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# California Future Grid Study

## Independent Facilitator Final Report

California Public Utilities Commission (CPUC): Proceeding No. R.21-06-017

**September 30, 2024**

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# ACKNOWLEDGEMENTS

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# KEY TERMS & DEFINITIONS

**Advanced Distribution Management Systems (ADMS)[1]:** Advanced Distribution Management System – Refers to the next generation of DMS (Distribution Management System). Compared to traditional DMS, ADMS includes advanced, modern features such as new analytic tools, advanced communication with grid devices and DERs, and other grid support functions and tools.

**Distributed Energy Resource Management System (DERMS)[2]:** Distributed Energy Resource Management System (DERM or DERMS) is computer interface that allows controllability, visibility, and scheduling of DERs on the system.

**Distribution Management Systems (DMS)[3]:** Distribution Management System consists of software applications that provide monitoring and control of the distribution network.

**Hosting Capacity or Integration Capacity[4]:** Hosting capacity or Integration Capacity is an indication of the amount of solar photovoltaics (PV) that can be hosted in a distribution system without additional changes to infrastructure or operations. Utilities are also estimating hosting capacity for new demand from electric vehicles and other large electric end uses.

**IEEE 2030.5[5]:**The Institute of Electrical and Electronics Engineers (IEEE) 2030.5 standard is a protocol developed to enable utility management of the end user energy environment, including demand response, load control, time of day pricing, management of distributed generation, electric vehicles, etc.

**Power Control System (PCS)[6]:** A power control system (PCS) can control the output of one or more power production sources, energy storage systems (ESS), and other equipment.

**Smart Inverter[7]:** An inverter is a device that converts Direct Current (DC) to Alternating Current (AC). Typically, this is used to convert the DC power provided by solar panels into AC power that can be interconnected directly with the grid. A smart inverter has communication capabilities as well as advanced features which modify the output of the inverter to improve integration with the grid.

**Supervisory Control and Data Acquisition (SCADA)[8]:** Supervisory Control and Data Acquisition (SCADA) is a network of devices that provide controllability and data to control centers. For example, SCADA circuit breakers provide real time load, voltage, and other measurements, as well as the ability to operate remotely via from control centers.

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[1] Distribution Grid Operation 101: Presentation from California Joint Investor Owned Utilities and supporting glossary
[2] ibid
[3] ibid
[4] Wang, Wenbo, Daniel Thom, Kwami Senam Sedzro, Sherin Ann Abraham, Yiyun Yao, Jianli Gu, and Shibani Ghosh. 2022. PV Hosting Capacity Estimation: Experiences with Scalable Framework; Preprint. Golden, CO: National Renewable Energy Laboratory. NREL/CP-6A40-81851. https://www.nrel.gov/docs/fy22osti/81851.pdf.
[5] See IEEE - https://standards.ieee.org/ieee/2030.5/5897/
[6] National Electrical Code (NEC), Section 705.13.
[7] Distribution Grid Operation 101: Presentation from California Joint Investor Owned Utilities and supporting glossary
[8] ibid

**Virtual Power Plant (VPP)[9]:** VPPs[10] are aggregations of distributed energy resources (DERs) such as rooftop solar with behind-the-meter batteries, electric vehicles (EVs) and chargers, electric water heaters, smart buildings and their controls, and flexible commercial and industrial loads that can balance electricity demand and supply and provide utility-scale and utility-grade grid services like a traditional power plant.

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[9] U.S. Department of Energy, "Pathways to Commercial Liftoff: Virtual Power Plants Commercial Liftoff," Online at https://liftoff.energy.gov/vpp/.

[10] https://www.energy.gov/lpo/articles/sector-spotlight-virtual-power-plants

# INTRODUCTION

California's electric system is undergoing an evolution from a system of one-way flows from large electric generators to customers to a system of two-way flows with a large penetration of distributed energy resources (DERs). California is a national leader in the adoption of rooftop solar, energy efficiency, and demand response technologies, with the growth of energy storage, electric vehicles and building electrification following the same trajectory. The growth in DERs offers both challenges and opportunities for distribution system operators and customers; addressing the challenges and enabling the opportunities will require a different set of tools and processes to operate the distribution system.

In July 2021, the California Public Utilities Commission (CPUC or Commission) initiated Rulemaking (R.) 21-06-017 (the High DER Proceeding) to consider how to prepare the electric grid for a high number of DERs. In service of that effort, Gridworks, a consultant to the Commission, facilitated the Future Grid Study workshop series, a set of three workshops giving stakeholders an opportunity to collaborate to modernize the electric grid for a High DER Future.

This report is the culmination of that workshop series and offers a comprehensive account of:

- distribution system operational needs to enable a High DER future;
- the gaps between current distribution system operational capabilities and identified operational needs; and
- a set of recommendations to address the identified gaps.

Much work is already underway to enable a High DER Future, and continued collaboration amongst the Commission, utilities and stakeholders will ensure that the High DER Future lives up to its potential.

## Project Background

In 2013, Assembly Bill 327 directed the integration of DERs into investor-owned utility (IOU) electric distribution planning and mandated that the Commission review, modify, and approve IOU distribution resources plans. In 2014 the Commission opened R.14-08-013 and redirected R.14-10-003 with the aim of enabling DERs to provide services to the distribution grid and thereby increase the value of those resources while lowering costs and increasing service quality. There has been considerable effort on the part of the Commission and parties towards these goals, including:

- Creating the Distribution Investment Deferral Framework, which is an annual utility report detailing information about forecast grid needs, investments planned to address the needs, and opportunities for DER to defer those investments;
- Implementing a Request for Offer solicitation process and tariff mechanisms whereby DERs have the opportunity to defer identified distribution grid investments;
- Developing Integration Capacity and Locational Net Benefit Analyses assessing the ability of the distribution grid to accommodate new DERs and the value of DERs to the grid by location;
- Guiding DER siting decisions and accelerating interconnection by publishing the above through publicly available data portals;
- Establishing a Grid Modernization Framework to guide utility investment in technologies and grid upgrades necessary to integrate DER.

In July 2021, the Commission opened R.21-06-017 (the High DER Proceeding) to consider how to prepare the electric grid for a high number of DERs. The proceeding has three tracks:

1. Distribution Planning and Execution Process and Data Improvements;
2. Distribution System Operational Needs and System Operator Roles and Responsibilities; and
3. Smart Inverter Operationalization and Grid Modernization Planning.

The focus of this report is Track 2, Distribution System Operational Needs and System Operator Roles and Responsibilities.

Track 2 initially kicked-off on May 3, 2022 with a workshop titled "Evaluating Alternative Distribution System Operator Models for California."[11] Following this workshop, the CPUC received public feedback requesting that the CPUC engage with communities, particularly disadvantaged communities. Between September and November 2022, CPUC staff with support from their consultants (Gridworks and Verdant) facilitated 20 informal tribal and community outreach meetings to begin the community engagement efforts for Track 1 and Track 2 of R.21-06-017.

The outreach meetings gathered insight and input from tribes, local governments, and community-based organizations across various topics related to the High DER Proceeding, including priorities for distribution planning as well as challenges and barriers to adopting clean energy and distributed energy resources. A high-level overview of these informal outreach meetings is provided in the Summary of Fall 2022 High DER Informal Outreach Meetings[12]. In addition, CPUC staff and their consultants (Gridworks and Verdant) led a Distribution Planning Community Engagement Needs Assessment Workshop on December 13, 2022.

In August 2023, the CPUC released an Amended Scoping Memo[13] in R.21-06-017. Track 2 of the rulemaking now assumes that the electric investor-owned utilities (IOUs) remain in their current role as distribution system operators. The updated focus of Track 2 is on how to ensure additional DERs installed provide maximum value to the grid through effective distribution system operations. Toward that end, the amended scoping memo posed the following key questions:

1. What are the operational needs necessary to efficiently operate a high DER grid, unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives?
2. What are the existing gaps and barriers in achieving the needs identified above within our current Distribution System Operator (Utilities)? What are the potential solutions in overcoming these barriers?

## Future Grid Study Workshop Series

To address these questions, Gridworks organized and facilitated the Future Grid Study workshop series in the first half of 2024. This set of three workshops offered stakeholders an opportunity to collaborate to modernize the electric grid for a High DER Future. Gridworks facilitated conversations between the IOUs, stakeholders, and the CPUC on how to ensure additional DERs

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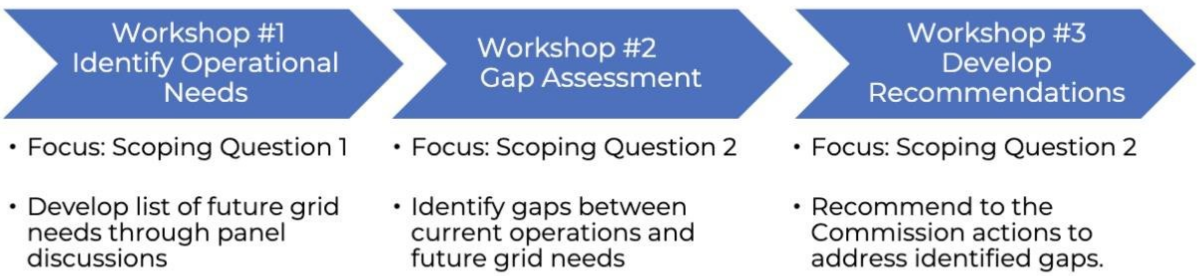
[11] https://gridworks.org/wp-content/uploads/2022/07/Gridworks-May-3-DSO-Workshop-Summary-final.pdf
[12] https://gridworks.org/wp-content/uploads/2022/12/Summary-of-Fall-2022-CPUC-High-DER-Informal-Outreach-Meetings.pdf
[13] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M516/K786/516786462.PDF

installed provide maximum value to the grid through effective distribution system operations. Each workshop focused on a different topic:

1. identifying operational needs to enable a High DER Future;
2. assessing gaps between current operational capabilities and identified operational needs; and
3. developing recommendations to address identified gaps.




Workshop participants offered abundant input on each topic, including discussion of issues that are live in other proceedings at the Commission. This report attempts to capture all input received, including input related to other proceedings. Gridworks' purpose in doing so is to offer a comprehensive picture of all the issues related to a High DER Future, to identify which issues are being addressed, and to identify which issues require further attention from the Commission and stakeholders.

All presentations and workshop recordings are available on Gridworks' Future Grid Study webpage as well as the Commission's High DER webpage[14]

## Navigating this Report

This report is broken into three sections, with three supporting appendices. Each section offers a summary of key discussions and takeaways from each workshop.

- The discussion in Workshop 1 informed the list of Operational Needs for a High DER Future found on pages 24-28.
- The discussion in Workshop 2 and the IOUs' most recent Grid Modernization Progress Reports (Appendix B: IOU Grid Modernization Progress Reports) informed the Operational Needs Gap Assessment found in Appendix A: Operational Needs Gap Assessment.
- The discussions across all three workshops, but particularly in Workshop 3, daylighted the recommendations documented in the third section. The third section also includes some guiding questions for the Commission and stakeholders to consider in resolving open issues.
- Finally, Appendix C: IOU Related Pilots offers a detailed list of IOU pilots related to the operational needs for a High DER Future.

[14] https://gridworks.org/initiatives/california-future-grid-study/ and https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning

# WORKSHOP 1: IDENTIFYING OPERATIONAL NEEDS

On February 8, 2024, Gridworks facilitated the first workshop in the Future Grid Study workshop series to address the first question in the amended scoping memo:

1. *What are the operational needs necessary to efficiently operate a high DER grid, unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives?*

## Workshop Structure

The first workshop was divided into four sections: introductory remarks from the CPUC and Gridworks, and three panels. There were 256 participants in total. Throughout the workshop, the audience had the ability to use the chat feature in Zoom to ask questions and provide comments, and to use Slido, an external survey tool, to offer suggestions of operational needs for a high DER future.

Commissioner Houck spoke at the beginning of the workshop about the context and goals of the High DER proceeding, followed by five speakers from the CPUC Energy Division that provided background on this proceeding and four other related proceedings:

- Transportation Electrification (R.23-12-008),
- Microgrids (R.19-09-009),
- Interconnection (R.17-07-007), and
- Demand Flexibility through Electric Rates (R.22-07-005).

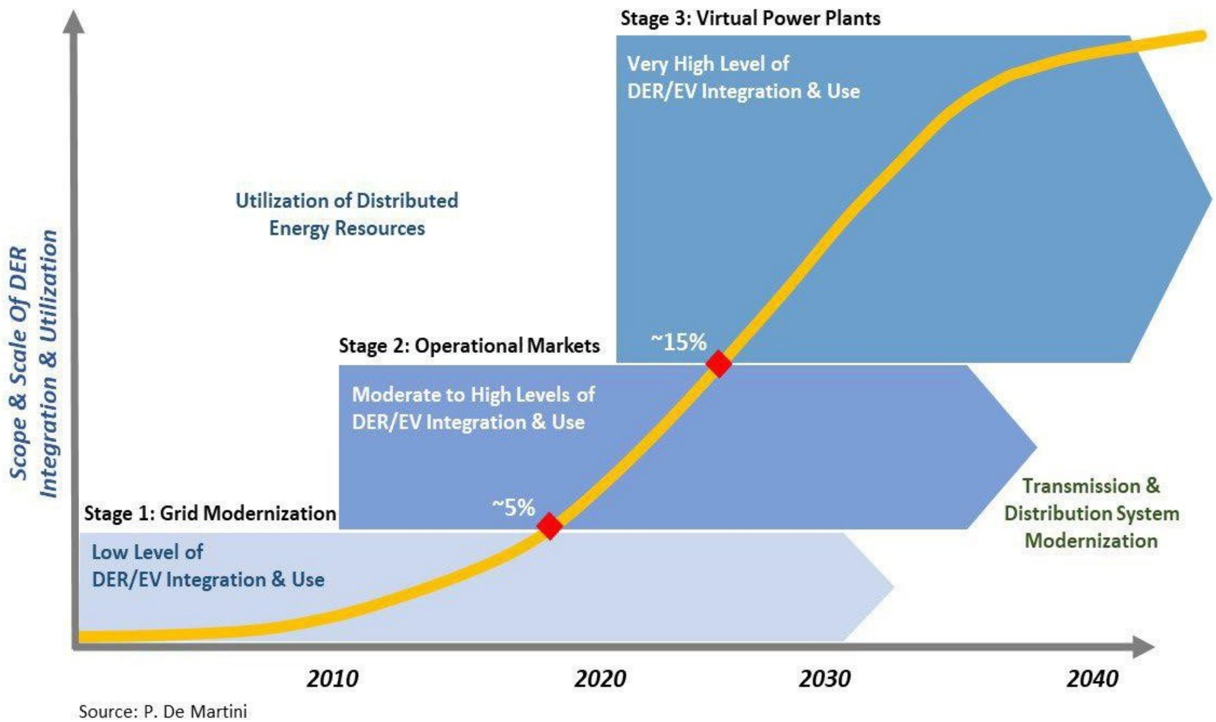
The three panels were composed of speakers in three groups: Utilities and CAISO, thought leaders, and advocates. Speakers offered context for a High DER future, and their suggestions of operational needs to enable that future.

## Context for a High DER Future

The CPUC initiated this proceeding to prepare for the High DER future that is underway and expected to accelerate in the next ten years. California is already a national leader in the adoption of rooftop solar, energy efficiency, and demand response technologies. Customer adoption of energy storage systems and electric vehicles is growing quickly today and expected to reach significant scale in the next ten years. Building and vehicle electrification are expected to increase electricity use while also offering opportunities to shape local electricity use with flexible technologies and new pricing and program models, such as dynamic and real-time pricing and load shifting. If these new models are implemented successfully, customers can meet their energy needs while being compensated for providing valuable services to the other users of the electricity grid. This Track of the High DER Proceeding is intended to develop insight into the operational needs of a High DER Future and the steps needed to prepare for the expected changes in the next 5-10 years.

To help illustrate the changes underway with electric utility distribution systems, Gridworks presented the conceptual model of DER adoption shown below, which was developed by the U.S. Department of Energy[15] and presented at the beginning of Workshop 1.

**Figure 1: Three Stage Evolution of Distribution System**




**Source:** U.S. Department of Energy Office of Electricity, *Distribution System Evolution,* pp. 3

The conceptual framework describes three stages of distribution system evolution that broadly correspond with increasing levels of DER adoption. The authors anticipate continued growth of DERs over time due to top-down (public policy) and bottom-up (customer choice) factors and each stage represents increasing levels of market and distribution system functionalities.

**Stage 1 – Grid Modernization:** In this stage, DER adoption is low (below 5% of distribution system peak) and DER levels can be integrated into existing distribution systems without significant changes to infrastructure, planning, and operations. Utilities undertake grid modernization to address reliability, resilience, safety, operational efficiency, and enable future DER growth.

**Stage 2 – Operational Markets**: This stage involves increasing scale of DER adoption (5% - 15% of distribution system peak) with customer-sited storage, smart thermostats, EVs, and rooftop solar

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[15] See U.S. Department of Energy Office of Electricity, *Distribution System Evolution,* at pp. 3-12. Online at https://www.energy.gov/sites/default/files/2023-11/2023-11-01%20Distributed%20System%20Evolution%20nov%202023%20r1_optimized.pdf.

PV as the most common forms of DERs. At this stage, local pockets of high adoption of customer solar PV, community solar, and/or EVs reach hosting capacity constraints and DER adoption begins to achieve sufficient scale that utilities can leverage aggregated DERs to provide bulk power and distribution grid services.

**Stage 3 – Virtual Power Plants**: Stage 3 markets have a high level of DER adoption (solar PV nameplate capacity above 15% of distribution system peak with growing levels of distributed storage and EVs) which provide significant numbers of DERs to enable virtual power plants and more advanced applications of DERs to form community microgrids and localized distribution-system markets. At this stage of adoption, dynamically managing hosting capacity is an emerging practice to allow higher levels of export from solar PV systems and charging by EVs with existing distribution system capacity. The framework also describes the concept of Grid Orchestration as "leveraging flexible loads and storage to offset distributed generation exports or EV charging load so that net power flows on the distribution system remain within operational limits (i.e., hosting capacity)."[16]

California is currently one of the few states in the US with a Stage 3 level of DER adoption according to the broad guideposts in this framework, and with expected customer demand for EVs, energy storage, and front-of-the meter DERs growing, the State expects significant additional growth in DERs over the next ten years. The Future Grid Study workshop series convened stakeholders to identify the operational needs to support this advanced stage of DER integration and expected future growth.

As noted in the qualitative description of Stage 3, these markets face potentially costly constraints on DER growth without new methods to manage existing distribution system hosting capacity. In addition, the significant growth and scale allow new potential opportunities for DERs to provide grid services, support community microgrids, and develop localized distribution-level markets. The workshop series elicited feedback from participants on the operational needs to support this advanced level of DER adoption and utilization.

The first workshop included a series of presentations and panel discussions. Throughout the discussion, participants were asked to identify the operational needs to support a High DER Future. This list was compiled and guided the discussions in the subsequent workshops. The summaries below briefly discuss the presentations/panel discussions in the initial workshop.

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[16] *Ibid, pp. 4-11.*

**Table 1: Workshop 1 Speakers**

| Panel | Speakers |
|---|---|
| Energy Division | Woon Jung, Grid Planning<br>Audrey Neuman, Transportation Electrification<br>Patrick Saxton, Resiliency and Microgrids<br>Jose Aliaga-Caro, Interconnection and Distribution<br>Parimalram "Achintya" Madduri, Retail Rates |
| Utilities & CAISO | Quinn Nakayama, Pacific Gas and Electric Company (PG&E)<br>Kirsten Petersen & Christopher Franco, San Diego Gas & Electric (SDG&E)<br>Devin Rauss, Southern California Edison (SCE)<br>Jill Powers, CAISO |
| Thought Leaders | Jenny Riesz, Australian Energy Market Operator (AEMO)<br>Bryan Hannegan, Holy Cross Energy<br>Debra Lew, Energy Systems Integration Group (ESIG) |
| Advocates | Amin Younes, Cal Advocates<br>Samuel Golding, Utility Consumers' Action Network<br>Kenneth Sahm White, 350 Bay Area<br>Lorenzo Kristov, The Climate Center<br>Nikhil Vijaykar, Joint CCAs |

## Energy Division

The discussion started with a presentation by the Energy Division[17] that covered several closely related proceedings: transportation electrification (R.23-12-008), microgrids (R.19-09-009), interconnection (R.17-07-007), and demand flexibility through electric rates (R.22-07-005). For each topic, Energy Division staff provided an overview and addressed two questions:

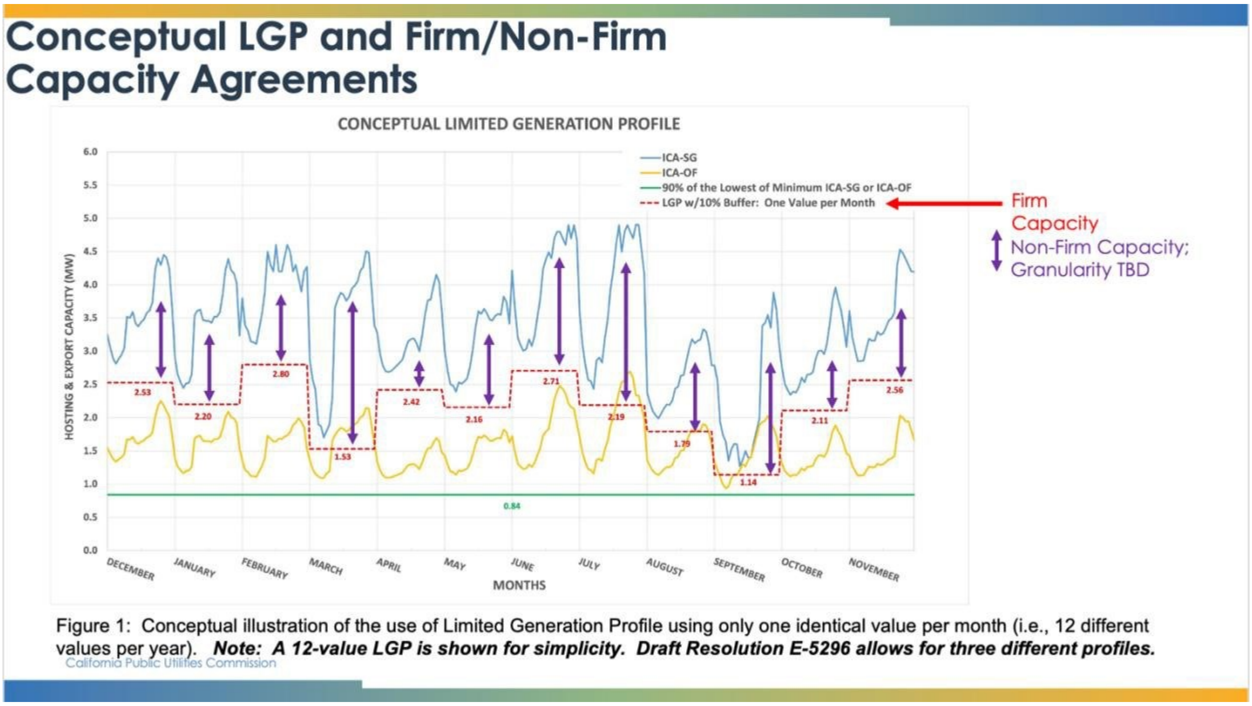
1. What are the objectives of your related proceeding; and
2. How can "High DER Future" grid operations help (contribute) or hinder (challenge) the objectives of your related proceeding?

The Energy Division presentation provided important foundational material for participants to understand the ongoing work related to a High DER Future and references to the key proceedings.

For example, the initial presentation included the graph shown below in Figure 2, which illustrates the concept of "Limited Generation Profiles" from DER systems.

[17] https://gridworks.org/wp-content/uploads/2024/02/ED_Proeceeding_Acssociated_HighDER_Track2_updated020524-FINAL.pdf

**Figure 2: Conceptual Diagram of Limited Generation Profiles**




**Source:** Workshop 1 Presentation Deck[18], slide #22

Figure 2 shows a concept discussed in the interconnection proceeding, which can increase the amount of DERs interconnected to the existing distribution system. The green line in Figure 2 shows the level of export from DERs that would be allowed using traditional hosting capacity limits. Under the traditional approach, export limits for the entire year would be set by the most limiting conditions, even if they only occur for a few hours a year.

Under the Limited Generation Profiles (LGP), DER systems can be programmed to limit exports to varying levels over the year based on the available hosting capacity predicted during that period. The red line in Figure 2 shows the export limits on a system using one of the approaches in the draft resolution for LGPs. Under this approach, the DER can provide 2-3x the amount of generation during times of year when the distribution system has available capacity while limiting output when the system is most constrained. This concept provides the technical basis for Flexible Generation Interconnection, which was discussed in Workshop 3. In addition, the ability to communicate the distribution system limits on more granular timeframes, and potential additional integration capacity that would become available, is referenced by the purple arrows. These concepts have been discussed in reports[19] by the Smart Inverter Operationalization Working Group (SIOWG) in Track 3 of the High DER Proceeding, with the more dynamic limits being termed 'non-firm limits'. The gap analysis in Workshop 2 reviewed the current abilities of

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[18] https://gridworks.org/wp-content/uploads/2024/02/CPUC-High-DER-Workshop_Final.-PDF.pdf

[19] May 29, 2024 and June 4, 2024 administrative law judges' rulings in the High DER Proceeding issued two SIOWG reports and a list of questions to parties.

IOUs to support these more advanced approaches to integrate DERs. Workshop 3 also addressed this topic.

### IOUs & CAISO

The first panel discussion in Workshop #1 included a combined presentation from the Joint Investor Owned Utilities[20] (Joint IOUs). The Joint IOUs provided an overview of their vision for a High DER Future, expected changes from the growth in electric vehicle adoption, a description of the concept of "Grid Orchestration," and an overview of the operational needs that are needed for grid management in the High DER future. Figure 3 shown below shows the overview of operational needs in the Joint IOUs presentation:

**Figure 3: Joint IOUs Conceptual Diagram of Operational Needs in High DER Future**


**Source:** Workshop 1 Presentation Deck[21], slide #51

The diagram shows increasing levels of grid management capabilities that correspond with the evolving operational needs. Into the future, the Joint IOUs' presentation highlights the expected significant growth from building and transportation electrification as requiring more complex grid management or orchestration. In addition, their presentation notes the potential for conflicting management needs between different system levels as grid services markets evolve further for both distribution and bulk power system needs.

[20] https://gridworks.org/wp-content/uploads/2024/02/2024-Future-Grid-Workshop-1-Joint-IOU-Presentation-FINAL.pdf

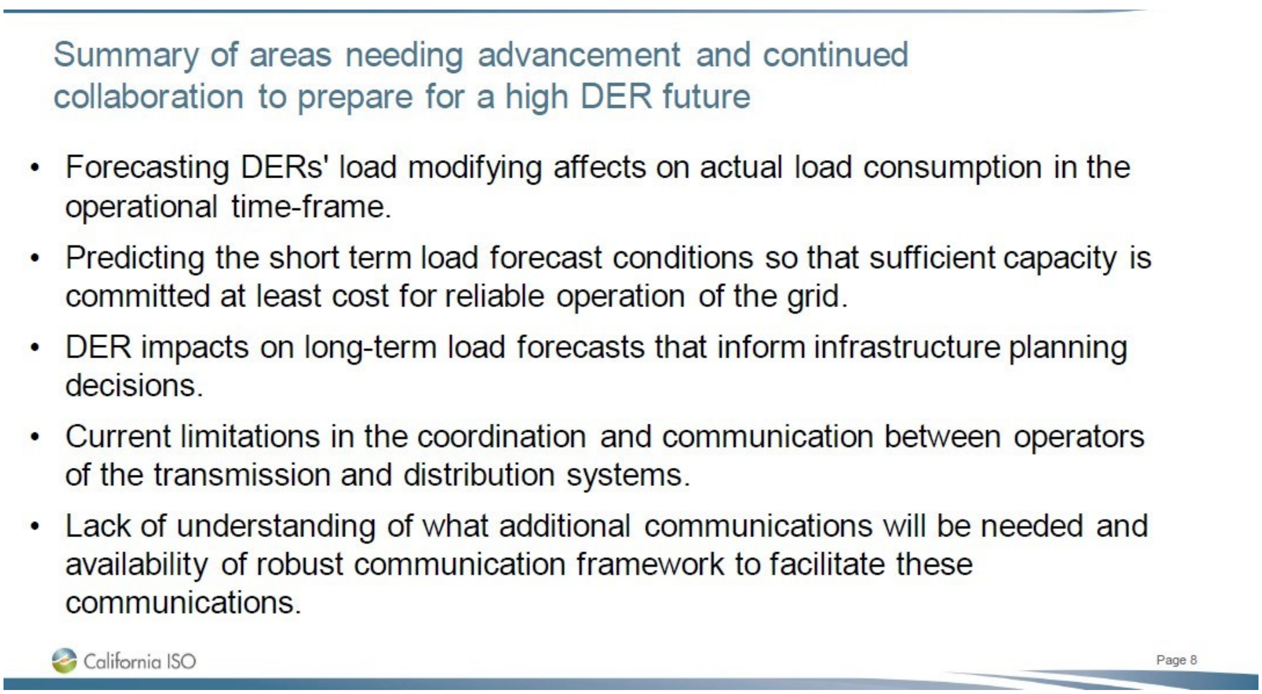
[21] https://gridworks.org/wp-content/uploads/2024/02/CPUC-High-DER-Workshop_Final.-PDF.pdf

Staff from the California Independent System Operator (CAISO) presented next on this panel[22] and offered their perspectives on operating the bulk power system with increasing levels of DERs. They shared three different scenarios or pathways that DER growth could follow. These include:

- DERs controlled and managed under intelligent power control systems responding to grid signals such as dynamic retail rates which are 'grid informed' or to meet customer needs;
- DERs aggregated into virtual power plants which can participate directly in ISO markets or be dispatched based on distribution system needs; or
- DERs expected to be inflexible and somewhat immune to external signals.

CAISO staff indicated that the following three areas would need further advancement and continued collaboration: Visibility and Situational Awareness, Reliability Coordination, and Communications and Data Sharing. Their presentation further explained the operational needs in these areas and summarized these in their final slide, shown in Figure 4.

**Figure 4: CAISO Summary of Operational Needs in High DER Future**




**Source:** Workshop 1 Presentation Deck[23], slide #65

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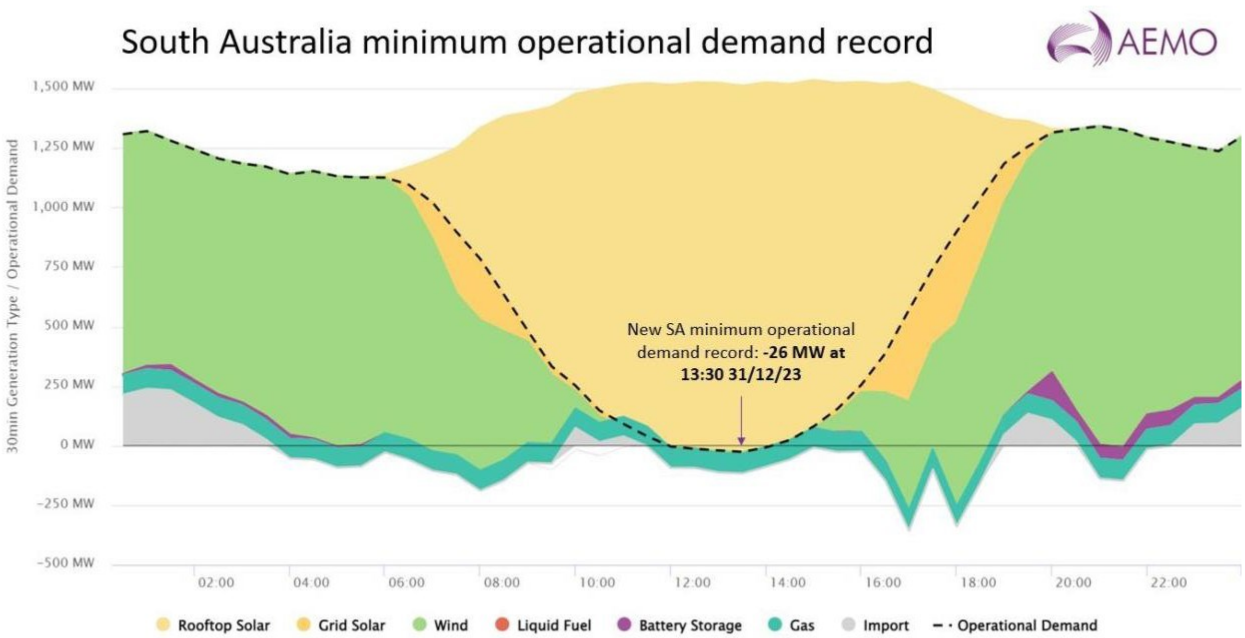
[22] https://gridworks.org/wp-content/uploads/2024/02/Future-Grid-Workshop-ISO-presentation-2_8_24.pdf
[23] https://gridworks.org/wp-content/uploads/2024/02/CPUC-High-DER-Workshop_Final.-PDF.pdf

## Thought Leaders

The thought leaders panel included a Jenny Riesz, grid operator, Bryan Hannegan, a utility executive, and Debra Lew, an industry expert on electric system integration and operations, presenting their perspectives on a High DER Future.

