators be permitted to design their own customer agreements that meet a list of specific requirements. 3rd party aggregators will still be responsible for ensuring customers have agreed to participate in demand response programs and that the appropriate customer data needed for identification and enrollment are allowed to be shared with the aggregator, their partners, and the CEC.

**Customer Terms:**
At a minimum, each customer agreement must meet the following criteria:

1. Authorization from the customer to participate with select devices and systems to maintain grid service and demand response related purposes.
2. Authorization from the customer allowing for the use of their device and/or site electric load data for purposes of program participation as long as the data do not contain personally identifiable information.
3. Description of instances in which customer data may be used or released by the aggregator outside of program participation, including:
    a. If disclosure is required by law or court action, including subpoena or warrant.
    b. In anticipation of legal action, including instances of potential fraud or unlawful uses.
    c. Confidential disclosure to aggregator partners, service providers, and contractors, as appropriate to maintain program integrity.
4. A clear and accurate method to unenroll.
    a. Customers should have a simple way to elect to disenroll. Aggregators should provide instructions in the customer agreement, which customers can follow to remove themselves from the program.

Compliant agreements may take any reasonable format used by the aggregator.  There is precedent for such an approach with existing programs.

**Dual Participation:**

A key component of the enrollment process is ensuring that customers are not signed up for an existing program or aggregation that provides the same service(s) from the same devices as the program we recommend here to prevent dual participation and double compensation. Aggregators can and do ask prospective customers to identify any programs they are signed up for, but the reality is that oftentimes customers do not realize they are already enrolled in a program. In order to facilitate quick enrollment and ensure that customers do not subsequently enroll in a conflicting program without that program's ability to verify enrollment, we recommend working through an eligibility check.

This would likely be handled via coordination with the customer's LSE, and potentially the CAISO for market integrated resources. This could be handled by the aggregators, or be a process that is routed through the CEC for efficiency purposes if preferable for the LSEs/CAISO.

One possible approach is to maintain a live spreadsheet, wherein aggregators would record relevant potential customer details and the LSE would confirm whether the customer is enrolled in an existing program by notating as such in the spreadsheet. The spreadsheet or database would be submitted to the LSE. The LSE would respond within a prescribed period of time (ie - 10-15 business days). Any customers that participate in a conflicting program would be ineligible to receive payments for this program. The aggregator would allow customers to opt-out at any time. It is also worth noting that payments will be conditioned on performance, as detailed below, which mitigates the risk of overpayment.

Given the complexity and time required to set up a new verification process, we recommend that, for the first year of the program - 2023 - an interim process be adopted wherein customer dual participation is verified after the season is over. The Joint Parties believe there to be little risk in this approach, as we have tools to minimize any risk that a customer enrolled in this program in 2023 will also enroll in another. For example, we would leverage a combination of the CAISO Demand Response Registration Systems (DRRS)[3] and Demand Response Management Systems that are integrated with device OEMs to ensure no device is being actively managed for a different demand response program. Additionally, we can require attestation at the device or platform level that the devices are not being dispatched for another program.

**Data:**

It is critical that payments be based on performance and that they incentivize load reduction and exports that benefit the electric system. In order to effectively increase the number of participating customers and assets, we strongly recommend leveraging device data and/or sub meter data for the purposes of settlement. These are robust data sets, but they do not require the cumbersome Share My Data process that has proven to be a major obstacle to customer

[3] The CAISO's DRRS system will not allow for a single customer to sign up for more than one market-integrated PDR at the same time. We acknowledge that it's unclear whether aggregators would have the ability to get confirmation from CAISO on a meter's enrollment in the market absent a cumbersome Share My Data authorization, though we are committed to finding an appropriate resolution to avoid dual participation.

enrollment. It is also important that the collection and submission of these data ensure customer data protections.

Nationally, there are many programs (with details outlined in Appendix A) that leverage device level data rather than site level meter data to validate reductions in grid energy usage and export. By leveraging this data, we can accurately reflect curtailments in load from the specific devices that are enrolled in this program without needing to incorporate the effects of other loads at the customer site that might not be actively engaged and being controlled for grid services purposes. This will help simplify and legitimize performance, ensuring that aggregators are only paid for reductions that have occurred due to direct actions from our programs. Further, this highly accurate device metering is already being installed and can be utilized at no additional cost to the customer or ratebase.

