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California Efficiency + Demand Management Council and OhmConnect, Inc. Comments on Distributed Energy Resources for Reliability Draft Solicitation Concept

I. Introduction

The California Efficiency + Demand Management Council ("Council") and OhmConnect, Inc. ("OhmConnect") (collectively, "the Joint Parties") appreciate this opportunity to provide written comments on the California Energy Commission's ("CEC") Distributed Energy Resources ("DER") for Reliability Draft Solicitation Concept ("DER Solicitation" or "Draft Concept"). The Draft Concept represents a promising opportunity to bring to bear additional new DERs to California and maintain existing DERs that might otherwise be left idle or disappear due to the likely sunsetting of the Demand Response Auction Mechanism ("DRAM") Pilot. As always, the Joint Parties urge the CEC to avoid letting the perfect be the enemy of the good, prioritize greater simplicity, and limit the administrative burden wherever possible. In addition, the Joint Parties recommend the CEC seek to lower the bar to participation, where possible, to ensure smaller demand response ("DR") and DER providers ("resource providers") can participate. Finally, the Joint Parties strongly recommend that the resources procured through the solicitation be recognized in the California Public Utilities Commission's ("CPUC") Resource Adequacy ("RA") regime. In these comments, the Joint Parties highlight several opportunities to meet these goals, followed by areas where clarification is needed, and concluding with responses to the questions posed in the Draft Concept.

II. Joint Parties' Comments on the Draft Concept

a. The resources procured through the DER Solicitation should be accounted for in the Resource Adequacy process.

The availability requirements contained in each Performance Demonstration Pathway ("Pathway") are generally consistent with the CPUC's DR RA minimum availability requirements. In spite of this, there is no discussion in the Draft Concept about whether or how the resources that would be procured would tie into the RA regime. The Draft Concept should recognize these similarities and incorporate resources procured through the DER Solicitation into the RA regime as described below.

The table below compares the current DR RA availability requirement for DR resources to each Pathway's availability requirement:

Table: Comparison of DR RA Availability Requirements to the Performance Demonstration Pathway Availability Requirements

RA & Performance Demonstration Pathway	Availability Requirement
Current RA Availability Requirements	May: Mon.-Sat., 5-10 p.m. June-Oct.: Mon.-Sat., 4-9 p.m.
Market-Integrated Dispatch	4 consecutive hours during the peak net load hours (required days are undefined)
Market-Aware Dispatch	4 hours daily within the peak net load hours
Hourly Dynamic Pricing	Depends on the hourly dynamic price tariff
Daily Dispatch	4:00-9:00 p.m. daily, at minimum
Emergency Dispatch	24 hours/day, 7 days/week

While it appears that the resources procured through the DER Solicitation are not intended to be considered as RA resources, this overlooks the actual reliability contribution that they will make. This reliability contribution is evident in the close similarities of the availability requirements for the five Demonstration Pathways and the CPUC's for DR to provide RA capacity. For example, presuming that the term, "peak net load hours," for the Market-Integrated Dispatch and Market-Aware Dispatch Pathways is intended to mean the CAISO's Availability Assessment Hours ("AAH"), these two Pathways align with DR RA resources. The Daily Dispatch Pathway explicitly requires daily availability from 4:00-9:00 p.m. The Emergency Dispatch Pathway must be available 24x7 so that clearly meets the DR RA availability requirement, and the Hourly Dynamic Pricing Pathway requires enrollment in a CPUC-approved dynamic rate program that shifts load away from the peak net load hours. In addition, the Market-Integrated Dispatch, Market-Aware Dispatch, Hourly Dynamic Pricing, and Daily Dispatch Pathways are subject to a 100-hour seasonal minimum dispatch requirement in order to get full demonstrated capacity credit; this exceeds any minimum DR dispatch requirements under the CPUC RA rules.

