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Description:	***This document supersedes TN 254646*** Draft Solicitation Concept revised to correct formatting errors and update in-text references to document sections. Additional minor edits were made to Section V.F: Tie Breakers to improve clarity.
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DRAFT SOLICITATION CONCEPT

Distributed Electricity Backup Assets Program

Distributed Energy Resources for Reliability

No applications are being accepted at this time. This is a draft compilation of solicitation concepts. Do not design or submit proposals according to this DRAFT. The actual solicitation will be issued at a later time and may include concepts different from this draft solicitation concept.

The purpose of this draft solicitation concept is to solicit public feedback on eligibility requirements, goals and vision, and solicitation format (See Section VI. for specific questions). Staff will accept comments submitted to the California Energy Commission (CEC) Dockets Unit or by email until **Friday, March 15, 2024**, at 5:00 p.m. (See Section VII. for additional details on how to comment.)

Solicitation Information
https://www.energy.ca.gov/funding-opportunities/solicitations
State of California
California Energy Commission
February 27, 2024

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I. Introduction

A. Purpose of Solicitation

This “draft solicitation concept” document details the framework under consideration for a competitive grant solicitation for resources that will provide emergency supply or load reduction during extreme events through the Distributed Electricity Backup Assets (DEBA) Program as part of the state’s Strategic Reliability Reserve. The purpose of this competitive solicitation, or grant funding opportunity (GFO), is to incentivize the construction of cleaner and more efficient distributed energy resources (DERs) that increase supply or reduce (or shift) load to improve the reliability of the state's electrical grid. This solicitation can be referred to as the “DEBA DER GFO”.

As California transitions to a clean energy future and contends with climate impacts and other challenges, sufficient capacity of new and existing grid resources will be required to maintain reliability during extreme events. Due to the increased frequency, intensity, and duration of extreme weather events, the grid is more vulnerable and therefore needs greater investments in cleaner technologies, in alignment with the state’s clean energy goals, to bolster reliability.

Applications for proposed projects selected through this GFO are expected to provide new capacity in the form of supply or load reduction that is incremental to the state’s resource adequacy supplies and existing strategic reliability reserves and improves grid reliability. Successful projects are expected to begin deploying DER resources quickly, by Summer 2025 at the latest.

Applicants interested in pursuing Department of Energy (DOE) loan programs should note that a CEC grant (including a grant from DEBA program) may contribute as a match for other Federal and State opportunities. The California Energy Commission has been identified as State Energy Financing Institution (SEFI) for the purposes of DOE’s Loan Program Office (LPO) Title 17 program; as such the CEC will consider an award under this GFO to be a meaningful contribution.

B. Background

Created by Assembly Bill (AB) 205 (Ting, Chapter 61, Statutes of 2022) as part of the Strategic Reliability Reserve, the Distributed Electricity Backup Assets (DEBA) Program provides incentives for constructing cleaner and more efficient distributed energy assets. These distributed energy assets will serve as on-call emergency supply or load reduction for the state’s electrical grid during extreme events, such as heat waves. DEBA Program funding is authorized under Assembly Bill 180 (Ting, Chapter 44, Statutes of 2022) and Assembly Bill 102 (Ting, Chapter 38, Statutes of 2023) with a program budget of $595 million, $545 million of which was authorized in Fiscal Year 2021–2022 and the remainder to be authorized in future years.

C. Key Activities and Tentative Dates

Key activities including anticipated dates for this draft solicitation are presented below. All dates are tentative and are subject to change. Times listed are Pacific Standard Time or Pacific Daylight Time, whichever is being observed.

ACTIVITY	TENTATIVE DATE
Draft Solicitation Concept Release	February 23, 2024
Draft Solicitation Concept Workshop	March 5, 2024
Public Comments Due	March 15, 2024
Solicitation Release	April 2024
Deadline to Submit Applications (General Application Period)	**June 2024**
Notice of Proposed Awards Posting	July 2024
Deadline to Submit Applications (Disadvantaged Community Set-Aside)	July 2024
Notice of Proposed Awards Posting	August 2024
CEC Business Meeting (General Application Period)	September 2024
CEC Business Meeting (Disadvantaged Community Set-Aside)	October 2024

II. Funding

A. Availability of Funds

A total funding level of $250 million is available for awards under the DEBA DER GFO ("this/the solicitation").

- At least $62.5 million is available only for projects located in local publicly owned electric utility (POU) service territories.
- This solicitation seeks to award at least $125 million to projects located in or benefitting Disadvantaged Communities (DACs).

$220 million is expected to be available for awards during the general application period, and an additional $30 million is expected to be set aside for awards during the subsequent application period available only for Group 1 projects (defined below) located in or benefiting DACs.

CEC, at its sole discretion, reserves the right to increase or decrease the amount of funds available under this solicitation and the minimum/maximum award amounts described in this section.

B. Minimum and Maximum Award Amounts

The total funding level of $250 million is available for awards to projects selected under this solicitation.

Three project types are eligible under this solicitation, which are categorized into three "Groups" (see Section III for definitions of "Groups"):

- **Group 1** encompasses projects for Large DER Installations.
- **Group 2** encompasses virtual power plants (VPPs) with new DER installations.
- **Group 3** encompasses projects to develop and manage Load Flexibility Aggregation Programs.

Maximum funding award amounts available for each Group are described below.

The CEC expects to award at least one project in each Project Group. Once the highest ranked projects achieving at least the minimum passing score in each Project Group are recommended for funding, if funding remains available, the CEC will award the next highest-ranking project achieving at least the minimum passing score.

For **Group 1: Large DER Installations** and **Group 2: VPPs**, the DEBA award will be a maximum of 50% of the total eligible project costs net of tax credits.

- For Group 1 Large DER Installations located in a DAC that have a letter of support from an environmental justice community-based organization, the DEBA could be increased to 50% (or higher) of the total eligible project costs gross of tax credits.

For **Group 3: Load Flexibility Aggregation Programs**, the CEC will award up to 100% of the requested budget for eligible project proposals.

Project Group	Available Funding	Minimum Award Amount	Maximum Award Amount	Match Share (% of total eligible project costs)
Group 1: New Large DER Installations	$60 million	$1 million	$20 million	50% (net of credits)*
Group 2: VPPs with New DER Installations	$190 million	$1 million	$95 million	50% (net of credits)
Group 3: Load Flexibility Aggregation Programs		$1 million	$95 million	0%

*Except for proposed projects located in disadvantaged communities and that have a letter of support from an environmental justice community-based organization.

Applicants must identify whether their proposed project will be in either Group 1: New Equipment Installations or Group 2: VPPs or Group 3: Load Flexibility Aggregation Programs. Applicants whose proposed project qualifies for Group 1 are eligible for up to $20 million per application award, while Applicants whose proposed project qualifies for Group 2 or Group 3 are eligible for up to $95 million per application award. If an Applicant plans to submit an application for a project in Group 1, and another separate and distinct application for a project in Group 2, the Applicant can be eligible for the maximum award amount in both categories, totaling $95 million.

Applicants should request an award amount that can be justified with supporting details to be competitive under the cost-effectiveness criterion (see Section V.D.4). For Group 3, while the total requested budget will be covered by DEBA, Applicants are encouraged to seek cost share from other entities or customers to minimize the requested award amount to be competitive under the cost-effectiveness criterion.

Applicants may submit one or more applications, up to the maximum number of applications specified in Section III.A.2.