## IV. Dispatches and Triggers

Alignment with wholesale market needs is key to ensuring that resources receiving payment are used and useful. Accordingly, these resources should be dispatched on non-holiday weekdays and Saturdays in hours when the CAISO day ahead market prices reach $200/MWh during the 4-9 pm window. We would utilize the SP15 or NP15 DA DLAP CAISO prices for dispatch triggers. If the new program is fully approved by April 1, we would have the capability to dispatch based on day ahead market prices in 2023. However, if approval comes after April 1, then we will make commercially reasonable efforts to implement that capability for 2023, and will have it in effect no later than 2024. If approval comes after April 1, then for 2023 3rd party aggregators should be able to choose between either dispatching based on the price triggers detailed above, or based on when the CAISO issues an Energy Emergency Alert (EEA) at any level.

For test events in any month, we recommend a simplified approach to streamline the operational process. The CEC can reserve the right to schedule a dispatch on their own. However, if there is no eligible dispatch event in any given month, the 3rd party aggregators will schedule a test event during the last day of the month between 4 - 9pm and the length of the dispatch window will be identical to the product duration nominated during the enrollment process. The testing results will be reported to CEC and at minimum, they will include the aggregated performance and the timestamp of the testing window.

Finally, we recommend maximum dispatch hours during the season at 80 hours. This limit is not inclusive of any test events.

### Visibility

There are several different options available depending on the level of visibility required. The Joint Parties propose something similar to the existing RA framework where a ‘supply plan’ would be provided to the utility prior to each delivery month. This supply plan would include a list of each of the participating assets, their locations and resource attributes. In addition, there would be an aggregate nomination of total dispatchable capacity across all of the enrolled resources. Similar to the existing RA framework, there would be a mid month update to account for any new additions or subtractions to the aggregate resource. The Joint Parties propose providing this supply plan in .csv format for each of the utilities. The utilities can then incorporate this supply plan into load forecasts provided to the CAISO, with a forecast of when the resources will be dispatched based on DAM prices. We believe this approach would give both the utility and the CAISO the necessary visibility. The Joint Parties are open to working with parties to consider any additional visibility needs.

This structure is largely similar to the existing Emergency Load Reduction Program where participating DRPs are required to provide nominations at the beginning of the season for the amount of capacity they expect to be available to the ELRP during a dispatch. Note that the proposed method discussed here would provide more visibility into available capacity to the utilities than the existing ELRP. There would be an update every two weeks on the available capacity as opposed to once a season.

It is important to note that telemetry requirements are burdensome and unnecessary for behind-the-meter resources. In fact, just this week, FERC rejected part of ISO-NE's Order 2222 compliance due to telemetry requirements, stating that:

> *(W)e find that ISO-NE fails to demonstrate that its proposed metering and telemetry requirements are just and reasonable and do not pose an unnecessary and undue barrier to individual distributed energy resources joining a distributed energy resource aggregation. Specifically, as discussed further below, we find that ISO-NE does not demonstrate that its proposal to require measurement of behind-the-meter DERs at the RDP, unless the Assigned Meter Reader can accommodate submetering or parallel metering of the DER, is just and reasonable and does not pose an unnecessary and undue barrier to individual DERs joining a DER aggregation.*[4]

## V. Measurement and Verification

Under this program performance will be measured at the device or system level and will vary based on technology.

1. *Battery Storage and Electric Vehicles with the capability of discharging to the home and/or grid:*

It is important to distinguish the performance measurement methodology between existing and new resources. For existing submetered behind-the-meter batteries and electric vehicles, we recommend that Measurement and Verification ("M&V") leverage the existing metered generator output (MGO) methodology option adopted by the CAISO for use with asset-backed resources participating via the Proxy Demand Response (PDR) model. This methodology accounts for

[4] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230301-3087&optimized=false (Paragraph 162)

existing use of the battery in the baseline calculation which addresses any concerns regarding incrementality that can be specifically attributed to the DSGS program. The MGO baseline used for this new program would include exported energy and charging energy in the baseline. Aggregators should have the option of choosing between a 10-in-10, 5-in-10, or control group methodology to calculate the output baseline. The relevant comparison period in non-event days is for the exact period in which the battery was dispatched on the event day.

An alternative baseline methodology, for existing resources, that assumes a fixed amount of base dispatch on an hourly basis could also be considered. Having a fixed amount of dispatch that sets the minimum threshold for performance would allow the program to account for the amount of dispatch that is typically occurring for TOU purposes. If a system could show dispatch above and beyond this fixed amount of TOU based dispatch then it would be considered incremental from existing use and therefore be credited as performance under this program. Further modeling is required to determine the appropriate fixed amount of capacity that is typically occurring for TOU purposes. It is also important to consider that a minimum state of charge is generally reserved in a battery for backup power purposes - that minimum state of charge (e.g., 20-40%) must be considered when evaluating a modeled baseline approach. In other words, that reserved capacity should not be included when considering how much of the battery should be assumed to perform for TOU baseline.