Jenny Riesz, Manager, Operational DER Management, from the Australia Energy Market Operator (AEMO) presented on Australia's experience operating grids with high levels of distributed PV[24] with a focus on South Australia. Ms. Riesz shared AEMO's lessons on operating High DER grids in five areas: technical performance standards, dispatchability, visibility, roles and responsibilities evolving, and cybersecurity. Figure 5 shows a record day on the South Australia grid when generation from distributed PV systems supplied all of the electricity demand in the middle of the day with a small excess amount that was exported to the National Electricity Market.

**Figure 5: South Australia Grid Operating on 100% Distributed PV**




**Source:** Workshop 1 Presentation Deck[25], slide #71

South Australia's recent example provides insight for a High DER Future in California. First, the graph shows a GW-scale power grid operating entirely on distributed PV systems for a period of the day and a combination of renewable sources during most of the day. A limited amount of the balancing resources were provided by a combination of dispatchable generation (gas), battery storage, and intertie with the regional grid.

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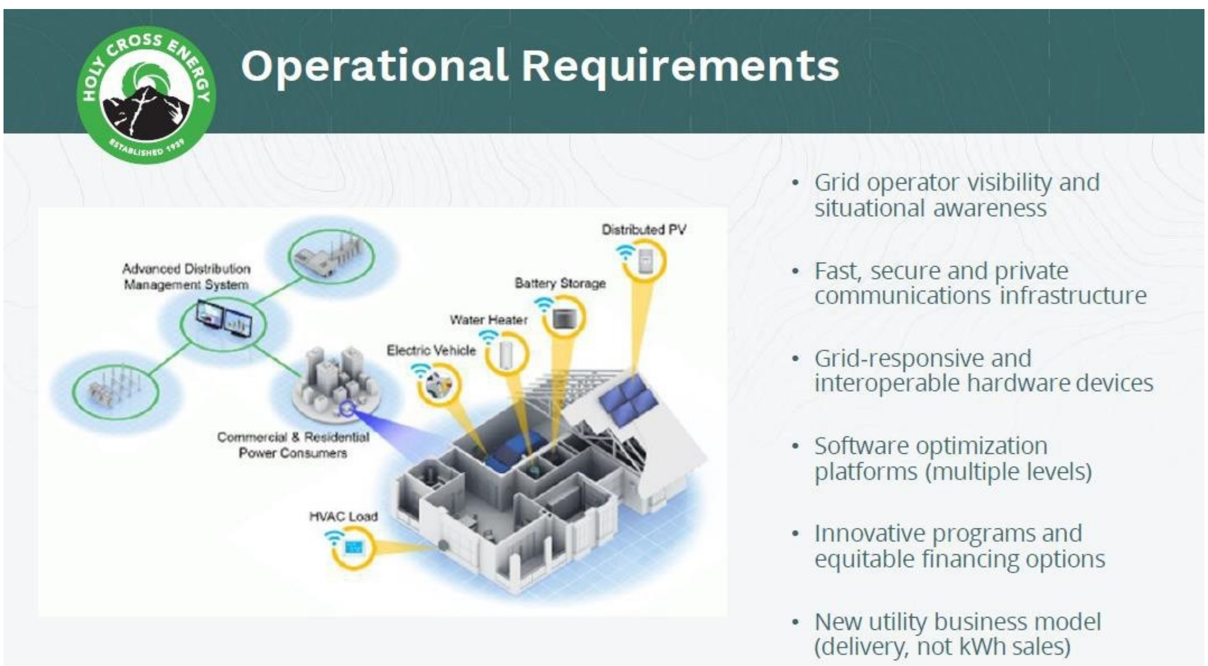
24 https://gridworks.org/wp-content/uploads/2024/02/2024-02-09c-Gridworks-California-DER-3.pdf
25 https://gridworks.org/wp-content/uploads/2024/02/CPUC-High-DER-Workshop_Final.-PDF.pdf

Ms. Riesz's presentation also discussed the focus areas in AEMO's DER Program to enable this level of operations. These include:

- Disturbance ride through requirements – Slide 6 discussed how DER systems required new settings to make sure they stay connected to the grid and generating during a wider range of disturbances.
- DER management – Slides 7-8 discussed AEMOs near- and longer-term efforts to enable different levels of DER management that are used to balance supply and demand on the bulk power system.
- Visibility – Slide 9 summarizes the level of aggregation and methods AEMO is using to monitor and estimate DER generation across the grid.

Bryan Hannegan, President and CEO of Holy Cross Energy (HCE), was the second speaker on the Thought Leaders Panel[26]. HCE is a member-owned cooperative in Colorado with near-term goals for 100% clean energy. HCE expects to meet these goals with a combination of utility-scale renewables and DERs. In this presentation, Bryan explained HCE's actions to achieve 100% carbon-free electricity by 2030. Specifically, he emphasized HCE's focus on DERs providing demand flexibility to balance out energy demand and supply. Figure 6 shows HCE's perspective as a utility operator on operational needs in a High DER future.

**Figure 6: Holy Cross Energy Operational Needs in High DER Future**

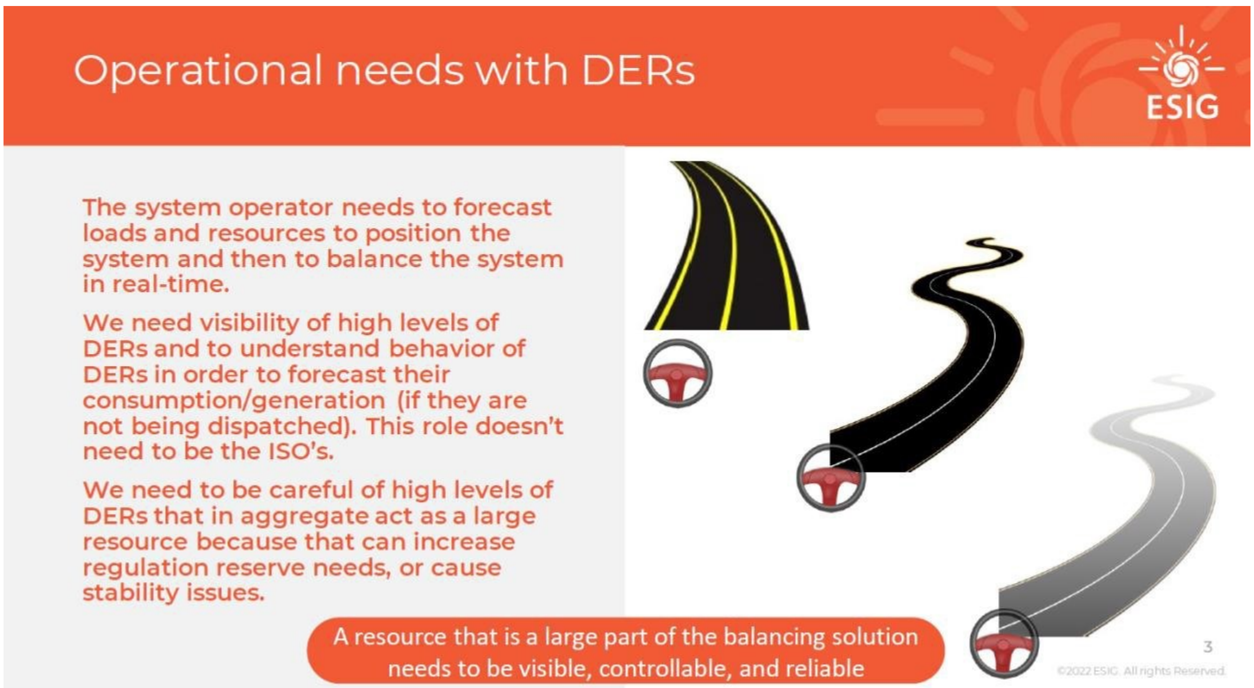



**Source:** Workshop 1 Presentation Deck[27], slide #85

[26] https://gridworks.org/wp-content/uploads/2024/02/2024.02.06-CA-PUC-Future-Grid-Hannegan.pdf
[27] https://gridworks.org/wp-content/uploads/2024/02/CPUC-High-DER-Workshop_Final.-PDF.pdf

Debra Lew, Associate Director of Energy Systems Integration Group (ESIG), was the final speaker on the Thought Leaders Panel.[28] Her presentation discussed a series of papers that ESIG has published on DER integration.[29] Her presentation also discussed several operational considerations for High DER systems in maintaining adequate reserve requirements and aggregate response of DERs during grid disturbances. The presentation also covered several recent examples of DER aggregation in Arizona, Texas, and Vermont. Figure 7 shows the summary of operational needs discussed in this presentation.

**Figure 7: ESIG Summary of Operational Needs in High DER Future**




**Source:** Workshop 1 Presentation Deck[30], slide #89

## Advocates

The final panel in Workshop 1 included presentations from the Public Advocates Office (Cal Advocates), Utility Consumers' Action Network (UCAN), 350 Bay Area, The Climate Center, and the Joint Community Choice Aggregators (Joint CCAs). The panel started with each presenter sharing their prepared remarks and then moved to a facilitated discussion. The section below briefly summarizes the presentations, specifically the priorities for a High DER Future.

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[28] https://gridworks.org/wp-content/uploads/2024/02/CPUC-Lew4-FINAL.pdf
[29] https://www.esig.energy/der-integration-series/
[30] https://gridworks.org/wp-content/uploads/2024/02/CPUC-High-DER-Workshop_Final.-PDF.pdf

**Cal Advocates**[31]

Amin Younes, a Utilities Engineer, presented on behalf of Cal Advocates. He shared Cal Advocate's key goals and objectives for a High DER Future, which are reflected in the bullet points below:

- Aligning DER operation with the grid's needs holds potentially tremendous value to California's electricity ratepayers; shifting demand to periods of abundant supply (and optimizing existing resources) can reduce the costs of generation, transmission, and distribution infrastructure.
- Future grid operations and planning should <u>provide the right signals to DERs so that they operate and locate when and where they maximize societal net benefit</u>, considering the following objectives:
    - I. minimize cost;
    - II. maximize safety;
    - III. maximize reliability;
    - IV. minimize environmental impact; and,
    - V. maximize equity.

Cal Advocates shared fourteen (14) operations needed to meet the objectives. Cal Advocates' list of operations included the following:

- Operate distribution grids: Maintain operational flexibility, voltage stability, safety, etc.
- Maintain grid frequency: Ensure sufficient (local and bulk) inertia, generation capacity, and frequency response.
- Plan and procure the distribution grid.
    - Forecast grid needs.
    - Optimize DER integration to defer or displace wires build.
    - Timely energize customers.
- Set policy on, authorize, and implement interconnection; establish DER operating limits and (smart) inverter requirements.
- Choose when to operate (i.e., schedule) DERs.
- Operate (i.e., dispatch) DERs.
- Monitor/model DER and non-DER data and convey to transmission operator
    - e.g., develop the function $Net\ Demand = f(Price)$.
- Manage data access for all data relevant to distribution grid operation: Track DER performance and interconnection characteristics, DER state-of-charge, cost of operation, historical performance, aggregator data, real-time prices. Manage confidentiality and data access.
- Own and fund distribution grid. Some entities or entities must pay for grid infrastructure; ownership rights are typically associated with funding.
- Own and fund DERs. Some entities or entities must pay for DERs; ownership rights are typically associated with funding.
- Set appropriate rates for consumption and generation based upon cost causation.
    - Prevent market manipulation
- System defense and restoration (e.g., cybersecurity, emergency load reduction, resiliency, black start).

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31 https://gridworks.org/wp-content/uploads/2024/02/cal_advocates_slides_20240205-FINAL.pdf

- Measure meter data (including submetering) and settle bills.
- Customers make informed consumption choices.

**Utility Consumers' Action Network (UCAN)[32]**

Samuel Golding, a consultant for UCAN, presented and opened their remarks with the following observations on future grid operating needs:

- Objectives require displacing future utility T&D investments with 3rd party DERs, controls & services that maximize use of existing grid.
- Operating framework requires (1) market-enabling systems and (2) market reforms to enable LSE & DER aggregator service innovations.

UCAN then summarized their recommendations in two priority areas: statewide platforms and market reforms. Figure 8 shows UCAN's recommendations.

**Figure 8: UCAN Recommendations for High DER Future**

## Summary of Recommendations

**Statewide Platforms**

- Data Hub: "API of APIs" ensures data access for all parties
- DER Register: database tracks location / capabilities of DER
- DER Market: facilitate trading & scheduling DERs, microgrid & CAISO coordination.

**Market Reforms**

- Shift to 5-/15- minute smart meter and CAISO load scheduling
- Implement LMS dynamic rates
- Expand DER submetering
- Allocate transmission costs to LSEs
- Enable Supplier Consolidated Billing
- Count Community-Scale DER as wholesale load reducers

**Source:** Workshop 1 Presentation Deck[33], slide #109

UCAN's presentation then further describes the two priority areas and provides examples of a proposed regional data hub in New England, AEMO's DER register, a flexibility platform in New York, transactive energy rates in New Hampshire, and supplier consolidated billing in Texas.

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32 https://gridworks.org/wp-content/uploads/2024/02/UCAN_Future-Grid-Workshop-1-Feb.-8-2024-public-final.pdf

33 https://gridworks.org/wp-content/uploads/2024/02/CPUC-High-DER-Workshop_Final.-PDF.pdf

**350 Bay Area**[34]

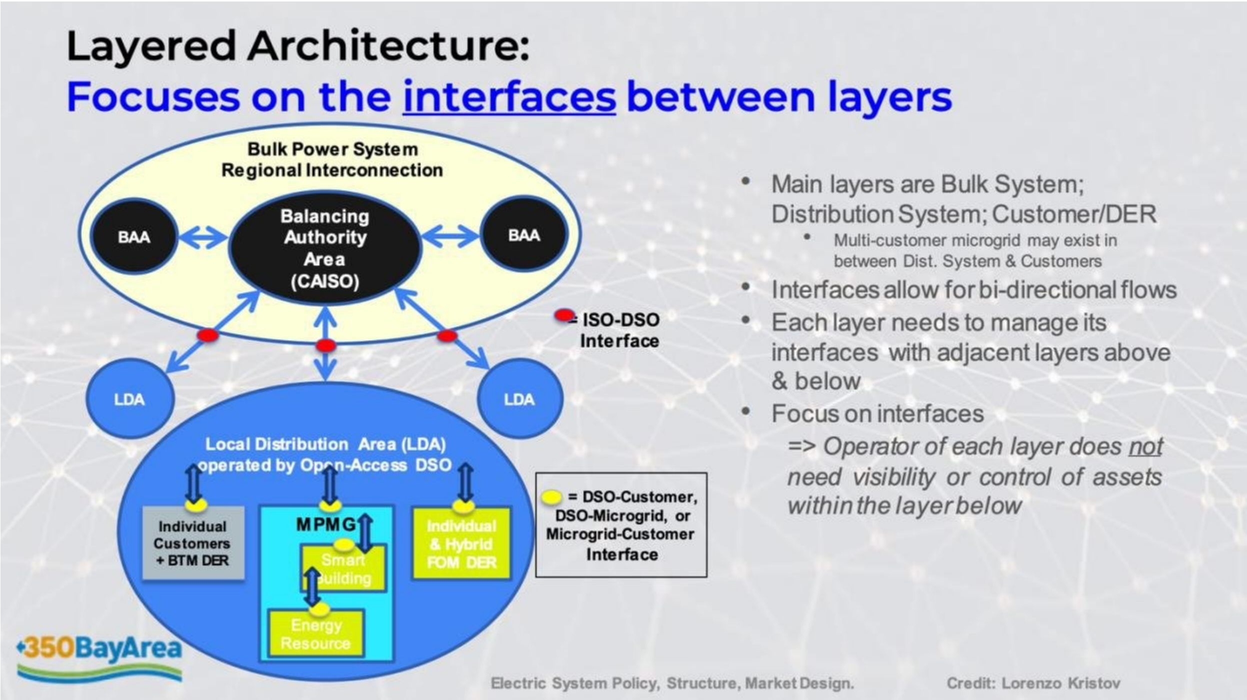
Sahm White, policy advisor to 350 Bay Area, presented and started with an overview of how the distribution grid is changing to a distribution system that "is no longer a one-way flow from a substation to loads, but a multidirectional scalable interaction between distributed energy resources (DER) and intermingled loads."

350 Bay Area states that, "Operation starts at load, working from the bottom up", and:

- The distribution system connects all of this in a layered architecture which is replicated at every junction, approaching a fractal design, from homes to ISO.

To further explain the layered architecture, 350 Bay Area presented the following diagram shown in Figure 9.

**Figure 9: 350 Bay Area Illustration of Layered Grid Architecture**




**Source:** Workshop 1 Presentation Deck[35], slide #133

350 Bay Area's presentation then discusses operational needs in the seven areas listed in Scoping Question #1 for this workshop series. On area #1 (efficiently operating a High DER grid), 350 Bay Area recommends the following (presentation provides further details in sub-bullets):

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[34] https://gridworks.org/wp-content/uploads/2024/02/350BA-HighDER-Workshop-1-2.8.24-Final.pdf
[35] https://gridworks.org/wp-content/uploads/2024/02/CPUC-High-DER-Workshop_Final.-PDF.pdf

- Efficient operation requires semi-optimal utilization of all available distributed energy resources
- Utilization requires having enabling systems in place, i.e. any available means for DER to receive and respond to information with reasonable timeliness and sufficient certainty
- Coordination of individual DER should include layered aggregation
- Efficient operation means least net cost

350 Bay Area also highlighted reducing ratepayer costs and increasing equity. On these focus areas, the presentation recommends (presentation provides further details in sub-bullets):

- Focus on least net total costs over time, including grid costs
- Inequitable energy burdens start with costs
- Savings require easy DER engagement and pricing for energy and services

**The Climate Center**[36]

Lorenzo Kristov, an energy systems consultant for The Climate Center, presented and provided comments on Identifying Operational Needs for a High DER Future.

The presentation highlights the core structural element needed to address the operational needs of a High DER Future. The Climate Center summarized these with the following statements (Slide #3):

"The core structural element needed to achieve all seven goals and maximize the societal, system & customer benefits of DERs is:

- an open-access distribution network & transactive distribution-level markets
- that enables all DERs, on both sides of the end-use customer meter, to economically transact energy & grid services.

The operational needs of the distribution system operator (DSO) derive from this core functional role — to operate a transactive network & markets reliably, efficiently, in accordance with open access principles, & in coordination with CAISO."

The rest of the presentation further details the key elements of an open access transactive network. These include:

- Define grid services DERs can economically provide
- Conduct non-discriminatory procedures for procuring, dispatching & compensating DERs
- Integrate DER grid services into distribution network planning
- Provide up-to-date network information to local governments, tribes, LSEs, DER developers & CBOs seeking to plan & deploy DERs
- Coordinate with CAISO operations & markets (day-ahead & real-time) at T-D interfaces to manage bulk system impacts of DER activities

The Climate Center's presentation then discussed how the open access transactive network addresses elements of Scoping Question #1 for this Track of the proceeding and focus of this Workshop.

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[36] https://gridworks.org/wp-content/uploads/2024/02/240208-L-Kristov-Climate-Center-High-DER-Workshop-FINAL-1.pdf

**Joint Community Choice Aggregators (Joint CCAs)** [37]

Nikhil Vijaykar, Counsel to the Joint CCAs, discussed the DER programs that CCAs currently run to serve their membership. The presentation then explained that CCAs lack sufficient information on distribution system needs to develop new programs.

The Joint CCAs shared the following key takeaways for the workshop participants:

- CCAs already run a variety of DER programs that are generally optimized around wholesale market conditions
- CCAs lack sufficient information and incentive to optimize DER programs based on distribution system needs
- CCA DER programs can provide better value to all customers with better information on grid constraints and economic signals that incentivize solutions to those constraints

## Outcome: Operational Needs for a High DER Future

The list below is the identified operational needs, compiled from answers submitted through Slido and from the presentations during the workshop. This list of operational needs formed the basis of the gap analysis conducted in Workshop 2. The operational needs can be organized into ten broad categories.

- DER Visibility to Distribution System Operator[38]
- DER Visibility to CAISO[39]
- DER dispatchability/control[40]
- Operational planning and analysis[41]
- Reliability Coordination at Transmission-Distribution interface[42]
- DER Technical Performance Standards[43]
- Cybersecurity[44]
- Open access to distribution system[45]
- Layered system architecture from bottom-up[46]
- Animate distribution-level markets/granular pricing[47]

Further detail within each category is below.

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[37] https://gridworks.org/wp-content/uploads/2024/02/Joint-CCA-Deck-for-Future-Grid-Workshop-1-2.8.24-R.21-06-017.pdf
[38] Source: IOU, Public Advocates, and thought leader presentations
[39] Source: CAISO, Public Advocates, and thought leader presentations
[40] Source: IOU, Public Advocates, and thought leader presentations; 1 stakeholder comment
[41] Source: CAISO, IOU, Public Advocates, and thought leader presentations
[42] Source: CAISO and Public Advocates presentations
[43] Source: Public Advocates and thought leader presentations
[44] Source: Thought leader presentations
[45] Source: Energy Division, IOUs, Public Advocates, and The Climate Center presentations; 5 stakeholders
[46] Source: 350 Bay Area presentation; 4 stakeholder comments
[47] Source: Energy Division, thought leaders, IOUs, UCAN, The Climate Center, and Joint CCAs presentations; 7 stakeholder comments

**DER Visibility to Distribution System Operator**[48]

- Real-time awareness of DER status and output
    - Improve reliability through better understanding of current grid conditions
- Mutual sharing of DER schedules, operations, constraints
- Real-time monitoring and automated grid control enabled by intelligent sensors, switches, protection, communication devices
    - Improve reliability through faster response to emergencies and changing grid conditions and
    - Enable more granular ability to re-configure the distribution grid to re-route power during abnormal conditions

**DER Visibility to CAISO**[49]

- Coordinated visibility of specific DER information to understand and anticipate their impacts on grid operations
    - technology type, location, size, operational behavior and performance
    - at various granularities (aggregated and/or device level)
- Need enhanced data collection, access, and reporting:
    - For planning and forecasting processes to improve grid asset utilization;
    - short term load forecasting accuracy; and
    - ISO market optimization and dispatch.
- Situational awareness of both market participating and non-participating DERs is critical for CAISO operations
    - Understanding the impact of all types of DERs under various uses is critical to situational awareness and reliability
        - expect transportation electrification to present greater complexity
- Mutual sharing of DER schedules, operations, constraints
    - Enable multiple uses, avoid operational conflicts. Eventually, enable market coordination.

**DER dispatchability/control**[50]

- Signal participating DERs to provide output at specified time (day-ahead and real time)
- Progressively integrate DERs into scheduling and dispatch
- Develop emergency backstop capability (curtailment)
- Fast, secure and private communications infrastructure
- Software optimization platforms to support dispatchability (multiple levels)
- A communications platform and information sharing framework used to advise appropriate entities, in the appropriate timeframe, the status and feasibility of DER activity in relation to grid operations and reliability.

**Operational planning and analysis**[51]

- Increase granularity of DER forecasts to utilize in operational timeframes
- Analyze High DER grid conditions to identify potential reliability risks

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[48] Source: IOU, Public Advocates, and thought leader presentations
[49] Source: CAISO, Public Advocates, and thought leader presentations
[50] Source: IOU, Public Advocates, and thought leader presentations; 1 stakeholder comment
[51] Source: CAISO, IOU, Public Advocates, and thought leader presentations

- Optimize use of grid assets based on DER forecasts to provide maximum value
- Maintain operating reserves to control the supply/demand balance and to meet reliability standards

**Reliability Coordination at Transmission-Distribution interface**[52]

- Coordinate operation of DERs providing services to distribution and bulk electric systems
- Communications and information sharing to support coordination of DERs across distribution and bulk electric systems
- Framework to coordinate operation of DER resources when they are providing services to the distribution system or to the bulk electric system to ensure the feasibility of those services and preserve reliability.

**DER Technical Performance Standards**[53]

- Develop inverter ride through standards to support High DER grid
- Implement measures to ensure broad compliance with inverter standards

**Cybersecurity**[54]

- Growing concern with high levels of DER

**Open access to distribution system**[55]

- Improve, simplify interconnection agreements and process
- Treat DERs and loads in a microgrid in an equivalent manner as DERs and loads outside of microgrids
- Meet expected demand for transportation electrification while minimizing infrastructure upgrades
- Improve opportunities for DERs to avoid/defer infrastructure upgrades
- Utilize dynamic distribution prices to delay/reduce distribution system upgrades
- Fully implement an open-access distribution network & transactive distribution-level markets
    - Define grid services DERs can economically provide
        - E.g., compensate DERs & Aggregators for flattening circuit-level peaks (load & supply "ducklings") to increase hosting capacity without upgrading circuits
    - Conduct non-discriminatory procedures for procuring, dispatching & compensating DERs
        - Market mechanisms that receive & clear bids (day-ahead & day-of) linked to current distribution system conditions & transmit results to participants
        - Establish real-time communication with participating DERs
        - Conduct solicitations for longer-term grid services contracts
        - Accurately measure DER grid service performance & perform settlement
- Integrate DER grid services into distribution network planning

[52] Source: CAISO and Public Advocates presentations
[53] Source: Public Advocates and thought leader presentations
[54] Source: Thought leader presentations
[55] Source: Energy Division, IOUs, Public Advocates, and The Climate Center presentations; 5 stakeholders

- Provide up-to-date network information to local governments, tribes, LSEs, DER developers & CBOs seeking to plan & deploy DERs
- Coordinate with CAISO operations & markets (day-ahead & real-time) at T-D interfaces to manage bulk system impacts of DER activities
    - Clear DSO markets in time to provide accurate forecast to CAISO DA & RT markets on expected net flows across T-D interfaces
    - Transmit customer meter data & current distribution system conditions to LSEs to support their CAISO bidding & scheduling
    - Support direct DER participation in CAISO markets through timely provision of current system conditions & non-discriminatory curtailment procedures

**Layered system architecture from bottom-up**[56]

- Distribution-system architecture built from bottom up from within homes to the ISO level
- Efficiently operate a High DER grid:
    - Efficient operation requires semi-optimal utilization of all available distributed energy resources
    - Utilization requires having enabling systems in place, i.e. any available means for DER to receive and respond to information with reasonable timeliness and sufficient certainty
    - Coordination of individual DER should include layered aggregation
    - *Efficient* operation means least net cost
- Unlock economic opportunities for DERs to provide grid services:
    - Smart Inverter Operationalization Working Group (SIOWG)
        - focused on utilization of existing advanced inverter functionalities
        - identified numerous high priority use cases and business cases
        - based on technological readiness, cost, scale, and timeline
    - Standard tariffs and contracts are needed
        - designed to support stacked value uses of resources
    - DSO as the nexus
        - to simplify signaling (layered coordination)
        - to simplify single point access to revenue streams (market and utility/tariff)

**Animate distribution-level markets/granular pricing**[57]

- DSOs enable dynamic distribution prices
    - Integrate SCADA data with price machine to generate local distribution load forecasts
- Statewide distribution data sharing hub
    - Data Hub: "API of APIs" ensures data access for all parties
    - DER Register: database tracks location / capabilities of DER
    - DER Market: facilitate trading & scheduling DERs, microgrid &CAISO coordination.
- Market reforms to support distribution-level markets
    - Shift to 5-minute Supply/Demand Balancing
    - Dynamic Pricing + LSE Transmission + DER Submetering

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[56] Source: 350 Bay Area presentation; 4 stakeholder comments
[57] Source: Energy Division, thought leaders, IOUs, UCAN, The Climate Center, and Joint CCAs presentations; 7 stakeholder comments

    - Supplier Consolidated Billing
    - Account for Community-Scale DER as Load Reducers
- Enhanced data sharing between IOUs and CCAs to identify grid needs
    - CCAs already run a variety of DER programs that are generally optimized around wholesale market conditions
    - CCAs lack sufficient information and incentive to optimize DER programs based on distribution system needs
    - CCA DER programs can provide better value to all customers with better information on grid constraints and economic signals that incentivize solutions to those constraints

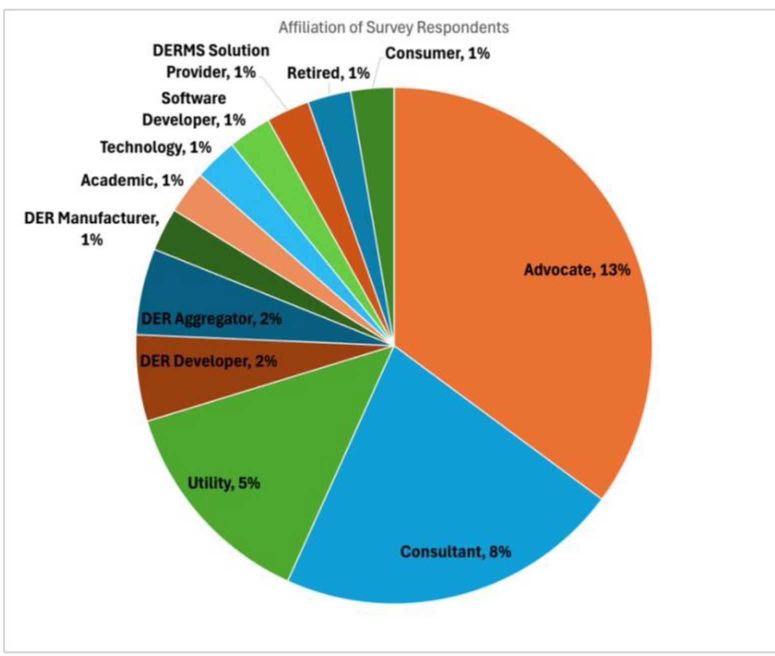
## Prioritizing Operational Needs

Prior to Workshop 2, stakeholders were asked to respond to a two-question survey, where they ranked the importance (low, medium or high) and urgency (short-, medium- or long-term) of the operational needs identified in Workshop 1. Workshop participants at Workshop 2 were again invited to complete the survey.

The survey received 38 responses from a broad range of stakeholders: utilities, DER manufacturers, DER developers, environmental advocates, equity advocates, consumer advocates, consultants, academics, technology, software developers, DER aggregators, DERMS solution providers, and consumers.