For this solicitation, the minimum match share requirement is equal to half of the remaining total eligible project costs after any applicable Federal tax credits have been applied (50% net of credits). Section II.D. below provides more detail as to what counts as match that would need to be provided by the Applicant.

C. AWARD PAYMENT STRUCTURE

For **Group 1: Large DER Installations** and **Group 2: VPPs**, Applicants will be eligible to receive 50% of the total award while the project is under construction. This portion of the award will be disbursed based on incurred expenses and monthly or quarterly progress reports demonstrating that satisfactory and continued progress is made towards meeting identified project milestones. The remaining 50% will be disbursed annually over a 5-year period, or by June 30, 2030, whichever comes first, contingent on successful performance (annual performance-based payment). The annual performance-based payment (up to 10% of total award) will be paid following the conclusion of each calendar year if the resource successfully fulfills its performance, measurement and verification, and reporting obligations. See Section III.B.10-13 for the applicable requirements.

For **Group 3: Load Flexibility Aggregation Programs**, the entire award will be disbursed based on incurred expenses and monthly or quarterly progress reports demonstrating that satisfactory and continued progress is made towards achieving the project objectives described in the Scope of Work.

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.

D. MATCH FUNDING

"Match funding" or "match share" means cash or in-kind (non-cash) contributions provided by the Applicant/Recipient, subrecipients, or other parties that will be used in performance of the proposed project. Match share percentage is calculated by dividing the total match share contributions by the total allowable project cost. "Total allowable project cost" is the sum of the CEC's reimbursable share and Recipient's match share of the project costs. Match share expenditures have the following requirements:

a. All match share expenditures must conform to the terms and conditions of this solicitation and the resulting grant agreement.

b. Applicants must disclose the source and provide verification and documentation for the match share funding committed to the project. For any match share committed by a third party (i.e., other than match share committed by the Applicant), Applicants must submit a letter of commitment from each match share partner identifying the source(s) and availability of match funding.

c. During the term of the grant agreement, Recipients will be required to document and verify all match share expenditures through invoices submitted to CEC.

d. Match share funding may be in the form of cash or in-kind contributions such as donated labor hours, equipment, facilities, and other property.

e. Equipment, facilities, and property may count as match funds as long as the value of the contribution is based on documented market values or book values, prorated for its use in the project, and depreciated or amortized over the term of the project using generally accepted accounting principles (GAAP).

f. Match share expenditures (cash and/or in-kind) must be documented, reasonable, allowable, and allocable to the project as determined by CEC.

g. Match share expenditures are allowable under an agreement only if they are incurred after CEC notifies the Applicant that its project has been proposed for an award through the release of a Notice of Proposed Awards (NOPA). Match expenditures incurred after the release of a NOPA but prior to the execution of an agreement are made at the Applicant's own risk. CEC is not liable for Applicant's match share costs if the grant is not approved, if approval is delayed, or if the match share expenditure is not allowable under the terms and conditions of the grant or this solicitation. Please note that non-match expenditures incurred prior to agreement execution are not reimbursable from CEC funds.

Cash match means the net of any funds expended by the Applicant for the project. Net means after any sort of discount or rebate is applied. Expenditures for Applicant's compensated labor hours, including allowable fringe benefit and overhead rates, travel, materials, supplies, equipment, subrecipient costs, and other miscellaneous expenditures may be claimed as cash match if the expenditures are included in the approved agreement budget, paid in full with funding sources other than grant funds, and supported with appropriate documentation, including proof of payment. For indirect overhead, backup documentation, such as a cost allocation plan based on actual expenditures incurred and paid, is required. Cost allocations must be reasonable and allocable to the proposed project.

In-kind match share contributions are: 1) non-cash contributions provided by the Applicant; 2) cash or non-cash contributions provided by subrecipients; and 3) cash or non-cash contributions provided by other third parties. Applicant in-kind match share can be in the form of volunteer labor, real property, existing equipment, existing supplies, services provided by a third-party or subcontract, and other expendable property. The value of in-kind match is based on the fair market value of the goods and services provided at the time it is claimed as match. In-kind match share must be included in the agreement budget and supported with appropriate documentation. Cost allocations must be reasonable and allocable to the proposed project.

Match Share Restrictions

a. **Other Sources of CEC Funding** – Other sources of CEC funding may not be claimed as match share. This includes block grants funded by the CEC.

b. **Property Not Owned by the Applicant** – Donated property may be claimed as match based on the fair market value of renting or leasing the property. Fair market value is based on rental costs of comparable property (if any), market conditions in the area, alternatives available and the type, life expectancy, condition, and value of the property.

c. **Existing Property Owned by the Grant Recipient** – Applicants may use the property's depreciation expense as a method to allocate the value of the property to the project. Valuation will need to be documented to support the initial acquisition costs as well as the method of depreciation.

d. **Valuation of Land** – Land cannot be depreciated. If the value of land is claimed as match, the Applicant must provide documentation to support a fair market value for the use of the land (i.e., rent or lease cost) for the time period it is used. Appraised value of land cannot be used since this represents the full value of the land if it is sold which includes value beyond the term of the proposed project.

e. **Property Owned by a Related Party** – Related parties are individuals or other entities that are able to control or substantially influence the actions of the Applicant and includes spouses, board members, family members of principals or employees of the Applicant as well as property owned by principals/employees of the Applicant. Because an agreement between an Applicant and a related party is a "less than arms-length" transaction, Applicants must disclose the relationship between the Applicant and the related party and be able to support the fair market value of property that is claimed as match.

   If CEC funds are used to reimburse lease/rental payments for property owned by a related party, the Applicant can only claim the **lesser** of fair market value or actual lease payments, regardless of lease agreement terms.

f. **Prorated Value of Property** – The allowable claimed value of property must be prorated based on the percentage the property is used for the proposed project. For example, if only half of a building is being used for the proposed project, then only 50% of the monthly fair market value of the entire building can be claimed as match while the building is being used for the project.

Documentation – If selected for an award, all claimed match share expenditures must be adequately documented to CEC during the agreement invoicing process which may include but is not limited to the fair market value of existing property, methodology to allocate existing property on a prorated basis, lease agreements, and other appropriate documentation.

E. UNALLOWABLE COSTS (COSTS NOT REIMBURSABLE OR ELIGIBLE FOR COST SHARE)

For an item of cost to be allowable for reimbursement with CEC funds, it must be included in the executed agreement budget and allowable per the terms and conditions of the resulting agreement. The following are examples of unallowable costs under an agreement resulting from this solicitation. This list is not comprehensive and additional items of cost may be unallowable in accordance with the agreement terms and conditions.

1. ***Forgone Profit*** – For example, if a company usually charges 10% profit but only charges 4% to CEC. The unclaimed difference is not an allowable item of cost.
2. ***Forgone Rent*** – For example, rents that are not paid is not an allowable item of reimbursable cost.
3. ***Foregone Salary, Fringe, Indirect or Other Types of Cost*** – For example, a person normally charges or is paid $100 per hour but will only charge $50 per hour towards the CEC award. Only actual costs incurred and paid to the employee are allowable.
4. ***Discounted or Refunded Equipment Costs*** – For example, a claim that equipment costs $10,000 but the grant recipient only pays $6,000 due to some “special” discount. The difference of $4,000 is not an allowable cost share expense. Another example is if the grant recipient actually pays $10,000 but the vendor refunds $4,000 – only the net $6,000 is an allowable item of cost.
5. ***Permitting Costs*** – CEC will not reimburse expenditures for permitting or insurance.

