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Sunrun and Leap Proposal - DER Program Design

Additional submitted attachment is included below.

January 26, 2023

Distributed Energy Resource Program Recommendations
22-RENEW-01 and 21-ESR-01

Sunrun, Inc. and Leap (hereafter "Joint Parties") respectfully submit these recommendations for an effective DER program. These recommendations are intended to help guide the California Energy Commission (CEC) as they review the Demand Side Grid Support (DSGS) program guidelines, determine how to allocate funds for Distributed Energy Backup Assets (DEBA), and/or funding from Senate Bill 846.

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", as well as CEC's 21-ESR-01 "Energy System Reliability" docket. We do not take a position here on which funding allocation is more appropriate for our proposed program design. Our purpose is, instead, 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 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 below 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 proposal below steps through the core elements of a successful DER program.

I. Third Party Aggregators as Direct Providers and Expanded Customer Eligibility

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 DSSP. 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.

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 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.

II. 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 process 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 Share My Data stage of the current enrollment process. To help address the substantial attrition we see in the enrollment process and bring all the resources available online, we propose that aggregators be permitted to design their own customer agreements that meet a list of specific requirements. 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 agreements 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[1]. 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)[1] 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 enrollment. It is also important that the collection and submission of these data ensure customer data protections.

There are nationally recognized methodologies that leverage device level data rather than site level meter data to validate reductions in energy usage. By leveraging these methodologies, we can accurately reflect curtailments in load from the specific devices that are enrolled in this

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[1] 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.

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 should help simplify and legitimize performance, ensuring that aggregators are only paid for reductions that have occurred due to direct actions from our programs.

III. 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 $500/MWh, OR when the CAISO issues an Energy Emergency Alert (EEA) at any level. We would utilize the SP15 or NP15 DA DLAP CAISO prices for dispatch triggers, and similar to EEAs would only regionally dispatch resources in SP15 or NP15 when those respective prices exceed the $500/MWh threshold. 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.

Additionally, we recommend there be a minimum number of guaranteed events per season, and a test each month that the resource is not otherwise dispatched. We propose a minimum of 10 events per season. Creating this certainty will increase the number of opportunities to understand the potential available.

For test events in any month, we recommend the CEC be responsible for determining when those events occur, as opposed to allowing aggregators to determine this separately on their own. Test events should be a minimum of 2 hours long and be within the 4-9 pm window and targeted towards the highest forecasted load days of the month. Notices for these “test” events should be within an hour of the day ahead market results being posted, and resources should have an opportunity to retest.

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

IV. 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:*

For submetered behind-the-meter batteries and electric vehicles, measurement and verification would 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 typical use of the battery. 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.

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.

2. *Electric Vehicle managed charging:*

Massachusetts' Clean Peak Standard[2] 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.

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

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:*

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.

V. Incentive Structure and Performance Measurement

We recommend a performance-based program that only provides fixed monthly compensation, with no dispatch, or energy, payment. 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 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.

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 or 4-hour resources. Compensation would be set at $80 per kilowatt per season for 2-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 2023 resource adequacy capacity market pricing. Assuming 80 hours of dispatch per season, which we recommend as the program limit, the fixed payments we propose here convert to $2/kWh, which is equivalent to both ELRP and DSGS Option 1. Resources would only collect payment for months in which they actually participated and dispatched. This structure is reflected in the following table.

Month	2-hour	4-hour
June	$9/kW	$18/kW
July	$10/kW	$20/kW
August	$23/kW	$46/kW
September	$25/kW	$50/kW
October	$13/kW	$26/kW

Aggregators should only be compensated based on the delivered performance of their portfolio of participating customers. Performance will be based upon the actual performance of the resource in the hours in which it is dispatched. 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. Participating customers, in turn, would be compensated based on their performance.

V. Conclusion

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

Respectfully submitted,

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