On this basis, the contribution to reliability of the resources procured through the DER Solicitation equals or exceeds those of DR RA resources. The performance evaluation in the Draft Concept is based on the highest-priced or highest net load hours, giving a clear incentive to perform in a way that improves grid reliability. This performance incentive fits well within the Slice-of-Day framework that sets RA expectations based on the most grid-stressed day of the month. Since the RA forecast is based specifically on coincident peak load during previous years, even without explicit RA accounting, the performance of behind-the-meter ("BTM") Distributed Electricity Backup Assets ("DEBA") resources will be used by default to reduce a load-serving entity's ("LSE's") load forecast, and subsequently reduce RA requirements in future years.

Even if these resources are not explicitly included in the load forecast used to determine the RA requirement, the dispatches will be reflected in it unless they are added back by the CEC. Presuming that does not happen, the load forecast will be reduced which consequently will reduce the RA requirement. However, given the scale of resources that potentially could be procured through the DER Solicitation, it would seem logical to explicitly account for them in the load forecast to ensure that they are fully accounted for. Otherwise, simply allowing their load impacts to passively manifest in the historical load data risks them not being fully accounted for if the CEC uses more than only the prior year's load data to inform its Integrated Energy Policy Report ("IEPR") load forecast. This would needlessly add costs to ratepayers through additional capacity costs.

Incorporating these resources into the RA regime would maximize their value to the grid by mitigating the current tightness in RA capacity supply and ensure that taxpayers are receiving full value for this program. It would also ensure that California's LSEs do not overprocure capacity by accounting for DEBA resources in their RA obligations. This approach would also not be in contradiction with Assembly Bill ("AB") 205 which is silent on the RA treatment of resources procured through the DEBA Program.

b. The Draft Concept does not provide for a profit opportunity for customers and third-party providers.

The Joint Parties appreciate all of the work and consideration that has gone into the Draft Concept but it is not apparent there will be a sufficient revenue stream to incentivize customers and third-parties to participate. As described below, the Draft Concept should be revised to eliminate the Match Share requirement and allow all three Groups to seek an award to meet 100 percent of costs plus a reasonable profit.

According to the Draft Concept, bids for Group 1 and 2 resources must include a 50 percent Match Share. Eligible forms of Match Share funding include "cash or in-kind contributions such as donated labor hours, equipment, facilities, and other property."[1] From the perspective of the resource provider, this Match Share represents a cost because these contributions must be paid for by some combination of participants, the resource provider, or some other entity. Though the Draft Solicitation appears to envision in-kind contributions (presumably implying a zero cost to the resource provider), it is not clear how realistic it is to expect this to occur on any significant scale. In the absence of such donations, the resource provider and customers will bear this cost.

The Draft Concept also specifies that awards for Group 1 and 2 projects may not exceed 50 percent of the total project cost. Of this amount, half (i.e., 25 percent of the project cost) would be disbursed during the construction period based on incurred expenses, with the remaining half disbursed over five years as an annual performance payment.[2] At face value, these annual performance payments would appear to be the profit opportunity for a resource provider which, in turn, would disburse incentive payments to its respective enrolled participants. However, accounting for the cost of the 50 percent Match Share requirement and 25 percent toward construction costs, it appears that the total cost to receive an award exceeds the amount of profit that could be made in doing so. In other words, the 25 percent for construction costs is reimbursed but the 50 percent Match Share is only partially offset by the 25

[1] Draft Concept, at p. 8.
[2] *Id.*, at p. 6.

percent performance payment. Therefore, unless the Match Share is met by entities who will not be reimbursed for their contributions to the Match Share, the resource provider would suffer a significant loss for receiving an award in the DER Solicitation.

The Match Share requirement also introduces a significant amount of administrative effort for the resource providers and CEC staff, which will add to the overall project costs and CEC administrative expenses. To reduce these costs and address the revenue imbalance described above, the Draft Concept should be revised to align with Group 3 by eliminating the Match Share for Groups 1 and 2, and allow the full project cost (including profit margin) to be requested in the project application. The CEC should simply treat the DER Solicitation as any other resource solicitation and require bidders to bid their all-in cost, including profit margin and customer incentives. In order to reduce their costs (and keep their bids as competitive as possible), bidders will already be motivated to leverage external funding and non-cash resources at their disposal such as property, buildings, and, when allowed under the Project Requirements, existing DERs and other enabling technologies.

c. The funding allocations are overly complex and should encourage the most economically-efficient projects.