III. Eligibility Requirements

A. Applicant Requirements

1. Eligible Applicants

For **Group 1: Large DER Installations** and **Group 2: VPPs**, eligible Applicants are any public and private entities that can develop and deploy DERs.

For **Group 3: Load Flexibility Aggregation Programs**, eligible applicants must be one or more California load serving entities (LSEs) or utilities or an entity under contract with one or more California LSE/utility and applying on behalf of the LSE/utility.

2. Maximum Number of Applications

Applicants may submit up to 5 applications, each with one eligible project (defined below), under this solicitation. Each proposed project must be separate and distinct and adhere to all requirements contained in this solicitation. Each proposed site must not participate in multiple project groups or multiple DEBA programs.

B. Project Requirements

1. Eligible Projects

Applications must fall into one of three project groups to be eligible under this solicitation:

- **Group 1: Large DER Installations:** Project proposals for the installation of new, large eligible DER equipment (as defined in Section III.B.5 (“Eligible Technologies”) of this solicitation manual), with a capacity of 100 kilowatts (kW) or greater, at one or more sites located either in front-of-the-meter (FTM) or behind-the-meter (BTM). Applicants may choose to bundle DER equipment installations at multiple distinct sites into one project proposal to meet the minimum capacity requirement specified below. The installation sites may or may not be pre-identified in the application, up to a maximum of 20 sites that are not pre-identified. However, proposals for installations with sites and customers already identified will score more favorably against proposals without sites or customers pre-identified.

- **Group 2: Virtual Power Plants (VPPs):** Project proposals for installing one or more new eligible DER equipment (as defined in Section III.B.6 (“Eligible Technologies”) of this solicitation manual) at multiple sites BTM and aggregating them together to perform as a single VPP resource in response to an external input and to meet the minimum capacity requirement specified below. The installation sites may or may not be pre-identified in the application. However, proposals for installations with sites and customers already identified

will score more favorably against proposals without sites or customers identified.

- **Group 3: Load Flexibility Aggregation Programs.** Project proposals for developing aggregations or scaling demand flexibility within the service territory(ies) of the Applicant using either new eligible load flexibility equipment or a combination of both new and existing load flexibility equipment (as defined in Section III.B.7 (“Eligible Technologies”) of this solicitation manual) that meet the minimum capacity requirements specified below. The project proposal may involve one or more third-party aggregators or demand flexibility service providers under contract with the Applicant that may or may not be pre-identified in the application. However, proposals with third-party aggregators or demand flexibility service providers already identified will score more favorably against proposals without them identified. The Applicant is encouraged to seek cost share from other entities or customers to minimize the requested award amount to be competitive under the cost-effectiveness criterion. The Applicant is expected to apply the performance requirements and performance-based payment/penalty schedule described in Sections III.B.10-13 below to the aggregation programs.

2. Project Location

Proposed projects must be located in California. Project development and operations must also occur in California, with the finished asset located on the distribution grid.

Subject to the DEBA Program Guidelines being amended at a future CEC Business Meeting, DERs in Group 1 projects connected to the transmission grid BTM, where the meter is associated with a load center that does not take distribution service, would be eligible under this solicitation.

3. Project Readiness

Proposed projects must be completed and online no later than May 1, 2027.

All project proposals are expected to provide best available estimates of project completion date. Projects that are multi-phase involving multiple installations or customer sign-ups must demonstrate at minimum 25 percent of total project capacity installed and online by May 1, 2025, 50 percent by May 1, 2026, and 100 percent by May 1, 2027, and in each subsequent year. Proposals must include a deployment schedule detailing the committed incremental nominal capacity (MW) in each year that meets or exceeds this minimum standard.

To meet immediate grid reliability needs, it is imperative that the technologies utilized in the proposed projects are commercially available. Proposed projects may include cutting-edge solutions that are readily accessible in the market, ensuring a seamless integration process and timely implementation. The

emphasis on commercially available technologies aligns with our commitment to a rapid turnaround and the success of the program.

4. Rated Project Capacity

To evaluate and compare project proposals with varying durations of nominal capacity, or maximum power output or load reduction, projects will be compared on the basis of 4-hour or “rated” capacity. Projects with a nominal capacity that can be maintained for a duration of less than 4 hours will be normalized to rated capacity.

The rated capacity of the project is the average power output or load reduction level that could be sustained over a 4-hour period. For a project with a nominal capacity level that can be maintained for 4 or more hours, the nominal and rated capacity will be considered equal.

As an example, an application with a proposed VPP with 20 MW aggregate nominal capacity and aggregate storage capacity of 40 megawatt-hour (MWh) and designed to operate for 2 hours would be normalized to a rated capacity of 10 MW.

5. Group 1 Requirements: Large DER Installations

a. Eligible Technologies

Eligible project proposals must include the purchase and deployment of new equipment (must be commercial ready, Technology Readiness Level (TRL) 9 or greater), which may include:

i. **Energy storage**. Batteries, thermal energy storage, pumped hydro, bi-directional EV chargers, etc.

ii. **Distributed generation (DG) technologies**. Examples include but are not limited to:
   a. Fuel cells
   b. Microturbines
   c. Linear generators
   d. Reciprocating engines
   e. Combined heat and power (CHP) systems that use waste heat to power (WHP) technologies

   All DG technologies must be permitted by the local Air Quality Management District (AQMD) or certified under the California Air Resources Board (CARB) Distributed Generation Certification Program. They must also possess a Rule 21 or other interconnection permit allowing parallel operation with the grid.

iii. **Microgrids**. Any of the above technologies used as a component of a microgrid.

iv. **Load flexibility technologies**. Hardware and software to enable load flexibility. Examples include but are not limited to:
    a. Load flexibility controls, automation, and communications (smart thermostats, pump controllers, water heater controllers, managed charging, etc.).
    b. Supervisory control and data acquisition (SCADA) systems.
    c. Demand flexibility software.
    d. Building energy management systems (BEMS).

Eligible project proposals for Group 1 do not include the purchase of any of the ineligible technologies listed in Section III.B.8.

b. Minimum Project Capacity

Eligible project proposals in Group 1 must be available to supply electricity or reduce load at a minimum 6 MW of incremental rated capacity. The nominal capacity for Group 1 projects involving BTM storage must be sustainable for a duration of at least two hours during peak net load hours.

c. Eligible Project Costs

Costs incurred for the following activities are eligible for CEC reimbursement or as the Applicant's match share:

i. Project pre-engineering and design.
ii. Engineering plans and specifications.
iii. Project installation, construction, modifications, and/or commissioning.
iv. Asset and/or equipment acquisition.

The CEC will not reimburse for land acquisition, but this may be counted towards match share. See Match Funding Requirements.

6. Group 2 Requirements: Virtual Power Plants (VPPs)

a. Eligible Technologies

Eligible project proposals must include the purchase and deployment of new equipment (must be commercial ready, TRL 9 or greater), which may include:

i. **Energy storage**. Batteries, thermal energy storage, pumped hydro, bi-directional EV chargers, etc.

ii. **Distributed generation technologies (DG)**. Examples include but are not limited to:
    a. Fuel cells
    b. Microturbines
    c. Linear generators

d. Reciprocating engines
e. Combined heat and power (CHP) systems that use waste heat to power (WHP) technologies

All DG technologies must be permitted by the local Air Quality Management District (AQMD) or certified under the California Air Resources Board (CARB) Distributed Generation Certification Program. They must also possess a Rule 21 or other interconnection permit allowing parallel operation with the grid.

iii. **Microgrids**. Any of the above technologies used as a component of a microgrid.