The intent of this baseline is to automatically account for the discharging that already happens due to Time-Of-Use rates, yet still allow for a relatively simple methodology. There would be no need to compare against operations from prior days, and it would solely measure against the modeled potential capacity that could be delivered based on the battery's technical capabilities.

Importantly, it is not necessary to consider on-site load with direct submetering of BTM generation and storage, for several key reasons.

- First, only the BTM hybrid or storage system is actually responding to dispatches, and not host load. Grid services dispatched by these systems are optimized by the aggregator and are seamless to the customer. Thus, it is not appropriate to measure event performance against customer activity, as the customer's load does not respond to the event.
- Second, the battery output is a direct and empirical measurement of service provided to the electric system, and is thus superior to any constructed counterfactual. Any load met with on-site hybrid or battery discharge would have otherwise been consumed from the grid.
- Third, a baseline is applied to the BTM system only, and for the exact hours in which the resource is dispatched on an event day, to capture an estimation of normal output during event hours on non-event days.
- Fourth, and finally, a customer's retail bill will naturally account for any increases or decreases in load that would have to be served by grid supply, in absence of the BTM battery.

For any new storage resources deployed through either the DEBA or DSGS programs, we recommend that the M&V measure committed capacity and performance without reference to performance on non-event days and hence no baselining in the performance evaluation. This aligns with what CALSSA proposed in their DEBA/DSGS proposal filed on January 20, 2023 and we agree with the reasons that CALSSA described for omitting the baseline for new storage resources.

To define the point of demarcation between what resources are considered “new” and “existing,” we recommend referencing the installation date. Any installations completed after the final DSGS guidelines are published would be considered “new” and performance for those resources would be measured solely based on discharge without a baseline.

2. *Electric Vehicle managed charging:*

Massachusetts’ Clean Peak Standard[5] has specific baseline methodologies for different load types. For charge throttling of EVs, the baseline is set at 35% of daily energy consumption by the EV. Curtailment would be measured based on the charging that occurs during the period. Said differently, if an electric vehicle used 10 kWh to charge over the course of the day on which an event occurred, and it charged 1 kWh during the event, it would be attributed with 2.5 kWh of performance. This would be divided across the number of hours of the event. To carry the example forward, if the event lasted 2 hours, then the resource would receive 1.25 kW of performance credit.

3. *Residential Smart Thermostats:*

For residential smart thermostats, we recommend two potential approaches. The first approach is to leverage the 5-in-10 day baseline currently employed for settlement for CAISO-participating resources. The CEC, Aggregators, or a jointly selected third party would be able to conduct the performance calculations utilizing data that is available for the participating customers via the CEC. Any party performing the settlement calculations would need to be contractually obligated to strict customer confidentiality standards. While we have seen issues with baseline under-representing performance, particularly on hot days, we recognize that utilizing an existing methodology has implementation benefits.

The second approach would be to utilize a deemed savings calculation. This would be a pre-approved third party calculation that converts runtime data from residential smart thermostats into kWh values. From there, the 5-in-10 day baseline calculation described above would be executed. This approach is an approved methodology for multiple DR programs across the United States.

4. *Commercial HVAC:*

[5] https://www.mass.gov/doc/clean-peak-demand-response-resource-guideline-0/download