The Draft Concept provides $250 million in funding but creates a series of overlapping carveouts and requirements that risk undermining its success. Of this amount, $62.5 million is allocated for projects located in Publicly-Owned Utility ("POU") service areas; the Draft Concept also expresses an intention to spend at least $125 million on projects "located in or benefitting Disadvantaged Communities (DACs)."[3] Applying these carveouts to the three Group funding categories will unnecessarily balkanize the program budget and could lead to some competitive bids being rejected. Instead, the CEC should eliminate these carveouts and prioritize the most economically-efficient projects within each Group.

The Draft Concept indicates that the CEC "seeks to award" $125 million of the $250 million program budget to projects located within or benefitting a DAC. However, it is not clear whether this is intended to be a firm allocation or only a stretch goal. Regardless, the Joint Parties respectfully recommend that this allocation be eliminated so that the most cost-effective projects are approved, regardless of where they are located or who they benefit beyond the

[3] Draft Concept, at p. 5.

intended reliability value of the resources being procured. As the name implies, the Strategic Reliability Reserve is intended to create a pool of resources that can be deployed during times of grid stress to avoid any blackouts, not to be used as a tool to achieve other policy goals. For similar reasons, the CEC should eliminate the $62.5 million allocation to POUs who already have the option to create and fund their own programs.

These allocations to POUs and DACs become more complicated when considered in the context of a $60 million allocation to Group 1 projects, and a combined $190 million to Group 2 and 3 projects. It is not clear if the intent is to allocate the Group 1 and Group 2/3 funding on a proportional basis to POUs and DACs. If this structure is approved as proposed, the CEC will inevitably find itself in the position of rejecting more cost-effective projects in favor of less cost-effective projects in order to ensure that the myriad funding constraints are satisfied. This would be an inefficient outcome and unnecessarily limit the quantity of resources procured through the solicitation.

Also, it is not clear why Group 2 and Group 3 funding should be combined when funding is specifically allocated to Group 1. Combining Group 2/3 funding risks projects from one Group dominating the funding and limiting the number of projects from the other Group. The Joint Parties recommend that the $190 million be split evenly between Group 2 and Group 3 projects. However, the CEC should anticipate the possibility that some Group funding will be allocated faster than other Groups; in anticipation of this possibility, it should establish a mechanism by which unused and uncommitted funding can be reallocated to one or two other Groups that are seeing a greater demand for funding. Such a mechanism could be applied after the first three or four years of the program to ensure that all funding is deployed to maximize the quantity of resources procured.

The Joint Parties also believe that the minimum project sizes, and minimum and maximum award amounts are too high. The proposed minimum MW amounts are so high that they risk precluding resource providers with smaller portfolios from participating, especially those with projects in smaller LSE service areas. Accordingly, the Joint Parties recommend that the minimum project size be reduced to three MW. Also, due to the minimum MW project sizes, a minimum award amount is unnecessary. Furthermore, the maximum award amounts are so large that just a few projects could potentially take up all of the funding.

Though the Joint Parties have encouraged procurement of the most cost-effective projects, there is also some diversity value in terms of the number of resource providers that should be able to participate in this program, especially given that Virtual Power Plants ("VPP") and load flexibility aggregation programs are still in their early stages in terms of scale. This is especially critical given that the CPUC appears poised to sunset the DRAM Pilot and in light of delays seen in the construction of new resources in the state. Therefore, the Joint Parties recommend eliminating the minimum award amount and reducing the maximum award amount for Group 1 to $10 million and $25 million for Group 2 and 3. This would not preclude the same applicant from receiving an award for multiple projects and receiving a higher sum.

d. Rules around DEBA resource participation in other load management programs should be clarified.

