DOCKETED	
Docket Number:	23-ERDD-01
Project Title:	Electric Program Investment Charge (EPIC)
TN #:	262492
Document Title:	Josh Harmon Comments - PG&E Response to DER Orchestration Research RFI
Description:	N/A
Filer:	System
Organization:	Josh Harmon
Submitter Role:	Public
Submission Date:	3/28/2025 2:32:36 PM
Docketed Date:	3/28/2025

Comment Received From: Josh Harmon
Submitted On: 3/28/2025
Docket Number: 23-ERDD-01

PG&E Response to DER Orchestration Research RFI

Additional submitted attachment is included below.

Pacific Gas and Electric Company

Josh Harmon
CEC Liaison
State Agency Relations

1415 L Street, Suite 280
Sacramento, CA 95814
(628) 777-4138
Joshua.Harmon2@pge.com

28 March 2025

California Energy Commission
Docket Number 23-ERDD-01
715 P Street
Sacramento, CA 95814

RE: CEC DER Orchestration Research - Request for Information (RFI)

Pacific Gas and Electric Company (PG&E) welcomes the opportunity to respond to the California Energy Commission's (CEC) Request for Information (RFI) on Distributed Energy Resources (DER) Orchestration Research. Coordinated DERs can significantly enhance load flexibility, supporting PG&E and California's decarbonization goals. When expanding research into coordinated DERs and their potential to offer grid services beyond load shaping, shedding or shifting, it is crucial to prioritize public funds for the highest value applications and consider the existing and ongoing work related to DER orchestration within the broader EPIC project portfolio.

The orchestration and usefulness of coordinated DERs for the distribution system are subjects of various past and current EPIC projects which should be reviewed before additional solicitations for further research demonstrations.

These EPIC projects include:

1) EPIC Project 4.07 "Battery Energy Storage System (BESS) Controls for Capacity and Voltage Support on Electric Distribution," is demonstrating new controls on a distribution-sited battery energy storage system in a rural community, which will enable about thirty-five new business customers to start electric service with PG&E. The BESS will support voltage and increase capacity to avoid up major, costly upgrades for that specific circuit.
2) EPIC Projects 4.09 A " Advanced Load Management Analytics (ALMA)" is developing a long-term planning model to determine the optimal, least-cost mix of supply-side generation and load management needed to meet California's GHG goals while maintaining reliability. In addition, we are evaluating how load management can be utilized to cost-effectively mitigate a forecasted overload on a specified area of the transmission and distribution system, to compare against the cost, reliability, and feasibility of wires and non-wires, load management solutions.
3) EPIC Project 4.09 B "Aggregated Customers on Distribution Circuits (ACDC)" is conducting a VPP demonstration project with week-ahead hourly signals informed by grid needs. These hourly signals indicate PG&E's distribution grid energy capacity needs at a specific day, time, and duration, to allow aggregators to shift participating customers' usage to meet those needs. PG&E seeks to understand how reliable a load management response can be to a specific proactive and reactive dispatch signal/schedule.

4) EPIC Project 4.10 "Local DER Orchestration," aims to develop and test an orchestration framework with a variety of attributes, a scoring system to measure these attributes, and prioritization methodology and allocation rules that coordinate multiple DERs with the distribution grid. The goal is to assess the potential to orchestrate multiple DERs to meet the needs of the distribution grid, reducing costs for customers and enhancing the grid's capacity to accommodate new loads and renewable energy sources more efficiently. This project will equip utilities and regulatory organizations with strategies to evaluate DER orchestration attributes and align them with grid needs, ensuring the design of impactful, future-ready programs (e.g. virtual power plant (VPP) providing multiple value streams to maximize customer benefits from their DERs and enable utilities to use DERs as flexible grid assets).

In addition to the application of coordinated Distributed Energy Resources (DERs) in these ongoing EPIC projects, aggregations of non-load shifting/shedding/shaping DERs are eligible to participate in CAISO's ancillary markets. However, the cost associated with installing telemetry and the required speed of dispatch have posed challenges for the success of these resources, as discussed further below. PG&E is dedicated to collaborating with the California Energy Commission (CEC) to maximize the value of coordinated Behind-The-Meter (BTM) DERs by effectively utilizing EPIC funds for unique applications that account for the costs of telemetry and the impacts and values of load shaping, shifting, and shedding. The answers provided below are submitted in support of this objective.

Use Cases that Require Validation through Demonstration:
1. As California transitions away from traditional centralized fossil-gas generation and approaches a high penetration of intermittent renewables and inverter-based resources, what are the most needed grid service functions that aggregated DERs should be able to dispatch and that require validation in the near-term?