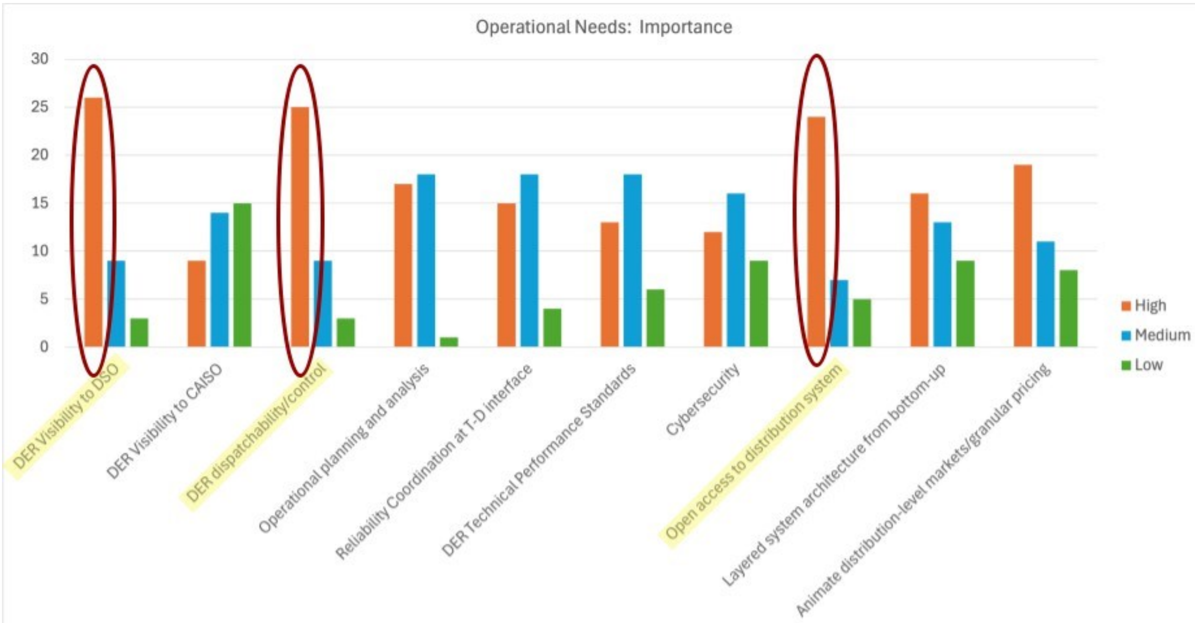
Figures 11 and 12 show the results from that survey. While all categories of operational needs received votes for high importance and urgency, a few key operational needs stood out: DER Visibility to the Distribution System Operator, DER dispatchability/control and open access to the distribution system.

**Figure 10: Affiliation of Survey Respondents**




**Source:** Operational Needs Survey

**Figure 11: Importance of Operational Needs**




**Source:** Operational Needs Survey

**Figure 12: Urgency of Implementing Operational Needs**


**Source:** Operational Needs Survey

# WORKSHOP 2: ASSESSING GAPS

On March 12, 2024, Gridworks facilitated the second workshop in the Future Grid Study workshop series to begin to address the second question in the amended scoping memo:

> 2. *What are the existing gaps and barriers in achieving the needs identified above within our current Distribution System Operators (Utilities)?*

## Workshop Structure

The second workshop was divided into two sections: an operational needs discussion, and presentation and discussion to identify gaps. There were 182 participants in total. Throughout the workshop, the audience could use the chat feature in Zoom to ask questions and provide comments, and to use Slido, an external survey tool, to offer their assessment of gaps between current operational capabilities and the operational needs identified in Workshop 1.

Commissioner Houck spoke at the beginning of the workshop. She acknowledged the ample feedback provided in the first workshop and expressed her interest in discussing the gaps during this second workshop.

Gridworks presented the list of operational needs identified in Workshop 1, and the results of the prioritization survey. Participants were given another opportunity to answer the prioritization survey, and ultimately a total of 38 stakeholders provided responses. Participants had an opportunity to share feedback on the operational needs that ranked highest in importance and urgency.

The latter portion of the workshop focused on identifying gaps between current operational capabilities and the operational needs identified in Workshop 1. There were two panels, one composed of speakers from the utilities, and one composed of speakers from advocacy organizations. The workshop concluded with a facilitated discussion based on the information shared during the two panels.

## Current & Planned Operational Capabilities

The Joint IOUs presented[58] an Overview of Future DSO Capabilities and then described technology progress by each IOU. They then discussed their perspectives on current policy gaps and recommendations.

### IOU Overview

In discussing technology progress by the IOUs, this section of the presentation started with the slide shown in Figure 13 (slide #8 of the Joint IOU presentation).

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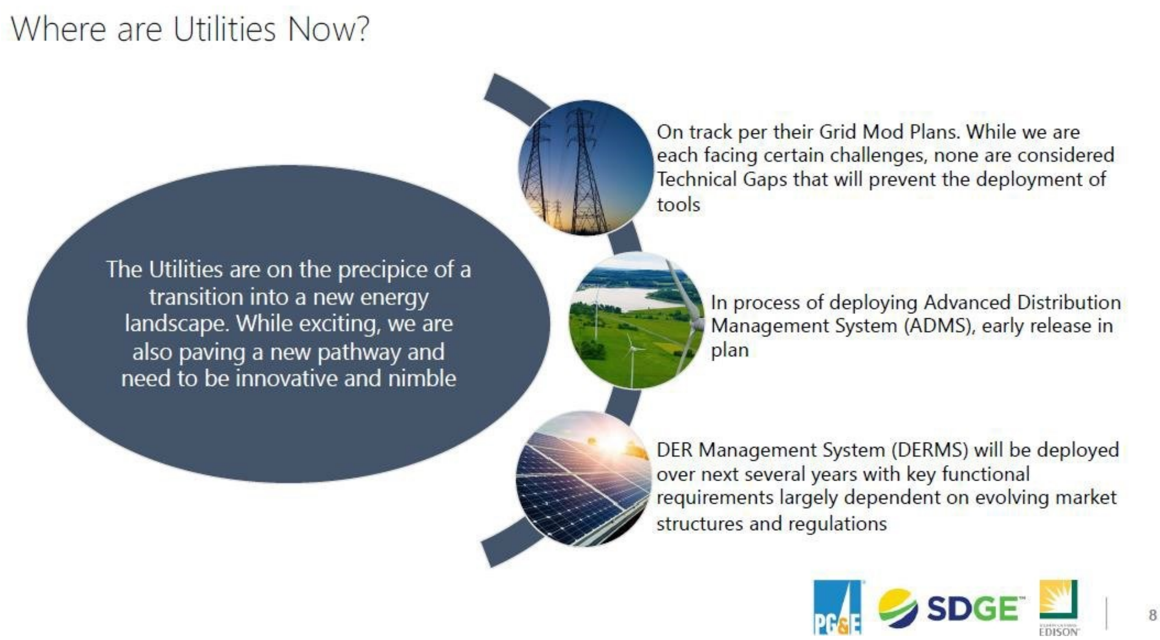
[58] https://gridworks.org/wp-content/uploads/2024/03/2024-DSO-Workshop-2-Joint-IOU-Presentation.pdf

**Figure 13: Summary of Current Joint IOU Technology Progress**




**Source:** Workshop 2 Presentation Deck[59], slide #24

The Joint IOUs describe that they are on track with current Grid Modernization Plans. Notably, they state that while each utility is facing challenges, "none are considered Technical Gaps that will prevent the deployment of [these] tools."

The Joint IOUs then summarized their stepwise progression in deploying Advanced Distribution Management Systems (ADMS) and DER Management Systems (DERMS) over the next several years. Below are summaries by utility that provide highlights of their Grid Modernization Plans and current progress.

## Southern California Edison (SCE)

SCE shared the diagram in Figure 14, which describes their proposed approach to developing a Grid Management System ("GMS"). In their progress report to the CPUC[60], SCE describes the GMS as, "an advanced software platform that integrates multiple systems designed to monitor, manage, and optimize the performance of our increasingly dynamic electric grid characterized by high DER penetration. The GMS will provide SCE with the requisite capabilities to not only manage SCE's grid assets, but to also engage with customers and their DERs so that they become a core part of operating the grid." Figure 14 shows the recent progress and next steps in building this software platform.

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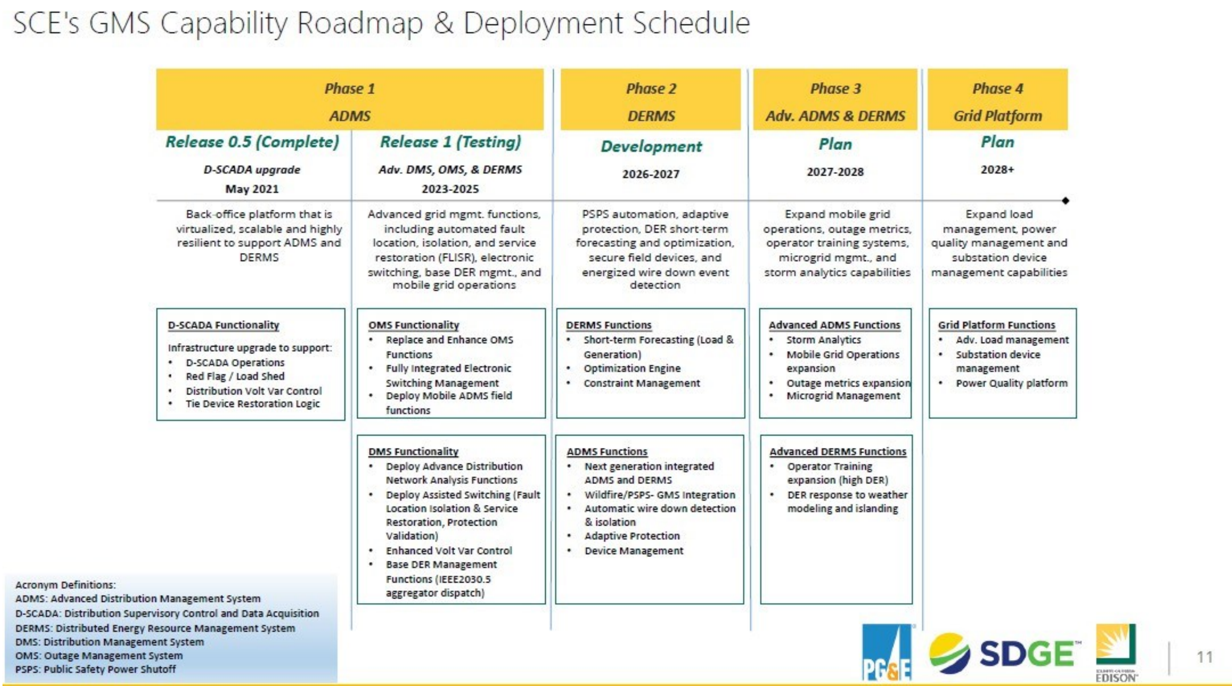
59 https://gridworks.org/wp-content/uploads/2024/03/CPUC-HI-DER-Workshop-2-Final-Slides.pdf
60 https://gridworks.org/wp-content/uploads/2024/04/SCE-2024-Grid-Modernization-Progress-Report.pdf

**Figure 14: SCE Roadmap in Developing a Grid Management System (GMS)**




**Source:** Workshop 2 Presentation Deck[61], slide #27

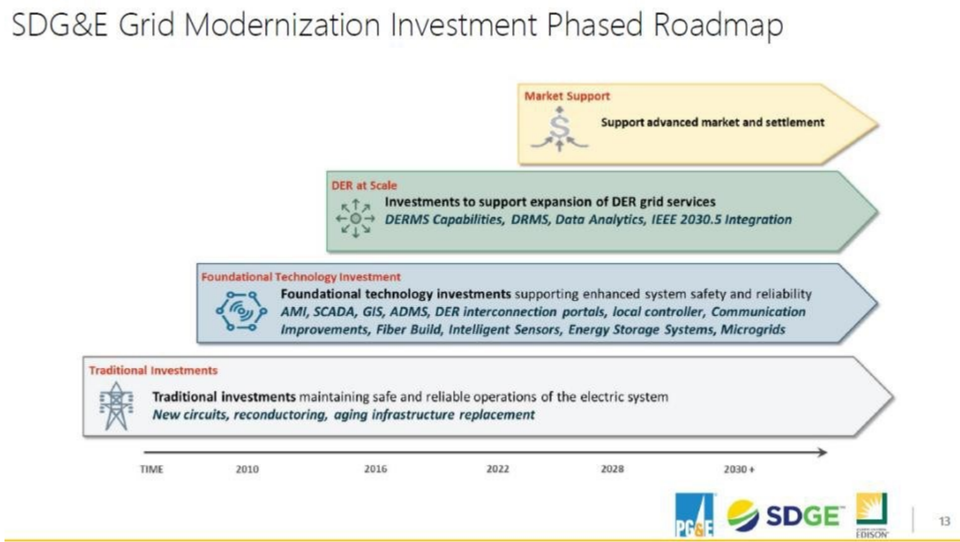
The figure shows the current work in Phase 1, which involves testing and releasing an ADMS, Outage Management System (OMS), and DERMS. Successive phases of the plan build additional functionality into the ADMS and DERMS platforms.

## San Diego Gas & Electric (SDG&E)

SDG&E also presented their roadmap of Grid Modernization investments which indicates that investments to support DER Grid Services rely on the traditional and foundational investments illustrated in Figure 15. This roadmap was followed with a more detailed description of SDG&E's capabilities in 2024 (see Figures 15 and 16).

61 https://gridworks.org/wp-content/uploads/2024/03/CPUC-HI-DER-Workshop-2-Final-Slides.pdf

**Figure 15: SDG&E Grid Modernization Investment Roadmap**




**Source:** Workshop 2 Presentation Deck[62], slide #29

**Figure 16: SDG&E Grid Orchestration Capabilities in 2024**

SDG&E Current Capabilities for DER Orchestration (2024)

| Capability | Description |
|---|---|
| DER Visibility | • Telemetry requirement for DERs >1MW, allowing for control center visibility. Situational awareness includes topographical visibility in Network Management System (NMS). Ability to isolate CAISO DER via SCADA switch if operational emergency calls for it.<br>• In-flight project, PIVA: Photovoltaic Integration over Virtual Airgap, to quantify "True Load" |
| Short-term Forecasting | • Short-term forecasting is available and being evaluated with distribution system model. Additional efforts to integrate with other functional modules and operational processes. |
| Advanced Grid Analytics | • Building out ADMS capabilities to prepare for DERMS, including power flow and day-ahead forecasting. Additional future capabilities included in the roadmap are fault location, VVO, and FLISR. |
| Grid / DER Optimization | • DER-Aware NMS today and future plans for DER-Aware ADMS.<br>• Local Area Distribution Controllers (LADC) deployed at our internally owned DER locations to optimize DER assets within an electric microgrid environment. |
| DER Scheduling and Dispatching Tools | • For DERs >1MW there is control center visibility of static charge limits. |
| Advanced CAISO Coordination / Communication | • Requests to attach and permission to operate per an interconnection agreement which includes safety and reliability requirements (SCADA Isolation Switch, Telemetry, Anti-Islanding, Charging/Discharging Parameters, Ramp Rates) |
| Grid Infrastructure Orchestration | • In-flight projects and demonstrations:<br>o Vehicle2Grid Partnerships<br>o EPIC projects focused on evaluating communications<br>o Two Virtual Power Plant (VPP) Projects<br>• Need to integrate with future grid management tools (DERMS) |

15

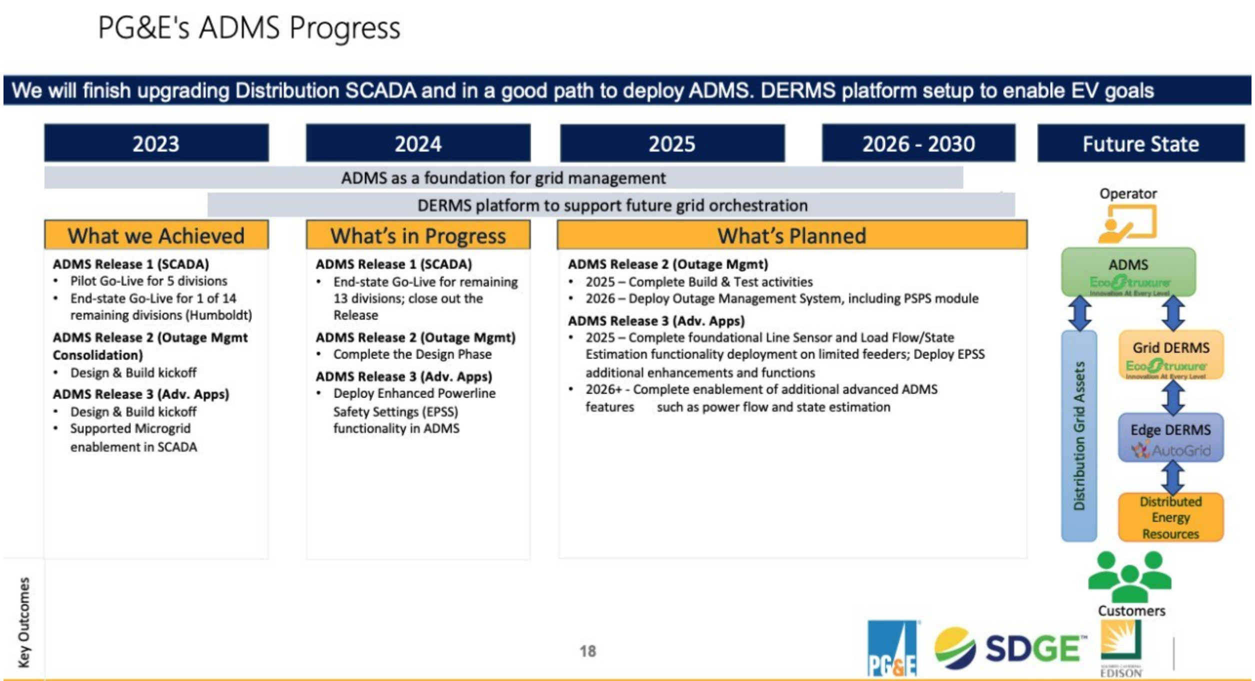
**Source:** Workshop 2 Presentation Deck[63], slide #31

62 https://gridworks.org/wp-content/uploads/2024/03/CPUC-HI-DER-Workshop-2-Final-Slides.pdf
63 https://gridworks.org/wp-content/uploads/2024/03/CPUC-HI-DER-Workshop-2-Final-Slides.pdf

## Pacific Gas and Electric Company (PG&E)

PG&E shared their DER Orchestration Roadmap (shown below in Figure 17) which also anticipates developing additional DER management capabilities in their DERMS.

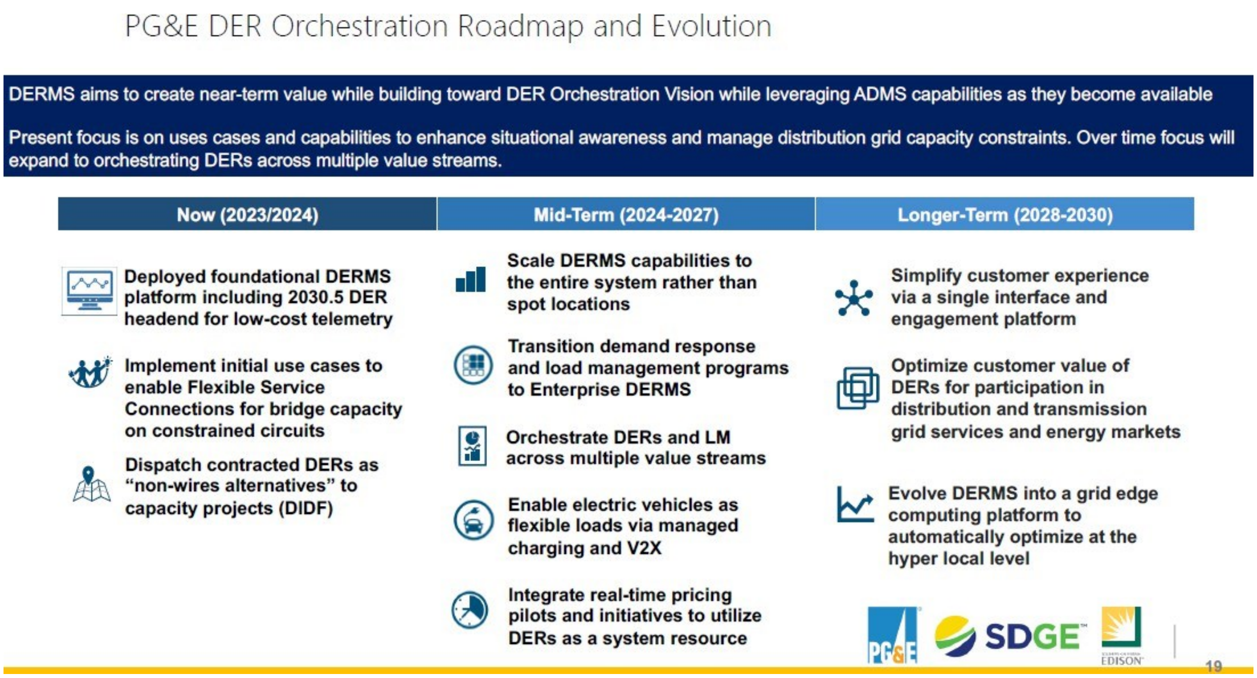
**Figure 17: PG&E ADMS Progress**




**Source:** Workshop 2 Presentation Deck[64], slide #34

64 https://gridworks.org/wp-content/uploads/2024/03/CPUC-HI-DER-Workshop-2-Final-Slides.pdf

**Figure 18: PG&E DER Orchestration Roadmap**




**Source:** Workshop 2 Presentation Deck[65], slide #35

## Outcomes

### Operational Needs Gap Assessment

Following Workshop 2, Gridworks analyzed how the IOUs' grid modernization plans would support the various operational needs identified in Workshop 1. To complete this gap assessment, Gridworks reviewed the presentations and discussion from Workshop 2, reviewed each IOUs' most recent grid modernization progress report (see Appendix B: IOU Grid Modernization Progress Reports), and met with the IOUs to gather additional detail and clarifications. In reviewing those materials, Gridworks looked to answer three different questions:

1. What is each IOU's expected operational capabilities (in 2024) in relation to the identified operational need?
2. What would be each IOU's operational capabilities if their grid modernization plans were to be fully implemented?
3. Are there any remaining gaps in operational capabilities after accounting for all planned grid modernizations?

Key takeaways from the gap assessment are below, and the complete gap assessment is included in Appendix A: Operational Needs Gap Assessment.

65 https://gridworks.org/wp-content/uploads/2024/03/CPUC-HI-DER-Workshop-2-Final-Slides.pdf

**Key Takeaways from Workshop 2**

1. **The IOUs are planning and implementing significant upgrades in their capabilities to operate High DER Grids.** The IOUs shared details on their planned capabilities for 2024, and their Grid Modernization Progress Reports and comments in the gap assessment indicate that most of these plans are on track. The planned upgrades establish visibility and management for DERs > 1MW, including aggregated DERs.
2. **Proposed future capabilities depend on the IOUs' progress in implementing their Grid Modernization Plans.** Therefore, it is unclear when the IOUs will fulfill the operational needs identified in Workshop 1. Three examples from the discussions during the workshop series include flexible interconnection and energization, and implementation of dynamic rates. The timelines for these capabilities have already been extended and new rounds of pilot projects are being proposed to test these capabilities. Without clear roadmaps and timelines for regulatory processes and decisions on these issues, the IOUs and market participants cannot develop the operational capabilities or grid services for a High DER Future.
3. **Significant gaps appear in the operational interface between CAISO and DSOs.** The discussions in Workshop 1 indicate that the CAISO has an important role in a High DER Future, and that the CAISO and DSOs need to better coordinate on data sharing and DER participation in grid services markets.
4. **The pace of developing grid services markets appears to be falling behind DER adoption**. A consistent theme among the workshop participants is the expected rapid growth in new DERs across all of the IOUs' service territories, particularly with the widespread adoption of electric vehicles. Utilization of grid services from DERs was a priority operational need among workshop participants. In the gap assessment, the pace of developing local grid services markets does not appear to align with the expected near-term growth. A gap on this operational need can result in lost opportunities to build the future distribution grid at lower cost, to improve community resilience, to stimulate local economic development, and to address equity.
5. **Diverging approaches to enabling the High DER Future.** Throughout the workshop series, stakeholders have articulated different long-term visions for a High DER Future. The IOUs have presented a vision of "grid orchestration" in a High DER Future. The selected terminology and corresponding Grid Modernization Plans indicate a significant role for the DSOs as the "conductors" in grid orchestration of DERs but gaps appear to remain on the timelines to develop and implement the required operational needs. The IOU data responses on pilot projects show a significant amount of pilot work that is underway but do not explain how the proposed pilots will inform further necessary actions to address these gaps. Alternatively, several stakeholders, notably 350 Bay Area and The Climate Center, articulated a bottom-up, open-access vision for the High DER Future. Many of the operational needs for a bottom-up, open-access High DER Future do not appear to be supported by the IOUs' near-term plans, and work remains to define the necessary market and distribution operations changes required to support this vision.
6. **Data sharing and transparency in DER interconnection remain friction points.** The discussions throughout the workshop series have also highlighted diverging views on various types of data sharing and tension over the interconnection process and the accuracy of Integration Capacity Analyses (ICAs). Several stakeholders have identified data sharing as a current limitation to broad participation in a High DER Future. In addition, concerns over the interconnection process and ICAs produced by the IOUs reflect a lack of transparency/confidence in key steps of DER interconnection.

# WORKSHOP 3: DEVELOPING RECOMMENDATIONS TO ADDRESS GAPS

On May 1, 2024, Gridworks facilitated the third and last workshop in the Future Gird Study workshop series to address the final question in the amended scoping memo:

3. *What are the potential solutions in overcoming these barriers?*[66]

## Workshop Structure

The third workshop was divided into five sections, with discussion in each section addressing one of five topics. There were 127 participants in total. Throughout the workshop, the audience had the ability to use the chat feature in Zoom to ask questions and provide comments.

Commissioner Houck's Deputy Chief of Staff, Amanda Singh, provided welcoming remarks at the beginning of the workshop. Gridworks then provided an overview of the preliminary Operational Needs Gap Assessment (discussed above), including how it was developed and planned additions. The majority of the workshop was spent discussing five topics:

1. Implementation of Flexible Generation Interconnection
2. Scoping of IOU system upgrades to support dynamic rates
3. DER Visibility to
    a. DSOs
    b. CAISO
4. Roadmap for Distribution-Level Grid Services from Flexible Load Energization[67]
5. Data Sharing in a High DER Future.

## Selecting Discussion Topics

Gridworks proposed this focused approach to provide greater time and depth of discussion on the selected topics. The full list of operational needs includes ten (10) topic areas, and it would have been challenging to cover each topic in the available time for the workshop. In addition, some participants in Workshop 2 recommended identifying priority areas for discussion in the final workshop.

Gridworks selected the topics after reviewing the following:

- operational needs shared in Workshop 1,
- survey results from Workshop 2,
- operational needs gap assessment conducted after Workshop 2, and
- discussions from both prior workshops.

Gridworks reviewed the proposed topics with Energy Division staff and refined the discussion areas while planning Workshop 3. During the comment period on this report, parties to the High DER Proceeding can comment on and offer recommendations on other operational needs that were not included in the final workshop. These comments will help build the record for the

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[66] "[B]arriers" means the gaps and barriers to achieving the identified operational needs.
[67] "Flexible Load Energization" refers to the approach of setting variable firm and non-firm import limits for a DER.

CPUC's decision making. Finally, Gridworks has compiled the recommendations provided by participants in the earlier workshops. This full list is presented on pages 43-44.

## Topic Summaries

### 1. Implementation of Flexible Generation Interconnection

**Related Operational Needs**

- Open access to the distribution system

Flexible generation interconnection allows DER systems to reduce output during periods when the distribution grid has reached a hosting capacity limit while allowing higher output during times when the distribution grid can integrate more generation. By adopting this approach, greater levels of DERs can be interconnected using the same grid infrastructure and projects can begin operating earlier than if grid infrastructure upgrades are needed.

In 2017, the CPUC initiated rulemaking R.17-07-007 with a key objective to streamline interconnection of DERs and a primary focus at that time was interconnection of generation resources. In September 2020, Decision 20-09-035 modified interconnection procedures to allow a DER customer to include a "Limited Generation Profile (LGP)" with their application. This approach would allow distributed energy resources to perform within existing hosting capacity constraints and avoid triggering upgrades. In March 2024, the CPUC finalized the details to implement use of LGPs in flexible generation interconnection.

In the High DER proceeding (R.21-06-017), the CPUC issued a staff proposal in Track 1 that recommends improvements to distribution planning and execution. Sections of the proposal address potential improvements to the Integration Capacity Analyses (ICA) and customer data portal, which provide information on the hosting capacity available for generation interconnection.[68] Under the LGP decision discussion above, DER developers would use ICA results for a location to submit a schedule of limits for the DER system over the year. With this dependency on the ICA results, the success of Flexible Generation Interconnection is tied to the usability and accuracy of this information. The proposed improvements include adding more detail on limiting criteria in ICA results, removing registration requirements for access to the data portal, and modifying ICA maps to facilitate creation of limited generation profiles.

In Track 3 of the High DER proceeding, the CPUC recently released the Smart Inverter Operationalization Working Group ("SIOWG") report and requested comments from parties.[69] According to the report, the SIOWG focused on operational flexibility as the highest priority. The SIOWG defines operational flexibility as the ability of the distribution system operator, in a future where there is a high number of distributed energy resources, to flexibly optimize the use of existing capacity, allowing more rapid connections of distributed energy resources and loads, while still maintaining grid safety and reliability.

The SIOWG found that Firm and Non-Firm Export Limits of power are necessary for operational flexibility and optimal use of existing capacity as more distributed energy resources are

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[68] See March 13, 2024 Staff Proposal to Improve the Distribution Planning and Execution Process: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K221/527221491.PDF.

[69] May 29, 2024 and June 4, 2024 administrative law judges' rulings in the High DER Proceeding issued two SIOWG reports and a list of questions to parties.

interconnected to the grid. Establishing both firm and non-firm limits can allow more generation from DERs without requiring further upgrades to the distribution system. The firm limits establish a set schedule which could be a single value or multiple values, as proposed in the Limited Generation Profile. These schedules are established periodically based on modeling of future conditions on the distribution grid. The non-firm limits allow opportunities to export even higher levels of generation based on real-time conditions monitored by the DSO or updates to the modeling from day- or week-ahead forecasts. The DSO would then communicate the updated non-firm limits to the DER systems. The SIOWG report notes that the monitoring, modeling, and communications capabilities to set the non-firm limits would be implemented by the DSOs in their ADMS and DERMS systems.

Given this background, the discussion on this topic in Workshop #3 focused on identifying how the CPUC can track progress on how the IOUs' Grid Modernization Plans support flexible generation interconnection and identifying any further actions that are needed implement this operational need.

**Discussion**

During the discussion on this topic, participants noted the following:

- Concerns with the accuracy of the Integration Capacity Analyses (ICAs) and impacts on flexible generation interconnection – Several participants shared that inaccuracies and delays in updating the ICAs could undermine flexible generation interconnection. Participants also noted that the CPUC needs to have the technical expertise to be able to evaluate the utility's analysis.
- "Roadmap" for flexible generation interconnection - Energy Division staff noted that different aspects of this topic were under discussion in separate regulatory proceedings (or different tracks of same proceeding) and requested feedback on ensuring comprehensive oversight in implementing flexible interconnection.

**Stakeholder Recommendations on Flexible Generation Interconnection**

- An independent third party should provide oversight to ensure usability and accuracy of Integration Capacity Analyses.
- The CPUC should obtain additional support to ensure Staff have the technical expertise to provide oversight of the ICAs.

**Gridworks Recommended Next Steps on Flexible Generation Interconnection**

Flexible interconnection (firm export limits) is in scope in the Interconnection Proceeding (R.17-07-007), integration capacity analysis is in scope in Track 1 Phase 1 of the High DER proceeding and non-firm export limits are in scope Track 3 Phase 1 of the High DER Proceeding.