The Draft Concept, at Section B.9(d) under "Eligibility Requirements,"[4] specifies that eligible projects cannot include service accounts enrolled in other load reduction programs, unless they are participating under Pathway 4. It specifically calls out Supply-Side DR programs, the Emergency Load Reduction Program ("ELRP"), and the Demand Side Grid Support program (DSGS) under this prohibition, but it does not provide a clear definition of other programs that would be considered "load reduction programs." For clarity, the Draft Concept should provide a clearer definition of what programs and rate plans would fall under this list, or refer to a pre-established definition such as that supplied in Attachment A of the CPUC's recent Decision 23-12-005.[5]

In addition, although the Draft Concept places a strict prohibition on participation in ELRP or DSGS outside of Pathway 4, it implicitly allows participation in the RA program provided customers forfeit additional DER Solicitation payments in the year they participate and in all subsequent years thereafter. To make these conditions clearer, the Draft Concept should revise the last paragraph in Section C under "Funding" to say the following (bold lettering added):

[4] Draft Concept, at p. 17

[5] D.23-12-005 "DECISION DIRECTING CERTAIN INVESTOR-OWNED UTILITIES' DEMAND RESPONSE PROGRAMS, PILOTS, AND BUDGETS FOR THE YEARS 2024-2027," issued in CPUC Application (A.) 22-05-002, et al. (DR Programs) on December 14, 2023.

"**Projects may opt to participate their capacity in the Resource Adequacy market rather than participate in one of the performance pathways described below. However,** any project awarded funding through this solicitation that has its capacity committed to the Resource Adequacy market at any time during the program year of May 1 to October 31 will forfeit the annual performance-based payment for that year, as well as the remaining portion of the award that has been reserved for annual performance-based payments in future program years."

Finally, the Draft Concept should specify that projects awarded funding through the DER Solicitation can participate in other load reduction programs once the funding has been fully disbursed. Otherwise, projects will have no incentive to continue providing grid services after the five-year period that this program's funding is designed to cover.

e. The triggers for the Market Aware Performance Demonstration Pathway require modification.

Under the Market Aware Performance Demonstration Pathway, the price trigger would be \$100/MWh for Group 1 and 2 projects, and \$100/MWh or \$300/MWh for Group 3. The Draft Concept would also utilize an Absolute Trigger and Relative Trigger, apparently for the purpose of determining which dispatch hours can be counted for performance measurement purposes. The two triggers are unnecessarily complicated, utilize factors that cannot be known until after the fact, and are outside the control of resource providers. Consequently, they should be discarded from the Draft Concept. Furthermore, the Group 1 and 2 price triggers are far too low for the summer period and, when natural gas prices rise, would result in these resources being dispatched before many conventional power plants. The Joint Parties respectfully remind the CEC that the resources being procured through this solicitation are use-limited and that the DEBA Program is intended to "incentivize the construction of cleaner and more efficient distributed energy assets that would serve as on-call *emergency supply or load reduction for the state's electrical grid during extreme events*." (emphasis added) (AB 205, at Section 3). Therefore, it would be counterproductive and contrary to state law to adopt a price trigger that would be so low as to virtually guarantee dispatch during most days of the summer. The Joint Parties do not object to a price trigger but it should be the \$300/MWh Group 3 trigger and applied across all three Groups. This is still far lower than the CPUC's \$949/MWh bid cap for Proxy Demand Resources and PG&E's \$650/MWh Capacity Bidding Program bid cap, thus virtually guaranteeing that Market-Informed Pathway resources will be dispatched first.

f. VPP aggregation software costs should be eligible for funding under Group 2.

Software costs are explicitly included as eligible costs in Group 1 (and Group 3), but are excluded from Group 2. This seems like an oversight as the projects in Group 1 and Group 2 are substantially similar (differentiated primarily by size), so there is no clear reason why software costs would be funded for Group 1 projects but not Group 2. Like Group 1, software costs for Group 2 projects are non-trivial and necessary to enable effective VPP aggregation. If anything, software is an even more critical input for Group 2 projects, as they would be orchestrating a larger number of smaller DERs over wider geographic areas. As such, Group 2 projects should also be able to use program funding to cover software costs, similar to Group 1.

g. Group 3 should not require that LSEs be involved.