Capacity support through load/generation management is the most near-term grid service function that can be provided by aggregated DERs. This includes:

- Active power flexibility to support overload/over-generation scenarios for distribution or transmission level constraint management
- The orchestration of multiple DERs types and program types to efficiently support the grid while managing potential multi-use applications

Other potential grid services include:

- Reactive power for power-factor and voltage regulation for distribution and transmission
- Ability to support frequency regulation markets
- Dispatch to support prolonging community microgrid operation duration

While not a "grid service," PG&E is also piloting other capabilities to manage DERs to enable faster customer energization with higher capacity on constrained grid assets as a bridging solution until infrastructure can be built. This includes providing limit schedules (operating envelopes) for customers to manage their load and generation assets within.

2. What performance metrics should a research demonstration achieve to assure confidence in resource dispatchability?

In general, the performance metrics regarding a particular DER or DER aggregation should follow the requirements and the criticality of the specific grid service and use case being addressed. For example, in areas of greater liquidity of available DERs to address a need (i.e., transmission) there may be less strict performance requirements than areas with less liquidity (i.e., distribution feeders).

The following are example performance metrics to help assure confidence in resource dispatchability:

- DER baselining for primary use dispatch
- Measured DER active power dispatch minus baseline vs target dispatch
- Measured DER reactive power dispatch vs target dispatch
- Compliance to power limit schedules
- System/communication uptime metrics (e.g., latency/ramp rate between dispatch signal and corresponding DER response)
- Ability and effectiveness to meet multiple dispatches across grid operation
- DER seasonal variability where DER performance varies based on season
- DER efficacy per duration of event call (e.g., customer fatigue driven by extended duration of event calls)
- Utilization and recovery of energy and state-of-charge time
- Some performance metrics from the SGIP report[1] that may be relevant:
    - Energy Storage Performance Metrics:
        - Roundtrip Efficiency – Total kWh discharge/Total kWh charge.
        - Energy Storage Utilization
            - Hourly Storage KWH per KW
            - Hourly Charge and Discharge during peak CAISO NET DAY
            - Average Daily Residential Discharge Per KWH Capacity
    - Generation Performance Metrics:
        - Capacity Factor-defined as the amount of energy generated during a given period divided by max possible amount of energy that could have been generated during said period.
    - Environmental Impacts:
        - Hourly GHG Emissions and utilization by PV pairing (standalone vs on-site PV).
- DER bounce-back, where demand increases following a dispatch event

3. What role would Investor-Owned Utilities (IOUs) play in potential field demonstrations?

The involvement of IOUs in field demonstrations depends on the scope of work. Generally, PG&E is open to supporting field demonstrations if costs and resources permit and the EPIC field demonstration aims to reduce hardware/software costs, identifies opportunities for creating EPIC "sister projects" (such as Joint PG&E and CEC Redwood Coast Airport Microgrid EPIC Projects) or in providing letters of support. Based on the specific scope of work, it may be necessary to connect to IOU systems, including DERMS, to ensure interoperability for testing efficacy. IOUs should receive data from relevant projects to evaluate impacts on the grid. Such efforts enable IOUs to develop DER orchestration offerings which maximize customer benefits, help IOUs operationalize DERs as grid assets, and ultimately drive affordability and streamlined experiences for customers with DERs.

Gateway Conformance Testing for Dispatchable DERs:
5. Which requirements should this testing tool cover in its scope?

---

[1] **https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/self-generation-incentive-program/2023_sgip_impact_evaluation.pdf**

In general, any gateway conformance testing or tool development should follow the requirements of the specific use case that is being addressed or the goals of a specific research opportunity. Moreover, PG&E's experience with some of these standards/certifications has shown that this area is still relatively nascent and evolving to where existing certifications or standards may not be enough to fully accomplish a use case without extensions. PG&E's experience integrating with third-party systems via gateways has also shown that the gateway may not actually communicate with an inverter level device but rather communicates with meters (for telemetry) and control systems that manage devices at a site level.

Depending on the use case being tested, the following may be of interest in the scope of a potential testing tool:

- IEEE 2030.5-2023 "Standard for Smart Energy Profile Application Protocol"
- IEEE 1547-2018 "Standard for Interconnection and Interoperability of DERs with Associated Electric Power Systems Interfaces"
- IEEE 1547.1-2020 "Standard Conformance Test Procedures for Equipment Interconnecting DERs with Electric Power Systems and Associated Interfaces"
- IEEE 1547.3-2023 "Guide for Cybersecurity of DERs Interconnected with Electric Power Systems"
- Common Smart Inverter Profile (CSIP) – (Note the next version of CSIP will be updated by IEEE starting in 2025 and will be based on IEEE 2030.5-2023)
- IEC 62746-10-1 "Open automated demand response (OpenADR)"
- The Open Charge Point Protocol (OCPP) – Application protocol for communication between electric vehicle charging stations and management systems
- Matter Protocol – Open standard for smart home technology and Internet of Things (IoT) devices
- IEEE 1815.2 "SCADA protocol IEEE 1815 (DNP3 mapped with the IEC 61850-7-420 DER information model"
- UL 3141 "Outline of Investigation for Power Control Systems"

Valuation of Aggregated DER Services:
8. How could technology demonstrations be designed to increase confidence in the efficacy of market signals?