In R.17-07-007, Resolution E-5296 was issued on March 21, 2024 and provides the specifics on whether and how reductions to a customer's Limited Generation Profile (LGP) are determined, and provides recommendations regarding the standard review, certification requirements, and interconnection processes necessary for implementation of the LGP option.

The CPUC issued a Ruling in the High DER Proceeding on March 13, 2024 seeking Party comment on a Staff Proposal in Track 1 Phase 1 to improve the Distribution Planning and Execution Process.[70] Party opening comments were due on May 28, 2024, and reply comments were due on June 18, 2024. The CPUC developed a proposed decision (PD) based on the staff proposal and Party comments and reply comments and issued the PD on September 13, 2024.

The CPUC issued a Ruling in the High DER Proceeding on May 29, 2024 seeking Party comment on two SIOWG reports produced for Track 3 Phase 1: a report from the Smart Inverter Operationalization Working Group (SIOWG) and the Cybersecurity Working Group (SIO-CS).[71] A ruling correcting some formatting errors reissued the reports on June 5, 2024. Party comments were received on July 8, 2024 and reply comments were received on July 22, 2024 and the CPUC is working to develop a Staff Proposal based on these reports and party comments and reply comments.

Interested stakeholders should join the service lists for R.17-07-007 and R.21-06-017 to stay apprised of proposed changes to the interconnection process and ICAs, and to stay apprised of opportunities to intervene.

The CPUC should require the IOUs to provide a walkthrough of each IOU's ICA backend software and system architecture to stakeholders and CPUC Staff via a webinar. In addition, the IOUs should coordinate with CPUC staff to ensure that stakeholders in Track 2 of this proceeding are informed of reports and public workshops on ICAs directed by the CPUC in Track 1.

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[70] Administrative Law Judges' Ruling Seeking Comment on Staff Proposal, March 13, 2024. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K056/527056843.PDF.

[71] Administrative Law Judge's Ruling Providing Two Working Group Reports and Directing Responses to Questions on Reports, May 29, 2024. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M532/K677/532677182.PDF.

## 2. Scoping of IOU system upgrades to support dynamic rates

**Related Operational Needs**

- Open access to distribution system
- Animate distribution-level markets/granular pricing

In Workshop 1, Energy Division staff provided an overview of the Demand Flexibility proceeding (R.22-07-005) and several participants noted that more granular, distribution-level pricing mechanisms were an operational need.

During the discussions in Workshop 2, representatives from the IOUs noted that current Grid Modernization Plans did not yet support dynamic pricing because they would need to understand the structure of dynamic rates before scoping additional work in their software platforms. The final scoping for these plans would need to wait until a final decision is issued in the demand flexibility proceeding.

The focus of discussion in the final workshop was to highlight any further actions necessary to support this operational need.

**Discussion**

The discussion included:

- Concerns expressed by participants on the complexity of dynamic rates;
- Updates from Energy Division lead staff in the demand flexibility proceeding on different proposed approaches for distribution-level pricing;
- IOU representatives discussed current pilots related to dynamic pricing pilots and load management (see Appendix C: IOU Related Pilots for further detail on these pilots); and
- Potential impacts of spikes in distribution system demand just outside high price periods.

**Stakeholder Recommendations on IOU system upgrades to support dynamic rates**

- Participants suggested two approaches for managing potential for spikes in distribution system demand just outside high price periods:
    - LSEs can set distribution prices that are localized to different areas of the distribution system and reflect the distribution capacity in that area, or
    - The IOUs can use automated controls to limit demand when local infrastructure, such as a distribution transformer, is nearing a limit.

**Gridworks Recommended Next Steps on IOU system upgrades to support dynamic rates**

In April 2024, parties in the Demand Flexibility Proceeding (R.22-07-005) were asked to respond to a set of ruling questions regarding the proposals for dynamic pricing[72] and are currently filing comments with the Commission. In May 2024, the Energy Division issued a data request to each IOU to describe current and planned pilot projects related to the ten (10) categories of operational needs identified in the Future Grid Study Workshop series. Appendix C: IOU Related Pilots contains the data request(s) and responses from each utility. Topic #4 in the data request includes, "dynamic and real-time rates (e.g. CALFUSE)." Participants can review the proposed pilots on this topic in the utility responses.

Given these recent events to inform decision making on future dynamic rates, the IOUs should host semi-annual meetings to share results and lessons learned from their dynamic and real-time rate pilots. In sharing these pilot results, the IOUs should notice any meetings, workshops or webinars to both the Demand Flexibility Proceeding (R.22-07-005) and the High DER Proceeding (R. 21-06-017) to ensure all interested stakeholders have the opportunity to hear about results related to dynamic rates and provide feedback on any next steps.

The Demand Flexibility Proceeding will address establishing distribution prices and how load forecasts for distribution substations and/or circuits should be used to establish these prices. The High DER Proceeding (R. 21-06-017) can collaborate with the Demand Flexibility Proceeding, for example, to determine whether existing or upcoming distribution network management systems (e.g. the IOUs' SCADA or ADMS/DERMS systems) are capable of providing accurate load forecasts for distribution substations and/or circuits. These forecasts will inform the effort to establish distribution prices in the Demand Flexibility Proceeding.

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[72] See "ADMINISTRATIVE LAW JUDGE'S RULING ON TRACK B WORKING GROUP 1 PROPOSALS AND ISSUE 5," Issued in Rulemaking 22-07-005 on April 24, 2024.

## 3a. DER Visibility to DSOs

### Related Operational Needs

- DER Visibility to the Distribution System Operator
- Operational planning and analysis

In earlier workshops, multiple participants expressed that visibility into the status of and output from DERs is an important operational need for utilities in a High DER future. Some participants disagreed on the scope of visibility that was necessary for operators and the challenge of collecting this information at a highly granular level. In the survey sent out in preparation for Workshop #2, respondents ranked this operational need as both high importance and a near-term priority.

According to the IOUs' Grid Modernization Plans, each IOU already has visibility on real and reactive power output of individual DERs > 1 MW and into aggregated DERs (see Appendix A: Operational Needs Gap Assessment, Table A1). Each IOU plans to increase visibility at different levels of their distribution system in the next few years in the course of implementing their current Grid Modernization Plans.

Gridworks selected this topic for further discussion to confirm IOUs' expected capabilities with respect to this operational need and to identify any milestones that the CPUC should monitor.

### Discussion

This session started with discussion of the scope of visibility that the IOUs anticipate having once they have implemented their Grid Modernization Plans. Subsequently, IOU participants discussed their current visibility into DERs > 1MW and for aggregators. They also discussed the reporting that they provide to the CPUC on their progress on implementing their Grid Modernization Plans.

PG&E staff further described pilots they are planning related to vehicle to grid integration, virtual power plants, and grid edge computing. See Appendix C: IOU Related Pilots for additional detail on these pilots as well as similar pilots being conducted by SCE and SDG&E.

Another participant highlighted that more entities beyond the IOUs will be interacting with DERs. Specifically, non-IOU LSEs such as CCAs will likely be enrolling and controlling DERs, and data on DERs will need to be shared more broadly across market participants in California.

**Gridworks Recommended Next Steps on DER Visibility to DSOs**

The discussion in Workshop 3 and IOU responses in the Gap Analysis broadly indicate that each IOU expects to address DER visibility to the DSO through implementing their current Grid Modernization Plans. While implementing these plans, the IOUs will determine if additional disaggregation or granularity is needed. IOU representatives indicated that the utilities are not preparing for visibility into every DER in their distribution system.

The current Grid Modernization Progress Reports require each utility to update the Commission on progress with their Grid Modernization Activities, including grid management systems, communications and cybersecurity infrastructure, and engineering software and planning tools. Each IOU reports on implementing use cases related to DER visibility to the DSO in the section on grid management systems.

To continue monitoring progress with current planned use cases and identify any new use cases related to DER visibility, the IOUs should host semi-annual meetings to share their progress on:

- share their progress on implementing their planned use cases for enabling DER visibility,
- identify any new use cases for enabling DER visibility, and
- describe what additional functionalities are needed to support the newly identified use cases.

The IOUs should describe their next steps to implement those additional functionalities in annual written updates to their Grid Modernization Plans. Track 3 Phase 2 of the High DER Proceeding will address issues related to Grid Modernization Planning and could be an appropriate procedural home for further discussions to identify and plan for additional functionalities. Thus, the semi-annual meetings and the annual written updates to the Grid Modernization Plans could be hosted within Track 3 Phase 2, which would allow parties to participate in the meetings and comment on the annual updates.

### 3b. DER Visibility to CAISO

#### Related Operational Needs

- DER Visibility to the CAISO
- Reliability Coordination at the T-D interface
- Layered system architecture from bottom-up

In Workshop 1, representatives from the CAISO highlighted DER visibility as an important operational need, which was shared by some other participants. CAISO participants shared that the current platform for providing visibility on rooftop solar systems (Distributed Generation Statistics or DG Stats) is an important operational tool and they hope to expand this platform in the near-term to include other DERs. During the subsequent discussions, representatives from the IOUs asked about the scope of detail required for transmission operations and how to manage the confidentiality/security implications of sharing this information.

During Gridworks' gap analysis, this operational need appeared to have numerous unresolved questions from participants, which informed Gridworks' decision to include this topic for discussion in Workshop 3. In short, the CAISO identified this as an important operational need, and DSOs are collecting some of this information. However, there appears to be no consensus on the necessary level of data aggregation by location and end use or on how to manage confidentiality/security considerations in sharing this information.

Finally, in discussing the topic of visibility, participants also share concerns over the need for further dialogue on coordination on use of DERs by the CAISO and DSOs. As DERs continue to grow across each utility service territory, the opportunities for grid services at both the distribution- and transmission-level services also expand, but coordination is needed for DERs the deliver the services to operators as expected. For example, coordination is required to avoid DERs being called on by both operators simultaneously, or situations where local distribution conditions may prevent discharge of a DER to serve the transmission system. In review of participant feedback in Workshops 1 and 2, Gridworks also identified this area as a gap that needs to be addressed as DERs continue to grow throughout California.

#### Discussion

Staff from the CAISO started the discussion with an overview of how day-ahead and 15-minute load forecasts inform operational decisions. The CAISO currently has visibility into behind-the-meter ("BTM") solar but lacks information on other types of DERs. As these DERs continue to grow, the CAISO sees a need for aggregated information on other DERs similar to the information available for BTM solar. In this initial discussion, CAISO staff recommended a statewide data platform to share this information, similar to the existing DG Stats system. Some stakeholders that have advocated for a statewide data sharing platform agreed with the CAISO's recommendation. Other participants reiterated the importance of coordination between the transmission- and distribution-system operators on data sharing and operations.

#### Stakeholder Recommendations on DER Visibility to CAISO

- The CAISO can currently monitor behind-the-meter ("BTM") solar systems but lacks information on other types of DERs. As these DERs continue to grow, the CAISO sees a need for aggregated information on all DERs.
- The CPUC should establish a statewide DER Registry that provides a centralized and standardized repository for DER asset attributes, similar to the existing DG Stats system.

- Stakeholders emphasized the importance of coordination between transmission and distribution system operators for data sharing and operations.

**Gridworks Recommended Next Steps on DER Visibility to CAISO**

Based on the discussion in Workshop 3, further dialogue between the CAISO, DSOs, and interested parties could help answer open questions on the appropriate level of visibility/data sharing for CAISO operations. Furthermore, the discussion revealed that the gap on coordination between transmission and distribution operators on utilization of DERs for grid services could expand over time as DERs grow in scale and opportunity to provide grid services.

Gridworks recommends that the CPUC convene the CAISO, the IOUs, other LSEs and other interested stakeholders for a workshop series to discuss DER visibility to the CAISO. The CPUC should seek comments from stakeholders on the scope of the workshop series. Potential topics include:

- operational rules for sharing grid services across the transmission and distribution systems, and
- data needs at different nodes of the transmission and distribution systems.

## 4. Roadmap for Distribution-Level Grid Services from Flexible Load Energization

**Related Operational Needs**

- Operational planning and analysis
- Open access to the distribution system
- Animate distribution-level markets/granular pricing

Recent projections in California anticipate significant growth in electricity demand from EV charging, building electrification, and higher electricity demand from growing municipalities. Potential delays to energize these new customers are a significant concern and the CPUC has been investigating new methods for load management that would allow partial or variable load energization until distribution infrastructure could be upgraded.

Given the scale of new demand, flexible load energization could defer or even obviate the need for distribution infrastructure upgrades and/or enable DERs to reduce demand during contingency events.

This discussion topic engaged participants in this stepwise approach to first interconnect new customers/demand using innovative technology and then build broader grid services markets as customer demand reaches greater scale.

**Discussion**

Energy Division staff started the discussion by highlighting the importance of avoiding delays in energization requests for beneficial electrification, such as electric vehicle charging. In addition, they noted that future distribution-grid service opportunities may emerge as additional flexible loads are connected to the distribution system. After this initial discussion, staff from Cal Advocates reiterated support for this concept along with other meeting participants. Representatives from the IOUs discussed their pilot projects related to flexible energization and the volume of requests they are receiving for flexible load energization. Some IOUs are seeing an uptick in requests while others have not seen this growth/challenge yet. The IOUs provided details about these pilots in response to a data request from Energy Division. The IOUs' full data responses are provided in Appendix C: IOU Related Pilots.

The second section of the discussion focused on building distribution-level grid services markets. A set of participants proposed a statewide market platform for DER grid services, which would expand the set of market actors and encourage consistent approaches across IOU service territories. Some participants expressed support for this approach, while others questioned if the benefits would support the costs of establishing the platform. Some participants suggested alternative approaches may be possible where a large, sophisticated customer negotiates an agreement directly with other customers to share capacity on a constrained circuit and opportunities where dynamic pricing is complemented by agreements for capacity services. Representatives from the IOUs discussed that they expect load growth from transportation electrification, which could provide opportunities for grid services. However, Requests for Offer distribution deferral have been challenging and markets for operational flexibility remain nascent. Despite these challenges, identifying the opportunities for grid services from flexible loads earlier in the distribution planning process could improve the likelihood of success. Finally, IOU representatives expressed the importance of integrating grid service market opportunities into grid operations.

**Stakeholder Recommendations on Roadmap for Distribution-Level Grid Services from Flexible Load Energization**

- The CPUC should establish a statewide market platform for grid services from flexible load.
- The CPUC should establish firm import limits using a similar process to Limited Generation Profiles.
- The CPUC should modify energization rules to allow for the use of load management technologies and limited load profiles.
- The CPUC should simplify the number of limited load profiles based on current pilot results.
- The CPUC should review pilot results for flexible energization of customers on the same circuit and use those results to inform flexible energization rules.
- The IOUs should allow customers to negotiate agreements for sharing capacity on a constrained circuit with aggregators and/or other customers.
- The IOUs should establish dynamic hosting capacity.
- The IOUs should evaluate the opportunities for grid services from flexible loads earlier in the distribution planning process to develop operational flexibility.
- The IOUs should scale initial circuit-level dispatch programs building on pilot experiences.
- The IOUs should provide Load Serving Entities (LSEs) with better price signals to enable them to use flexible demand to lower forecasted peak loads.

**Gridworks Recommended Next Steps on Roadmap for Distribution-Level Grid Services from Flexible Load Energization**

Flexible energization is in scope in Track 3 Phase 1 of the High DER proceeding. The CPUC issued a Ruling in the High DER Proceeding on May 29, 2024 seeking Party comment on two SIOWG reports produced for Track 3 Phase 1: a report from the Smart Inverter Operationalization Working Group (SIOWG) and the Cybersecurity Working Group (SIO-CS).[73] A ruling correcting some formatting errors reissued the reports on June 5, 2024. Party comments were received on July 8, 2024 and reply comments were received on July 22, 2024, and the CPUC is working to develop a staff proposal based on these reports and party comments and reply comments.

Interested stakeholders should join the service lists for R.21-06-017 to stay apprised of proposals for flexible energization and opportunities to intervene.

To continue monitoring progress on flexible energization, the IOUs should host semi-annual meetings to share results and lessons learned from their flexible energization pilots. In sharing these pilot results, the IOUs should indicate what additional functionalities may be needed to fully implement flexible energization. The IOUs should describe their next steps to implement those additional functionalities in annual written updates to their Grid Modernization Plans.

The CPUC should also host a series of workshops or establish a working group to identify potential distribution-level grid services market opportunities (e.g. circuit-level peak shaving) and to develop pilot and/or implementation plans to advance those market opportunities. Building upon the recent work by the Smart Invertor Operationalization Working Group ("SIOWG"), pilots and/or implementation plans should aim to address:

- the market rules / rules for participation (including nondiscriminatory rules for dispatch and curtailment),
- compensation mechanisms (e.g. bilateral agreements, bill credits), and
- projected timelines for broad customer participation.

The CPUC should identify an appropriate venue for discussions regarding flexible energization and distribution-level grid services markets.

[73] Administrative Law Judge's Ruling Providing Two Working Group Reports and Directing Responses to Questions on Reports, May 29, 2024. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M532/K677/532677182.PDF.

## 5. Data Sharing in a High DER Future

**Related Operational Needs**

- DER Visibility to the CAISO
- Open access to the distribution system
- Animate distribution-level markets/granular pricing

The topic of data sharing has been discussed throughout the workshop series and multiple participants have proposed different methods for improving data sharing across different market actors (e.g. transmission and distribution operators, DER owners, customers, CCAs, and third-party aggregators). During the workshop series, there were diverging viewpoints on the level of data sharing that is necessary and the appropriate platforms to make the information available (common statewide system vs. utility specific). This session provided the opportunity to further discuss participants' recommendations on data sharing needs.

**Discussion**

A number of participants asked how this request interfaced with Phase 1 Track 2 (Expanding Data Use and Access) of the DER Customer Program Proceeding (R.22-11-013), which has launched a Data Working Group (DWG) to address specific questions.[74] Energy Division staff suggested that the DWG be the focus of data-related issues and if distribution grid data needs are not addressed in DWG then the High DER proceeding can identify other needs. A participant noted that the High DER proceeding is focused primarily on distribution grid data while the R.22-11-013 is focused on consumption data and program participation.

Several participants have advocated for a third-party, statewide data sharing platform throughout the workshop series and explained their reasons for this recommendation. Several parties concurred on the importance of this topic and urged near-term action by the CPUC to continue dialogue on how to improve data sharing while protecting private information.

**Stakeholder Recommendations on Data Sharing in a High DER Future**

- The IOUs should provide access to data on DERs to non-IOU LSEs
- The CPUC should establish a statewide DER Registry that provides a centralized and standardized repository for DER asset attributes, similar to the existing DG Stats system.

[74] See Assigned Commissioner's Ruling in R. 22-11-013 issued on December 1, 2023 at pp. 4-6. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M521/K134/521134386.PDF.

**Gridworks Recommended Next Steps on Data Sharing in a High DER Future**

The CPUC has launched the Data Working Group (DWG) in R.22-11-013 and extended the proceeding's timeline until December 31, 2025. The scope of the DWG is detailed in the Assigned Commissioner's Ruling from December 1, 2023[75] and appears to cover both distribution grid data and consumption data.

The proposed schedule of DWG meetings includes topics identified by participants in this workshop series and the DWG webpage enables stakeholders to submit use cases for which energy data sharing is relevant.[76] Interested stakeholders should participate in the DWG in R. 22-11-013.

## Additional Recommendations

In addition to the recommendations shared during Workshop 3, participants offered recommendations and topics for further discussion throughout Workshops 1 and 2. They are provided below.

**Stakeholder Recommendations**

- The CAISO should shift the day ahead market to 15 min settlement intervals. (UCAN)
- The IOUs should enable supplier consolidated billing. (UCAN)
- The CPUC should allow DERs < 5 MW to be allowed to be counted as load reducers for CCAs and ESPs, including for lowering peak demand for transmission cost allocation. (UCAN)
- The IOUs should work directly with inverter manufacturers to ensure better compliance with inverter ride through standards. (AEMO)
- The CPUC should form working groups or task forces to collaboratively identify responsibilities and operational needs to enable grid orchestration. (IOUs)
- The CPUC, IOUs and stakeholders should develop and learn from pilots to inform regulatory framework. (IOUs)
- The CPUC should lead a process to develop and implement flexible import limits, following-on the work of the SIOWG. (Cal Advocates)
- To advance progress towards a High DER Future, the CPUC should start by looking at the five nearest term programs or functions that the utilities would like to roll out and determine the technical requirement for those options. (California Solar & Storage Association)

[75] See Assigned Commissioner's Ruling in R. 22-11-013 issued on December 1, 2023 at pp. 4-6. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M521/K134/521134386.PDF.
[76] See workshop schedule and proposed topics on the LARC DER Data Access Working Group webpage (https://www.laregionalcollaborative.com/data-working-group/#schedule)

## Other Relevant CPUC Proceedings

The table below provides an overview of other proceedings at the CPUC where issues related to a High DER Future are being addressed. This table is intended to support stakeholders in tracking relevant discussions occurring outside of R.21-06-017, Track 2.

**Table 2: List of other proceedings addressing topics relevant to proceeding R.21-06-017.**

| **Proceeding** | **Relevant Topics** |
|---|---|
| High DER<br>(R.21-06-017) | • Track 1: Staff Report re: ICA and Data Portal Improvements<br>• Track 3: SIOWG Report re: firm and non-firm export & import limits |
| Interconnection<br>(R.17-07-007) | Rule 21, firm export limits (Limited Generation Profiles) |
| Energization Timelines<br>(R.24-01-018) | Timely energization of electric service |
| Transportation Electrification<br>(R.23-12-008) | Transportation electrification |
| Demand Flexibility Through Electric Rates<br>(R.22-07-005) | California Flexible Unified Signal for Energy (CalFUSE) framework, SCE and PG&E CalFUSE pilots |
| DER Customer Program Proceeding<br>(R.22-11-013) | DER Data Access and Use Working Groups (Pending formation) |
| Microgrids<br>(R.19-09-009) | Coordinate on rules and eligibility for DERs within microgrids |

# CONCLUSION

The Future Grid Study workshop series drew a broad spectrum of participants, representing regulators, utilities, grid operators, CCAs, consumer advocates, DER providers, environmental advocates, researchers and others, both inside and outside of California. Collectively, this group discussed their visions for a High DER Future and identified the operational needs to achieve that future.

The IOUs are already addressing many of these operational needs through their Grid Modernization Plans, and many others are under discussion in various venues at the Commission. However, some uncertainties and gaps remain, including:

- **Proposed future capabilities depend on the IOUs' progress in implementing their Grid Modernization Plans.** Therefore, it is unclear when the IOUs will fulfill the operational needs identified in Workshop 1.
- **Significant gaps appear in the operational interface between the CAISO and DSOs.** The discussions in Workshop 1 indicate that the CAISO has an important role in a High DER Future, and that the CAISO and DSOs need to better coordinate on data sharing and DER participation in grid services markets.
- **The pace of developing grid services markets appears to be falling behind DER adoption.** A gap on this operational need can result in lost opportunities to build the future distribution grid at lower cost, to improve community resilience, to stimulate local economic development, and to address equity.
- **Diverging visions of the High DER Future.** One version envisions the DSOs as the "conductors" in grid orchestration of DERs. The other envisions a bottom-up, open-access High DER Future. Each vision implies some differences in operational needs, which may or may not be supported by the IOUs' near-term plans.
- **Data sharing and transparency in DER interconnection remain friction points.** Several stakeholders have identified data sharing as a current limitation to broad participation in a High DER Future.

Throughout the workshop series, stakeholders offered recommendations for addressing the gaps in preparing the electric grid for a High DER Future. The recommendations are tagged to individual operational needs, but in some cases may address more than one operational need.

**Table 3: Table of Stakeholder recommendations for each operational need.**

| Operational Need | Stakeholder Recommendation |
|---|---|
| DER Visibility to CAISO | *Workshop 3 Topic 3b – DER Visibility to CAISO*<br>• The CAISO can currently monitor behind-the-meter ("BTM") solar systems but lacks information on other types of DERs. As these DERs continue to grow, the CAISO sees a need for aggregated information on all DERs.<br>• Stakeholders emphasized the importance of coordination between transmission and distribution system operators for data sharing and operations.<br>*Workshop 3 Topic 5 – Data Sharing in a High DER Future* |

| Operational Need | Stakeholder Recommendation |
| --- | --- |
| | • The CPUC should establish a statewide DER Registry that provides a centralized and standardized repository for DER asset attributes, similar to the existing DG Stats system. |
| DER dispatchability/control | *Workshop 3 Topic 2 – Scoping of IOU system upgrades to support dynamic rates*<br>• Participants suggested two approaches for managing potential for spikes in distribution system demand just outside high price periods:<br>  o LSEs can set distribution prices that are localized to different areas of the distribution system and reflect the distribution capacity in that area, or<br>  o The IOUs can use automated controls to limit demand when local infrastructure, such as a distribution transformer, is nearing a limit.<br>• The IOUs should scale initial circuit-level dispatch programs building on pilot experiences. |
| Operational Planning & Analysis | *Workshop 3 Topic 4 – Roadmap for Distribution-Level Grid Services from Flexible Load Energization*<br>• The IOUs should evaluate the opportunities for grid services from flexible loads earlier in the distribution planning process to develop operational flexibility. |
| Reliability Coordination at Transmission-Distribution interface | *Workshop 3 Topic 5 – Data Sharing in a High DER Future*<br>• The CPUC should establish a statewide DER Registry that provides a centralized and standardized repository for DER asset attributes, similar to the existing DG Stats system. |
| DER Technical Performance Standards | *Additional Recommendations – Workshop 1*<br>• The IOUs should work directly with inverter manufacturers to ensure better compliance with inverter ride through standards. (Jenny Riesz, AEMO) |
| Open access to the distribution system | *Workshop 3 Topic 1 – Implementation of Flexible Generation Interconnection*<br>• An independent 3rd party should provide oversight to ensure usability and accuracy of Integration Capacity Analyses.<br>• The CPUC should obtain additional support to ensure Staff have the technical expertise to provide oversight of the ICAs.<br>*Workshop 3 Topic 4 – Roadmap for Distribution-Level Grid Services from Flexible Load Energization*<br>• The CPUC should establish firm import limits using a similar process to Limited Generation Profiles.<br>• The CPUC should modify energization rules to allow for the use of load management technologies and limited load profiles.<br>• The CPUC should determine the number of limited load profiles based on current pilot results. |

| Operational Need | Stakeholder Recommendation |
|---|---|
| | • The CPUC should review pilot results for flexible energization of customers on the same circuit and use those results to inform flexible energization rules.<br>• The IOUs should explore allowing customers to negotiate agreements for sharing capacity on a constrained circuit with aggregators and/or other customers.<br>• The IOUs should explore establishing dynamic hosting capacity.<br>*Workshop 3 Topic 5 – Data Sharing in a High DER Future*<br>• The IOUs should provide access to data on DERs to non-IOU LSEs<br>• The CPUC should establish a statewide DER Registry that provides a centralized and standardized repository for DER asset attributes, similar to the existing DG Stats system.<br>*Additional Recommendations – Workshop 2*<br>• The CPUC should lead a process to develop and implement flexible import limits, following-on the work of the SIOWG. (Amin Younes, Cal Advocates) |
| Animate distribution-level markets/granular pricing | *Workshop 3 Topic 4 – Roadmap for Distribution-Level Grid Services from Flexible Load Energization*<br>• The IOUs should provide Load Serving Entities (LSEs) with better price signals to enable them to use flexible demand to lower forecasted peak loads.<br>• The CPUC should establish a statewide market platform for grid services from flexible load.<br>*Additional Recommendations – Workshop 1*<br>• The CAISO should shift the day ahead market to 15 min settlement intervals. (UCAN)<br>• The IOUs should enable supplier consolidated billing. (UCAN)<br>• The CPUC should allow DERs < 5 MW to be allowed to be counted as load reducers for CCAs and ESPs, including for lowering peak demand for transmission cost allocation. (UCAN) |

**Process Recommendations:** In addition to recommendations for addressing gaps in operational needs, participants also offered some process recommendations for addressing open questions.

*Additional Recommendations – Workshop 2*

- The CPUC should form working groups or task forces to collaboratively identify responsibilities and operational needs to enable grid orchestration. (IOUs)
- The CPUC, IOUs and stakeholders should develop and learn from pilots to inform regulatory framework. (IOUs)
- To advance progress towards a High DER Future, the CPUC should start by looking at the five nearest term programs or functions that the utilities would like to roll out and

| Operational Need | Stakeholder Recommendation |
| --- | --- |
| | determine the technical requirement for those options. (Brad Heavner, California Solar & Storage Association) |

The Future Grid Study workshop series emphasized the breadth and depth of work that must be done to enable a High DER Future. Continued collaboration amongst the Commission, utilities and stakeholders will be required to further explore and implement the operational needs and recommendations identified above, in order to "efficiently operate a high DER grid, unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives.

# APPENDICES

# APPENDIX A: OPERATIONAL NEEDS GAP ASSESSMENT

Following Workshop 2, Gridworks analyzed how the IOUs' Grid Modernization Plans would support the various operational needs identified in Workshop 1. To complete this gap assessment, Gridworks reviewed the presentations and discussion from Workshop 2, reviewed each IOUs' most recent Grid Modernization Progress Report (see Appendix B: IOU Grid Modernization Progress Reports), and met with the IOUs to gather additional detail and clarifications. In reviewing those materials, Gridworks looked to answer three different questions:

1. What is each IOU's expected operational capabilities (in 2024) in relation to the identified operational need?
2. What would be each IOU's operational capabilities if their grid modernization plans were to be fully implemented?
3. Are there any remaining gaps in operational capabilities after accounting for all planned grid modernizations?

Each of the tables below describes the current and expected capabilities for an operational need and describes any remaining gap in addressing the given operational need.