The Draft Concept specifies that Group 3 projects encompass Load Flexibility Aggregation Programs, and that eligible Group 3 applicants must be one or more California LSE or utility, or an entity under contract with one or more California LSE or utility.[6] It is not clear exactly why LSE or utility participation is necessary in this instance; in fact, requiring their involvement will very likely freeze out any third-party providers because the likelihood of an LSE/utility executing a contract with one before CEC approval of a project is very low. Furthermore, investor-owned utilities ("IOUs") rarely, if ever, enter into a contract with a third-party provider without being directed to do so by the CPUC. Finally, LSEs and utilities already have the ability to propose programs to their respective regulatory authorities to receive cost recovery from their ratepayers, so it is unnecessary and unfair that their participation be allowed, let alone required for Group 3 projects. The program funding should be used to incentivize resource providers to retain and create new capacity. The Draft Concept should be revised to eliminate LSE or utility eligibility to submit an application and to eliminate the requirement that a resource provider have an executed contract before submitting an application.

[6] Draft Concept, at p. 11.

III. Responses to CEC Staff Questions

Solicitation Requirements

1. *Are the minimum and maximum award amount funding levels and match requirements appropriate for each Group?*
   Please refer to Section II.b and II.c above.

2. *Is the proposed timeline in the solicitation, including application submission windows, reasonable to accommodate project proposals for project group?*
   No comment.

3. *Is it reasonable to allow project proposals that do not have all sites or customers pre-identified at the time of application? Are there any concerns with this approach?*
   Yes, it is reasonable that not all sites should be pre-identified, especially given the compressed timeframe for submitting applications, because additional recruitment might be driven by receiving an award from the DER Solicitation. The prospect of the incentive is something that will get customers onboard who may not otherwise be interested. The Draft Concept does a good job of taking this into account by giving bonus credit to identified sites but not requiring them.

4. *To mitigate the risks of funding multiphase projects, staff have proposed minimum deployment targets for multiphase projects under "Project Readiness" (25% by June 1, 2025, 50% by June 1, 2026, and 100% by June 1, 2027). Are these proposed deployment targets reasonable? What measures should the CEC take in the event of a deployment shortfall?*
   The June 1, 2025 milestone for the first 25 percent of the project is too early. This only allows for eight months following the notice of award which may not be sufficient if interconnections are required. The first milestone should be pushed out to January 1, 2026, with the second and third milestones pushed out by the same amount of time.

5. *Is the proposed payment structure, with 50% of the award disbursed during project development, and 50% disbursed annually based on successful performance, adequate to ensure successful performance by DEBA assets, including during emergencies?*
   Notwithstanding the Joint Parties' concerns about limits on the portion of the project cost eligible for an award, this is a reasonable approach to ensure that a resource provider will have the funds to construct its project while also being motivated to perform over the five-year performance period.

6. *This GFO proposes to amend the DEBA Program Guidelines, First Edition, to grant eligibility under Group 1 to projects connecting to the transmission grid behind-the meter at a load center not receiving distribution service. Please comment on whether this use case is of interest and, if possible, describe potential proposed projects and the reliability benefit they would offer.*
   No comment.

Project Requirements

7. *Are the Project Group definitions and requirements clear and adequate to sufficiently target DER technologies and projects capable of supporting statewide grid reliability?*
   The different project groups have significant overlap in terms of eligible technologies, and it is not altogether clear what the purpose is of some of the delineations. Group 1 and Group 2 are largely similar except Group 1 has a higher minimum size requirement and allows for FTM storage projects. Group 2 and Group 3 are the same in size but greatly differ in how incentives are paid out. The CEC presentation also contrasts with the initial proposals on what technologies are eligible for compensation under Groups 2 and 3, including what software versus hardware costs are eligible. Since Group 3 is intended to be an incentive program offered by LSEs, utilities, or a third party, it is unclear what the purpose is of restricting eligible technologies.