Eligible projects for Group 2 do not include the purchase of load flexibility technologies or any of the ineligible technologies listed in Section III.B.8.

b. Minimum Project Capacity

Eligible projects in Group 2 must propose to install and aggregate a minimum of 15 MW of incremental rated capacity over the period of program deployment consistent with the requirements described in Section III.B.3. The nominal capacity for Group 2 projects involving BTM storage must be sustainable for a duration of at least two hours during peak net load hours.

c. Eligible Project Costs

Costs incurred for the following activities are eligible for CEC reimbursement or as the Applicant's match share:

i. Project pre-engineering and design.
ii. Engineering plans and specifications.
iii. Project installation, construction, modifications, and/or commissioning.
iv. Asset and/or equipment acquisition.

The CEC will not reimburse for land acquisition, but this may be counted towards match share. See Match Funding Requirements.

7. Group 3 Requirements: Load Flexibility Aggregation Programs

a. Eligible Technologies

Eligible project proposals must include the purchase and deployment of new **load flexibility technologies**, which are hardware and software to enable load flexibility (must be commercial ready, TRL 9 or greater).

Examples include but are not limited to:

i. Load flexibility controls, automation, and communications (smart thermostats, pump controllers, water heater controllers, managed charging, etc.).

ii. Supervisory control and data acquisition (SCADA) systems.

iii. Demand-response aggregation or demand flexibility software.

iv. Building energy management systems (BEMS).

Eligible projects for Group 3 do not include the purchase of energy storage, distributed generation technologies, or any of the ineligible technologies listed in Section III.B.8.

b. Minimum Project Capacity

Eligible project proposals in Group 3 must propose to install and/or aggregate a minimum of 15 MW of incremental rated capacity over the period of program deployment consistent with the requirements described in Section III.B.3.

c. Eligible Project Costs

Costs incurred for the following activities are eligible for CEC reimbursement:

i. Incentives paid to third party aggregators and customers for the purchase and deployment of load flexibility technologies and program participation, as defined in this solicitation.

ii. Administrative costs incurred to develop and implement a Load Flexibility Aggregation Program.

8. Ineligible Technologies

The following technologies are not eligible for CEC reimbursement or as part of the Applicant's match share.

a. Projects relying on occupant behavioral changes.

b. Diesel backup generators regardless of fuel type (diesel, biodiesel, or renewable diesel or a combination thereof).

c. Variable renewable resources, such as solar photovoltaic panels and wind turbines.

d. Purchase of new load-only appliances, such as: electric water heaters, pool pumps, HVAC, EVs or EV batteries, etc.

9. Special Terms and Conditions

Eligible projects must meet the following requirements:

a. Technologies must be commercial ready, with a technology readiness level (TRL) 9 or greater.[1]

b. Must comply with all codes, Rule 21 or Wholesale Distribution Access Tariff (WDAT) interconnection requirements, UL certifications, and other standards such as: California electric code, National Electric Code, local and state fire marshal codes. Must acquire all necessary permits and perform load calculations to ensure system is safely installed.

c. BTM sited DER systems specifically must have interoperability to enable communication between the customer's system and the grid, as well as the various system components; consistent with Rule 21 communications requirements that comply with either IEEE 2030.5 or SunSpec Modbus Protocol.

d. Must comply with the applicable Local Regulatory Authority (LRA) dual enrollment rules. Must not be sited at a service account enrolled in another load reduction program, including supply-side demand response or the Emergency Load Reduction Program (ELRP) or Demand Side Grid Support (DSGS) programs, unless the project is applying the daily dispatch/continuous generation performance pathway (see subsection III.B.10, Pathway 4).

10. Performance Demonstration Pathways

Project proposals must elect one of the pathways listed below to demonstrate the performance of the project's resources. In some cases, depending on the resource type, some pathway options may be required or may not apply. The available performance demonstration pathways are:

1. **Market-Integrated:** Dispatch in response to the applicable California Balancing Authority (BA) market instructions.
2. **Market-Aware:** Dispatch in response to a "market-aware" California ISO price signal.
3. **Hourly Dynamic Rate:** Dispatch in response to an hourly dynamic pricing tariff linked to BA's energy market and grid conditions.
4. **Daily Dispatch:** Dispatch daily in designated hours (including resources operating continuously or most of the time, such as a baseload generator or fuel cell).
5. **Emergency Dispatch:** Dispatch in real time under emergency conditions.

For all performance pathways, demonstrated capacity will be measured using up to one hundred hours of performance data during each program year. A program year is defined as May 1 through October 31. The selected hours will be the

1 The Technology Readiness Level scale is a means of assessing the maturity of evolving technologies prior to incorporating that technology into a system or subsystem. U.S. Department of Energy, "Technology Readiness Assessment Guide". https://www2.lbl.gov/dir/assets/docs/TRL%20guide.pdf

hours applicable to the resource in which an Energy Emergency Alert (EEA) (or EEA Watch) is called by the host BA, plus the hours with either 1) the highest locational marginal prices (LMPs) over the applicable pricing or aggregate pricing node for resources located within the California ISO BA or 2) highest net load or load for resources located in other BAs. Additional detail on the applicable hours and selection of the top one hundred hours follows the description of each performance pathway.

Pathway 1: Market-Integrated Dispatch

Projects in any Group may elect this pathway. Front-of-the-meter (FTM) Group 1 projects, such as WDAT, must select this pathway.

Project proposals electing this pathway for demonstrating resource performance are expected to make the resource available on a day-ahead and real-time basis to the host California BA for economic and exceptional dispatch, consistent with the applicable requirements and eligible project's operational capabilities.

Under this pathway, resources must bid or self-schedule into the California Independent System Operator (ISO) market for at least four consecutive hours during the peak net load hours in the day-ahead and real-time markets and then dispatch per market instructions. Similar resources connected in non-ISO territories must be available for dispatch subject to the rules of the host BA.

The one hundred hours included in the demonstrated capacity calculation will be selected from all peak net load hours throughout the program year, excluding either 4:00–5:00p.m. or 8:00–9:00p.m. to accommodate the 4-hour bidding requirement. Resources that do not receive a dispatch because of failure to bid or schedule shall be assigned a discharge value of 0 MW during those hours.

Pathway 2: Market-Aware Dispatch

Project proposals in any Group, except Group 1 projects connected under WDAT, may elect this pathway.

Project proposals electing this pathway must be available every day for four hours (or the nominal capacity duration in the case of BTM storage). Performance must be demonstrated through responses to a "market-aware" California ISO price signal or events called by a California BA or non-ISO POU.

A market-aware dispatch is triggered in response to a mix of California ISO market prices and reliability-related alerts. The price is defined as the California ISO day-ahead LMP for the applicable distribution utility company default load aggregation point (DLAP) in which the project's host customer resides, or Path

15 zone for POUs.[2] The price triggers for the market-aware pathway are set at the following levels:

- Group 1: $100/MWh
- Group 2: $100/MWh
- Group 3: $100/MWh or $300/MWh

A market-aware dispatch is defined as any hour or set of hours within the peak net load hours that meets both of two criteria. A dispatch may last from one hour to the maximum resource duration. These criteria are:

- **Absolute Trigger:** If an EEA or EEA Watch is called by 3:00 p.m. on the relevant day, all peak net load hours shall be considered to meet this criterion. Otherwise, any hour with an LMP greater than or equal to the price trigger shall be considered to meet this trigger. If multiple hours within the program window meet the absolute price trigger but are not consecutive, the hour or hours in between shall also be considered to meet this criterion.