## Table A1: DER Visibility to Distribution System Operator

| Operational Need | Expected Capability in 2024 | Expected Capability with Grid Mod Plans Fully Implemented*<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Real-time awareness of DER status and output<br>○ Improve reliability through better understanding of current grid conditions | **All IOUs** - Enabled for 2024 for DER > 1MW.<br><br>**PG&E** - Situational awareness for initial microgrid locations and DERs participating in capacity use cases. Situational awareness includes topographical visibility in Network Management System; ability to isolate CAISO DER via SCADA switch if operational emergency calls for it.<br><br>**SDG&E** - SDG&E communicates limits to DER Aggregators as part of the interconnection agreement. Telemetry is required at the Point of Interconnection for all systems >1 MW, per Rule 21; data collected is just watts/vars. SDG&E can curtail by opening a SCADA switch if necessary in an emergency situation. SDG&E In-flight project, PIVA: Photovoltaic Integration over Virtual Airgap, to quantify "True Load". | **SCE** - 24h forecasting (true planned schedule, not just limits) planned for second round of ADMS (DSO-->DER)<br><br>**PG&E** - next step (10 pilot sites, e.g. large EV charging) is to communicate load limits day ahead (crawl), looking to scale across territory (walk/run -- scale flexible service connection for EV charging & then enable this capability for other use cases), part of early capability might mean that some DERs can operate flexibly but others may not, pilots will inform new questions, some use cases may work out better than others (pilots occurring over the next few years). SDGE- DERMS will bring our next phase of real time awareness of status and output of DER. In the meantime, we have DSO | **PG&E** - as they roll out DERMS and different use cases, there are questions re: how DERMS works with different customer classes.<br><br>**SDG&E** - questions remain on what level of granularity is most beneficial for each asset type and scale. For example, requirements for >1MW DER would differ from behind-the-meter assets including PV and EVs. |

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| | | visibility of telemetry, location, and charge limits. | |
| • Mutual sharing of DER schedules, operations, constraints | **SCE** - Base DER management for generation enabled. Current capability is DERMS, next iteration of capabilities will come with ADMS. SCE currently does not share DER schedules with CAISO. SCE does share schedules (limits of the next 8 hours) with DER Aggregators, (1MW limit does not apply to aggregators), SCE receives confirmation from Aggregators of DER settings and actual performance, two-way communications with Aggregators via ieee 2030.5. SCE does not currently share DER Schedules beyond SCE and the DER itself or the DER aggregator.<br><br>**PG&E** - Field test <10 sites to manage capacity constrained customer sites through the control of flexible loads and operationalize PG&E's first Distribution Investment Deferral Framework (DIDF) project. PG&E has the ability to set limits, manually communicate with DER, | **SCE** - Microgrid management (2027-2028) - pilot involves ADMS for microgrids, depending on how that works will scale from there, understand what sort of control customers are willing to give up. SCE - 24h forecasting (true planned schedule, not just limits) planned for second round of ADMS (DSO-->DER)<br><br>**PG&E** - plans to scale DERMs capabilities to entire system after pilots. Next step (10 pilot sites, e.g. large EV charging) is to communicate load limits day ahead (crawl), looking to scale across territory (walk/run -- scale flexible service connection for EV charging & then enable this capability for other use cases), part of early capability might mean that some DERs can operate flexibly but others may not, | **SCE** - Expanded load management planned after 2028. Load management included ability to continuously manage load, including load from EV charging. This capability will include indirect load control through aggregators or other third parties, direct load control, where appropriate, and it will also support customer demand flexibility through delivery of price signals to customer devices.<br><br>**PG&E** - DERMs evolves to automate optimization at hyper-local level. Majority of DERMS focused at bulk system level for generation, need to determine if they can take a signal from a distribution telemetry point then use DERMS to dispatch DERS to serve a more hyper local need. PG&E - as they roll out DERMS for different use cases, there are questions on how DERMS can |

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| | remote operation (open the relay) if need be for emergency or performance issue. PG&E only shares information between utility and DER owner operator or aggregator.<br><br>**SDG&E** - For DERs >1MW there is control center visibility of static charge limits. SDG&E communicates limits to DER Aggregators, Aggregators agree/confirm limits, SDG&E can curtail if necessary in an emergency situation. | pilots will inform new questions, some use cases may work out better than others (pilots occurring over the next few years).<br><br>**SDG&E** - planning to procure and implement DERMs system; plans to pilot use cases in GRC application. | work with different customer classes<br><br>**SDG&E** - need feedback on expected future use cases. |
| • Real-time monitoring and automated grid control enabled by intelligent sensors, switches, protection, communication devices<br>○ Improve reliability through faster response to emergencies and changing grid conditions and<br>○ Enable more granular ability to re-configure the distribution grid to | **SCE** - implementing adv. grid mgmt. functions - advanced network analysis, assisted switching, enhanced Volt-Var control.<br><br>**PG&E** - Implementing SCADA , OMS, and Enhanced Power Safety Settings (EPSS) applications in ADMS across service territory.<br><br>**SDG&E** - DER-Aware NMS today and future plans for DER-Aware ADMS. Local Area Distribution Controllers (LADC) deployed at our internally owned DER locations to optimize | **SCE- I**mplementing next gen integration of ADMS-DERMs.<br><br>**PG&E** - ADMS release 3 includes advanced management applications for line sensors and load flow/state estimation.<br><br>**SDG&E** - further implement and refine advanced applications such as Volt/Var Optimization ("VVO"), Fault Isolation and Service Restoration ("FLISR"), | **SCE** - Phase 4 of Grid Platform identifies power quality management and substation device management capabilities.<br><br>**PG&E** - **I**dentifying needs for DERMs to optimize at hyper local level.<br><br>**SDG&E** - integrate DERMs with ADMS applications. |

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| re-route power during abnormal conditions | DER assets within an electric microgrid environment. | Fault Location ("FL") and day ahead forecasting. | |

## Table A2: DER Visibility to CAISO

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Coordinated visibility of specific DER information to understand and anticipate their impacts on grid operations<br>○ technology type, location, size, operational behavior and performance<br>○ at various granularities (aggregated and/or device level) | **SCE** - Capabilities being built for 1MW and above of DER data. SCE identifies this operational need as a gap and does not support DER Visibility at the device level, only aggregated up to the substation.<br><br>**PG&E** - Market participants notify CAISO in the event of local dispatch via modification of bids. From utility modeling, planning, and ops perspective, external visibility OK limited to substation. Information is internal only, potentially sensitive information.<br><br>**SDG&E** - Requests to attach and permission to operate per an interconnection agreement which includes safety and reliability requirements (SCADA Isolation Switch, Telemetry, Anti-Islanding, Charging/Discharging Parameters, Ramp Rates). | **SCE** - DER Schedules, Operations, Constraints (2026-2027).<br><br>**PG&E and SDG&E** - additional near-term capabilities unclear from presentation. | Gap #1 - IOU responses in 4/15 session indicate that DSOs are uncertain about the level of disaggregated data that CAISO is seeking. SCE identifies this operational need as a gap and does not support DER Visibility at the device level, only aggregated up to the substation. PG&E: Remaining gap is having an integrated view of what DER's are downstream of a constraint, how they can or are intended to be used, what programs they are enrolled in to call for action, what aggregator is operating and for what kind of signal response. how can that visibility be stacked for different grid needs- if we had visibility, we could develop an escalation of priorities and values. We have data sets but don't have aggregated in one visual management tool to be used for planning and operations. |

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| | | | Gap #2 - Increasing level of coordination required when DERs providing services to bulk power and distribution systems. Multiple questions remain unresolved in this area.<br><br>Proposed as topic of discussion in Workshop #3. |
| • Need enhanced data collection, access, and reporting:<br>○ For planning and forecasting processes to improve grid asset utilization;<br>○ short term load forecasting accuracy; and<br>○ ISO market optimization and dispatch. | **PG&E and SDG&E** - implementing short-term DER forecasting.<br><br>**SDG&E** - Currently still in development of pilot scope. This is a research project evaluating and leveraging our day-ahead forecasting tools. | **SCE** implementing short-term DER forecasting | See comments above. Coordination between IOUs and CAISO on sharing forecasts appears to be a gap. |
| | The data access issue is currently being addressed in Track 1 of R.21-06-017 (High DER proceeding). The staff proposal will include recommendations to address this issue and improve forecasting methods. | | |

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| | Although there may be some overlap with R.22-11-013 (the proceeding covering Distributed Energy Resource (DER) program cost-effectiveness, data access and use, and equipment performance standards), the High DER proceeding is at a more advanced stage and will provide recommendations on data access sooner. | | |
| • Situational awareness of both market participating and non-participating DERs is critical for CAISO operations<br>○ Understanding the impact of all types of DERs under various uses is critical to situational awareness and reliability<br>▪ expect transportation electrification to present greater complexity | See above. DSOs implementing situational awareness for DERs > 1 MW.<br><br>**PG&E** - DERs inform CAISO in event of local dispatch.<br><br>**SDG&E** - for all distribution-connected DERs that participate in the CAISO market, CAISO-required telemetry is available through the CAISO Remote Intelligence Gateway (RIG). | Appears to be basic level of coordination but next steps require further discussion. | Advanced level of coordination appears to be a gap.<br><br>**SCE** - further details on CAISO current API are required to determine ability to share information. |
| • Mutual sharing of DER schedules, operations, constraints<br>○ Enable multiple uses, avoid operational conflicts. Eventually, enable market coordination. | See above. DSOs implementing initial applications of this capability. Questions remain on appropriate level of data aggregation. | Appears to be basic level of coordination but next steps require further discussion. | Advanced level of coordination appears to be a gap.<br><br>**SCE** - Clarification needed on scale and scope of this request, and driver and necessity, including type and size of DERs.<br><br>**PG&E** - This comes into play when DER's are serving grid purposes other than bulk system. |

## Table A3: DER dispatchability/control

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Signal participating DERs to provide output at specified time (day-ahead and real time) | IOUs currently implementing base functionality | Dispatchability capabilities expected to improve under Grid Mod Plans. | Long-term IOU plans are unclear on level of dispatchability. Progress will depend on results from current pilots. |
| • Progressively integrate DERs into scheduling and dispatch | See above. IOU's currently implement scheduling/dispatch for limited applications | Dispatchability capabilities expected to improve under Grid Mod Plans. | Long-term IOU plans are unclear on details of DER integration. Generally refer DER optimization. |
| • Develop emergency backstop capability (curtailment) | **SCE** - Confirms that emergency backstop is a current capability.<br><br>**PG&E** - GAP: DER dispatch for grid needs will vary based on Dx, sub, Tx, G. Performance reliability is a key issue and requires backstops as down stream number of DER's vary or MW need increases. More of an issue at Dx and sm. Tx. | Does not appear in IOUs Grid Mod Plans | **PG&E** - Confirms this is a current gap. DER dispatch for grid needs will vary based on Dx, sub, Tx, G. Performance reliability is a key issue and requires backstops as down stream number of DER's decrease. Dx requires more firm with contingency planning, Substation has slightly more usable service points, Tx has more but load need is higher, bulk system is large aggregation and less affected by performance deficiencies. |
| • Fast, secure and private communications infrastructure | All IOUs upgrading private communications infrastructure. Details provided in Grid Modernization Progress reports. | Network capabilities expected to improve under Grid Modernization Plans | Unclear from IOU presentation/progress reports if a gap exists for communications infrastructure |

| **Operational Need** | **Expected Capability in 2024** | **Expected Capability with Grid Mod Plans Fully Implemented*** *not all components of the IOUs' grid modernization plans have been approved, funded and implemented | **Remaining Gap** |
|---|---|---|---|
| | **SCE** - Capability in place for a fast, secure and public communication, with a secure tunnel between the DER and SCE. | | |
| • Software optimization platforms to support dispatchability (multiple levels) | **SCE** - implementing ADMS release 1.<br><br>**PG&E** - implementing ADMS and Base DERMs.<br><br>**SDG&E** - proposed enhancements to ADMS. | IOU capabilities expected to improve with Grid Mod plans. All IOUs expecting to expand ADMS and DERMs capabilities. | IOU presentations identify that some future DER enablement functions will need to be clarified in current proceedings but indicate that software systems can support High DER expectations.<br><br>**PG&E** - Confirms this is a gap. Need software integration for modeling during planning infrastructure to integrate DER's into mitigated load shaping. This requires visibility into downstream DER's and power flow modeling integration (some vendor software has capabilities). |
| • A communications platform and information sharing framework used to advise appropriate entities, in the appropriate timeframe, the status and feasibility of DER activity in relation to grid operations and reliability. | See above. All IOUs implementing DER software platforms. | All IOUs expecting to expand ADMS and DERMs capabilities. | Functions will need to be clarified in current proceedings but indicate that software systems can support High DER expectations. Defining the information sharing framework is a gap. |

## Table A4: Operational planning and analysis

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Increase granularity of DER forecasts to utilize in operational timeframes | **SCE** - not in scope for 2024.<br>PG&E - short-term forecasting at targeted grid constrained locations where SCADA is available.<br><br>**SDG&E** - short-term forecasting is available and being evaluated with distribution system model. | **SCE** - implementing short-term forecasting in 2026-2027.<br><br>**PG&E and SDG&E** - future forecasting plans not included in joint presentation. | Unclear if gap exists after IOUs implement current Grid Mod plans |
| • Analyze High DER grid conditions to identify potential reliability risks | All IOUs implementing base ADMS functionality to support more advanced power flow analysis/DER integration | All IOUs implementing ADMS, DERMs in Grid Mod Plans | Unclear if gap exists after IOUs implement current Grid Mod plans. PG&E preparing for a high electrification impact study |
| • Optimize use of grid assets based on DER forecasts to provide maximum value | All IOUs implementing base ADMS functionality to support advanced optimization | IOUs propose to implement grid optimization with ADMS/DERMs systems | Unclear if gap exists after IOUs implement current Grid Mod plans.<br><br>**PG&E** - Pilots will need to be conducted to provide the basis of load shaping at various levels that can provide system efficiencies. |
| • Maintain operating reserves to control the supply/demand balance and to meet reliability standards | Not addressed in workshop #2 presentations | IOUs propose to implement grid optimization with ADMS/DERMs systems | Unclear if gap exists after IOUs implement current Grid Mod plans |

## Table A5: Reliability Coordination at Transmission-Distribution interface

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Coordinate operation of DERs providing services to distribution and bulk electric systems | **PG&E** - Market participants notify CAISO in the event of local dispatch via modification of bids.<br><br>**SDG&E** - Requests to attach and permission to operate per an interconnection agreement which includes safety and reliability requirements (SCADA Isolation Switch, Telemetry, Anti-Islanding, Charging/Discharging Parameters, Ramp Rates)<br><br>**SCE** - ADMS is doing the coordination part of this capability (for Distribution). Outside of the Distribution system will be longer to implement, have to wait until EMS is fully integrated into ADMS, currently not doing any coordination between distribution and bulk system. | **SCE** - Identifies implementing DER Schedules, Operations, Constraints with CAISO (2026-2027). | See above. CAISO presentation in Workshop #1 and feedback from DSOs indicates this is a gap. Further coordination needed as DERs provide grid services for distribution-level and bulk power markets.<br><br>**SCE** - Further definition needed on voltage class for bulk system. |
| • Communications and information sharing to support coordination of DERs across distribution and bulk electric systems | **SCE** - ADMS is doing the coordination part of this capability (for Distribution). Outside of the Distribution system will be longer to implement, have to wait until EMS is fully integrated into ADMS, currently | See above - level of communications/information sharing is unclear | See above. CAISO presentation in Workshop #1 and feedback from DSOs indicates this is a gap. Further coordination needed as DERs provide grid services for |

| **Operational Need** | **Expected Capability in 2024** | **Expected Capability with Grid Mod Plans Fully Implemented*** *not all components of the IOUs' grid modernization plans have been approved, funded and implemented | **Remaining Gap** |
|---|---|---|---|
| | not doing any coordination between distribution and bulk system. | | distribution-level and bulk power markets.<br><br>**SCE**: Further definition needed on voltage class for bulk system. |
| • Framework to coordinate operation of DER resources when they are providing services to the distribution system or to the bulk electric system to ensure the feasibility of those services and preserve reliability. | **SCE** - ADMS is doing the coordination part of this capability (for Distribution).Outside of the Distribution system will be longer to implement, have to wait until EMS is fully integrated into ADMS, currently not doing any coordination between distribution and bulk system. | | Joint IOU presentation state that a policy gap exists for common framework(s) for wholesale market participation. SCE: Further definition needed on voltage class for bulk system. |

## Table A6: DER Technical Performance Standards

| Operational Need | Expected Capability in 2024 | Expected Capability with Grid Mod Plans Fully Implemented*<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Develop inverter ride through standards to support High DER grid | Current inverter standards in place; SIOWG working group report published; staff proposal released | IOUs implementing support for flexible interconnection | Not apparent if gap exists |
| • Implement measures to ensure broad compliance with inverter standards | No workshop material has addressed levels of compliance | | May need to confirm if a gap exists with compliance |

## Table A7: Cybersecurity

| Operational Need | Expected Capability in 2024 | Expected Capability with Grid Mod Plans Fully Implemented*<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Growing concern with high levels of DER | IOU Grid Modernization Progress reports describe current cybersecurity efforts.<br><br>**SCE** - progress slightly delayed but largely on track. Delayed in build out of architecture of cybersecurity systems but dedicated team from IT working on build out. | IOUs propose cybersecurity improvements with ADMS and DERMs platforms | Would require separate review to understand if any gaps exist. CPUC will continue to monitor with progress reports on Grid Mod plans. |
| | Currently under discussion in Rulemaking 21-06-017, "Modernize the Electric Grid for a High Distributed Energy Resources Future": Track 3 Phase 1 SIOCS working group report published. Cell merged since the plan has short term (1 -3 years) and long terms (5 -10year) | | |

## Table A8: Open Access to Distribution System

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented*** *not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Improve, simplify interconnection agreements and process | Flexible interconnection process under development.<br><br>**PG&E** - identifies flexible service connection in 2023/2024 scope for ADMS.<br><br>**SD&GE**- Rule 21 and WDAT generator interconnection processes in place. LGP to provide some hourly operating flexibility. SDG&E does not have need for flexible load interconnection process -- distribution upgrade requirements not delaying ability to interconnect new load. | Unclear how SCE future software updates would support flexible interconnection. SDGE - Not identified as a gap at this time in SDG&E's service territory. | Need to confirm if gap exists after implementing current Grid Mod Plans. **Flexible Interconnection proposed as topic of discussion in Workshop #3.** |
| • Treat DERs and loads in a microgrid in an equivalent manner as DERs and loads outside of microgrids | IOUs implementing systems to integrate microgrids.<br><br>**SDG&E** - Supporting the microgrid OIR and associated projects. | Capabilities to manage microgrids expected to improve with Grid Mod Plans. | Improvements limited to certain sizes, specified locations. Appears to be a gap in supporting microgrids throughout service territories. |
| • Meet expected demand for transportation electrification while minimizing infrastructure upgrades | Flexible interconnection proposed to support TE. | IOU responses that progress will depend on results from pilots. SDGE - Experience with community-initiated microgrids may identify needed capabilities, including communication and | **Flexible load energization proposed as topic of discussion in Workshop #3.** |

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| | | automation. Reference: Microgrid OIR. | |
| • Improve opportunities for DERs to avoid/defer infrastructure upgrades | Limited mechanisms for capacity deferral. SDG&E - already supports capacity deferral programs and projects primarily through DIDF process to the extent that that scales, the operationalization will be further enabled SDG&Es plans related to a DERMS. | **SDG&E** - Interconnected DERs contribute to distribution optimization and capacity project deferral (shifting and ultimately reducing peak load) due to planning process capacity studies using peak loads. SDG&E's Grid Mod provides the technology tools to allows us to interconnect active DER technologies safely, whereas our current system is limited to passive DERs at scale. | **Future grid services from flexible load proposed as topic of discussion in Workshop #3.** |
| • Utilize dynamic distribution prices to delay/reduce distribution system upgrades | Demand flexibility proceeding underway | IOU presentations indicate future programming related to this needs | **Future support for dynamic pricing proposed as topic of discussion in Workshop #3.** PG&E: This requires a process to deliberate the best way to approach. Distribution system upgrades require a specific mix of firm resources that may or may not react in the best reliable way in a pricing market. A variable price suggests a non-firm structure which will create multiple layers of predictability issues. |

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Fully implement an open-access distribution network & transactive distribution-level markets | | | |
| ○ Define grid services DERs can economically provide | Limited capability currently | DERMs system expected to support capacity deferral DERs. SDGE - DERMS will support dispatchability of a limited number of larger DERs to ensure distribution reliability and accommodate passive DER dispatch of many smaller DERs (customer-determined value proposition). | **Future grid services from flexible load proposed as topic of discussion in Workshop #3.** |
| ▪ E.g., compensate DERs & Aggregators for flattening circuit-level peaks (load & supply "ducklings") to increase hosting capacity without upgrading circuits | | | **SDG&E** - Additional compensation and revenue streams are dependent on more and dynamic pricing and rate structures, which should be determined first to inform the additional technology needed. |
| ○ Conduct non-discriminatory procedures for procuring, dispatching & compensating DERs | IOUs implementing DER scheduling in current Grid Mod plans | Dispatchability improvements planned in Grid Mod. Pilots underway with more advanced dispatchability. | Future grid services from flexible load proposed as topic of discussion in Workshop #3. |

| **Operational Need** | **Expected Capability in 2024** | **Expected Capability with Grid Mod Plans Fully Implemented*** *not all components of the IOUs' grid modernization plans have been approved, funded and implemented | **Remaining Gap** |
|---|---|---|---|
| ▪ Develop Market mechanisms that receive & clear bids (day-ahead & day-of) linked to current distribution system conditions & transmit results to participants | See above discussion on DER scheduling. Initial functionality implemented by IOUs currently | Functionality expected to improve with Grid Mod plans. SDGE - With the execution of Grid Modernization plan day-ahead load forecasting can be executed. | Gap appears to exist to support this level of market for distribution-level grid services. **Initial step proposed for Workshop #3.**<br><br>**SD&GE** - Additional compensation and revenue streams are dependent on more and dynamic pricing and rate structures, which should be determined first to inform the additional technology needed. |
| ▪ Establish real-time communication with participating DERs | Initial capabilities implemented for DER > 1MW including aggregators. | | **Future grid services from flexible load proposed as topic of discussion in Workshop #3.** |
| ▪ Conduct solicitations for longer-term grid services contracts<br>▪ Accurately measure DER grid service performance & perform settlement | | | **Future grid services from flexible load proposed as topic of discussion in Workshop #3.** |
| • Integrate DER grid services into distribution network planning | Not addressed in workshop presentations. Grid Mod Progress reports identify proposed improvements to Integration Capacity Analysis. | | Unclear if gap exists. DER planning was not a focus for workshops. |

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented*** <br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Provide up-to-date network information to local governments, tribes, LSEs, DER developers & CBOs seeking to plan & deploy DERs | Broad range of stakeholders have expressed data sharing as limited | | Gap appears to exist in current level of information sharing and stakeholder expectations. **Data sharing proposed as topic of discussion in Workshop #3.** |
| • Interfaces to manage bulk system impacts of DER activities | Coordination, information sharing is currently limited | DSOs plan improvements to DER visibility and forecasting but unclear how these will be coordinated with CAISO. | See above discussion on Reliability Coordination at T-D Interface |
| ○ Clear DSO markets in time to provide accurate forecast to CAISO DA & RT markets on expected net flows across T-D interfaces <br>○ Transmit customer meter data & current distribution system conditions to LSEs to support their CAISO bidding & scheduling | | | See above discussion on Visibility to CAISO. **Proposed as topic of discussion in Workshop #3.** |
| ○ Support direct DER participation in CAISO markets through timely provision of current system conditions & non-discriminatory curtailment procedures | **SDG&E** - DER participation in CAISO markets is already allowed. Need to engage CAISO related to additional wholesale market opportunities, before determining additional system requirements. | | See above discussion on Visibility to CAISO. **Proposed as topic of discussion in Workshop #3.** |

### Table A9: Layered system architecture from bottom-up

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Distribution-system architecture built from bottom up from within homes to the ISO level | Current distribution systems generally developed with a traditional "one-way" power flow architecture | Current IOU Grid Mod Plans expected to support increased DER levels. IOUs identify gaps in future pricing and distribution-level grid services. | Gaps appear to exist between expected improvements and Grid Mod plans ability to fully support "bottom up" architecture. **Initial steps proposed for discussion in workshop #3 with future grid services from flexible load.** |
| • Efficiently operate a High DER grid:<br>○ Efficient operation requires semi-optimal utilization of all available distributed energy resources<br>○ Utilization requires having enabling systems in place, i.e. any available means for DER to receive and respond to information with *reasonable* timeliness and *sufficient* certainty<br>○ Coordination of individual DER should include layered aggregation<br>○ *Efficient* operation means least net cost | Initial steps underway with development and integration of ADMS/DERMs systems | IOU Grid Mod plans anticipate improvements. Will depend on progress of implementing plans. | Gap appears in the expected timelines to achieve this level of DER utilization (IOU presentation suggests this as long-term objective) |

| **Operational Need** | **Expected Capability in 2024** | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | **Remaining Gap** |
|---|---|---|---|
| • Unlock economic opportunities for DERs to provide grid services:<br>○ Smart Inverter Operationalization Working Group (SIOWG)<br>▪ focused on utilization of existing advanced inverter functionalities<br>▪ identified numerous high priority use cases and business cases<br>▪ based on technological readiness, cost, scale, and timeline | Working group report released | Level of progress will depend on timelines for decisions and implementation by IOUs | Proposed discussions on Flexible Interconnection and Load Energization require implementing use cases recommended by working group. |
| ○ Standard tariffs and contracts are needed<br>▪ designed to *support stacked value uses* of resources | Flexible interconnection and SIOWG propose improvements (pending decisions by CPUC). | Level of progress will depend on timelines for decisions and implementation by IOUs | Proposed discussions on Flexible Interconnection and Load Energization require implementing use cases recommended by working group. |
| ○ DSO as the nexus | | | Gap appears between current progress and "DSO as the nexus" |
| ▪ to simplify signaling (layered coordination) | | | Timeline may be more extended |



Appendix A - Table A9: Layered system architecture from bottom-up

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented*** *not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| ▪ to *simplify single point access to revenue streams* (market and utility/tariff) | | | |
| • Support grid resiliency: Enable layering of system architecture to prevent propagation of grid failures to larger areas | IOUs implementing systems to integrate microgrids. Enabling management of DERs > 1MW. | Capabilities to manage microgrids expected to improve with Grid Mod Plans. | Improvements limited to certain sizes, specified locations. Appears to be a gap in supporting microgrids throughout service territories. |

## Table A10: Animate distribution-level markets/granular pricing

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented*** <br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • DSOs enable dynamic distribution prices | Currently under discussion in Rulemaking 22-07-005, "Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates" | IOUs anticipate supporting dynamic pricing | Gap depends on details of final decision on pricing structure. **Proposed for further discussion in Workshop #3.** |
| ○ Integrate SCADA data with price machine to generate local distribution load forecasts | | **SDG&E** - Substation and circuit level load forecasts available, but not determined by pricing machine. | |
| • Statewide distribution data sharing hub <br>○ Data Hub: "API of APIs" ensures data access for all parties <br>○ DER Register: database tracks location / capabilities of DER <br>○ DER Market: facilitate trading & scheduling DERs, microgrid & CAISO coordination. | Proposed by UCAN as operational need. IOUs appear to disagree on this need. | | Current IOU Grid Mod plans do not support level of data sharing proposed by advocates. **Proposed topic for discussion in Workshop #3.** |
| • Market reforms to support distribution-level markets <br>○ Shift to 5-minute Supply/Demand Balancing <br>○ Dynamic Pricing + LSE Transmission + DER Submetering <br>○ Supplier Consolidated Billing <br>○ Account for Community-Scale DER as Load Reducers | Proposed by UCAN as operational need. IOUs appear to disagree on this need. | | Current IOU Grid Mod plans do not appear to support these recommendations |

| Operational Need | Expected Capability in 2024 | **Expected Capability with Grid Mod Plans Fully Implemented***<br>*not all components of the IOUs' grid modernization plans have been approved, funded and implemented | Remaining Gap |
|---|---|---|---|
| • Enhanced data sharing between IOUs and CCAs to identify grid needs<br>○ CCAs already run a variety of DER programs that are generally optimized around wholesale market conditions<br>○ CCAs lack sufficient information and incentive to optimize DER programs based on distribution system needs<br>○ CCA DER programs can provide better value to all customers with better information on grid constraints and economic signals that incentivize solutions to those constraints | Proposed by Joint CCAs as operational need. | Current IOU Grid Mod plans do not appear to support this level of data sharing with CCAs. **Proposed topic of discussion for Workshop #3.** | Current IOU Grid Mod plans do not appear to support this level of data sharing with CCAs. **Proposed topic of discussion for Workshop #3.** |

# APPENDIX B: IOU GRID MODERNIZATION PROGRESS REPORTS

California Assembly Bill (AB) 242 amended Section 916.6 of the Public Utilities Code to require that "On or before February 1, 2023, and biennially thereafter, the [c]ommission, in consultation with the Independent System Operator and the Energy Commission, shall report to the Legislature and the Governor on the progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources on the state's distribution and transmission grid and ratepayers."[77]

In support of this report, each IOU submits regular Grid Modernization Progress Reports to the Commission. These progress reports provide the Commission with updates on each IOUs' progress in implementing their grid modernization plans (presented during Workshop 2).



[77] Public Utilities Code § 913.6 (a).

Pacific Gas and Electric Company®

# PG&E's Grid Modernization

# Progress Report

## April 24, 2024

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# I. Introduction

California is a leader in the growth of Distributed Energy Resources (DERs) including solar, battery storage, electric vehicles, and demand response. This progress is driven by a confluence of technology advancements, consumer preferences, and complementary legislative and regulatory actions in the state. Moreover, increasing climate-related risks have also accelerated the proliferation of resilience-focused DER solutions in California. PG&E plays a central role in enabling the safe and continued adoption of DERs. As of December 31, 2022, PG&E has interconnected over 700,000 Behind-the-Meter (BTM) Solar PV systems (~7 GW) over 50,00 BTM batteries (~500 MW) and ~400,000 electric vehicles.

While DERs may help achieve California's clean energy and resilience objectives, they may also potentially create new challenges and complexity on the grid including capacity constraints, power quality issues, and adverse impacts on protection systems due to bi-directional flow. In addition to the electrical complexities, there are programmatic and policy requirements that also need to be managed as the rules and regulations around DERs in PG&E's service territory continue to evolve.

Modern Operational and Planning tools and capabilities form an essential foundation for PG&E to achieve a secure, reliable, and affordable electric grid that enables clean energy and California's economic interests while providing maximum flexibility and value for customers. The goal of PG&E's grid modernization effort is to meet today's challenges while also positioning the grid to meet the demands of a dynamic energy future with improved situational awareness, operational efficiency, cybersecurity, and DER integration and orchestration capabilities.

# II. Highlights of PG&E's Grid Modernization Activities in 2022-2023

This section shares PG&E's grid modernization activities and deployment projects done in 2022 and 2023.

## A. Grid Management Systems

### 1. Advanced Distribution Management System (ADMS)

The ADMS is PG&E's core distribution operations software tool to enable visibility, control, forecasting, and analysis of a more dynamic grid. When fully deployed, the platform will bring the capabilities of today's Distribution Supervisory, Control and Data Acquisition (D-SCADA), Distribution Management System (DMS), and Outage Management System (OMS) applications into a single, integrated platform and enable many new capabilities.

The ADMS is a foundational tool that will bring far-reaching benefits to PG&E, its customers, and the distribution system. Some of the capabilities enabled by ADMS include:

- Reduced cybersecurity risk from replacement of PG&E's legacy RT-SCADA system

- Labor efficiencies from automated switching recommendations, automated switch log development, and consolidation of functionality into a single application and screen
- Reliability improvements from instantaneous fault location, automated switching recommendations, and enablement of more flexible, model-based Fault Location, Isolation, and Service Restoration (FLISR) schemes
- Improved safety from streamlined internal processes and automated detection and mitigation of overload conditions on non-telemetered points on the distribution grid
- Better quality of communication to customers during outages
- Energy savings, peak demand reduction, and greenhouse gas emissions reductions from future ADMS-managed automated Volt Var Optimization (VVO) schemes
- Improved management of Distributed Energy Resource (DER)-related grid issues through awareness of masked load associated with DER generation and the automated mitigation of DER-related thermal, voltage, and protection issues
- Enablement of Distributed Energy Resource Management System (DERMS) functionality such as the proactive dispatch of DER to mitigate real-time and forecasted grid constraints identified via the ADMS

PG&E has divided its ADMS implementation into three main “releases”, which are described in more detail below.

- **ADMS Release 1:** The scope of ADMS Release 1 is to replace PG&E’s legacy RT-SCADA system with an ADMS-based SCADA system that is integrated with PG&E’s network model. Scope for ADMS Release 1 also includes replacing PG&E’s legacy Yukon Feeder Automation (YFA) FLISR software with a native ADMS FLISR product, developing ADMS functionality to support PG&E wildfire risk mitigation efforts such as reclose blocking, implementing the Operator Training Simulator (OTS) in ADMS to assist with new Operator training.
- **ADMS Release 2:** The scope of ADMS Release 2 is to replace PG&E’s current outage management applications with OMS functionality in ADMS including outage planning, calculation of outage location and extent, crew dispatch, customer outage notification, switch log generation, and reliability reporting in a single vendor-supported product. ADMS will replace the highly custom-built and complex ecosystem of outage management applications PG&E uses today that is costly to maintain and challenging to integrate.
- **ADMS Release 3:** The scope of ADMS Release 3 is to enable Advanced Applications within the ADMS platform. PG&E’s initial focus for Release 3 will be enabling foundational integrations with Line Sensor data and implementing Enhanced Powerline Safety Setting (EPSS) and Fault Calculation functionality. PG&E’s focus will then shift to enabling Load Flow/State Estimation and Forecasting capability, which provide the ability to model real-time and predicted future power flows at any location on the distribution grid using a combination of SCADA telemetry, physical properties of network features stored in GIS and CYME, device settings stored in PowerBase, and the as-switched state of the grid as maintained in ADMS. These foundational capabilities enable many additional advanced applications on PG&E’s future roadmap including:
  - Identification of real-time and predicted future grid constraints
  - Automated switching recommendations for outages or constraint mitigation

- Fully automated FLISR schemes, allowing faster and more flexible service restoration than PG&E's current "rule-based" FLISR
- Automated adjustment of voltage and power factor regulation device settings (Volt-Var Optimization)
- Automated adjustment of protective device settings (Adaptive Protection)

Work on ADMS Release 1 during the twelve months ending in March 2024 was highlighted by the following activities:

- Cutover 8 out of 19 PG&E operating divisions to the ADMS SCADA platform
- Cutover of rules-based FLISR capabilities on the ADMS SCADA platform
- Cutover of Load Shedding functionality to the ADMS SCADA platform
- Conducted pre-cutover field point-to-point testing of SCADA signals to ensure accuracy of signal mapping into the network model
- Successful maintenance of the ADMS Network Model by the newly established ADMS support team
- Deployed regular maintenance patches and updates to the ADMS SCADA systems containing issue fixes and additional functions

Delivered continued ADMS refresher training to Operator and Engineer end users of ADMSADMS Release 1 is scheduled to conclude later in 2024 after D-SCADA functionality is cutover to the ADMS platform for the remainder of PG&E's operating divisions.