During a technology demonstration, it is important to ensure granular data of all participating DERs is collected. Measurement of the individual response of various DER types included in the aggregation, such as stand-alone batteries, hybrid solar PV and storage resources, and vehicle-to-grid systems is needed to clearly break them out and estimate the distinct firmness potentials of mixed DER aggregations. The more granular the data collected, the greater the confidence in market signals. Additional methods to increase firmness of aggregations should be considered in a demonstration, such as including a front-of-the-meter battery within an aggregation to account for variability of BTM resources.
It is also important to understand the primary use baseline and its confidence level of included DERs, to accurately measure the impact of a market signal on its capacity. The technology demonstrations could be designed to evaluate the capacity difference between DER baseline for primary use and market signal dispatch. BTM DERs are generally designed to minimize electric service cost at the premise level as the

primary use, so understanding the available capacity for the aggregation is essential to assess the efficacy of market signals.

9. Identify existing market mechanisms that enable DER aggregators and VPP platforms to provide each of the grid services identified in Question 3. How effective are these market mechanisms in facilitating that service, and what barriers must be overcome for these market mechanisms to be more effective than they are now?

CAISO's tariff permits Heterogenous Distributed Energy Resource Aggregations (HDERAs) with a minimum qualified aggregate Pmax value of at least 100kW to participate in all markets and Proxy Demand Response (PDRs) to participate in spin and non-spin markets. To bid exporting resources in ancillary markets, telemetry is required. The installation of telemetry on all DERs in an aggregation is particularly cost-prohibitive, especially for smaller, residential DERs. Technical capabilities of aggregations also limit participation by HDERAs, such as dispatch times not meeting minimum requirements for services such as frequency regulation.
Eight barriers to BTM dispatch for Resource Adequacy were laid out in the Resource Adequacy proceeding in D.20-06-031. Although specific to resource adequacy, these barriers, listed below, are relevant when evaluating dispatch by BTM DERAs for other energy services:

(1) forward determination of capacity associated with renewable production, consumption, charging, and export,
(2) RA requirements associated with customers providing capacity,
(3) wholesale market participation including metering, dispatch control, and communication with CAISO,
(4) cost for energy associated with consumption, charging, and export,
(5) changes such that net energy metering (NEM) and self-generation incentive program (SGIP) resources are compensated for capacity, while discounting for their NEM and SGIP compensation as necessary to ensure that the resources do not receive compensation beyond their value,
(6) load forecasting and adjustment for BTM resources,
(7) interaction of such resources with existing BTM resources such as proxy DR, and
(8) deliverability determination.

10. Are there existing market mechanisms for dispatching inverter-based resources to provide voltage regulation and transformer overload prevention at the secondary distribution level?

There are currently no market mechanisms for dispatching inverter-based resources for voltage regulation or transformer overload prevention at the secondary distribution level, nor for primary distribution or transmission voltage regulation ($/MVAR). TOU rates encourage BTM DERs to reduce demand during peak times when service transformer loading is highest.

BTM DER dispatch is too slow for voltage regulation, and centralized dispatch for overload prevention is unreliable due to inaccurate service transformer models. EPIC 2.02 testing showed typical response times of nearly sixty seconds. Detailed data on service transformers is lacking; load flow studies typically bypass them. Accurate load flow results are essential for voltage determination and dispatch calculation. Primary voltage regulating equipment combined with Rule 21 automated smart inverter functions maintain secondary voltage. Automated smart inverter functions for Volt-Var and Frequency-Power are more effective for managing secondary distribution based on local measurements. IEEE 1547-2018 frequency ride-through requirements support system frequency without a market mechanism.

Behind-the-Meter (BTM) DERs primarily aim to reduce electric service costs at the premise. Ancillary service prices peak during high-demand hours, making the opportunity cost for BTM DERs to dispatch for ancillary services instead of load shaping, shedding or shifting substantial. Due to the overlap between ancillary service needs and time-of-use peak hours, BTM DERs reduce ancillary service demand through load shaping shedding or shifting, incentivized by rates and/or future demand response programs. These existing mechanisms, along with automated smart inverter functionality, negate the need for additional mechanisms for BTM DERs to contribute to distribution grid services.

What consumer protections measures must be put in place for DER aggregation? This is especially important for projects to be designed with an equitable focus. For example, solicitation requirements could require including protections that ensure DER enrollees are fairly compensated by aggregators for the value they provide to the DER portfolio being dispatched. What are some examples of best practices?

Bill impact disclosure requirements may help prevent unexpected bill increases from DER aggregation participation. Reporting on DER performance could increase transparency for customers, facilitating more informed consumer choices. Clear information about additional fees charged by manufacturers of DERs (such as Data Access Fees) might mitigate unforeseen barriers to entry if customers are responsible for these costs in aggregations.

--

PG&E appreciates the opportunity to respond to this RFI and looks forward to continuing to collaborate with the CEC. Please reach out to me if you have any questions.

Sincerely,

Josh Harmon
State Agency Relations