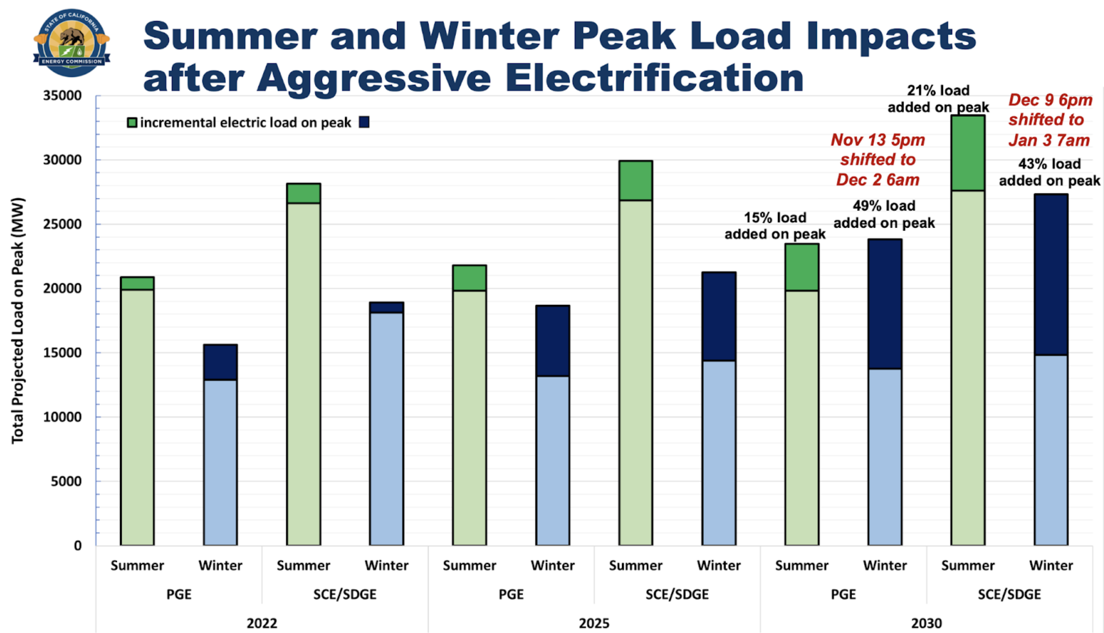
For commercial HVAC, we recommend leveraging the 10-in-10 day baseline currently employed for settlement for CAISO-participating resources. The CEC, Aggregators, or a jointly selected third party would be able to conduct the performance calculations utilizing data that is available for the participating customers via the CEC. Any party performing the settlement calculations would need to be contractually obligated to strict customer confidentiality standards. While we have seen issues with baseline under-representing performance, particularly on hot days, we recognize that utilizing an existing methodology has implementation benefits.

## VI. Incentive Structure and Performance Measurement

The Joint Parties recommend a pay for performance-based program that only provides monthly capacity payments. We believe this structure is superior to an energy-only structure, like ELRP, as it will cover all fixed and variable costs, encourage more participation, and ensure a reliable and functional emergency resource. A capacity payment enables aggregators to build a consistent offer and therefore a consistent resource.

There is an acute need for 2-hour and 3-hour resources to address the CAISO system net peak, as evidenced during emergency heat waves in August and September of 2020 and again in September of 2022. Requiring all resources to participate for four hours creates the unintentional consequence of excluding willing customers from the market. Further, the foundation of the four hour dispatch assumption has its roots in the state's resource adequacy program, which is currently in the process of revision to account for each hour - or "slice" - of the day. Appendix C shows the number of hours that cleared the DAM above $200/MWh in the MOO window for the past four years in Northern and Southern California. Additionally, it breaks this out by the number of consecutive hours that cleared above $200/MWh. Across the past four years, there were three separate events where prices cleared above $200/MWh for four hours in a row. By contrast, there were a total of thirty events that cleared above $200/MWh that were either one hour, or two hours, in length.

We recommend an approach that scales payments with the duration of the resource, in order to maximize participation while also incentivizing longer duration response. Resources participating in this program may do so as either 2-hour, 3-hour, or 4-hour resources. Compensation would be set at $122 per kilowatt per season for 2-hour resources, $145 per kilowatt per season for 3-hour resources, and $160 per kilowatt per season for 4-hour resources, as reflected in the table below. These payments are in line with the costs associated with bringing on incremental system capacity, based on prevailing resource adequacy capacity market pricing between 2023 and 2025 ($30-$40 per kilowatt per month for Q3 2023 for example) and expectations of increasing system peak due to potential retirement of Diablo Canyon as reflect in the chart below.




The proposed DSGS payment rates are substantially lower than the pricing incentives offered in similar programs nationwide[6]. We strongly believe that the incentive structure should reflect the current and expected future market conditions, rather than anchoring it purely based on publicly available historical data since the California bilateral resource adequacy pricing has dramatically increased in the past five years and the annually published CPUC RA report is not wholly indicative of the current RA market. Resources would only collect payment for months in which they actually participated and dispatched. This proposed pricing structure is reflected in the following table.