The team is also underway with delivery of ADMS Releases 2 & 3 which had previously kicked off in parallel to Release 1. Work on ADMS Releases 2 & 3 during the twelve months ending in March 2024 was highlighted by the following activities:

- Continued the Design and Build phases of the Release 2 & 3 Network Model, which will extend the existing ADMS Network Model to include the low voltage network, customer data, load profile data, and new device settings information
- Completed the Plan & Analyze Phase for Release 2 and finalized a detailed implementation plan for the Design, Build, Test, and Cutover Phases
- Started development of key systems integrations required for Release 2
- Completed Design activities for Release 2 Planned Outage functionality and portions of Unplanned Outage functionality
- Completed Plan & Analyze activities for Release 2 PSPS functionality
- Finished contract negotiations for the System Integrator, Business Integrator, Network Model, and Product Vendor roles for Release 2
- Completed Design activities for Release 3 Enhanced Powerline Safety Setting (EPSS) functionality to be built within ADMS
- Completed Plan & Analyze activities for Release 3 Line Sensors data integration and Load Flow/State Estimation functionality
- Supported Release 3 Microgrid Enablement functionality through the Redwood Coast Airport Microgrid (RCAM) SCADA screen build
- Supported Plan, Analyze & Design activities for the 2030.5 IEEE protocol enabled by the DERMS platform

This work has set PG&E on a course for the continued success of Design, Build, and Test activities related to ADMS Release 2 & 3 functionality in 2024-2025. The Go-Live date for ADMS Release 2 is scheduled to occur in 2026. The Go-Live date for ADMS Release 3 EPSS functionality is scheduled to occur in 2024, with additional Release 3 functionality deployments anticipated in subsequent years.

## 2. Distributed Energy Resource Management System (DERMS)

PG&E's Enterprise Distributed Energy Resource Management System (DERMS) will complement the foundational technology improvements and grid management tools built by the Advanced Distribution Management System (ADMS) program. The DERMS will allow PG&E to manage the added operational and programmatic complexity of ever-growing Distributed Energy Resources (DERs) and DER Programs on the PG&E grid. PG&E will build a DERMS platform to deliver the following capabilities:

- Full integration with ADMS – DERMS will seamlessly integrate with the ADMS, building on the integrated network model and grid modeling capabilities provided by the core ADMS product.
- DER advanced situational awareness for normal and abnormal conditions – DERMS will provide additional DER visibility beyond what is typically included by an ADMS such as DER status, flexibility, availability, forecasted flexibility, and program insights.
- Monitoring, dispatch, and program management of DER systems – DERMS will be a secure platform that enables the monitoring and dispatch of both front-of-the-meter (FTM), behind-the-meter (BTM), and aggregated DER assets with rules based on program types.
- DER constraint management for interconnection and abnormal conditions – DERMS will manage constraints on DERs including a limited generation profile, and other more dynamic constraints including during abnormal grid configurations due to outages or planned work. DERMS will also help manage DER impacts at the Transmission and Distribution interface including coordination of wholesale market participants on the Distribution system and enable more dynamic hosting and load serving capacity.
- Operation of DER-based deferral solutions - Examples of such solutions include projects participating in the Distribution Investment Deferral Framework (DIDF) and other alternatives to conventional infrastructure investments. As the number of these projects expand, platform-based controls and processes will increase the efficiency to manage the dispatch, mitigations, and settlements of these systems.

In 2023, PG&E deployed the first phase of an enterprise DERMS providing a foundational cloud-based platform integrated with ADMS. This DERMS platform replaced the existing DER Headend deployed through the Electric Program Investment Charge (EPIC) Project 3.03 which was based on PG&E's legacy SCADA vendor that is now being transitioned to the new ADMS platform. This function enables cybersecure communications between utility systems and third party owned DERs leveraging the Institute of Electrical and Electronics Engineers (IEEE) 2030.5 protocol and the SunSpec Common Smart Inverter Profile (CSIP), and is available for all DER interconnection customers with 1MW or greater DERs. This enables DER customers to use their own certified-interoperable devices to fulfill their interconnection telemetry requirement at a lower cost than was possible with the existing options for PG&E installed, owned, and maintained telemetry equipment.

This DERMS communication platform using IEEE 2030.5 will also be leveraged for planned automated DER control testing in 2024, with an initial focus on use cases related to managing dynamic distribution grid constraints with enhanced situational awareness of grid conditions, operational forecasts of grid conditions in the hours/days ahead, and control of participating DERs including flexible loads.

These particular use cases are driven by existing capacity constraints and the timelines required for PG&E to build infrastructure to support the full load requests of customers, for example, large EV charging stations. In 2024, PG&E will be piloting DERMS functionality to establish capacity allowances for constrained customers with flexibility based on day-ahead hourly forecasts versus the status-quo planning processes that are often limited by the worst times of the year. This is expected to allow customers to connect more quickly while unlocking significant additional capacity for them by better utilizing PG&E's existing assets based on near-term load forecasts. DERMS will provide a bridge solution for these customers until the scheduled PG&E work is completed, which can sometimes be more than a year.

Initial lab testing completed in 2023 involved the baseline modeling, forecasting, and control functionality in DERMS, however, more testing and enhancements are required and planned prior to field testing in the second half of 2024. PG&E plans to field test at a limited scale (<10 sites) in 2024 flexible service connections and to operationalize PG&E's first Distribution Investment Deferral Framework (DIDF) project. Pending the results of these tests, PG&E will use learnings to modify the system, processes, and plans to scale DERMS functionality in subsequent years.

## B. Communications and Cybersecurity Infrastructure

### 1. Communications Networks

PG&E owns and operates a large private network to service the needs of its critical operations for the Grid, Pipeline and Generation locations and personnel. It is augmented by public networks from the carriers for redundancy, enhanced coverage, less critical applications. PG&E includes the investments of the lifecycle and enhancements to these networks in the General Rate Case.

The pertinent work that PG&E has been investing in support of the Grid Modernization Plan in 2021 and 2022 and in alignment with the GRC submittal is as follows:

- Field Area Network. PG&E is continuing the installation of the Field Area Network (FAN) mesh technology as a means of increasing the data capacity, volume of devices, cyber security and remote management of grid devices. Currently, 4000 filed nodes have been installed to support SCADA enables devices managed through ADMS.

- Satellite Communications. This 3rd party service has been and continues to be deployed in more remote areas of the service territory where private networks are not economically feasible to build and where cellular networks are not available. Aside from grid devices, this technology has been used for Weather stations in support of Wildfire Threat Area situational awareness. 1300 such connections have been procured and installed.
- Cellular Connections. With the proliferation of AT&T's FirstNet and Verizon's Frontline cellular services, PG&E is taking advantage of the higher priority cellular networks and installing more SCADA devices where this service is available.
- Fiber Optic Cable Replacement. PG&E has been investing in lifecycle replacement of existing aging fiber optic cables which service the network backbone needs with high capacity.
- Lifecycle Replacements. PG&E has engaged in replacing technically obsolete communications equipment to improve the overall health, reliability, and maintainability of our communications transmission infrastructure, migrating to IP based communications. PG&E has also continued its efforts to maintain the health of its IP based routed MPLS network at the critical core operating centers and substations.
- Monitoring Tools. Additional tools have been added to consolidate functionality that was previously disparate and difficult to integrate. This improves our situational awareness and predictive event management to effectively manage a critical private network.

### 2. Architectural Considerations for DER Connectivity

The communications network considerations for the DER connectivity need to take into account all the requirements for a comprehensive set of data needs at a DER location, inclusive of the following: the DER core functionality (transacting with DERMS), non-functional overhead data such as cyber protocols, device remote management, communications network performance management, access control, as well as supporting native local applications such as analytics, batch reports and distributed computing needs. Additional data requirements stem from the environmental instruments at the DER location, such as physical alarms, cameras, fuel levels, weather stations, etc.

The second level of communications Network considerations is attributed to the network resiliency requirements of the DER. This would be driven by the physical location and reach, size of DER and its importance to the grid. These types of considerations drive the network designs in terms of number of redundant network paths, mediums, constructability limitations, and availability of third-party communications service providers.

The basic premise of the communications network is IP based protocols to accommodate all the device, data and security requirements. Migrations to IP based communications enable many functions not available today such as remote software updates, increased data acquisition, and configuration updates. As these devices are converted to IP based communications and data requirements increase PG&E will need to continue to invest in new technologies to meet the growing demand. It is likely that PG&E will need to deploy emerging technologies such as private LTE, other private radio systems, and increased public carrier technologies (cellular, satellite, and leased services).

Many DERs of smaller size today are well serviced through internet connections as well as cellular services while utilizing the secure protocols described below. PG&E would only extend its private network to DER assets that it owns and operates. This private network is not considered for public DERs.

### 3. Cybersecurity Developments with the DER proceedings

As part of the continued work for DERs in the Rule 21 proceeding, the IOUs established a goal for the creation of the "Utility Cybersecurity Requirements Guide for Communication to DER Facilities".[1] IOU and stakeholder weekly meetings were held to discuss development of cybersecurity recommendations with final publication of the guide in the Interconnection Handbook in August 2021. In early 2022, the Smart Inverter Operationalization Working Group (SIOWG) was launched with the scope of formulating business use case prioritization. A sub-group of SIOWG was created to discuss an approach for a cybersecurity workstream. The subgroup has concluded its work and developed a working group report that includes assessment of IEEE 1547.3 and cybersecurity recommendations along with proposed regulatory guidance for the CPUC. This stakeholder effort contributed to addressing cybersecurity considerations for endpoints. This effort contributed to the development of technical standards for cybersecurity of DERs and furthers discussions for potential development of broader standards for DER stakeholders.

### 4. Enhanced Cybersecurity controls for ADMS

Cybersecurity controls and requirements were taken into consideration during the early design phases of Advanced Distribution Management System (ADMS) deployment. Thus, PG&E have a modern distribution grid management platform with cybersecurity embedded and not bolted-on. PG&E ADMS implementation involves extremely granular segmentations and access control both at the network and application layer. ADMS platform is implemented with multiple dedicated security directory services from Microsoft and next generation Palo Alto application aware firewalls. ADMS compute resources are subjected to continuous monitoring by the enterprise Security Information and Event Management (SIEM) platform. All remote administrative interactions with the system are brokered and monitored. Other cybersecurity capabilities extended to ADMS infrastructure includes Tenable for vulnerability management and Forescout EyeInspect for SCADA device monitoring and anomaly detection.

### 5. Cybersecurity for Integrated Grid Platform

[1] Rule 21, Smart Inverter Working Group Phase 2 Recommendations, Communication Requirements

Improving Operations Technology (OT) Cybersecurity will benefit PG&E, our employees, and the communities we serve. More than ever before, PG&E's Operations Technology (OT) asset landscape is being transformed considerably due to the accelerated adoption of connected smart devices with modern connected technologies. PG&E recognized the need for not to rely only on rule-based solutions but heuristic approach for early detection and alerting of anomalies in the SCADA network. This paved way for a new strategy and PG&E launched a multi-year Advanced OT (Operations Technologies) Cybersecurity program in 2019.

Key outcome - *Reinforces PG&E business values*

- Protects against an increasing, ever-evolving threat (e.g., energy sector targets on the rise, potential risk of grid control compromise, individual site takedown, or some variation)
- Addresses vital OT security needs, not just compliance (NERC CIP is a minimum baseline for limited # of assets)
- Comprehensive OT asset inventory – device properties/classification, configuration, and network context. Enable Vulnerability assessment of OT devices
- The baseline of normal communications for both IT and ICS protocols in the ICS network. Mathematical model of network life or pattern to define normalcy
- Consolidated and streamlined Alert ingestion (Integrations with asset management and SIEMs
- Multi-layer anomaly with real time alerting capability on critical and process impacting events. Ability to detect unusual engineering port, unusual time of the day, etc

The program kicked off with a pilot deployment at 10 critical Electric Transmission and Distribution sites including control centers and data centers. The program executed subsequent projects to deploy the solution at all High, Medium and low NERC sites along with critical Distribution substations.

Further, the migration from legacy SCADA to ADMS significantly enhanced the security posture by enabling centralized OT asset enumeration capabilities from Cybersecurity point of view.

### 6. Operational Data Network (ODN) Security Program

ODN is the industrial control system network at PG&E. ODN security program is designed to mature cybersecurity industry best practices as part of the design, build, and implementation of the new/enhance security capabilities. To enable these best practices, certain technological investments have been put in place that includes firewall upgrades, expansion and fine tuning of OT asset discovery and anomaly detection. The design and onboarding of Endpoint Detection and Response (EDR) capabilities in the OT network will significantly improve security posture of cyber assets supporting grid operations.

PG&E identified need for improving configuration management capabilities in ODN. Ansible platform was chosen to bridge the gap of Tripwire platform that serves as configuration management tool.

This investment track also enabled the design, development and adoption of NERC ECAMS capability for virtualized computes resources.

### 7. SORT – Security Intelligence Operations Center OT Monitoring and Response

To improve the Security Intelligence and Operations Center (SIOC)'s operational response capabilities, we have created the SIOC Opsec Response Team (SORT). This team's primary focus is on cyber threat detection and response capabilities within the OT networks at PG&E. The individuals on the team have received external training and certification (CISA/INL 301 and SANS ICS515/GRID) and are additionally working with the functional areas of the business to build relationships, understand their business processes, and develop our own response playbooks. The deployment of additional tools, such as ICS-tailored passive network monitoring and EDR, are being deployed and will further strengthen SORT's abilities to detect and respond to threats in PG&E's OT networks.

## C. Engineering Software and Planning Tools

Modernization efforts for PG&E’s engineering and software planning tools include:

- **Distribution Resources Plan (DRP) Tools:** The DRP required the creation and use of new tools, including Integration Capacity Analysis (ICA), the DRP Data Portal, and the ongoing analysis and publication of distribution data via the Grids Needs Assessment (GNA) and Distribution Deferral Opportunity Report DDOR annual reports:
    - ICA – The objective of ICA is to simulate the ability of individual distribution line sections to accommodate additional DERs without potentially causing issues that would impact customer reliability and power quality. PG&E has worked with a third-party vendor to operationalize ICA and incorporate intelligent quality control into the ICA process. The Rule 21 Interconnection Process has adopted the use of ICA. On select circuits monthly, ICA is performed, results are validated as-needed, circuit models are updated as-needed, and results are published.
    - DIDF – The annual Distribution Investment Deferral Framework (DIDF) includes the publication of the GNA and DDOR, hosting of Distribution Planning Advisory Group (DPAG) meetings, and coordination with an Independent Professional Engineer (IPE) and Independent Evaluator (IE).
        - The objective of the GNA is to provide transparency into the assumptions and results of the distribution planning process that yield the Candidate Deferral Opportunities shortlist, propose grid modernization investments, and proactive hosting capacity upgrades

        - proposed to accommodate forecast DER growth. PG&E's GNA presents data available regarding PG&E's projected distribution grid needs over a five-year planning horizon.
        - The objective of the DDOR is to utilize the GNA to identify PG&E's candidate distribution deferral opportunities shortlist. In addition, other objectives of the DDOR are to provide transparency into the assumptions and results of the distribution resources planning process that yield the DDOR candidate shortlist and provide the associated DER attributes required to meet these opportunities.
    - DRP Data Portal – The DRP Data Portal is an externally-facing, map-based portal that provides information about PG&E's distribution network, including ICA, GNA, and DDOR results.
- **Planning Tools Driven by DRP Compliance:** The scale of the data and analysis within the DRP requires specific and customized tools to process and ensure data quality and accuracy. GNA and DDOR requirements from the DRP require PG&E to make upgrades to existing planning tools, including the CYME application and the LoadSEER application. These items are driven by three main objectives: a) eliminating manual analysis and processes through automation, minimize manual application integration, and manage analysis complexities.
- **CYME Substation Modeling and Analysis:** This project will further model the substation within CYME, including but not limited to transmission protective devices at the interface between transmission and distribution, transformer banks, substation buses, and distribution breakers. Adding new substation components into the CYME model will allow for additional analyses to be performed within the CYME application. The current process requires engineers to do some of the substation-level analyses outside of CYME, either in separate protection analysis tools, spreadsheets, or on paper. Further incorporating the substation model into distribution planning software allows engineers to further study within CYME bank and feeder level upgrades, bank and feeder loss studies, substation elements of the distribution protection studies, and bank and feeder capability ratings.
- **Distribution Time-Series Analysis Phase 2:** This project will build upon the successful implementation of the CYME Time-Series Load Flow Analysis project and further automate the distribution planning process. This project will extend the existing time-series analysis to assist with Voltage Regulator and Capacitor optimization and Risk Prioritization. Additionally, this project will investigate the use of the Advanced Project Manager (APM), results from the time-series analysis, and the technoeconomic analysis module to generate standardized and templated project authorization documentation.
- **Distribution Planning Automation:** The Distribution Planning Automation project will develop a manage-by-exception analysis process within CYME for capacity planning study deficiencies. Circuit analyses will be initiated and reviewed at the dashboard level, allowing engineers to focus their review on circuits with forecasted deficiencies. Distribution planning tools will also be further integrated with two-way information flow.

The status of these projects are as follow.

- **DRP Tools:**
  - DIDF: PG&E has successfully published the GNA and DDOR Reports annually for the last six years. These reports contain over 1 million data points and include written assessments that provide transparency into PG&E's annual Distribution Planning Process (DPP). Through the DIDF process, PG&E has successfully procured, through third party vendors, 4 contracts for ~4.0 MW of distribution deferral services to replace or defer traditional wire-based projects in the Company's project planning pipeline.
  - ICA: The real-time use of Integration Capacity Analysis data within the interconnection application process of Rule 21 projects over 30 kW was implemented in September, 2022. Updates to the application system include:
    1. The ability for customers to use a typical solar photovoltaic (PV) profile for their interconnection application, instead of using the device nameplate capacity, which may allow for interconnection of larger PV projects, potentially increasing the proliferation of renewable power onto PG&E's grid.
    2. Consolidation of all generator interconnection applications and applications for service into one website including a refreshed dashboard with self-service abilities for customers to see project status down to the task level and any outstanding application issues.
    3. The ability for customers to check the available feeder capacity at a specific location and to see real-time Integration Capacity Analysis data within the application portal enabling a more accurate, efficient, and transparent assessment for interconnecting renewable DERs.
    4. Automated import of Integration Capacity Analysis values for Rule 21 projects over 30 kilowatts (kW).
    5. Direct link to refreshed maps to help applicants find information on potential sites for DERs. The maps show hosting capacity and other information about PG&E's electric distribution grid (Integration Capacity Analysis Maps). PG&E is working to add hosting capacity map information directly within the application portal, which will be more convenient to use and further streamline the process for customers.
- **Integration Capacity Analysis (ICA):**
  - PG&E has submitted its ICA Refinements Annual Report[2] in Q4, 2023. The load ICA refinements project is on track as scheduled and expected to be operational by the end of Q4, 2024. The progress, timelines, milestones, challenges and roadblocks, and solutions are provided in detail in the report. The ICA refinements will be built upon the features offered by the Long-Term Planning Tool (LTPT) and new version of LoadSEER described in the next sections. These include the load application database, projects database, and the ability to query 576 hours load forecast data at premise level. The future looking load information could include "DER forecast" and "load forecast". PG&E expects the Development phase to continue into Summer of 2024. This

[2] PG&E's ICA Refinements Annual Report, December 12, 2023

includes developing the software codes, web platforms, IT environments, creation of new data structures in databases, building of data and system interfaces, and identification of new procedures to support on-going maintenance. The Testing and Deployment phase will commence through Fall of 2024 and will happen at different stages of product development and deployment. The Support & Stabilization phase will take place throughout 2024 to monitor performance of the platform and ensure that the new stablished processes are stable.

- PG&E has been working on ICA methodology improvements on an ongoing basis, this includes but not limited to adjusting voltage fluctuations criteria to comply with IEEE standards, incorporation dynamic calculations of ICA limits for different voltage levels, modifications to processes and systems of record, automation of Rule 21 Screen L calculations and its publication on ICA portal, etc.
- PG&E has been identifying additional opportunities to modify the future ICA methodologies above and beyond the compliance requirements, this includes but not limited to modifications of the new study triggers, network hierarchy modelling to reduce unnecessary complexities, expedite calculations, and improve accuracy, modifications to voltage regulating devices modelling methodologies, parallel computing, exploring new database options to store historical data and reduce operational costs, etc.
- Rule 21 Limited Generation Profile (LGP) Use Case: LGP customers will be able to upload a 288-hour export profile into the PG&E application portal (12 month, 24 hours a month) in CSV format. These profiles will be treated as a separate category of generation and used as inputs for ICA calculations. Currently, the requirements have been captured and documented in the ICA refinements project but not implemented yet.
- PG&E has worked with CYME to identify a solution to reduce convergence issues associated with device status oscillations as recommended by ITE and reported in PG&E's supplemental advice letter for data validation plan. CYME's modified power-flow engine in CYME 9.3 Rev2 addressed voltage regulating device divergence issues identified in the previous statistical analysis, which is now used by PG&E to perform ICA calculations.
- PG&E has recently added a new interface on the public ICA map that indicates whether a desired location is expected to have capacity. This serves as an interim solution for "forward looking" functionality before Load ICA is refined to look at forecasted load and planned projects. It is intended to provide customers with better guidance for siting loads before going through the application process. For example, a customer may view whether their project location is likely to have either "Expected Load Interconnection Capacity" or require grid upgrades for interconnecting new load. This is made possible by utilizing a combination of existing Load ICA data and other available datasets such as forecast feeder capacity, forecast bank capacity, planned load applications, planned projects. This data was added to the PG&E data portal

on December 6, 2023, and will be updated on a quarterly basis. PG&E is providing three "Expected Load Interconnection Capacity" attributes at the line section level to support customers while Load ICA improvements are being implemented.

    - PG&E's proposed Load ICA use case: once ICA refinements are completed there is an opportunity for using load ICA data to streamline the early stages of the load energization process where capacity planners can assess all types of new business loads, including EVs. After the Intake phase is complete, Service Planning routes the application package to the Estimating (Design) team, who works with Distribution Planning to perform a review of the proposed load request and identify what equipment and/or modifications to the electric distribution system are required to safely serve the load request. If necessary, PG&E may need to study the load request further through a detailed study based upon the project size, location, and complexity for all types of customers during the Estimating phase. Projects can experience delays due to the high volume of work and the manual nature of the Distribution Planning review process. The new ICA use case is targeted to reduce processing time: to provide ready-to-use capacity information resulting in shorter processing cycle times. A pre-assessment phase can be offered for all types of service applications. PG&E is working with internal stakeholders to put together a scope and timeline of the project. The next step is to hold internal interviews and workshops to align on an implementation plan. The result of this will determine how existing processes and tools will be adapted to using the data, how the data will interface with capacity planners, and how the data will shape the customer experience.
    - PG&E's DRP Data Portal is operational and accessible to the public, with GNA and DDOR data published annually, and ICA data published monthly.
- **The DRP Data Access Portal is undergoing a multi-year upgrade on both platform and functionality**
    - New Platform implementation to Esri ARCGIS configured by internal PG&E GIS COE to improve
        - Resource effectiveness
        - Cost efficiency
    - Updating DRP Compliance use case found in DRP DAP 1.0 with ongoing regulatory requirements
    - Adding Electric Vehicle Use Case (For Public and internal use)
    - Adding Flexibility for:
        - Added data,
        - New map layers
        - New Use Cases in the future
    - Automation of Data Flow – Facilitate data flow while lessoning business resource impact
    - Auto-failover for our clients
        - No need for Disaster Recovery or backup clients

        - Decreased downtime for our clients
    - Client Layers Flexibility to add client layers
        - Public Layer
        - Internal Layer and Redacted layer to be added as needed
    - Optimized Software & Hardware is ongoing and managed by Esri
        - No dependency on Infrastructure upgrades and purchases

- **Planning Tools Driven by DRP Compliance**
    - PG&E adopted LoadSEER 4 in 2023, which adds numerous capabilities to PG&E's forecasting process, including:
        - Transition from SCADA to AMI meter based historical load shapes
        - Weather normalization
        - 8760 load shapes
        - Scenario based analysis
        - Automated report generation
    - PG&E will use LoadSEER to create annual Capacity GNA and DDOR reports in 2024
    - The adoption of the CYME WebApp (described further in section "Distribution Planning Automation" below) enables the automated generation of the Line Section GNA report. PG&E will use this functionality for its Line Section GNA report in 2024.
- **CYME Substation Modeling and Analysis**
    - This project is in the planning stages. The focus of current development is on integrating existing systems, creating the ability to study multiple capacity planning scenarios and furthering automation of CYME analysis.
- **Distribution Time-Series Analysis Phase 2**
    - PG&E deployed CYME's Advanced Project Manager (APM) module in 2023, which has scenario-based modeling capabilities
    - PG&E is using the CYME APM, alongside CYME's Load Flow With Profiles (LWFP) feature, for the 2023-2024 distribution planning process.
    - LoadSEER 4's 8760 load shapes allow all hours to be modeled in CYME for time series analysis
    - PG&E is scoping and prioritizing further enhancements to these tools in 2024 and 2025 to support:
        - Time-series analysis of load management and non-wires solutions
        - Scenario-based technoeconomic solution identification
        - Regulator and capacitor optimization
        - Templatized and automated project proposal documents
    - PG&E's Distribution Planning team is working with the Integrated Grid Planning team to develop risk-based prioritization of capacity projects
- **Distribution Planning Automation**
    - PG&E deployed the Distribution Planning Automation project to production in 2023, including the following components:

        - CYME Webapp Forecast Integration Tool used to complete the capacity planning process that integrates multiple systems into a single application.
        - Incoming load database of new business applications for use across multiple platforms.
        - Project Database of distribution capacity projects and transfers to reduce modeling or importing into each planning study and automate reporting.
        - Portfolio Server database of distribution capacity projects and justification to reduce manual tracking.
    - The Forecast Integration Tool is being used by PG&E Distribution Engineers for the 2023-2024 Distribution Planning Process.
    - The Project Database will be used in 2024 for investment planning
    - The Webapp will be used to support automated GNA reporting in 2024
    - PG&E is scoping and prioritizing stabilization and usability enhancements for the Webapp in 2024

## D. Grid Edge Computing & Applications

While the ADMS and DERMS technologies enable awareness, control, and grid coordination in a centralized system, for first party utility owned devices and third party DERs over the web, they do not scale effectively for millions of customer end points and do not have visibility to effectively manage the secondary network.

As an example:

1. For an electrified customer with a heat pump, electric vehicle, electric hot water heater, and a home battery; all four of these devices would have to coordinate across multiple centralized aggregators to perform even the most basic customer premise energy management. This incurs cost and complexities which can be difficult if not impossible to overcome utilizing centralized solutions.
2. For a grid constraint at a secondary transformer, there is no way to communicate a limit to a customer device with ADMS or DERMS, without deploying costly remote monitoring devices with associated telemetry. This would result in a need for 100's of thousands of transformer montiors to be able to gain basic visibility into the secondary network.

As a solution to these challenges, PG&E has begun exploring capability development for Grid Edge Computing which leverages the existing communications of the Advanced Meter Infrastructure (AMI) network with incremental upgrades to enable AMI 2.0 functionality.

Due to the nascent nature of AMI 2.0 technology, our approach is to first explore the capability utilizing EPIC funds before incorporating into the General Rate Case (GRC) or other funding sources. Our first meter application focuses on a high value challenge: Panel and service upgrades driven by vehicle electrification:

- **EPIC 4.02 – Socket of the Future & Residential EV Charging [Scoping phase, set to begin deployment in 2024 Q2]**

- Deployment of a cloud server which enables the AMI 2.0 platform capability, connected to our existing AMI network. This system allows for the provisioning of applications to AMI 2.0 meters, fleet management of applications, and associated functions of computing on the meters.
- Testing and configuration of our first AMI 2.0 application which seeks to enable a customer to avoid a panel, service wire, and service transformer upgrade by sending an active site limit in near real time.
    - Customer's Electric Vehicle Service Equipment (EVSE) connects wirelessly to an AMI 2.0 meter via local Wi-Fi connection using the Open Charge Point Protocol (OCPP) for signaling.
    - EVSE responds dynamically to the limit and defaults to a safe operating limit in the case of loss of communications.
    - Begun work with three EVSE partners, with plans to publish specifications more broadly for other EVSEs that meet the communication and program requirements to participate as well.
- Minimum Viable Product (MVP) approach which will support and fund up to 1,000 meters/chargers.
    - Deployment, testing, evaluation and improvement of the experience.
    - At conclusion of the project the AMI 2.0 platform remains useable for future AMI 2.0 application development/support, it becomes a permanent business system.
    - Support for the 1,000 customers after completion of the EPIC project, and any scale beyond, would need to be funded via the General Rate Case or other appropriate long term funding mechanisms (outside of EPIC).
- Out of scope at this time, but under consideration for further development either within this project or through other EPIC projects:
    - Offering EV submetered rates to the customer by leveraging the connection established between the smart meter and the EVSE.
    - "Add-on" electrification sub panels which manage smart breakers and coordinate with the smart meter to avoid panel and service upgrades using the same logic developed for the EVSE.

In parallel to the EPIC 4.02 deployment, PG&E will develop an AMI 2.0 roadmap which will include a capability scaling and application development/deployment strategy. This strategy would:

1. Develop our perspective on Grid Edge Computing, including when, where, and how the capability interacts with the other Grid Modernization technologies.
2. Leverage EPIC and other funding sources to develop, deploy, test, and scale individual applications that provide positive value to the system. Explore other types of applications beyond those listed in EPIC 4.02, such as:
    a. Wildfire mitigation
    b. Fault location, incipient fault detection, and asset health

c. Network model improvements such as detection of transformer phasing and/or service conductor sizing identification
d. Customer load disaggregation, energy management, and insights
e. DER enablement
f. Panel and service upgrade avoidance for other use cases beyond vehicle charging (e.g. solar and energy storage, V2G, etc.)

3. Coordinate with the 2027 General Rate Case (GRC), and will take an incremental scaling approach, rather than a full "rip and replace" of the electric AMI system.

## III. Other relevant activities

In addition to the highlighted activities above, PG&E has been proactively making investments to modernize the grid in the face of climate change and has continued to develop customer programs to foster the adoption of DERS and electrify traditionally fossil fuel-based energy consumption such in transportation. Below are references more information about these initiatives:

- PG&E's Wildfire Mitigation Plan
- Demand Response
- Electric Vehicle Programs
- Community Microgrid Enablement Program (CMEP)
- PG&E's Electric Program Investment Charge (EPIC) Program for applied research & development and technology demonstration.