- **Relative Trigger:** The hours with the highest mean consecutive LMP over the duration of capacity duration of the project shall be considered to meet this criterion. If the number of hours met by the absolute trigger exceeds the capacity duration, only those consecutive hours with the highest mean LMP over the capacity duration shall be considered event hours. If the highest mean consecutive hourly price applies to more than one set of hours (that is, if there is a tie), the event will be the first (that is, earliest) set of consecutive hours among the set of consecutive hours that are tied.

The up to one hundred hours included in the demonstrated capacity calculation will be taken from the peak net load hours meeting the triggers defined above.

Pathway 3: Hourly Dynamic Pricing

Projects, except FTM projects in Group 1, may elect this pathway, subject to tariff availability in the service area.

Project proposals electing this pathway must enroll customer sites in an hourly dynamic pricing rate or tariff that reflects hourly marginal costs based on current wholesale energy prices and other grid capacity utilization levels, such as the

[2] The distribution utilities and corresponding aggregate pricing node IDs are Pacific Gas and Electric ("DLAP_PGAE-APND"), Southern California Edison ("DLAP_SCE-APND"), San Diego Gas & Electric ("DLAP_SDGE-APND"), and the POUs of Anaheim, Azusa, Banning, Pasadena, Riverside, and Vernon (SP15, "TH_SP15_GEN-APND").

hourly dynamic rates offered in IOU pilots based on CPUC's California Flexible Unified Signal for Energy (CalFUSE) framework.[3]

The top one hundred hours with the highest LMP or EEA event hours will be taken from all peak net load hours, using the same pricing nodes defined in Pathway 2.

Pathway 4: Daily Dispatch

Group 1 projects connected under WDAT and Group 3 projects are not eligible to elect this pathway.

Project proposals electing this pathway must dispatch daily in designated hours that must be inclusive of 4:00–9:00p.m. time window. Under this option, a resource may choose to operate continuously or near continuously such as a baseload generator or fuel cell).

The top one hundred hours with the highest LMP or EEA event hours will be selected from all peak net load hours, using the same aggregate pricing nodes defined in Pathway 2.

Pathway 5: Emergency Dispatch

This pathway is limited to Group 1 projects with dispatchable DG.

Project proposals electing this pathway must be available for real-time emergency dispatch twenty-four hours a day and seven days per week, including holidays. The resource must be able to ramp up to full capacity within 10 minutes of an EEA 1, 2, or 3 from the host BA.

The top 100 hours are not applicable to this pathway. Instead, performance will be measured during all applicable EEA events, starting 10 minutes following the EEA announcement or the start of the EEA event, whichever is later, and ending when the EEA event is canceled.

In the absence of an EEA event in a given program year, a one-hour test event is required to demonstrate capacity. The event may take place on any day within the program year.

11. Measurement and Verification

The Project Narrative (Attachment 2) must include a Measurement and Verification Plan that describes both how actual performance will be evaluated and how project benefits will be measured and quantified. The applicant can identify measurable and quantifiable project benefit metrics through developing key performance indicators (KPIs) that are applicable to the project group and

[3] CPUC Energy Division Staff. 2022. "Advanced Strategies for Demand Flexibility Management and Customer DER Compensation." https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf.

type to track project milestones, evaluate project performance, and determine project success. The applicant must develop user-friendly, internal access database(s) for CEC staff to receive KPI data on an annual basis at minimum.

There are two mandatory performance requirements that must be included in the M&V reporting are 1) M&V for Dispatch Performance and 2) Determination of Demonstrated Capacity Performance.

a. M&V for Dispatch Performance

Dispatch performance of a DEBA resource is the measured generation, discharge, or load impact during an hour in which the resource is dispatched. Dispatch performance is measured at each resource, then summed across all resources in an aggregation to determine aggregate performance.

In the context of aggregate performance, an aggregation is defined as all resources within a single project that are dispatched in response to and measured using the same performance pathway and signal. For example, a project comprising market-aware resources in all three of the investor-owned utility territories would be considered to be composed of three aggregations, since all resources within each utility territory would be dispatched in response to the same DLAP aggregate pricing node and measured during the same top hours.

Resources with electric output (for example, fuel cells and batteries) must be measured directly at the device sub-meter or inverter. Proposals using thermal energy storage resources may be converted from cooling load (for example, in Ton-hours) to electric energy (kWh) if the applicant provides conversion assumptions, or if a site-level counterfactual approach to estimate load impacts from a pre-installation baseline is applied. The applicant must provide details on the proposed methodology, including but not limited to assumptions regarding chiller efficiency.

Group 3 proposals for load flexibility programs may include any of the following methods for developing a counterfactual baseline:

- Regression-based approaches
- Day matching
- Weather matching
- Comparison groups

Applicants must include additional details such as same-day adjustments (if applicable), and document that the chosen counterfactual baseline approach is the best method available.[4]

[4] More information on counterfactual baselines can be found here: https://www.caiso.com/Documents/2017BaselineAccuracyWorkGroupFinalProposalNexant.pdf.

b. Determination of Demonstrated Capacity Performance

The annual demonstrated capacity value of a project will be determined by the weighted average of measured hourly dispatch performance for non-weather-sensitive resources.

The annual demonstrated capacity value of a weather-sensitive aggregation will be determined by the weighted regression of hourly dispatch performance (load impacts) as a function of temperature.

Non-weather-sensitive resources include generation and electric storage resources, and weather-sensitive resources include thermal energy storage and load flexibility resources.

Non-weather-sensitive Project

The annual demonstrated capacity in the participation year *y* ($Demonstrated_y$) for a non-weather-sensitive project is defined as the weighted average of the hourly performance ($Performance_h$), as defined in the previous section, where the weights in hour *h* are given by the product of the applicable hourly LMP and an hourly emergency event multiplier (EEM) across the *N* (up to one hundred) dispatch hours in participation year *y*:

$$Demonstrated_y = \frac{\sum_{h=1}^{N} Performance_h LMP_h EEM_h}{\sum_{h=1}^{N} LMP_h EEM_h}$$

The hourly EEM is defined as 2 if any part of the hour *h* is subject to an EEA or EEA Watch, and 1 otherwise.

Weather-sensitive Project

The annual demonstrated capacity for weather-sensitive resources is defined by weighted least squares regression of hourly performance on temperature using the same LMP and EEM weights as for non-weather-sensitive resources. This methodology is detailed in Appendix A.

12. Performance-Based Payments

As described in Section II.C, 50% of the award amount for Group 1 and Group 2 projects will be paid after the conclusion of each program year following the annual capacity performance assessment. The annual payment amount will be determined based on the demonstrated capacity performance of the project relative to the nominal capacity amount from the project deployment schedule for that year, or "committed" capacity.

The target annual demonstrated capacity performance-based award payment shall be the product of the total eligible performance award and the proportion of committed capacity in each year.