Incentives per resource duration:

| Month | 2-hour* | 3-hour | 4-hour |
|---|---|---|---|
| June | $13.71/kW | $16.28/kW | $18/kW |
| July | $15.23/kW | $18.09/kW | $20/kW |
| August | $35.03/kW | $41.61/kW | $46/kW |
| September | $38.08/kW | $45.22/kW | $50/kW |
| October | $19.80/kW | $23.52/kW | $26/kW |
| *2-hour resources would be dispatched during the hours of greatest need. Propose that window initially be set at 6-8 pm based on recent history, with supporting data in Appendix B, or the two hours window with the highest average DALMPs that are over the $200/MWh price trigger. Adjustments can be made in the future | | | |

[6] MA and RI ConnectedSolutions programs provide $255/kW-yr to $400/kW-yr performance incentives for behind the meter storage to provide up to 60 dispatches during summer seasons

| |
|---|
| based on changing grid conditions. |

Aggregators should only be compensated based on the delivered performance of their portfolio of participating customers. Payment will be based upon the actual performance of the resource in the hours in which it is dispatched. We believe a pay for performance structure is the proper approach for the DSGS program for resources that aren't also receiving a DEBA incentive for a few reasons. Those reasons are: 1) It's simple to calculate, will reduce operational burden for all parties, and pays exactly for what was delivered; 2) It allows for more accuracy and precision in revenue estimates that can be communicated to end customers. This will increase the number of enrollments that can be expected in the program, and ensure less attrition from those resources in future years; 3) This will reduce complexity associated with nominations. As there are potentially new baselines that would be implemented and some competing priorities (e.g. NEM 3.0), allowing participants to understand performance expectations before being subject to penalties will accelerate the ability to bring needed resources into the program ahead of the summer peak. We propose a summer season of June 1 - October 31. For resources that enroll mid-season, they would receive zero performance for the months that have already passed.

The Joint Parties also agree that any new storage resources that have not yet applied or received SGIP incentives should be eligible for a DEBA incentive. This joint proposal focuses on the DSGS program and hence will not take a position on the DEBA incentive, but we strongly recommend that the DEBA incentive structure should largely mirror the existing SGIP program and provide adequate incentives to bring on new storage capacity to meet the growing demand on the system grid. The DSGS capacity payment structure should be separated from the DEBA incentive, and for resources that are not taking DEBA incentives, the DSGS capacity incentives should be higher.

## VII. Comparison to Other Programs

Our recommendations in this Joint Parties proposal have taken several programs or products that are currently offered in the California market into consideration. We summarized the best practices among all programs and included them in our proposal. The table below provides a comparison between different programs and illustrates the core pillars in this proposal to bring on hundreds of thousands, automated and intelligent, and flexible peak demand zero-carbon resources in 2023 and beyond.

These core pillars are: 1) customer friendly enrollment process, 2) dispatches that are responsive to stressed system conditions, 3) simple and fair M&V methodology, and 4) sufficient but not overly burdensome visibility into the program.

| | **Enrollment** | **Dispatch Trigger** | **M&V*** | **Visibility** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| **Joint Parties' Proposal** | Customer authorization via aggregators T&Cs<br><br>Customers presented the enrollment offer with an opt-out enrollment process | NP15 and SP 15<br><br>DA-LMP > $200/MWh | Inverter/Device level metering w/o baseline | Month ahead enrollment and nomination process with CEC |
| **CAISO PDR** | Authorization required from customer via the "Share My Data" process<br><br>Registration required via Demand Response Registration System | Based on CAISO market clearing results | CAISO approved baseline (zero export allowed) | No telemetry required if the resource (aggregated) is less than 10 MW or is not providing ancillary services<br><br>Year ahead and month ahead supply plan submission<br><br>Day-ahead and Real-time bidding |
| **PG&E 2023 Summer Reliability** | Customer authorization via Sunrun T&Cs;<br><br>Customers presented the enrollment offer with an opt-out enrollment process | Scheduled dispatch without price trigger or market clearing | Inverter/Device level metering w/o baseline | No telemetry required<br><br>No Day-ahead or Real-time nomination/bidding required<br><br>Month ahead enrollment process with the IOU |
| **Load Modification (Bay Area CCA)** | Customer authorization via Program T&Cs<br><br>Customers presented the enrollment offer with an opt-in enrollment process | Scheduled dispatch without price trigger or market clearing | Inverter/Device level metering w/o baseline | No telemetry required<br><br>No Day-ahead or Real-time nomination/bidding required<br><br>Month ahead enrollment process with the CCA |
| *This table only shows a comparison for M&V for behind the meter energy storage in this table | | | | |

## VIII. Conclusion

Thank you for considering these recommendations. In sum, the Joint Parties believe strongly that the structure that we recommend here is simple and will be very effective in bringing new DER resources on-line to support Summer system reliability.