SDGE™

# San Diego Gas & Electric Company

## Grid Modernization Progress Report

April 19, 2024

# Contents

# Introduction

Over the past decades, San Diego Gas & Electric Company ("SDG&E" or "the Company") has made investments in innovative, cutting-edge technologies and programs that have made it a leader in utility wildfire safety and grid resiliency. From integrating automation and control technologies, to implementing efficient work processes, to designing and building microgrids, our investments are already benefiting our customers and serve as a foundation for the grid of the future.

SDG&E and its customers are also no strangers when it comes to integrating distributed energy resource ("DER") technologies. To date, SDG&E has authorized over 317,000 DER interconnection requests, installed at a rate of over 2,000 each month. These DER installations represent approximately one in every five households in SDG&E's service territory, with over 2,185 megawatts ("MW") in aggregate nameplate capacity.

SDG&E believes that the future grid needs to be dynamic, robust, and resilient, and it must evolve to support continued DER proliferation and enhancements to safety and reliability through assimilation of other emerging technology. The future grid also needs to empower customers, increase renewable generation, integrate electric vehicles ("EV"), and reduce greenhouse gas ("GHG") emissions while simultaneously maintaining and improving system safety, reliability, operational efficiency, security, and customer privacy. Thus, SDG&E's grid modernization vision is to innovate and optimize a grid that is safe and reliable and accelerates decarbonization – all while delivering value and choice for all customers. This vision reinforces SDG&E as the operator, planner, and integrator for the distribution system, while being supportive of state goals regarding DER adoption, transportation electrification, and decarbonization.

The following report details SDG&E's advancements, challenges, and future outlooks in the grid modernization areas of grid management systems, communications and cybersecurity infrastructure, and engineering software and planning tools.

# Grid Management Systems

## Integrated Test Facility ("ITF") Expansion

The ITF provides a learning and testing space for SDG&E to develop its own institutional knowledge  and intellectual capital that aligns with CPUC goals and objectives. It is a vital asset that provides internal engineers and experts opportunities to work side by side. This resource provides a true cross-functional effort, designed to help projects from different groups and departments at SDG&E to coordinate and integrate, thereby increasing SDG&E's knowledge of power system and advanced technologies. Each laboratory room compliments efforts to improve the electrical power systems' reliability and efficiency. By testing within a laboratory environment, it allows SDG&E to safely test and troubleshoot different technologies, techniques and scenarios without putting SDG&E's personnel and operational systems at risk. The ITF is an integral part of SDG&E's safety culture.

*Recent Activity, Challenges, and Outlook*
Since 2021, the ITF has installed a smart board and Audio and Visual upgrades to the conference rooms. In addition, the ITF Team purchased software licenses and support for Real Time Digital Simulators that help model and test the technologies of the future within a lab setting. The ITF is

being utilized for projects that are being tested for wildfire prevention, system protection, reliability, and renewable communications. There have been successful outcomes of ITF projects. To name a few, SDG&E engineers pioneered and patented a falling conductor protection scheme in the event the power line breaks. This system can de-energize the line before it lands on the ground. This project was designed, developed, and tested in the lab to tell the electric system to immediately shut off power on a line if sensors detect that it is broken. There is also the development of servers using IEEE 2030.5 Protocol in the lab to test inverter communications for renewable energy resources, to enhance operational flexibility. SDG&E has also designed and tested our own 4G LTE communications system, to replace legacy systems and enable technologies such as Falling Conductor Protection to work quickly and reliably. SDG&E is also using the ITF to test behind the meter isolation switches that could help customers stay energized during utility outages. The CPUC has requested this effort be done by the three IOUs in California and the ITF is where SDG&E performs its testing.

The current challenges are the ability to collaborate with academia and third-party entrepreneurs within the bounds of prudent utility business practices. While SDG&E sees a potential value with working with outside parties in the ITF, there are safety and regulatory accounting concerns that make it infeasible.

SDG&E plans to double the size of the ITF laboratory space in the near future. As the grid handles more complicated technologies, there is a growing need to test the communications and connections of tomorrow in the safe environment the ITF lab provides.

**Advanced Distribution Management System (“ADMS”)**

SDG&E’s initial ADMS included an Outage Management System (“OMS”) integrated with a Distribution Management System (“DMS”). To achieve SDG&E’s desired operational vision, the ADMS was tightly integrated with other ancillary operational systems including the Geographic Information System (“GIS”), SCADA, Customer Information System (“CIS”), and Advanced metering infrastructure (AMI) systems. This initial ADMS deployment included a fully as-switched model of the distribution system which provides granular system visibility and management capabilities for the operators. The OMS also enabled the full suite of digital switch plan management, including documentation, tagging, and authorization capabilities across emergency and planned work, with all SCADA switching executed remotely from the control center. The full ADMS platform also enables timely customer outage communications, integrated workflow management and real-time resource status management both integrating data from AMI and SCADA with the internal as-switched grid model. ADMS has been a core enabling factor when it comes to SDG&E’s superior safety and reliability metrices.

Moreover, ADMS is a key foundational system that anchors SDG&E’s ability to operate and manage the distribution system in a high DER future. Its DER-aware modeling, integrated network analysis and system reconfiguration applications paves the way for SDG&E to develop its growing capabilities around DER management and is a first step towards the fully integrated ADMS and DER Management System (“DERMS”) platform.

In its TY 2024 General Rate Case (“GRC”), SDG&E proposes the Reliability and Operational Safety (“ROSE”) project and Smart Grid Operation (“SGO”) projects to ensure ADMS can be enhanced to address safety and reliability driven needs. These enhancements also provide a foundation for implementation of broader DER management capabilities, as proposed in the new Enterprise DERMS project. The scope of ROSE and SGO projects include enhanced customer communications during blue sky and Public Safety Power Shutoff (“PSPS”) events, expanded visibility to DERs and advanced outage and reliability analytics. Additionally, SDG&E intends to improve its electric modeling, which is the foundation for all optimization applications within the ADMS. Accurate modeling not only improves switching accuracy and operating efficiency, but also provides an accurate baseline for planning and operating with DERs in the distribution system. The projects will also build upon existing architecture and platforms and further implement and refine advanced applications such as Volt/Var Optimization ("VVO"), Fault Isolation and Service Restoration ("FLISR"), Fault Location ("FL") and day ahead forecasting. Both the ROSE project and the SGO project are driven primarily by safety and reliability, but also provide a meaningful foundation for supporting DER integration.

*Recent Activity, Challenges, and Outlook*

In the recent past, SDGE's ADMS teams have been focused on improving integrations with systems such as the new CIS system, providing better more timely outage notices and communications with individual customers. Many enhancements have been made to automate Distribution Operator functions, thus reducing workload, and improving Operator focus on safety. Other improvements to the IT infrastructure have created a more resilient and available ADMS system -- even during cybersecurity patching, planned system maintenance and disaster recovery -- thus also improving safety considerations.

Distribution model optimizations have been completed to enable more accurate prediction and management of circuits during planned and unplanned outages in preparation for DERMS. DER assets modeled in the ADMS were verified to improve power flow calculations and direction. To further increase the visibility of DERs, large scale DER assets (rated at 1MW and greater) require SCADA telemetry and the future roadmap includes leveraging this data to improve the ADMS model and forecasting accuracy. Currently this data is viewable to the operators, and SDG&E has a methodical approach to continue to add in real-time data to the ADMS model.

SDG&E regularly upgrades key systems including the Network Management Systems (NMS) and Oracle Utilities Analytics (OUA), to newer versions to enhance safety and reliability through improvements in both processes and technology. In conjunction with the system upgrades, SDG&E added enhancement tools including FLISR and Suggested Switching. These are under evaluation alongside day-ahead forecasting in 2024. Legacy applications were replaced by web-based IT supported solutions to quickly gather and report data needed. SDG&E has added indices to track customer experience to help improve identification of reliability improvements to prioritize.

A primary challenge to most ADMS systems is the rapid pace of change in smart grid device technology and incorporating those improvements into the SCADA and ADMS systems. In addition, the proliferation of DER devices, their emerging standards and the onboarding and integration of those devices onto the distribution grid have caused an influx of changing requirements that ADMS must support. While the ADMS distribution system model is updated with additional SCADA data and DER attributes, improving the accuracy of FLISR and FL solutions -- in addition to expanding these capabilities to other circuits --becomes more challenging. As a result, FLISR is currently set to manual mode to evaluate the potential solutions and make improvements to the algorithm and power flow. FL solutions are also closely monitored and evaluated to identify and correct model inaccuracies. Finally, as Distribution Operations responsibilities grow, the need to automate repetitive tasks and provide plans and actions that reduce Operator workload to manage the distribution grid more safely, will continue to challenge the ADMS.

SDG&E's ADMS will continue to include enhancements that incorporate new technologies that are focused on improving reliability, furthering automation, and setting the stage to add enhancements for DERMS. In 2023, the ADMS was updated to include capabilities that use the

Fire Potential Index (FPI) generated by the SDG&E Meteorology team to raise Distribution Operations and crew personnel awareness of the potential for wildfires and allow for greater controls to ensure safe operations in times of greater wildfire risk. Also, in areas of high FPI, a switch plan for minimizing customer outages will be automatically generated so that should a PSPS event be necessary, Distribution Operations personnel will be able to act more quickly. ADMS will also be reintroducing mobile application access to ADMS to provide field personnel and crews real-time access to ADMS data to increase field crew awareness during both planned and unplanned work, develop more accurate estimated restoration times during outages and provide quicker and more accurate damage assessments to be submitted from the field. SDG&E has been developing pilots and procedures for these applications since 2023. Finally, as part of modeling improvements, ADMS will also be expanding the use of FLISR to additional circuits to automate the detection and restoration of unplanned outages by enabling FLISR on additional circuits. To support the upcoming DERMS system, additional SCADA data will be acquired from the SCADA head-end system to more accurately identify the DER devices, ratings, and attributes so that SDG&E can accurately forecast and signal the need for dispatchable DER that we expect to interconnect in the future.

**Local Area Distribution Controller ("LADC") – Microgrid Controller**

To support the controls associated with microgrids, SDG&E is working on developing and deploying a new microgrid controller, known as the LADC. The LADC is designed as a fast local controller that can rapidly control inverter-based resources and distributed generation while leveraging synchro-phasor data as control input. This fast control was deemed necessary based on experiences dealing with transient microgrid operating conditions in a low inertia environment. This is especially true for uncontrolled customer DER with legacy inverters without strong ride through capabilities where voltage or frequency excursions associated with these transients can cause them to trip offline en masse. SDG&E expects to integrate all resources, including those operated by third parties within multi-premise microgrids, with the LADC in addition to utility assets. The LADC projects are primarily driven by DER Integration but are also necessary to ensure safe and reliable operation within microgrids connected to SDG&E's distribution system.

Utilizing the LADC and to increase visibility, management, and control of the distribution system, SDG&E has also been utilizing a combination of data, analytical method, engineering and operations knowledge, and various tools to build a data notification system and visualization dashboards. This enables timely and targeted response to data changes and system events. Some of the use cases implemented include voltage monitoring and notification, phase balancing, and overloading circuits watchlist. With more data available, including DER performance data, SDG&E expects to continue using analytics to further finetune its process to make more data-driven planning and operational decisions. In addition, SDG&E has ongoing grid technology deployment such as the Advanced Protection ("AP") technology to further extend branch circuit protection for improved reliability.

*Recent Activity, Challenges, and Outlook*

In the past 6 months SDG&E teams have been advancing LADCs at the Cameron Corners Wildfire Mitigation Plan (WMP) Microgrid, the Ramona Air Attack Base WMP Microgrid and the Borrego Springs Microgrid; overcoming technical issues inherent with mixed-maturity energy storage devices from different manufacturers. In December 2022, the teams completed two milestones, integrating both LADC and SCADA controls at the Ramona Air Attack Base WMP Microgrid. This milestone enabled SDG&E's Distribution Operations to have control of the Tesla Megapack Battery for use during Wildfire or PSPS events. In December 2023, Phase 1 LADC integration completed at the Borrego Springs Microgrid, but full automation was postponed until LADC Phase 2, due to mechanical failure of the two diesel generators. In the first quarter of 2024, engineering teams have completed LADC Factory Acceptance Testing and User Acceptance Testing for Elliot Microgrid using SDG&E's ITF Power systems Lab. Currently the SDG&E teams are performing Elliot Energy Storage Microgrid Controls Acceptance Testing at SDG&E's ITF Lab, and configuring Paradise Energy Storage Servers for Factory Acceptance Testing. Concurrently, the teams are supporting priority operational work, supporting Cameron Corners WMP Microgrid Flow Battery installation, supporting installation of new Tesla Megapacks, and supporting the Deisel Generator replacement at the Borrego Springs Microgrid.

The project teams have faced significant challenges from many angles. Most significantly for Borrego Springs was aging assets and for delay of the Cameron Corners flow battery. Additional challenges have come because each piece of microgrid hardware is programmed with custom logic and, although subsets of hardware are being tested in lab environments prior to field installation, full system lab tests are not possible; the entire system is operated for the first time in production environments with customers on the circuits.

In the next two years, the project teams will leverage the lessons learned and operational techniques developed while integrating the LADC at the Ramona Air Attack Base WMP Microgrid and Borrego Springs Microgrids. In 2024, SDG&E is working towards LADC integration for Elliot, Paradise, Boulevard, and Clairemont Microgrid sites, which are all Phase 2 LADC sites. The 2024 roadmap for LADC integration will be more productive because these four microgrids use the same technology and vendors. The teams expect Shelter Valley WMP Microgrid, Butterfield Ranch WMP Microgrid, Cameron Corners and Borrego Springs New energy asset construction to complete and become operational in early 2025 so LADC integrations for these sites are on the roadmap for 2025. Although the architecture and integrations are complex, the LADC puts SDG&E's Distribution Operations, Distributed Energy Resources, and Generation Operations teams in control of microgrid assets with their respective native control systems.

### Enterprise DERMS

SDG&E views DERMS as providing the overarching capabilities within the operational domain to monitor, manage, and optimize DERs. With the already solid foundation established by previous investments in SCADA Headend replacement, ADMS, and other network infrastructure, SDG&E believes it is important to carefully evaluate and design the capabilities needed to further enable DER integration in the operational domain and its existing systems portfolio. Instead of building out one enterprise application platform, SDG&E believes it can enhance its existing tools and build out scenario-driven capabilities as needed in a progressive manner.

Although SDG&E has not implemented an enterprise DERMS to date, it is one of the early adopters in expanding its grid management capabilities to embrace DER integration. SDG&E has a long history of working with national labs, vendors, research facilities, and universities via the avenue of state directed EPIC, Department of Energy Solar Energy and Technologies (SETO) Funding Opportunity Announcements, and other grant opportunities. However, additional capabilities and functionalities, along with consistent use cases, are needed to develop and implement DERMS at the production level. SDG&E envisions DERMS to perform functions in the following three categories:

**Day Ahead:** The DERMS will consider the day ahead load forecast and anticipated equipment configurations and settings on a circuit-by-circuit basis, which it will leverage from the ADMS. The ADMS forecast is sophisticated and leverages weather forecasts, static (non-dispatchable/controllable) nameplate solar, smart meter data, SCADA telemetry points, as well as the circuit and equipment impedance models to determine the projected load at various telemetry points on a 24-hour schedule. If a constraint is detected by the day ahead simulation, the DERMS will signal the need for dispatchable DER to come online the next day. This signal will be based on an optimization routine that considers the number and capabilities of DERs, circuit constraints such as voltage/thermal capacity, economic constraints), repetitive-use constraints such as not overusing demand response resources, and any other constraints that may come up depending on the type of use. For specific types of DER, like battery storage, DERMS could signal day ahead charging limits based on far more up-to-date forecasts, rather than the conservative annual forecast used today for our distribution-connected battery storage customers who are participating in the wholesale market. In 2023, SDG&E focused on the Distribution Management System (DMS) model updates and developed procedures to improve model accuracy and convergence, resulting in the ability to run day-ahead forecasts and estimate peak loads for subsequent days. In 2024 we have begun accuracy comparisons in preparation for a DERMS to ingest this data.

**Real Time:** SDG&E also expects the DERMS, which will be connected and integrated with SDG&E's as- switched distribution system model on ADMS, to react in real time if set electrical constraint values are exceeded to prevent voltage and overload problems that could lead to outages on the distribution system if not mitigated. The goal is for these constraints to be dynamically captured such that the DERMS has the capability of recognizing the actual constraints on the as-switched electric system. As an operator performs switching to restore service to customers, the DERMS can then evaluate the large DERs on the system and adjust their output, either up or down, depending on the scenario. These output adjustments will provide grid performance that stays within the system constraints that are recalculated as the system is reconfigured through switching operations. Key to this is the integration SDGE has built with our Enterprise GIS system. System changes are digitized and uploaded to our NMS on a daily basis and this year SDG&E continues to identify solutions that clean up data discrepancies.

**Record and learn:** The DERMS will need the capability of verifying the expected output from dispatchable resources and validating the actual output by measuring what the distribution system received in response to the dispatch signals sent to the resource. Event reporting will be necessary for determining if contract obligations are met. Event reporting can also act as a data feedback loop to improve the accuracy of day ahead forecasts and to improve the optimization programming of the DERMS. To date, SDG&E receives telemetry from all WDATs greater than 1MW. This data is brought into the control center for operator visibility and to inform decision making in switching on this distribution system. Additionally, static charge limits are viewable in the control center which give conservative predictability to the devices on our system.

*Recent Activity, Challenges, and Outlook*

SDG&E met with additional potential DERMS vendors to have them introduce and provide demonstrations of their product, and to allow SDG&E to ask technical questions regarding the capabilities of their product. Additionally, SDG&E representatives have participated in industry conferences and sessions to knowledge share on DERMS roadmap and specifications pertinent to brining on a DERMs vendor. We are working to better define our use cases and refine our vendor list for a formal Request for Proposal. SDG&E also established a 2030.5 server in its Technology lab to start demonstrating the capability of communicating to inverters and controlling inverter outputs, a key capability the DERMS will need to monitor and manage DERs. In SDG&E's current system, large DER assets participating in the wholesale market are interconnected with SCADA switches at the point of interconnection which provides telemetry and control. However, the control is static, SCADA can either isolate the customer or DER from the grid, or it can connect the customer or DER to the grid. The development of the 2030.5 technology would allow SDG&E and its future DERMS to control the inverter output providing a more sophisticated solution that is more friendly to both the customer and the electric system. Generation/load output values can be adjusted rather than completely isolating DER assets from the system.

As mentioned above, to have the DERMS SDG&E envisions, it will need to have the capability to control either directly or through real time request to customers at the inverter level vs at the SCADA level,[1] and SDG&E is still early in its development of the 2030.5 head end system. In addition, the DERMS system will rely heavily on day ahead forecasting to optimize dispatchable DER at scale, and SDG&E must work to refine its data inputs into the distribution system model to continue to improve the accuracy of its day ahead forecasts. The ADMS model enhancements continue to be SDG&E's focus before our DERMS implementation.

The LADC deployments detailed above alongside pilot projects, including vehicle to grid and virtual power plants, provide us with additional experience and use case understanding necessary capabilities as we move toward a DERMS solution.

SDG&E plans to submit a formal request for proposal to DERMS vendors in 2024 and is on track to purchase and integrate a DERMS system in 2025, with the goal of piloting the use cases described in future years consistent with SDG&E's current GRC application.

### Supervisory Control and Data Acquisition ("SCADA") Headend Replacement

SDG&E has long been using the SCADA system to monitor, control, and protect distribution assets. As the cornerstone of its operational platform, the implementation of the distribution SCADA ("DSCADA") system more than two decades ago initiated SDG&E's roadmap establishing system management capabilities within the distribution control center. Over time, this legacy DSCADA system faced increasing challenges as more and more communication edge devices were deployed in the field.

In 2017, SDG&E engaged a consulting firm to perform a full evaluation of the DSCADA system. Upon evaluation, it was identified that the legacy DSCADA system did not meet SDG&E's technical roadmap requirements for grid modernization. Key issues included a lack of support for Internet Protocol ("IP") communications as well as a limited capacity to send/receive DSCADA points associated with newer devices and general system scalability concerns. Moreover, given the DSCADA system was deployed more than 20 years ago with antiquated user interfaces, the development of DSCADA screens were very inefficient and time consuming. The system did not have a reliable backup process and was heavily dependent on an aging hardware configuration, which created many challenges for operational support of the system.

Consistent with the final recommendation by the consulting firm, SDG&E decided to replace the legacy system with a new DSCADA Head-end system. In 2020 SDG&E completed a full upgrade of DSCADA. The upgrade enabled the DSCADA system to continue serving as the critical data aggregation system to integrate additional grid sensing, switching and protection equipment for the control center. In 2022 and 2023, SDG&E completed the Phase 2 of SCADA Head-end upgrade project to further enhance the DSCADA system to have full testing capabilities.

[1] For some Behind-The-Meter (BTM) applications such control will require the presence of a Power Control System (PCS) that monitors power flow at the customer's Point of Common Coupling (PCC) with the utility and uses this data to signal the inverter to increase or decrease output as necessary to manage grid imports or exports to specified levels. A PCS will be necessary because control of the inverter by itself has no effect on the customer's end-use load.

*Recent Activity, Challenges, and Outlook*

Upgrading the SCADA system to newer versions enhances safety and reliability through improvements in both processes and technology. In conjunction with the system upgrades, SDG&E teams have successfully converted serial SCADA communications to an IP based communication protocol improving SCADA reliability. In addition, Security Profiler software was implemented to establish baselines and monitor deviations of software on the SCADA equipment within the SCADA network which hardened the cyber security posture. The SCADA team has successfully integrated to LADC and Falling Conductor Protocol controllers. The team transitioned from quarterly system security patching to monthly with no interruptions to operations. Scheduled nightly server backups of all non-production and production environments which are stored for six weeks improving business continuity. The number of active RTUs in the SCADA has increased by 15% in the last two years. Additionally, in 2022 SDG&E added a physical multi- factor authentication to critical areas where SCADA equipment is located. The team implemented the use of a new change management software that will monitor and record system changes for auditing purposes. Necessary segmentation of server processes will increase stability for integrations with NMS and provide SCADA data to SDG&E's corporate historian.

A primary challenge to SCADA systems is maintaining cyber security of the network in the current threat landscape. This requires constant monitoring and improvements to enhance system security. The implementation of automated security patch software would allow for better efficiency and consistency across SCADA hardware. Consistent upgrades to the operating systems and hardware will be needed to maintain business continuity and system security. Additional challenges include the need for a more advanced reporting and analytics application to fully utilize historical data to improve situational awareness. As the Distribution SCADA system continues to grow, the need increases for additional licensing and the migration of SCADA communications to SDG&E private Long-Term Evolution (LTE) network to improve visibility and reliability of the system.

In 2023, Inter Control Center Protocol (ICCP) was implemented, non-production and will be implemented in production in 2024, allowing for improved situational awareness and data sharing with other business applications. The team will implement the use of a new change management software that will monitor and record system changes for auditing purposes. Fully operational SCADA simulators will provide a necessary training tool for Distribution System Operators that will be integrated with the Oracle Network Management System (NMS) System. A new SCADA test environment will be integrated with Oracle NMS to improve testing between the critical system applications. Necessary segmentation of server processes will increase stability for integrations with Oracle NMS and provide SCADA data to SDG&E's corporate historian. The addition of a redundant non-production development environment allows business continuity in the event of a system emergency where system updates can be performed in an isolated environment and validated before implementation to the production SCADA in line with SDG&E's Operational Technology Standards. SDG&E is preparing for additional hardware and software upgrades in 2025. Efforts will include improvements to the integrations with the company's corporate historian, modifications for more intuitive SCADA alarming for the distribution control center, and continually enhancing the cybersecurity footprint.

### Demand Response Management System ("DRMS") Replacement

SDG&E has over two decades of experience in managing Demand Response ("DR") programs. The DRMS replacement project was targeted to implement a new DRMS system that meets the current and future needs of Demand Response ("DR") customers and the resulting DR programs. This platform allows SDG&E's internal DR team to track and manage the various DR Programs and Pilots via one single platform. The DRMS replacement system is designed to be able to grow and expand, allowing SDG&E to have the capacity to manage and signal smart devices. The new platform allows SDG&E's

DR team to provide a better customer experience as many more customers purchase smart devices and equipment that will be used to provide DR. The DRMS technology is primarily driven by DER integration, but the replacement project was primarily driven by aging IT infrastructure.

*Recent Activity, Challenges, and Outlook*
The new DRMS platform allowed SDG&E to retire these old legacy systems and look to the future. The new SDG&E DRMS system went live on March 28, 2023, and has been consistently updated to include more DR programs.

A significant benefit of the new DRMS platform is that all SDG&E DR programs and Pilots are now under one application. A single application provides scalability and adaptability that will accommodate new DR pathways and capacity, thereby enabling DR to grow for many years.

The role and types of DR programs are changing as we focus more on grid resiliency and reliability. The new DRMS system will allow the management of our existing DR programs and Pilots, our third-party programs and integration of these programs with the CAISO wholesale market. It will be expandable and therefore allow SDG&E to effectively manage future DR programs. These future DR programs will include commercial and residential devices, energy management systems along with battery storage, and electric vehicle to grid applications. The new DRMS system will also improve our third party and customer experience as we move to a more dynamic landscape of dynamic pricing, resiliency and demand flexibility.

# Communications and Cybersecurity Infrastructure

**Fiber Development**
SDG&E's current backhaul fiber optic network is comprised of over 900 miles of fiber connecting over 75 transmission substations. SDG&E is approximately 60% complete with another 590 miles to build towards completing a diverse fiber optic infrastructure network to all remaining substations. The fiber optic network not only provides a direct connection to substation equipment, but it also serves as backhaul and redundant pathways for Long-Term Evolution ("LTE") field area network technology and Microwave links that enables distribution automation devices to be interconnected to back-end control systems. In the 2024 GRC, SDG&E is continuing with the building fiber network through the Fiber Optic for Relay Protection & Telecommunications project, and the HFTD Transmission Fiber Optics project. Both projects are primarily driven by safety and reliability but provide the network foundation for supporting DER integration.

*Recent Activity, Challenges, and Outlook*
By the end of 2023, SDG&E installed 303-miles which of fiber. In 2023, SDG&E installed 29.7-miles which connected 12 Transmission substations. In 2024, SDG&E is scheduled to construct an additional 26-miles which connects 8 Transmission substations.

The two main challenges that impact project delivery are Agency permitting delays and material lead times that vary widely.

SDG&E has increased support for the Fiber Build Infrastructure projects. With the construction of an estimated 30+ miles per year, the long-term goal is to build a complete and diverse fiber network infrastructure by 2032.

**Private LTE**

SDG&E is deploying a privately-owned LTE field area network using licensed radio frequency ("RF") spectrum by means of the Distribution Communications Reliability Improvements ("DCRI") program. The private LTE ("PLTE") network and associated upgraded communication infrastructure will enhance the overall reliability of SDG&E's communication network, which is critical for enabling fire prevention and public safety programs. In the meantime, SDG&E envisions this network will also serve as a foundational network for DER integration efforts. Similar to the Fiber development projects, the private LTE Project is also primarily driven by safety and reliability but provides the foundation for supporting DER integration. The project is an ongoing program and is expected to continue through 2030.

*Recent Activity, Challenges, and Outlook*

The PLTE deployment is underway with 58 sites built and more slated for 2024. The acquisition of the PLTE Spectrum has been completed for San Diego and Imperial counties. Migration of existing sites, end uses, and system protection technologies have begun with a target of approximately 800 being converted in 2024.

SDG&E expects to ramp up in the coming years the actual number of sites that are installed per year.

Most sites planned for base station installation have engineered steel foundation piles that will have telecommunication antennas at the top of the pole and electric (12 kV and below) attachments in the middle of the pole. Poles are currently undergoing standardization. Development of pole specification, including workspace, operational, and manufacturing requirements, has taken longer than expected. To complete the pole standardization, three pilot sites were selected and pole orders were placed at the end of 2023. In 2024, construction of these three pilot sites and standardization of pole designs is expected to be completed, which will accelerate the program in 2025 and beyond. In addition, process improvements with substation and transmission facility engineering and operations groups are being developed to ensure proper design and construction and streamline the activities to help accelerate the program.

SDG&E projects completion of the PLTE project with full coverage of our service territory by 2030.

### Cyber Security

SDG&E has established holistic Operational Technology ("OT") and Information Technology ("IT") and cloud cyber security strategies to mitigate cyber risks and protect its systems and customers from cyber- attacks and potential catastrophic events. These integrated efforts are ongoing and continue to evolve as requirements, standards, policies, and threats change. Our OT cybersecurity program has quickly grown into a function utilizing technology and standards to enhance engagement across the business, expand asset visibility and enable enhanced vulnerability management capabilities. We have invested in measures to strengthen perimeter and internal defenses and have adopted use of modern technologies across various core cyber infrastructure capabilities. SDG&E will continuously assess associated cyber risks and evaluate new technology that can be adopted to mitigate these risks. SDG&E also plans to continue to actively engage in state initiatives working with broader stakeholders.

SDG&E will continue to support broader business objectives and adoption of modern grid, cloud, OT and IT systems and infrastructures by evolving security controls, utilizing, and conforming to NIST standards, and continuously assessing internal and external threats. In partnership with various business entities, SDG&E continues to develop a culture of cyber awareness and vigilance, ensuring our staff and contractors are informed on top security risks such as social engineering, phishing, and other related threat actor tactics.

SDG&E relies on Federal, State, and Local government partnerships for intelligence feeds along with peer utility industry relationships and private (subscription) based services for Industrial Control Systems (ICS) cybersecurity threat intelligence. We also obtain cybersecurity threat intelligence from a variety of entities and sources, including Information Sharing and Analysis Centers (ISACs), the Federal Bureau of Investigations (FBI), FERC, the DOE, the Department of Homeland Security (DHS), CISA, Transportation Security Administration (TSA) and a variety of US intelligence community agencies. Information from threat intelligence sources in the utility industry continues to reveal adversaries that are using advanced tradecraft in their attempts to access our nation's utility systems.

The Cybersecurity program utilizes risk management frameworks, including but not limited to the National Institute of Standards and Technology (NIST) Cybersecurity Framework, Center for Internet Security (CIS-20), NIST 800-53, and MITRE ATT&CK framework. Additionally, SDG&E complies with all applicable laws and regulations both at the State and Federal level.

# Engineering Software and Planning Tools

## Customer Facing Portals

To improve customer experience and support customers' energy transition interests, SDG&E has rolled out customer facing portals such as the Distribution Interconnection Information System ("DIIS") and Distribution Resource Planning("DRP") Data Portal, which have provided greater ease and flexibility to customers adopting DER technologies. A new Microgrid Portal was recently developed for local and tribal governments to support community resiliency planning. A description of the portals, recent updates and future lookout are included below.

*DRP Data Portal*
In Rulemaking 14-0808-13, issued on February 2015, the CPUC required SDG&E and other utilities to publish a DRP Data Portal. The portal is comprised of an Integration Capacity Analysis (ICA) map which includes information from SDG&E's annual Grids Needs Assessment (GNA) report, and Distribution Deferral Opportunity Report (DDOR), among other data types. The ICA maps published within the portal contain data from both the Generation ICA and the Load ICA. The data presented in the ICA map provides the estimated feeder level integration capacity results at a section level or node level. The Data Portal also hosts a data layer to allow registered customers to download SDG&E's GNA and DDOR reports.

*Recent Activity, Challenges, and Outlook*
Since 2021, in accordance with Administrative Law Judge's September 9, 2021, Ruling Ordering Refinements to the Load ICA, SDG&E has been working on implementation of several modeling changes to Load ICA. SDG&E made progress on the development of the modeling changes and intends to complete these changes by the first quarter of 2025. The data portal is also currently in the scope of the High DER Grid Planning OIR (R.21-06-017); additional changes may be identified and proposed as appropriate.

*Interconnection Portal*
In 2013, SDG&E launched an automated application process and online tool, DIIS for contractors and customers to manage interconnection projects. DIIS is a self-service portal which enables customers and contractors to fully manage the lifecycle of NEM projects. The tool allows users to create projects, receive real time status updates and notifications, and is available 24/7. As

mentioned in the overview, SDG&E's DIIS has greatly facilitated its customers embracing DER adoption quickly and easily. To date, SDG&E has authorized over 317,000 DER interconnection requests advancing over 2,185 MW of generation. Moreover, DIIS allows fast track applications to be processed in an average of 3 days for residential applications.