The annual award will be adjusted for demonstrated capacity performance achieved in the year according to the factors listed in Table 1. Resources that

meet or exceed the committed capacity for the year will receive a payment proportional to their performance relative to committed capacity. Resources with a demonstrated capacity of less than the committed amount will have the performance payment reduced by twice the amount of the shortfall between committed until the payment is reduced to zero, but the performance payment shall never be less than zero.

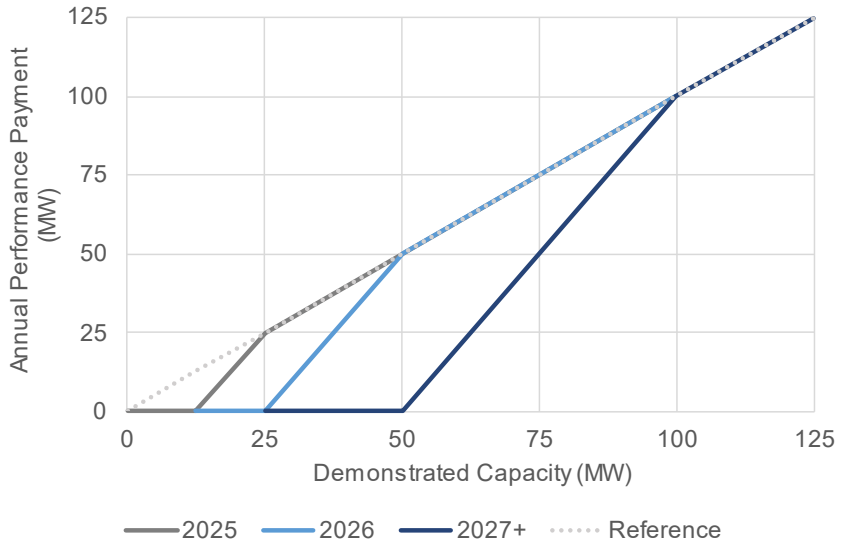
Table 1. Performance-Based Payment Schedule

Demonstrated Capacity	Factor
Demonstrated ≥ Committed, Demonstrated ≤ Awarded	$\frac{Demonstrated}{Committed}$
Demonstrated ≥ ½ Committed, Demonstrated ≤ Committed	$\frac{Committed - 2(Committed - Demonstrated)}{Committed}$
Demonstrated ≤ ½ Committed	0

The payment schedule allows for participants to exceed the target payment if demonstrated capacity exceeds committed capacity in an individual year. The additional amount will reduce the remaining funds encumbered to make performance payments in future years.

Figure 1 illustrates the calculation of annual performance payments relative to committed capacity for a proposal with a maximum 100 MW award and a minimum deployment schedule of 25, 50, and 100 MW for 2025, 2026, and 2027 and beyond, respectively.

Figure 1: Annual Performance Payment Formula Illustration



13. Reporting Requirements

Approved Applicants must provide measurement and verification data and performance reports on the project according to a measurement verification plan approved by the CAM that includes, but is not limited to, the following:

- Annual performance reports demonstrating hourly sub-meter or meter data, as applicable, hourly availability, hourly measured performance consistent with event hours as defined for each performance pathway (see Section III.B.10 Performance Demonstration Pathways), the annual demonstrated capacity at the applicable geographical granularity (see III.B.11 Measurement & Verification), and a description of the methodology used to determine the annual demonstrated capacity.
- Metrics or contract agreements summarizing participation in the Resource Adequacy (RA) market, if applicable.

If applicable, verification of compliance with regulations adopted pursuant to Part 2 (commencing with Section 38530) of, and Part 5 (commencing with Section 38570) of, the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code), including, but not limited to, the mandatory reporting of emissions of greenhouse gasses and market-based compliance mechanism.

IV. Application

A. Application Content

1. Application Package

Applicants will be required to provide standard solicitation application documents and forms as part of the application package, including:

- A project narrative that will include the majority of the applicant's responses to the Evaluation Criteria in Section V.D.
- Project team information and resumes
- Scope of Work and schedule
- Budget
- CEQA/Environmental Compliance Form
- Past performance reference forms
- Letters of support/commitment

2. POU Letter of Interest

Applications for projects that would provide funding to a local publicly owned electric utility (POU) do not require a governing board resolution to apply. However, a letter of interest from the utility director or general manager must be included with the application. The letter must include the date the POU plans to take the resolution to the governing board or city council, as applicable. The CEC must receive a copy of project approval from the POU governing board before an agreement can be executed.

A public agency that receives funding under this solicitation must provide an authorizing resolution approved by its governing authority to enter into an agreement with CEC. The resolution must designate the authorized representative to sign the agreement with CEC.

B. Trade Secrets and Confidential Information

If elements of an Application or any other materials submitted as part of this GFO contain information the Applicant considers to be trade secrets, confidential, privileged or otherwise exempt from disclosure under the Public Records Act (California Government Code Section 6250, et seq.), the Applicant shall assert a claim of exemption at the time of submission by identifying in an accompanying letter each of the items to be restricted, and highlighting the information in yellow in its Application. The asserted claim shall indicate the specific information within the Application or other materials submitted to which the claim is made. Upon receipt of a Public Records Act request for documents that may include information the Applicant has identified as trade secret, confidential, privileged or

otherwise exempt from disclosure, the CEC shall consider a claim of exemption and the basis for it, but retains the authority to make the final determination as to what information will be released under the Public Records Act.

V. Evaluation Process and Criteria

A. Application Evaluation

This section explains how the applications will be evaluated.

Applications will be evaluated and scored based on the responses to the information requested in this solicitation and on any other information available such as past performance of CEC agreements. The entire evaluation process from receipt of applications to posting of the Notice of Proposed Award is confidential.

To evaluate all applications, CEC will organize an Evaluation Committee. The Evaluation Committee may consist of CEC staff or staff of other California state entities.

Applications passing administrative and technical screening will compete based on evaluation criteria and will be scored and ranked based on those criteria. Unless the CEC exercises any of its other rights regarding this solicitation (e.g., to cancel the solicitation or reduce funding), applications obtaining at least the minimum passing score will be recommended for funding in ranked order until all funds available under this solicitation are exhausted.

If the funds available under this solicitation are insufficient to fully fund a grant proposal, the CEC reserves the right to recommend partially funding that proposal. In this event, the applicant/proposed awardee and Commission Agreement Manager shall meet and attempt to reach an agreement on a reduced scope of work commensurate with the level of available funding.

B. Administrative and Completeness Screening

The Contracts, Grants and Loans Office will screen applications for compliance with the Administrative Screening Criteria.

Applications that fail any of the Administrative or Technical Screening Criteria shall be disqualified and eliminated from further evaluation.

ADMINISTRATIVE SCREENING CRITERIA *The Application must pass ALL administrative screening criteria.*	Pass/Fail
1. The application is received by the due date and time specified in the "Key Activities Schedule" in Section I of this solicitation.	☐ Pass ☐ Fail
2. The requested funding falls within the minimum and maximum range specified in the solicitation.	☐ Pass ☐ Fail

C. TECHNICAL SCREENING CRITERIA

The Evaluation Committee will screen applications for compliance with the Technical Screening criteria. Proposals that fail this stage shall be disqualified and eliminated from further evaluation.

