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Responses of Leap and Sunrun, Inc., to Post-Workshop Questions re: DSGS and DEBA

Sunrun, Inc., and Leap (hereafter "Joint Parties") respectfully submit the following responses to questions raised by Energy Commission lead staff at workshops on the Demand Side Grid Support (DSGS) and Distributed Energy Backup Assets (DEBA) program workshop on January 27th. Included here too are responses to questions and issues raised at the workshop.

Demand Side Grid Support Program

1. What structure or provisions would best support cost-effective Resource Adequacy procurement while also enabling the development and growth of the Strategic Reliability Reserve to respond to extreme events?

At a minimum, we recommend that the CEC reflect resources funded by the Strategic Reliability Reserve in load serving entities' (LSE) resource adequacy (RA) forecasts, thus taking the capacity "off the top", which would lower supply side resource adequacy procurement obligations and reduce costs for ratepayers. The CEC may wish to allow dual participation of resources procured by the Strategic Reliability Reserve as both emergency reliability assets and resource adequacy assets - if not for the program months of June - October, then to provide RA in months outside of the program window - November to May. This season-based multi-use application - emergency resource during the summer months, and resource adequacy resource otherwise - ensures that the resources will be used and useful throughout the year, to the overall benefit of enhancing grid reliability and mitigating costs. Finally, we recommend against categorical eligibility-based prohibitions for resource participation in the Strategic Reliability Reserve.

2. How best can the Program unlock untapped DR or other stranded resources under its statutory constraints?

This objective can be achieved in two key ways. First and foremost, supporting a simplified customer enrollment process is absolutely essential. The enrollment process currently required by the CPUC for wholesale market integrated resources is onerous, such that the vast majority of eligible customers do not participate, thus leaving a lot of potential value on the table. Second, additional deployment will be supported by allowing third party aggregators to become direct providers under DSGS, as well as opening up eligibility to all customers within the state who are not already enrolled in demand response or load reduction programs. This should include those customers that fall within Investor Owned Utility territories.

3. As aggregators and others participate in DSGS directly:
    a. What is the most effective approach for host utilities to have visibility?

There are several different options available depending on the level of visibility required by the host utilities. 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 and their locations. 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.

This structure is largely similar to, but an improvement upon, 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.

    b. What would be an effective method to ensure customers are not participating in multiple programs?

The Joint Parties address this issue in our proposal.

4. Should DSGS be provided to other use-cases in IOU territories? If so, what use-cases and how?

The Joint Parties strongly believe that allowing for third parties to directly participate in DSGS as direct providers is a use case that will bring real benefits to customers and the grid, in both IOU and non-IOU service territories. Further, all customers in IOU service territory should be eligible for the program if they are not already participating in a demand response program. This would be consistent with statutory language in AB 209 affirming IOU customer eligibility in the DSGS[1]. Finally, the DSGS program should only focus on resources that do not emit greenhouse gasses. Importantly for both the state's climate and air quality policies and goals, fossil-fueled back up generation should not be prioritized in this program.

5. What other program modifications should be considered?

[1] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB209

The Joint Parties go into detail as to proposed program modifications in our proposal, as submitted on January 26th. The Joint Parties' proposal can be categorized within the third option for revision to DSGS Option 3 presented by Energy Commission staff as a modification to Option 3 (Slide 27). The pricing that the Joint Parties propose is for resources that do not emit greenhouse gasses.

6. Visibility - how to ensure visibility to the CAISO and LSE as necessary for awareness as to grid conditions.

The Joint Parties propose an approach to ensure LSE and CAISO visibility into total available DSGS units/capacity month-ahead and mid-month. Our proposed resource dispatch is tied to CAISO day-ahead market (DAM) prices and Energy Emergency Alerts, and so the dispatch of the resources can be assumed in any hour in which the DAM exceeds the trigger price threshold, or an emergency is declared. It is crucial to first define visibility in terms of both granularity and frequency.

While the Joint Parties agree that visibility into resource availability is important for grid operations, we caution the CEC against establishing excessive or prohibitive visibility requirements. We further recommend that the CEC use current requirements as a guide. It is important to point out that, to the Joint Parties' knowledge, no utility program nor the wholesale market requires real-time communications between behind the meter or load resources that are the subject of our proposal. The CAISO tariff exempts resources less than 10 MW that are not providing ancillary services from telemetry requirements and obtains information via the resources' scheduling coordinator (SC) for ongoing coordination and to report any outages. When telemetry is required—either in the case of a load resource of any size providing ancillary services, or if the total load resource aggregation capacity is equal to or greater than 10 MW—the CAISO tariff does not require each individual load resource to provide direct telemetry. Further, LSEs in the CAISO market submit load forecasts which could include forecasted dispatch of DSGS and/or DEBA resources.

Distributed Energy Backup Assets (DEBA) Program

1. How best can DEBA invest in assets for emergency load reduction without interfering in the Resource Adequacy Program or creating clean stranded assets? How can it best do both?