8. *Are the minimum project capacity requirements for each Group reasonable or should they be adjusted?*
   Please see II.c above.

9. *Are there any additional eligible technologies that should be included, or any currently eligible technologies that should be excluded?*
   Thermal storage should be included as an eligible technology for all groups.

10. *Are the proposed performance pathways sufficient and flexible enough to accommodate the variety of eligible technologies and project groups targeted by this solicitation?*
    The multiple performance pathways do allow for more flexibility, but also make administration and verification more challenging. Overall, this essentially creates dozens of different programs that CEC will have to review. Some of these pathways are similar to DSGS or other existing programs, and seem duplicative compared to a requirement that customers receiving an incentive participate in eligible programs, similar to how the Self Generation Incentive Program (SGIP) is designed.

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11. *What data should be required from DEBA Program participants for measurement and verification purposes as well as other public reports and initiatives?*
    No comment.

12. *Are the metering and telemetry requirements for projects sufficient for measurement and verification purposes and determining performance of DEBA funded projects?*
    No comment.

<u>Miscellaneous</u>

13. *What are the key performance indicators (KPIs) or metrics that should be used to evaluate and score VPP and Load Flex Aggregation projects and assess whether they will be reliable DEBA assets?*
    No comment.

14. *Are the proposed evaluation criteria, including preference points criteria, reasonable and sufficient to achieve the aims of funding DER projects that best bolster grid reliability in the state?*

    For Evaluation Criterion 8, the definition of "benefits" apart from statewide grid reliability and grid services should be further fleshed out and defined.

15. *Are the provisions for supporting projects that either benefit or are located in DACs sufficient? What other application components could facilitate greater participation from projects located in or benefiting DACs?*

    Notwithstanding the Joint Parties' recommendation that the DAC carveout be eliminated, there should be higher benefits for DAC projects without being overly proscriptive. The CEC could award bonus credit for DAC projects that explicitly replace polluting backup generators, especially if applicants show that the generator has been used frequently through 2023.

16. *What are the potential pathways for DEBA-funded projects across different Balancing Authorities and LRAs to continue to provide reliability value after the conclusion of the DEBA program?*

    Resources could participate as supply-side resources in the Western EIM or as load-modifiers similar to how they are considered by the CPUC. The duration of the DEBA program and the M&V process can be used to show the value of each project and be built on for future evaluation (including for any new state funding, ratepayer-funded, or third-party sourced DERs).

17. *Are there any other recommended improvements or necessary clarifications for the CEC to consider for this draft solicitation concept document?*

    The Joint Parties respectfully request the following clarifications:

    a. Are participants in the Self-Generation Incentive Program ("SGIP") eligible to participate in the DER Solicitation? Can SGIP grants be considered "Match Funding"?

b. Are there any provisions for extending the online date of a project in the event of circumstances that are outside the control of resource provider (e.g., due to interconnection or supply chain issues)? Are there any penalties for exceeding the online date?
c. If the CEC retains the DAC funding allocation, can it provide maps depicting qualifying DACs?
d. Does the limit of five applications apply separately to a consortium of resource providers? For example, can a resource provider submit five applications on its own and them five more as part of a consortium?
e. It is not clear whether a VPP is defined as a single location. If so, can multiple VPPs be bundled into one into one group to meet the minimum size and budget requirement? Also, can the same bundle of VPPs be counted under a single application?
f. When will the balance of the DEBA funding for distributed resources be released?
g. A minimum passing score of 70 percent is utilized for several of the Evaluation Criteria. What happens if a score falls below 70 percent?
h. How would notifications of an EEA event work? Is it incumbent upon the provider to register to receive EEA alerts?
i. Does thermal storage (no generation, just load shifting) qualify for eligibility, especially under Groups 1 and 2?
j. Can CEC clarify further what software costs (and potential load flexibility technologies) are eligible for recovery under Group 2, and what, if any, hardware costs can be included for incentives under Group 3?

IV. Conclusion

The Council and OhmConnect appreciate this opportunity to comment on the CEC's Draft Concept.