TECHNICAL SCREENING CRITERIA *The Application must pass ALL technical screening criteria.*	Pass/Fail
1. The Applicant is an eligible applicant.	☐ Pass ☐ Fail
2. The proposed project is an eligible project.	☐ Pass ☐ Fail
3. If the Applicant has submitted more than one application, each application is for a distinct project.	☐ Pass ☐ Fail
4. The Applicant passes the past performance screening criterion as described in Section V.C.1.	☐ Pass ☐ Fail

1. Past Performance Screening Criterion (Pass/Fail)

An Applicant may be disqualified under this solicitation due to severe performance issues under one or more prior or active CEC agreement(s) within the last 10 years. An Applicant is defined as at least one of the following: the business, principal investigator, or lead individual acting on behalf of themselves—received funds from the CEC (e.g., contract, grant, or loan) and entered into an agreement(s) with the CEC. Any Applicant that does not have an active or prior agreement equates to no severe performance issues and therefore would pass this screening criteria.

Severe performance issues are characterized by significant negative outcomes under an agreement and may include:

- Agreement was terminated with cause.
- CEC filed litigation against the Applicant.
- Severe audit findings are not resolved to CEC's satisfaction. Severe audit findings may include but are not limited to incomplete or unsatisfactory deliverables; grant funds used inappropriately (i.e., other than as represented); or questioned costs.
- Project objectives were not met and were caused by factors that are, or should have been, within the Applicant's control.
- Significant delays in project completion resulting in delayed benefits for California. Project completion delays of one year or more from

the originally proposed project schedule and caused by factors within the Applicant's control may be considered significant.

- Deliverables were not submitted to the CEC or were of poor quality. For example, Applicant delivered poorly written reports that required significant rework by staff prior to acceptance or publication.
- Demonstrated and documented poor or delayed communication when significant issues or setbacks were experienced that materially and negatively impacted the project. For example, delays in informing the CEC when the Applicant experiences loss of a key project partner or site control may be considered significant.

2. Grounds to Reject an Application or Cancel an Award

In addition to the Screening Criteria identified within this solicitation, CEC reserves the right to reject an application and/or cancel an award for reasons including, but not limited to the following:

a. The application contains false or intentionally misleading statements or references which do not support an attribute or condition contended by the Applicant.
b. The application is intended to erroneously and fallaciously mislead the State in its evaluation of the application and the attribute, condition, or capability is a requirement of this solicitation.
c. The application does not comply or contains caveats that conflict with the solicitation and the variation or deviation is material or it is otherwise non-responsive.

D. EVALUATION CRITERIA

The CEC's Evaluation Committee will review and score the written information provided in the Project Narrative attachment, based on the Evaluation Criteria in this solicitation. The scores for each application will be the average of the combined scores of all Evaluation Committee members. Potential Evaluation Criteria used in this solicitation could include the following, (note that these could change when the CEC solicitation is released):

Evaluation Criteria	Possible Points
1. Statement of Financial Need The application identifies, documents, and justifies the degree to which DEBA funding is essential to address market, financial, and policy barriers that are hindering project development, in addition to other mechanisms, such as: a. Existing and anticipated revenue streams or cost savings, including the value associated with participation in the applicable LRA's Resource Adequacy framework as a supply side or load modifying resource (during and beyond the DEBA grant agreement term) or other emergency grid reliability programs that the project may be eligible for, and the timelines for qualifying for these. b. Existing mass-market state, LSE, or utility programs to support a technology. c. Tax credits or other financial incentives the project is eligible to receive. d. Ability to access loans or feasible project financing.	10
Minimum Passing Score for Criterion 1 is 70% or 7 points	**10**

Evaluation Criteria	Possible Points
2. Contribution to Reliability The application will be evaluated on: a. The additional capacity (in MW) the project can deliver. b. The number of hours during net peak load hours (4 p.m. to 9 p.m.) that the project is capable of operating. c. The degree to which the proposed project will: i. Support grid reliability during net peak load hours through providing load reduction or supply, or both. ii. Provide energy capacity with high-precision metered accuracy. iii. Demonstrate dispatchability and responsiveness to a diverse range of event frequencies, durations, and notification periods on a real-time, day-ahead, or on-call basis. iv. Minimize the extent to which successful deployment of awarded capacity or stored energy during emergency events may be impacted by any limitations or exceptions. v. Incorporate unique design features that enhance the overall diversity of resources participating in the state's Strategic Reliability Reserve. d. The degree to which the project will contribute to reliability post-DEBA grant agreement term, such as a pathway for incorporating the DEBA incentivized capacity into the Resource Adequacy framework of the applicable LRA (as a supply-side or load-modifying resource, or some other proposed pathway.	25
Minimum Passing Score for Criterion 2 is 70% or 17.5 points	**25**

Evaluation Criteria	Possible Points
3. Project Readiness and Workplan The application will be evaluated on: a. The proposed project timeline with estimated dates by which the relevant phases of the project will be complete and fully operational. b. The degree to which the proposal's timeline is justified and demonstrates a high likelihood of success by reducing implementation risks associated with project deployment and operations by including the following aspects in the proposed workplan: i. A reasonable approach to performing the work by the estimated project completion date with a clear description of all project tasks and subtasks, with identified milestones, outcomes, and deliverables. ii. Whether the intended customer(s) or installation sites for the project has/have been identified in advance of the application, and the ratio of identified customers/sites to unidentified. iii. The intended location(s) of the project, including whether it is located FTM or BTM and site control has been obtained. iv. Any required ministerial or discretionary permits or other entitlements for use and associated CEQA studies (e.g., exemption, initial study, negative declaration, environmental impact report) for the project, including a permitting schedule that ensures successful project completion within the timeframes specified in the project workplan and timeline. v. Any utility and/or balancing authority interconnection studies or approvals that must be completed for the project to begin operations. vi. Any implementation risks or additional factors that may impact project completion within the proposed timeline, including, but not limited to risks, barriers, supply chain issues, weather considerations, financing, and other limitations, and how these will be addressed to successfully complete the project within the proposed timeline.	15
Minimum Passing Score for Criterion 3 is 70% or 10.5 points	**15**
Total Possible Points for criteria 1− 3 **(Minimum Passing Score for criteria 1− 3 is 70% or 35)**	**50**

Evaluation Criteria	Possible Points
4. Project Budget and Cost Effectiveness The application will be evaluated on the degree to which: a. The proposed project's budget minimizes the amount of DEBA funding requested relative to the incremental rated capacity provided by the project ($/MW-year). b. The expected useful life of the project. c. The budget is reasonable and justified, and the budget forms are filled out completely and accurately. d. The proposed match funding by the Applicant is documented, already secured, reasonable, available, and verifiable. e. The proposal demonstrates the financial ability of the Applicant and key project partners to successfully implement the proposed project and continue operations for the duration of the DEBA contract term and beyond. f. The financial plan identifies project risks and effective strategies to manage and mitigate those risks.	15
5. Team Qualifications, Capabilities, and Resources Evaluations of ongoing or previous projects including project performance by applicant and team members will be used in scoring for this criterion. a. Identifies credentials of applicant and any subrecipient and sub-subrecipient key personnel, including the project manager, principal investigator and technology and knowledge transfer lead (include this information in the Project Team Form Attachment). b. Demonstrates that the project team, including any partnered, Community Based Organization, has appropriate qualifications, experience, financial stability, and capability to complete the project. c. Explains the team structure and how various tasks will be managed and coordinated. d. Describes the facilities, infrastructure, and resources available that directly support the project. e. Describes the team's history of successfully completing projects in the past 10 years including subsequent deployments and commercialization.	5