Respectfully submitted,

Walker Wright
VP, Public Policy
Sunrun, Inc.
walker.wright@sunrun.com

Andrew Hoffman
Chief Development Officer
Leap
andrew@leap.ac

## Appendix A

**Examples Programs that Utilize Device Data for System Performance Information**

| State | Program | Description |
| --- | --- | --- |
| **California** | Self-Generation Incentive Program (SGIP)[7] | For storage systems of 30 kW or less, performance audit monitoring and verification may use data from metering systems built into the storage device. This is used to verify operation of the system in accordance with program requirements (e.g., annual cycling requirements). |
| **New York** | NY-SUN Incentive Program[8] | Participant solar systems must have monitoring equipment, which at the contractor's election may include a production meter, online monitoring system, inverter display recorded production, or another method. |
| **Pennsylvania** | Alternative Energy Portfolio Standard - SREC Generation[9] | All solar generation installed after May 18, 2017 require production metering for SREC generation. Inverter readings qualify as metered data for this purpose. |
| **Illinois** | Adjustable Block Solar Incentive Program (ABP)[10] | The ABP, a long-term SREC contract program, allows systems of 10 kW or less with inverters certified to +/- 5% accuracy with either web-based or digital output displays to qualify for production measurement. For systems over 10 kW and less than 25 kW, inverters with integrated ANSI C.12 compliant production meters are also allowed, provided that the inverter is UL-certified and has a digital or web-based output display. |

---

[7] Self-Generation Incentive Program Handbook, Section 5.5.2.2, pp. 79-80 (August 29, 2022) *available at* https://www.selfgenca.com/home/resources/#handbook.

[8] NY-SUN Upstate and Long Island Program Manual, Section 3.4, p. 46 (June 2022) *available at* *https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Resources-for-Contractors* (note: this citation references the upstate and Long Island regional program segment but the rules are the same for the downstate New York segment).

[9] Pennsylvania Pub. Utils Comm'n, L-2014-2404361, Second Amended Final Rulemaking Order at p. 111 (Oct. 17, 2016), *available at* http://www.puc.pa.gov/pcdocs/1483199.doc.

[10] Illinois Power Agency, Adjustable Block Program Guidebook, Section 4.N, p. 70 (October 18, 2022) *available at* https://illinoisabp.com/program-resources/.

| | | |
|---|---|---|
| **Vermont** | Green Mountain Power (GMP) BYOD Program[11], Enphase IQ Battery Pilot[12], and Tesla Powerwall Program[13] | Under GMP's BYOD program, GMP dispatches and monitors the performance of battery storage systems enrolled in the program remotely, including using the SolarEdge Monitoring Platform. Separate battery metering is not required for program participation. |
| **New Hampshire** | Liberty Utilities Residential Storage Pilot[14] | Liberty's initial utility-owned storage version of this program uses Tesla Powerwalls and the accompanying GridLogic platform for remote dispatch and monitoring. Separate battery metering is not required for program participation. |
| **Federal** | Treasury 1603 Grant Program[15] | The 1603 Grant Program requires annual production reporting for five years by grant recipients. Recipients may use inverter readings if the inverter has a display showing total production to date. |
| **ISO-NE (FERC-Jurisdictional wholesale market)** | On-Peak and Seasonal Peak Demand Resources[16] | Demand-side aggregations enrolled as this type of resource are subject to minimum measurement requirements and providers must submit plans specifying how these requirements will be met. The requirements are technology agnostic and governed by accuracy and certification parameters. Providers may submit alternative plans that are consistent with these generalized parameters for ISO-NE approval. |

[11] Green Mountain Power, Bring-Your-Own-Device "BYOD" Terms & Conditions (Nov. 2020) *available at* https://greenmountainpower.com/wp-content/uploads/2020/11/BYOD-Customer-Agreement-11-2-20.pdf.

[12] Green Mountain Power, Enphase IQ Battery, Energy Storage Lease, pp. 5-6 (March 2022), *available at*: https://greenmountainpower.com/rebates-programs/home-energy-storage/enphase-battery/.

[13] Green Mountain Power, Tesla Powerwall, V.P.S.B. No. 9, Second Revised Sheet 292 (June 1, 2020) *available at*: https://greenmountainpower.com/rebates-programs/home-energy-storage/powerwall/.

[14] New Hampshire Pub. Utils Comm'n, Docket No. 17-189, Supplemental Testimony of Heather Tebbetts at p. 19 (Feb. 9, 2018) *available at* https://www.puc.nh.gov/regulatory/Docketbk/2017/17-189/MOTIONS-OBJECTIONS/17-189_2018-02-09_GSEC_STESTIMONY_TEBBETTS.PDF.

[15] U.S. Dept. of Treasury, Treasury 1603: Recommendations for Annual Report Production Documentation (February 2013) *available at*: https://home.treasury.gov/system/files/216/Recomendations-for-annual-report-production-2013-Feb.pdf.