To appropriately frame and prioritize this issue, it is important to put it in the context of the broader RA market. Currently, the state's highest peak demand is about 50 gigawatts (GW). Over the next several decades, to meet higher electrification demand and decarbonize the grid, the CAISO has projected the need for an additional 120 GW of clean power.[2] In September 2022, and as presented at the workshop, 1.2 GW of demand response (DR) were integrated

[2] 2022-6 Strategic Plan. CAISO.

into the CAISO wholesale market, representing 2.4% of total peak demand. The potential for DR is significantly greater than this total. However, as many parties discussed at the workshop and in comments, current wholesale market customer participation requirements, as well as devaluation of capacity from behind the meter systems, taken together leave a lot of value unrealized from these resources. Without major changes to resource adequacy policy at the CPUC, and modifications to the CAISO market processes - none of which are in process currently - this potential will go largely unrealized. The current RA structure must, in no way, be an inhibitor to the design of any aspect of the Strategic Reliability Reserve.

With that context, the Joint Parties offer that the CEC can choose to both: a) require DEBA funded resources to dispatch more frequently than for emergencies, thus making the resource perform more like an RA resource; and b) take any DEBA funded capacity "off the top" of RA obligations, just as is done today with DERs funded by other programs such as the Self Generation Incentive Program (SGIP). These two, taken together, both avoid the complexities and value erosion associated with market participation, and ensure that DEBA-funded resources are more used and useful. It is worthwhile to point out that these resources would not be interacting with supply side resource adequacy at all, and thus no price distortion should occur.

Finally, there is no rule prohibiting resources that provide services over a particular period of time (in this case, emergency reliability services in June through October) to provide other services at other times (in this case, RA could be provided in November through May). This is called a time differentiated multiple use application and has been encouraged by both the CPUC and CAISO. The CEC may wish to ensure that customers will not be taken out of PDR aggregations providing RA and placed into this program.

2. Are the proposed program frameworks reasonable? What modifications could unlock additional resources for emergency events?

The proposed DEBA program framework is reasonable, apart from one important factor. The CEC has proposed ineligibility for DEBA funding for customers that are eligible for incentives from the Self Generation Incentive Program (SGIP). We agree that customers should not be able to **collect** funding from both SGIP and DEBA. To categorically prohibit customers who are eligible for SGIP would be to eliminate virtually all residential and non-residential energy storage in IOU service territories, leaving significant potential capacity for emergencies on the table. Energy storage in the residential customer class is projected to increase significantly in the next several years to reflect significant changes to the state's net energy metering (NEM) policy. Further, current funding for SGIP is all but exhausted, and new funding for SGIP in Governor Newsom's 2023-4 budget proposals is for low-income customers only. Finally, many residential storage systems are sold and installed without using SGIP today.

3. Are there additional criteria that the CEC should consider when evaluating projects? How should the CEC rank or weight the evaluation criteria?

One additional aspect the CEC should consider is prioritization of resources that do not emit greenhouse gasses. There can be a place for fossil fueled Back Up Generators to provide energy during emergencies, but they should be compensated at a lower rate in order to help the state achieve its clean energy goals. The second characteristic the CEC should consider is the level of automation a project has. Setting up systems and processes that are automated via software should lead to both better and more consistent performance as well as provide a pathway to scale over the next three to five years.

4. What are reasonable exceptions to non-performance in an emergency event?

The proposal as submitted by the Joint Parties would pay for performance only. Compensating resources based on their actual proven performance is a way to avoid the complicated task of determining all reasonable exceptions to non-performance. Rather than create a list of reasons for why a resource may not perform, the Joint Parties recommend that the CEC simply pays the incentive based on actual event or test performance.

5. What level of funding is needed to spur the development of a project?

The Joint Parties do not include upfront incentives as part of our proposal - the monthly capacity compensation levels that we included in our proposal represent the total payment required. With that said, we have reviewed the proposal of the California Solar and Storage Association, which does offer two levels of upfront incentives from DEBA. An important distinguishing factor between our proposal and that of CalSSA is that our proposal may be better suited for providers that do not require upfront incentives to bring new energy storage to market - indeed, BTM project developers are doing so today without the use of SGIP. CalSSA's proposal is better suited for companies that do require upfront incentives, either due to a higher cost structure or other factors. The two proposals are not mutually exclusive; the Joint Parties believe that optionality can be established, wherein upfront incentives are available for those that require it and a simplified capacity-only structure based on performance for those that do need the incentive.

More broadly, the Joint Parties believe the proposals submitted by CalSSA and Generac both have some common themes that we believe are crucial for the success of DSGS and DEBA. Those themes are: 1) third party aggregators being allowed to participate to maximize the impact on the grid; 2) customers in IOU territories that are not actively participating in a emergency load reduction or market integrated program be eligible to participate under DSGS/DEBA 3) the utilization of device data in order to unlock participation for a large swath of customers that have not completed the onerous Share My Data authorization process. The Joint Parties believe that those three features, along with sufficient incentives to generate interest from end customers, are necessary in order to maximize the impact for this summer.

Lastly, the Joint Parties don't view our proposal as mutually exclusive with OhmConnect's proposal. Our proposal focuses on solving challenges for non-market integrated resources, while OhmConnect's proposal focuses on supporting market-integrated resources. We support there being additional compensation available for market-integrated resources through DSGS, as the barrier to participating is higher for those resources. Supporting the deployment of new DER technologies with additional incentives as the industry is still maturing will allow for greater penetration of DERs and participation in wholesale markets.

Respectfully submitted,

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