Evaluation Criteria	Possible Points
6. Measurement and Verification Plan The application will be evaluated on the degree to which: a. The project capacity will be demonstrable through a clear and reasonable reporting and measurement and verification plan, including metering, documentation, and CEC's ability to verify. b. The timeline required for obtaining and reporting the relevant resource performance data to the CEC for verification is timely and reasonable. c. The expected accuracy, precision, and uptime of metering equipment; data quality control standards and practices for identifying erroneous data points, outliers, and missing data; and any methods and assumptions required to generate counterfactual baselines, are sufficient to provide robust demonstrated capacity estimates of participating resources. d. The identified measurable and quantifiable project benefit metrics uses key performance indicators, that are applicable to the project group and type to track project milestones, evaluate project performance, and determine project success.	10
7. Supporting Clean Energy and Climate Goals The application will be evaluated on the degree to which the proposed project: a. Supports the State's existing clean energy and load shifting goals, as outlined in SB 100, SB 846, and other relevant statutes, and provides sufficient supporting documentation. b. Generates no onsite greenhouse gas (GHG) emissions, air pollution, or both; or reduces overall GHG emissions, air pollution, or both, in California. c. Facilitates greater integration of renewable energy resources, including DERs, into California's electricity supply mix.	10

Evaluation Criteria	Possible Points
8. Community and Resiliency Co-Benefits The application will be evaluated on the degree to which the project proposal: a. Describes how the project offers benefits beyond statewide grid reliability, such as offering resilience to critical facility or infrastructure as defined by the CPUC, including, but not limited to, emergency operations centers, medical facilities, and drinking water and wastewater treatment plants.[5] b. Reduces the need for new distribution system investments by leveraging existing energy infrastructure. c. Provides grid services and benefits outside of emergency grid conditions and events. d. Avoids using toxic materials and end-of-life disposal issues. e. Promotes local workforce development.	10
Minimum Passing Score for Criteria 4 – 8 is 70% or 35 points	**50**
Total Possible Points for Criteria 1 - 8 (Minimum Passing Score for Criteria 1 – 8 is 70% or 70 points)	**100**

[5] List of CPUC defined critical facilities and infrastructure. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M296/K598/296598822.PDF.

E. PREFERENCE POINTS

Applications must meet all minimum passing scores for Evaluation Criteria 1, 2, 3, and 4-8 to be eligible for the additional preference points.

Preference Points Criteria Table

<table>
<tr><th>Preference Points Criteria</th><th>Possible Points</th></tr>
<tr><td>9. Match Funding
a. Additional points will be awarded to applications that exceed the minimum match requirements based on the percentage amount above minimum using the Exceeds Minimum Match Scoring table:

Exceeds Minimum Match Scoring Table
<table><tr><th>Percentage above Minimum Match (cash and in-kind)</th><th>Score</th></tr><tr><td>100 to 80%</td><td></td></tr><tr><td>60 to <80%</td><td></td></tr><tr><td>40 to <60%</td><td></td></tr><tr><td>20 to <40%</td><td></td></tr><tr><td>10 to <20 %</td><td></td></tr></table></td><td>5</td></tr>
<tr><td>10. Disadvantaged & Low-Income Communities
Applicants can receive up to an additional 10 points if the projects are located in or benefit disadvantaged and/or low-income communities, as according to CalEnviroScreen 4.0.[6]
a. Identifies economic impact on low-income and disadvantaged communities including customer bill savings, job creation, partnering and contracting with micro- and small-businesses, and economic development.
b. Describes how the project will promote clean energy or sustainability technologies within disadvantaged and/or low-income communities and how the development will benefit the communities.
c. Applicants have letters of support from community-based organizations, tribes, workforce development stakeholders, environmental justice organizations, or other partners that demonstrate their belief that the proposed project will lead to increased equity and is both feasible and commercially viable in the identified low-income and/or disadvantaged communities.</td><td>10</td></tr>
</table>

[6] CalEnviroScreen 4.0. https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40.

Preference Points Criteria	Possible Points
Total Additional Preference Points (Criteria 9 - 10)	**15**
Total Possible Points (Criteria 1 - 10)	**115**

During the evaluation and selection process, the Evaluation Committee may schedule a clarification interview with an applicant that will be held by telephone, videoconference, or in person at the Energy Commission for the purpose of clarification and verification of information provided in the proposal. However, these interviews may not be used to change or add to the contents of the original Proposal.

The total score for each Proposal will be the average of the combined scores of all Evaluation Committee members. After scoring is completed, Proposals not attaining a score of 70 percent of the total possible points will be eliminated from further competition.

All applicable Preferences will be applied to all Proposals attaining a minimum of 70 percent of the total possible points. The agreement shall be awarded to the applicant meeting the requirements outlined above and achieving the highest score after the application of Preferences.

F. TIE BREAKERS

If the score for two or more applications are tied and funding is available for only one of the applications, the application with a higher score in the Contribution to Reliability criterion will be ranked higher. If still tied, the application with a higher score for the Supports Clean Energy and Climate Goals criterion will be ranked higher. If still tied, a higher rank will be given in accordance with the loading order specified in the *Distributed Electricity Backup Assets (DEBA) Program Guidelines, First Edition*, which prioritizes 1) feasible, cost-effective renewable and zero-emission resources, and then 2) feasible, cost-effective conventional resources.

VI. Questions for Stakeholders

CEC staff are seeking responses and comments to the following to shape the direction and scope of this solicitation:

Solicitation Requirements

1. Are the minimum and maximum award amount funding levels and match requirements appropriate for each Group?
2. Is the proposed timeline in the solicitation, including application submission windows, reasonable to accommodate project proposals for project group?
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?
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?
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?
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.

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?
8. Are the minimum project capacity requirements for each Group reasonable or should they be adjusted?
9. Are there any additional eligible technologies that should be included, or any currently eligible technologies that should be excluded?
10. Are the proposed performance pathways sufficient and flexible enough to accommodate the variety of eligible technologies and project groups targeted by this solicitation?

11. What data should be required from DEBA Program participants for measurement and verification purposes as well as other public reports and initiatives?
12. Are the metering and telemetry requirements for projects sufficient for measurement and verification purposes and determining performance of DEBA funded projects?

Miscellaneous

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

VII. Written Comments

Comments on this "draft solicitation concept" document are due by **Friday, March 15th, 2024, at 5:00 p.m.**

Please submit comments to the CEC using the e-commenting feature by accessing the comment page for docket **22-RENEW-01** at: https://efiling.energy.ca.gov/Ecomment/Ecomment.aspx?docketnumber=22-RENEW-01.

A full name, e-mail address, comment title, and either a comment or an attached document (.doc, .docx, or .pdf format) is mandatory. Please include "**DEBA DER GFO Draft Solicitation Concept**" in the comment title. After a challenge-response test is used by the system to ensure that responses are generated by a human user and not a computer, click on the "Agree & Submit Your Comment" button to submit the comment to the CEC's Docket Unit.

Please note that written comments, attachments, and associated contact information included within the documents and attachments (e.g., your address, phone, email, etc.) become part of the viewable public record. This information may become available via Google, Yahoo, and any other search engines.

Interested stakeholders are encouraged to use the electronic filing system described above to submit comments. If you are unable to submit electronically, you may email your comments to: **DOCKET@energy.ca.gov** and include **"DEBA DER GFO Draft Solicitation Concept 22-RENEW-01"** in the subject line.