[16] ISO New England Manual for Measurement and Verification of On-Peak Demand Resources and Seasonal Peak Demand Resources (Effective Oct. 2018) available at https://www.iso-ne.com/static-assets/documents/2018/10/manual_mvdr_measurement_and_verification_of_onpeak_and_seasonal_peak_demand_resources_rev07_20181004.pdf.

## Appendix B
## Analysis on Historical LMPs

The average of all DA LMP prices for 2019-2022 summer seasons show that the hours ending 19 and 20 (6-8pm) are of highest need for both northern and southern California. This supports an initial dispatch window of 6-8pm for 2 hour resources under this proposal. The Parties recommend that this analysis be revisited annually to capture changing conditions on the grid to inform if a new window should be applied for two hour resources.

Historic DAM LMP price for TH_NP15_GEN-APND node.

| | Hour Ending | | | | |
|---|---|---|---|---|---|
| **Year - Month** | **17** | **18** | **19** | **20** | **21** |
| **2019** | **32.12** | **39.59** | **55.24** | **60.40** | **45.69** |
| 6 | 22.84 | 26.44 | 35.92 | 50.84 | 45.17 |
| 7 | 32.52 | 36.15 | 45.27 | 64.64 | 46.88 |
| 8 | 36.05 | 39.97 | 54.50 | 64.44 | 45.50 |
| 9 | 34.94 | 45.10 | 64.46 | 63.06 | 45.72 |
| 10 | 34.03 | 50.05 | 75.73 | 58.82 | 45.14 |
| **2020** | **39.59** | **62.71** | **100.80** | **89.38** | **50.45** |
| 6 | 24.42 | 29.35 | 37.78 | 51.91 | 41.45 |
| 7 | 28.10 | 31.02 | 40.77 | 59.54 | 41.21 |
| 8 | 50.19 | 82.76 | 186.49 | 185.37 | 71.80 |
| 9 | 46.70 | 68.84 | 128.04 | 85.72 | 49.99 |
| 10 | 48.28 | 100.69 | 109.78 | 63.02 | 47.51 |
| **2021** | **65.64** | **78.58** | **107.07** | **118.25** | **89.33** |
| 6 | 53.05 | 61.50 | 85.72 | 123.52 | 90.93 |
| 7 | 73.95 | 85.08 | 123.84 | 169.95 | 107.75 |
| 8 | 66.54 | 76.06 | 102.41 | 106.36 | 84.43 |
| 9 | 69.98 | 87.87 | 126.45 | 104.86 | 84.69 |
| 10 | 64.41 | 82.17 | 96.85 | 86.29 | 78.73 |
| **2022** | **92.94** | **117.69** | **148.80** | **158.72** | **127.52** |
| 6 | 74.99 | 87.44 | 102.88 | 131.41 | 119.81 |
| 7 | 78.39 | 85.70 | 101.12 | 127.04 | 109.31 |
| 8 | 105.49 | 118.61 | 148.71 | 169.64 | 133.31 |
| 9 | 136.94 | 213.29 | 293.34 | 280.28 | 194.67 |
| 10 | 69.72 | 85.53 | 101.11 | 88.28 | 82.43 |
| **Average** | 57.57 | 74.64 | **102.98** | **106.69** | 78.25 |

Historic DAM LMP price for TH_SP15_GEN-APND node.

| | Hour Ending | | | | |
|---|---|---|---|---|---|
| **Row Labels** | 17 | 18 | 19 | 20 | 21 |
| **2019** | **33.58** | **41.91** | **58.17** | **64.00** | **47.48** |
| 6 | 22.33 | 26.16 | 35.94 | 52.18 | 46.32 |
| 7 | 35.75 | 38.61 | 48.98 | 69.26 | 49.45 |
| 8 | 38.75 | 43.22 | 57.71 | 67.45 | 47.39 |
| 9 | 38.76 | 51.54 | 72.35 | 72.34 | 48.83 |
| 10 | 32.09 | 49.83 | 75.62 | 58.64 | 45.39 |
| **2020** | **56.62** | **82.56** | **135.46** | **117.65** | **64.73** |
| 6 | 21.92 | 25.87 | 36.90 | 52.20 | 41.57 |
| 7 | 31.01 | 36.08 | 55.18 | 81.16 | 47.02 |
| 8 | 128.44 | 160.30 | 305.89 | 292.59 | 130.80 |
| 9 | 52.35 | 82.13 | 158.51 | 94.57 | 55.14 |
| 10 | 48.12 | 106.58 | 118.38 | 64.89 | 48.05 |
| **2021** | **64.44** | **78.80** | **110.39** | **119.33** | **89.39** |
| 6 | 53.53 | 61.57 | 92.11 | 124.95 | 91.01 |
| 7 | 78.06 | 88.34 | 130.26 | 174.25 | 110.01 |
| 8 | 67.74 | 76.92 | 104.30 | 107.29 | 84.34 |
| 9 | 69.35 | 87.82 | 130.13 | 105.21 | 84.24 |
| 10 | 53.33 | 79.10 | 95.18 | 84.70 | 77.22 |
| **2022** | **94.37** | **121.87** | **160.71** | **169.33** | **133.47** |
| 6 | 67.19 | 76.49 | 98.03 | 130.90 | 119.82 |
| 7 | 80.21 | 90.37 | 110.59 | 140.33 | 117.99 |
| 8 | 118.76 | 135.23 | 179.00 | 195.86 | 149.44 |
| 9 | 142.16 | 224.42 | 317.98 | 295.00 | 200.87 |
| 10 | 64.19 | 84.69 | 101.00 | 87.40 | 80.99 |
| **Grand Total** | 62.25 | 81.29 | **116.18** | **117.58** | 83.77 |

**Appendix C**

**Distribution of >$200 Events**

The distribution of events with DA LMP prices exceeding $200/MWh skews heavily towards one and two hour duration windows. Said another way, it is much more common based on historic LMP data for an individual hour to exceed $200/MWh, or two hours in a row to exceed $200/MWh. While it has happened that four or more hours in a row have exceeded the $200/MWh price threshold, these events are much more infrequent. The tables below show the frequency of consecutive hours clearing above the $200/MWh price threshold during the 4-9PM window.

Historic instances of consecutive hours greater than $200/MWh for TH_NP15_GEN-APND Node

| Year | Month | Consecutive Hours >$200 | | | | |
|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 |
| 2019 | 6 | - | - | - | - | - |
| 2019 | 7 | - | - | - | - | - |
| 2019 | 8 | - | - | - | - | - |
| 2019 | 9 | - | - | - | - | - |
| 2019 | 10 | - | - | - | - | - |
| 2020 | 6 | - | - | - | - | - |
| 2020 | 7 | - | - | - | - | - |
| 2020 | 8 | - | 3 | 1 | 2 | - |
| 2020 | 9 | 3 | 1 | 1 | - | - |
| 2020 | 10 | - | 3 | - | - | - |
| 2021 | 6 | 3 | - | 1 | - | - |
| 2021 | 7 | 6 | 2 | 1 | - | - |
| 2021 | 8 | 1 | - | - | - | - |
| 2021 | 9 | - | 1 | 1 | - | - |
| 2021 | 10 | - | - | - | - | - |
| 2022 | 6 | 1 | - | - | - | - |
| 2022 | 7 | - | - | - | - | - |
| 2022 | 8 | 1 | 4 | 1 | - | - |
| 2022 | 9 | - | 1 | 1 | 1 | 6 |
| 2022 | 10 | - | - | - | - | - |
| **Total** | | **15** | **15** | **7** | **3** | **6** |

Historic instances of consecutive hours greater than $200/MWh for TH_SP15_GEN-APND Node

| Year | Month | Consecutive Hours >$200 | | | | |
|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 |
| 2019 | 6 | - | - | - | - | - |
| 2019 | 7 | - | - | - | - | - |
| 2019 | 8 | - | - | - | - | - |
| 2019 | 9 | - | - | - | - | - |
| 2019 | 10 | - | - | - | - | - |
| 2020 | 6 | - | - | - | - | - |
| 2020 | 7 | 2 | - | - | - | - |
| 2020 | 8 | 6 | 4 | 1 | 1 | 2 |
| 2020 | 9 | 3 | 1 | 2 | - | - |
| 2020 | 10 | - | 4 | - | - | - |
| 2021 | 6 | 2 | 1 | 1 | - | - |
| 2021 | 7 | 5 | 3 | 1 | - | - |
| 2021 | 8 | 1 | 1 | - | - | - |
| 2021 | 9 | - | 1 | - | - | 1 |
| 2021 | 10 | - | - | - | - | - |
| 2022 | 6 | 1 | - | - | - | - |
| 2022 | 7 | 1 | - | - | - | - |
| 2022 | 8 | - | - | - | - | - |
| 2022 | 9 | - | - | - | - | - |
| 2022 | 10 | - | - | - | - | - |
| **Total** | | **21** | **15** | **5** | **1** | **3** |