*Recent Activity, Challenges, and Outlook*
Since 2021, SDG&E has been working on further DIIS reporting functionality to support Rule 21 for CPUC reporting and auditing requirements. New features are being designed and deployed to intake Wholesale Distribution Access Tariff (WDAT) customer applications, provide new project management features to better track design, construction, and interconnection activities, in addition to dissemination of generation customer information to distribution operators to support distribution grid operations while supporting wholesale market participation. As of March 2024, SDG&E is nearing the first phase of releases for the DIIS upgrades related to the WDAT and tracking (scheduled for Q2 – Q3 of 2024).

*Microgrid Portal (Tribal/Local Government Portal)*
SDG&E completed development, in November 2023, of a separate, access-restricted data portal for local and tribal governments. The development and activation of the portal complies with requirements specified in the CPUC Decision 20-06-017.[2] This portal supports local and tribal efforts to promote community resiliency.
community resiliency.

The portal includes a map application that displays GIS data. The GIS data depicts (a) planned grid investments, (b) high fire threat districts, (c) electrical infrastructure and (d) weather-related factors that led to the decision to de-energize from each prior PSPS events and the resulting distribution and transmission line outages.

## Planning Tools

In the past decade, SDG&E has implemented many updates to its planning tools to meet the deliverables identified in the multiple tracks of the Distribution Resources Plan (DRP) proceeding. These tracks required creation of new analyses such as ICA for both generation and load and DER Growth Scenario forecast processes. The scale of the data and analysis requires specific and customized tools to process and promote data quality and accuracy. As discussed earlier, the ICA tool is housed within the DRP data portal. Information in the DRP data portal is intended to provide information that informs customers' efforts to interconnect new generation and to add load. ICA takes input from GIS, SCADA and AMI and is intertwined with existing planning tools such as Synergi and LoadSEER.

In 2015, SDG&E adopted a third-party proprietary software forecast toolset, LoadSEER, from Integral Analytics, Inc., to disaggregate the CEC's system-level forecast of loads and Behind-The-Meter (BTM) DER additions to the circuit level. This tool provides SDG&E a geospatial load disaggregation methodology and allows integration of DER forecasts required through the DRP DER Growth Scenarios. The enhanced forecast capability helps determine the timing and duration of future forecast distribution capacity needs. In 2020, SDG&E created a tool that queries the coincident contribution of DER resource impacts during each circuit's/bus's forecast peak time to better inform the "indirect distribution cost" utilized in the IDER Avoided Cost Calculator (ACC) proceeding. SDG&E currently uses a variety of methodologies, tools, and software including Synergi and LoadSEER, to perform the analyses necessary to accurately identify the planned infrastructure improvements that will prepare the distribution system for high electrification.

*Recent Activity, Challenges, and Outlook*

As discussed above in the DRP Data Portal section, since 2021, SDG&E has been working on implementation of several modeling changes to Load ICA. SDG&E has also been working on continuous improvement of analytical accuracy for both Load ICA and Gen ICA. Further, the changes to Load ICA are driving and will continue to drive several changes to SDG&E's distribution system modeling and analysis software, Synergi, including but not limited to software updates.

# Conclusion

The projects and programs that SDG&E has implemented under grid modernization support SDG&E's grid modernization vision and align with the state goals regarding DER adoption, transportation electrification, and decarbonization. As California continues to electrify, SDG&E understands the importance and value of DERs in meeting the significantly increased electric demand electrification will bring. At the same time, an increasing number of DERs add operational complexity. The tools and processes described in this Grid Modernization Report will allow SDG&E to continue to provide safe and reliable distribution service. The investments SDG&E is making today in its grid management tools, cybersecurity and communication, and engineering and planning tools will allow SDG&E to have fewer limits on distribution circuit hosting capacity, more dynamic charging limits for battery storage customers, and more nuanced DER management under abnormal configurations due to advancements in inverter control. All these enhancements allow for the safe and reliable integration of more DER of all varieties onto the electric system, supporting electrification and the high DER future.

SOUTHERN CALIFORNIA EDISON COMPANY

# Grid Modernization Progress Report

March 15, 2024

# Executive Summary

Southern California Edison Company's (SCE's) vision is to transform its distribution grid into a secure, flexible, networked platform that adapts to changing needs driven by higher customer distributed energy resource (DER) adoption, optimizes DER value through advanced grid management, supports customer electrification needs, and ensures grid reliability and resiliency in the face of climate change. This vision requires the continued investment in five categories of technologies and functional capabilities: (1) Engineering and Planning (E&P) Software Tools, (2) Grid Management System (GMS), (3) Communications and Cybersecurity, (4) Automation, and (5) DER Hosting Capacity Reinforcement. SCE made substantial progress across these five areas between 2021 and 2023, and this report highlights the accomplishments, use cases, benefits, and challenges for the first three areas (E&P Software Tools, GMS, and Communications and Cybersecurity).

As capabilities are deployed, the GMS will work in concert with field devices to provide customers with a safe, reliable, and resilient grid that powers our customers' clean energy choices. The GMS will also help increase DER hosting capacity through its load and DER management capabilities. SCE's modern communications systems are replacing SCE's legacy technology with low latency, high bandwidth, secure communications to support modern grid capabilities. Over the next few years, SCE will continue to enhance the E&P Software Tools to continue advancing our system planning approach and support SCE's future integrated planning vision that will allow us to optimize our levels of investment needed to address various types of future grid needs under increasing levels of uncertainty, including the location and magnitude of load and DER growth.

# Grid Modernization Progress Report

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# I. Introduction

## 1. Background

California Assembly Bill (AB) 242 amended Section 916.6 of the Public Utilities Code to require that "On or before February 1, 2023, and biennially thereafter, the commission, in consultation with the Independent System Operator and the Energy Commission, shall report to the Legislature and the Governor on the progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources on the state's distribution and transmission grid and ratepayers."[1]

SCE has prepared this Grid Modernization Progress Report to update the California Public Utilities Commission (Commission) on SCE's overall Grid Modernization vision and approach and its Grid Modernization efforts from 2021 to 2023 and provide an overview of its near-term Grid Modernization plans. The purpose of this report is to support the Commission in its preparation of the biennial update to the Legislature on the progress of modernizing SCE's electric distribution system.

## 2. Grid Modernization Overview

A modern distribution grid is instrumental for addressing climate resiliency, enabling a path to carbon neutrality by 2045, facilitating customer adoption of electrified solutions in the transportation and building sectors, and more broadly, achieving California's climate and air quality goals. SCE's vision is to transform its distribution grid into a secure, flexible, networked platform that adapts to changing needs driven by higher customer DER adoption, optimizes DER value through advanced grid management, supports customer electrification needs, and ensures grid reliability and resiliency in the face of climate change. This vision requires the development of a portfolio of foundational capabilities that enable Advanced Grid Management, DER Optimization, and Customers as Grid Partners. Developing such a portfolio will require SCE to continue investing in the five categories of new technologies and functional capabilities outlined in SCE's Grid Modernization Plan (GMP).[2] Figure 1 summarizes these technologies and their necessity in realizing customer benefits.

[1] Public Utilities Code § 913.6 (a).
[2] Please refer to A.23-05-010, Test Year 2025 General Rate Case Application of Southern California Edison Company (U 338-E), SCE-02 Vol. 06 – Grid Modernization, Grid Technology, and Energy Storage, filed May 12, 2023.

**Figure 1**
**Grid Modernization Technologies and Customer Benefits**

| | |
|---|---|
| Engineering & Planning Software Tools | A modernized distribution planning process further integrates DERs into the process and supports customer affordability by improving capital efficiency and helping customers identify DER opportunities. |
| Grid Management System | Advanced distribution management systems in concert with field devices will provide customers with a safe, reliable and resilient grid that powers clean energy technologies. |
| Communications | Modern communication systems will replace legacy technology with low latency, high bandwidth, secure communications to support modern grid capabilities. |
| Automation | Field devices such as advanced switches and line sensors will provide situational awareness and operational flexibility to improve customer safety and reliability and realize greater value from customer DERs. |
| DER Hosting Capacity Reinforcement | Technologies such as load and DER management will increase hosting capacity and drive further DER adoption, while circuits that exceed planning limits will be upgraded where needed. |

# II. Grid Modernization Activities from 2021 through 2023

This section summarizes the approach, status, use cases, and challenges of three aspects of Grid Modernization, which are: (1) Grid Management System (GMS), (2) Communications and Cybersecurity, and (3) Engineering and Planning (E&P) Software Tools. SCE has also made progress in Automation and DER Hosting Capacity Reinforcement, but the scope of this report follows guidance provided by the Commission and therefore does not cover these areas.

## 1. Grid Management System

### A. Description

SCE's GMS is an advanced software platform that integrates multiple systems designed to monitor, manage, and optimize the performance of our increasingly dynamic electric grid characterized by high DER penetration. The GMS will provide SCE with the requisite capabilities to not only manage SCE's grid assets, but to also engage with customers and their DERs so that they become a core part of operating the grid. The GMS is being deployed over four Phases: (1) Advanced Distribution Management System (ADMS), (2) DER Management System (DERMS), (3) Advanced ADMS & DERMS, and (4) Grid Platform. In Phase 1, the ADMS is replacing SCE's legacy distribution management system (DMS) outage management system (OMS), such that the ADMS will provide the combined DMS/OMS functionality. In Phase 2, SCE will introduce additional DER management functions such as the short-term forecasting engine, optimization engine, and microgrid management, through the DERMS. In Phase 3, SCE will enhance the ADMS and DERMS functions implemented in Phases 1 and 2, such as by expanding mobile grid operations for field personnel, augmenting outage metrics reporting functions, and enhancing operator training system and modeling capabilities to include advanced scenarios likely to arise from higher DER penetration and changing weather conditions. One example includes expanding mobile grid operations to allow further consolidation of field personnel work into the single ADMS platform. In Phase 4, SCE will initiate Grid Platform enhancements to improve SCE's capabilities in the areas of load management (including electrical vehicle (EV) charging), substation device management, and power quality management. Additional details on the functions and expected benefits are included in the Use Cases/Benefits section below. Each GMS release is supported by organizational change management (OCM) activities and employee training on the new capabilities.

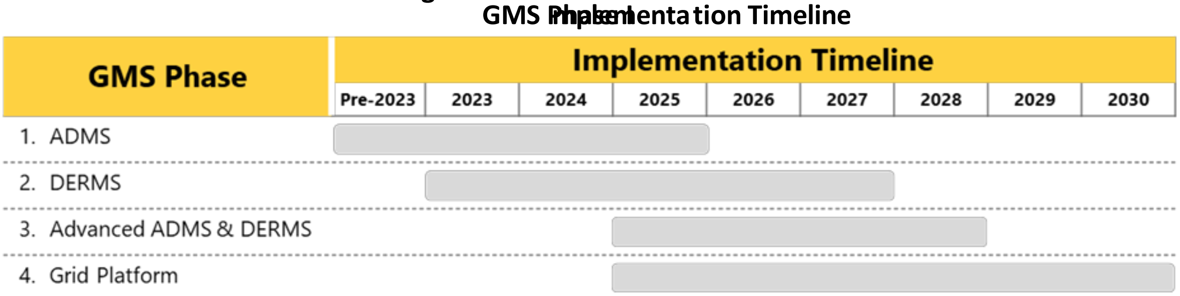
## B. Status

In 2021, SCE completed deployment of the distribution SCADA platform, marking the successful achievement of a major GMS milestone for Phase 1. SCE also completed the build phase and initiated site acceptance testing (SAT) of the Phase 1 distribution management functions. Additionally, SCE initiated design activities for the Phase 2 DERMS platform.

In 2022, SCE successfully deployed the GMS data historian in the production environment, another key implementation. The data historian and distribution SCADA upgrades are highly resilient and scalable to meet SCE's future ADMS computational requirements. SCE also completed factory acceptance testing (FAT) of the ADMS distribution management and outage management functions. Figure 2 summarizes the timeline for completing the four GMS phases.

In 2023, SCE completed the SAT and technical implementation of the Phase 1 base DER management capabilities (or Base DERMS), which will allow SCE to monitor and dispatch DERs. SCE also continued its SAT activities for the DMS functions planned for deployment in 2024, which include distribution system state estimation (DSSE) and fault location, isolation and service restoration (FLISR).

**Figure 2**
**GMS Implementation Timeline**




SCE is currently performing SAT of the ADMS and plans to deploy the ADMS to replace the DMS functions in 2024 (including several base DER-management capabilities). The OMS functions are planned for deployment in 2025.

## C. Use Cases/Benefits

Grid management is essential to managing the grid safely and reliably. As grid operations continues to increase in complexity due to more frequent and extreme climate events and higher amounts of DERs and electrification, Grid Modernization builds upon SCE's foundational grid management capabilities to improve resilience and enhance situational awareness and grid flexibility to address these challenges. SCE is implementing the four high-level capabilities for grid management identified in Table 1.

**Table 1**
**GMS-enabled Capabilities**

| Capability Category | High-level Capabilities |
|---|---|
| **Grid Management**<br>Enables grid operators to monitor grid conditions in real-time, control field devices remotely, manage and optimize use of load and DERs, and monitor and manage power quality | 1. Core grid management functions<br>2. Advanced grid management and optimization<br>3. Load and DER management and optimization<br>4. Power quality management |

In Phase 1, the ADMS will enable SCE system operators, operations engineers, and other users to receive and analyze real-time information on customer energy usage, system power flows, system outages and faults, and DER performance. The ADMS will also provide the necessary interfaces between the operations control centers and grid devices, thereby facilitating SCE's handling of grid events such as planned and unplanned outages and load transfers. Additional ADMS functions include distribution system state estimation (DSSE), load volt/VAR management, mobile grid operations, and fault location, isolation, and service restoration (FLISR). The ADMS also includes basic DER management functionality that enables DER program registration and enrollment, and DER monitoring and manual control via the IEEE 2030.5 communications protocol, which that will enable SCE to communicate with DER aggregators or other third parties in accordance with SCE's Tariff Electric Rule 21[3].

In Phase 2, the DERMS will improve SCE's ability to perform short-term DER forecasting to anticipate and manage potential grid issues and optimize DER dispatch decisions. SCE will also introduce ADMS enhancements such as Public Safety Power Shutoff (PSPS) automation, advanced red flag warnings, and automatic wire down detection and isolation—all which support SCE's wildfire mitigation efforts.

In Phase 3, enhancements to the ADMS and DERMS will expand mobile grid operations to allow further consolidation of field personnel work into the single ADMS platform; augment the outage metrics reporting functions; enhance operator training system to simulate advanced scenarios likely to arise from higher DER penetration; and enhance the modeling capabilities to include DER responses to changing weather conditions, microgrid islanding scenarios, storm condition simulations, and failed equipment scenarios. This phase will also introduce storm analytics to help optimize SCE's response to storm events with available resources to accelerate service restoration.

[3] Electric Rule 21 is a tariff that describes the interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system. The tariff provides customers wishing to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the distribution and transmission systems at the local and system levels.

In Phase 4, Grid Platform enhancements will improve SCE's capabilities in the areas of load management, substation device management, and power quality management. The load management enhancements will enable SCE to continuously manage load, including load from EV charging. This capability will include indirect load control through aggregators or other third parties, direct load control, where appropriate, and it will also support customer demand flexibility through delivery of price signals to customer devices. The substation device management enhancements include deployment of software on the Common Substation Platform that enables remote management of applications and devices operating within substations. Finally, the power quality management platform will include a model of the entire grid (transmission and distribution) that consolidates power quality sensor data to enable robust visibility and situational awareness, enables diagnosis of historical power quality issues, and simulates distributed control and DER and customer behaviors.

As noted above, between 2021 and 2023, SCE upgraded the distribution SCADA platform and GMS data historian and completed the technical implementation of the base DER management functions. These are foundational to the GMS functionalities such as distribution and outage management, load and DER management, and power quality management enabled throughout the four GMS Phases. SCE anticipates these capabilities will provide future benefits in the areas of safety, reliability, climate resiliency, decarbonization, customer empowerment and economic efficiency.

### D. Challenges

The schedule has been impacted by various challenges, including vendor product development delays caused by COVID-19, supply chain constraints, the conflict in Ukraine, and the need to address cyber-related concerns with the ADMS product. As a result, SCE was required to work with the vendor to revise the schedule for Phase 1 and Phase 2. Based on this revised schedule, SCE now expects to deploy the DMS, OMS and base DER management functions between 2024 and 2026, which represents an extension of the deployment timeline for Phase 2 from five years to seven years.

## 2. Communications and Cybersecurity Infrastructure

### A. Description

SCE currently connects distribution substations and distribution automation devices using its legacy and aging mesh radio-based communications system known as NetComm. The new Field Area Network (FAN) will replace the NetComm system with a private wireless LTE/5G system capable of supporting the capacity, speed, and connectivity needs of current and future grid devices to support automation.

In addition to FAN, the Common Substation Platform (CSP) is a computing platform (hardware and software) that acts as the communication and control hub between the operations control center and substation equipment. The CSP is designed to enable remote data acquisition and automatic control over substation devices. In addition, the CSP will also include the software-based algorithms that optimize DER and grid device performance and will provide secure communications between the substation and back-office systems.

The Grid Modernization Cybersecurity program focuses on addressing the comprehensive security and data protection needs of all new infrastructure and application assets being added through SCE's Grid Modernization program, including the FAN and CSP communications, GMS, and the external facing Engineering and Planning Software Tools.

## B. Status

The Federal Communications Commission (FCC) decision to auction the Citizens Band Radio Services (CBRS) Spectrum in 2020 offered a unique acquisition opportunity as the availability of affordable spectrum to pursue private LTE technology was previously very limited. Although unanticipated at the time of SCE's Track 1 forecast in the 2021 GRC, SCE's successful procurement of the CBRS licensed Spectrum channels allows SCE to move forward with a private LTE solution for FAN instead of the upgraded mesh radio solution that was previously planned. Following the CBRS spectrum acquisition in 2020, SCE conducted competitive industry solicitations in 2021 and 2022 for the FAN equipment and services. During 2021 and 2022 SCE also focused on developing the new private LTE solution design and execution plan. SCE began its eight-year FAN deployment in 2023 by deploying the network core and the first radio access network (RAN) site, which went "on air" and was used for SCE's first 5G call in a production environment in December of 2023.

For Grid Modernization cybersecurity, SCE completed the architecture assessment and cybersecurity tool designs based on the needs of the overall Grid Modernization program. SCE also implemented the first wave of core cybersecurity tools. In 2023, SCE completed implementation and go-live of the grid extranet at SCE's grid data center to help secure field area communications.

SCE is currently deploying a second wave of prioritized cyber tools and continuing to deploy the FAN by constructing additional RAN sites as well as deploying edge radios for the grid equipment (e.g., switches, capacitor banks, etc.). SCE is also continuing to deploy CSP at targeted substations.

## C. Use Cases/Benefits

Communications is foundational to enabling various grid management functions, including real-time situational awareness, analyzing and resolving grid reliability issues, as well as integrating and managing DERs. These functions are enabled by the GMS communicating securely with DERs and field devices at a speed and bandwidth that support current and future monitoring and control requirements.

SCE's new FAN is a critical component of the Grid Modernization program, enabling real-time, cyber-secure communications between grid devices (including DERs, DER aggregators and other third parties), distribution substations, and SCE's operations control centers, which will support the use of DERs to provide reliability services to the distribution system. The FAN also contributes to mitigating the cybersecurity risk in the existing legacy field network, which was ranked as one of the top nine risks in SCE's 2018 and 2022 Risk Assessment Mitigation Phase (RAMP) filings. The FAN will be capable of connecting over 250,000 devices and reducing the real-time information transfer delays from a couple of minutes under the NetComm system to a few seconds with the new FAN system. The FAN also incorporates modern cybersecurity capabilities, which will allow SCE to continue to protect data from cyber threats while supporting integration of 3rd party devices.

The CSP is a computing platform (hardware and software) that acts as the communication and control hub between the operations control center and substation equipment. The CSP is designed to enable remote data acquisition and automatic control over substation devices. In addition, the CSP will also include the software-based algorithms that optimize DER and grid device performance and will provide secure communications between the substation and back-office systems. The CSP workstream will deploy the new computing platform in distribution substations using virtualization technology to monitor, manage, control, and provide cybersecurity to substation equipment. The CSP will include redundant servers to mitigate potential server outages. SCE will manage the CSP remotely and can therefore deploy software packages remotely, including cybersecurity upgrades, from a central operations center.

The Grid Modernization Cybersecurity program focuses on addressing the comprehensive security and data protection needs of all new infrastructure and application assets being added through SCE's Grid Modernization program. This activity is necessary to prepare SCE's systems and operational processes to achieve California's 2045 net-zero carbon mandate and is focused on improving bulk power management, integration of grid and customer devices, integrated load management strategies, and customer electrification adoption and affordability.

As described above, between 2021 and 2023, SCE enabled the initial wave of cybersecurity tools and associated functionalities and implemented grid extranet at SCE's grid data center, all of which are foundational to SCE's communications and cybersecurity capabilities. SCE anticipates these capabilities will support the realization of future benefits in the areas of safety, reliability, decarbonization, customer empowerment and economic efficiency.

### D. Challenges

For the Communications scope, SCE faced a significant challenge in planning and successfully participating in the FCC Spectrum Auction 105. As a result, the FAN implementation schedule had to be postponed by approximately 2 years. Secondly, the tasks of building the new FAN across 15 counties, migrating all existing 30,000+ devices, and decommissioning the legacy NetComm system are nothing short of monumental. Undoubtedly, one of the most challenging aspects for the FAN is the physical construction and commissioning of over 800 Radio Access Network (RAN) sites across the service territory over the next seven years. SCE will be maintaining different field communications environments during the transition from NetComm to FAN while prioritizing reliability and security during this changeover, which may result in new obstacles to overcome.

## 3. Engineering & Planning Software Tools

### A. Description

SCE's E&P Software Tools will improve SCE's ability to identify DER opportunities, increase the economic efficiency of SCE's grid planning and project and portfolio management, and enhance the customer interconnection request process. SCE's E&P tools include the Grid Connectivity Model (GCM), a software model of the electrical connectivity and hierarchy of SCE's entire electrical grid; the Grid Analytics Application (GAA), which performs analytics and visualization of historical load data; the Long-term Planning Tool and Short-term Planning Tool (LTPT-SMT), which performs the load and DER forecasting, load flow analysis, and project management; the Distribution Resources Plan External Portal (DRPEP), a portal for customer access to DRP reports; and the Grid Interconnection Processing Tool (GIPT), a tool that allows customers and SCE to connect electrical generation and load to the grid more quickly and efficiently. Each E&P tool is supported by organizational change management (OCM) activities and employee training on the new capabilities provided by the tools.

## B. Status

During 2021 and 2022, SCE performed multiple enhancements to the E&P tools to improve the integration between the tools and augment their capabilities. The GCM included enhancements to the distribution connectivity model and further integrated the as-built connectivity modeling information with the GAA, LTPT-SMT, and DRPEP. The GCM also supported the Wildfire Mitigation program's aerial inspection efforts by providing transformer structure-to-feeder information.

SCE enhanced the GAA by automating the creation of 8,760 hourly load profiles and performing several load profile improvements, such as calculating daily peak kilowatt-hour (kWh) data, enhancing the user interface, performing backfill of historical Advanced Metering Infrastructure (AMI)/DER profile data for new nodes, and automating the interface with the GCM. The time-series based load and generation profiles prepared by GAA are foundational to enabling SCE's transition to profile-based planning.

SCE implemented several planning functions in LTPT-SMT, including the partial implementation of load flow analysis. SCE used this as part of its annual planning process beginning in 2022 for a limited part of its distribution system and plans to use it to support systemwide profile-based planning in 2025. SCE performed enhancements to improve weather station data accuracy and made other data cleansing and validation modifications, including integrating additional internal and external planning inputs into forecasting analysis, enabling profile-based power system analysis, and integrating ICA with forecasting analysis to inform system planning.

SCE performed DRPEP enhancements to continue publishing the DRP reports, GNA, DDOR, LNBA and ICA,[4] address new Commission requirements for publication, automate the 15/15 Rule,[5] and address additional capabilities consistent with the Commission decision on the ICA Working Group's (WG) Final ICA WG Long Term Refinements Report. Additional requirements included

[4] Grid Needs Assessment, Distribution Deferral Opportunity Report, Locational Net Benefits Analysis and Integration Capacity Analysis, respectively.

[5] The "15/15 Rule" requires that any aggregated information provided by SCE must be made up of at least 15 customers and a single customer's usage must not exceed 15% of the total usage of an assigned category. See, D.97-10-031.

identifying the location of all approved transmission projects, adding Fire Map layers, and implementing a microgrid portal using the DRPEP platform.

Finally, SCE implemented the Wholesale Distribution Access Tariff (WDAT) DER interconnection tariff process workflows into GIPT to support customer application submittal and review, and technical evaluation and contract development for WDAT applications.

In 2023, SCE continued to deliver additional planning capabilities, enhance those already enabled, and address challenges implementing system-wide load flow analysis. SCE enhanced the GCM services and connectivity modeling to support site acceptance testing of SCE's Advanced Distribution Management System (ADMS) and improved the integration of GCM with DRPEP.

SCE enhanced its ability to perform capacity analysis by making several improvements to load profile development. This included automating the syncs between the modules that provide the usage data and construct profiles, enhancing the GAA interface, and introducing the ability to aggregate user-sourced meter groupings to prepare load profiles.

To enhance the forecasting process, SCE also began the transition from circuit-level forecasting to transformer structure-level forecasting, which should improve the precision and efficiency of SCE's capacity planning and ICA processes. This also included developing an approach to aggregating transformer structure-level forecast to various other nodes upstream of the transformer in the planning hierarchy (e.g., circuits and substations). SCE also automated the processing and loading of weather data used for forecasting.

SCE performed upgrades to DRPEP and the microgrid portal, including adding new layers for distribution circuits and PSA locations, enabling customers to download ICA files in bulk, and other technical upgrades. SCE also added heat maps to DRPEP to allow customers to more easily identify potential locations for DER siting.

Finally, SCE enhanced GIPT to enable WDAT contract management and legacy project migration into GIPT and implemented the Transmission Owner Tariff (TOT) interconnection tariff application submittal and review processes. SCE also augmented the GIPT's DER data manager functionality, which provides DER information to GCM for inclusion in the grid connectivity modeling.

Over the next few years, SCE will continue to build upon the progress achieved to-date by delivering additional planning capabilities, enhancing those already enabled, and addressing challenges implementing system-wide load flow analysis. This will include completing SCE's transition to profile-based capacity planning by creating a dashboard that aggregates information from the various E&P software tools and enables system planners to evaluate the entire system and generate planning summaries. This will also enable SCE to perform end-to-end planning for multiple growth scenarios, accelerate the consideration of DERs as potential grid solutions upfront within the capacity planning process, and support SCE's future integrated planning approach that will allow us to optimize our levels of investment needed to address various types of future grid needs and drivers under increasing levels of uncertainty.

## C. Use Cases/Benefits

As the demands placed on our grid continue to grow, including those from DER growth and climate-driven events, SCE needs to improve its ability to address these growing needs while maintaining customer affordability. SCE's E&P capabilities help to integrate DERs into SCE's electric system planning processes, consider multiple future load and DER growth scenarios to better identify grid needs, and determine no-regrets solutions to resolve the forecasted grid needs. This requires more granular DER and load forecasting, power flow modeling and analysis to identify grid needs and potential solutions at the sub-circuit level. This also necessitates streamlined interconnections of customer DERs and load. SCE is implementing the five high-level E&P capabilities identified in Table 2.

**Table 2**
**E&P Software Tools-Supported Capabilities**

| Capability Category | High-level Capabilities |
|---|---|
| **Engineering & Planning**<br>Integrates DERs into grid planning processes, increases precision of grid needs and solutions identification, enables scenario analysis, and supports optimal project and portfolio management | 1. Electrical connectivity and hierarchy modeling |
| | 2. Time series-based capacity planning |
| | 3. Project and portfolio optimization and management |
| | 4. DER hosting capacity and deferral opportunity reporting |
| | 5. Customer interconnection request automation |

Between 2021 and 2023, SCE focused on integrating the GCM with the other E&P tools to improve the efficiency of the overall planning process and reduce the need for manual processes and rework that can result from manual processes. SCE advanced the E&P tools to support SCE's migration to profile-based capacity planning by enhancing the performance of the tools (such as through weather data improvements and implementing functions to identify discrepancies between the tools; and transitioning to transformer-structure level forecasting), and partially implementing the load flow analysis engine. These functions have supported SCE's current hybrid approach to profile-based planning that uses profile-based load and DER forecasts to identify potential violations. In 2025, SCE plans to use load flow analysis to identify grid needs with much greater temporal and spatial precision. This should improve the economic efficiency of the annual capacity planning process while also improving the potential to identify opportunities to defer traditional infrastructure investments with DERs. In addition to the planning tool uses, SCE also began using GIPT to process WDAT interconnection requests in 2022 and completed the first phase of implementing TOT in 2023.

## D. Challenges

Challenges with the load flow analysis tool have limited SCE's ability to perform systemwide load flow analysis. These challenges include (1) the limited scalability of the tool to handle SCE's approximately 4,500 distribution circuits, (2) its inability to analyze multi-voltage substations, (3) network configuration challenges (which equates to about 20% of SCE's distribution infrastructure), (4) tool instability, and (5) an inability to view and interact with the analysis results. SCE expects to overcome these challenges and complete its transition to profile-based planning within the next few years.

# III. Conclusion

During 2021 and 2022, SCE made substantial progress with the GMS, Communications and Cybersecurity, and E&P Software Tools. For the GMS, SCE deployed the distribution SCADA platform and data historian, and completed the build phase of the ADMS distribution management functions. In 2023, SCE completed the SAT and technical implementation of the Phase 1 base DER management capabilities, which will allow SCE to monitor and dispatch DERs. SCE also continued its SAT activities for the DMS functions planned for deployment in 2024. SCE is currently performing site acceptance testing of the ADMS and plans to deploy it to replace the DMS functions in 2024 (including several base DER-management capabilities). The OMS functions are planned for deployment in 2025. As capabilities are deployed, the GMS will work in concert with field devices to provide customers with a safe, reliable, and resilient grid that powers our customers' clean energy choices.

In the area of Communications and Cybersecurity, during 2021 and 2022, SCE conducted competitive industry solicitations for the FAN equipment and services and developed the new private LTE solution design and execution plan. In terms of cybersecurity, SCE implemented the first wave of core cybersecurity tools and the grid extranet at SCE's grid data center. In 2023, SCE initiated its eight-year FAN deployment by deploying the network core components and constructing the first RAN site. SCE also completed implementation and go-live of the grid extranet at SCE's grid data center to help secure field area communications. SCE's modern communications systems, including the FAN and CSP, are replacing SCE's legacy technology with low latency, high bandwidth, secure communications to support modern grid capabilities.

The E&P Software Tools received multiple enhancements during 2021 and 2022 to increase the integration between the respective tools and to augment their capabilities. Such enhancements included improving the integration of the GCM with the other planning tools, partial implementation of the load flow analysis tool, and completion of WDAT in GIPT. In 2023, SCE continued to deliver additional planning capabilities, enhance those already enabled, and address challenges implementing system-wide load flow analysis. Over the next few years, SCE will continue to enhance the E&P Software Tools to further advance our system planning approach and support SCE's future integrated planning vision. This in turn will allow SCE to optimize the levels of investment needed to address various types of future grid needs under increasing levels of uncertainty, including the location and magnitude of load and DER growth.

# APPENDIX C: IOU RELATED PILOTS

The Energy Division at the California Public Utilities Commission submitted a data request to each IOU requesting information on ongoing and planned pilot programs. The information is intended to inform stakeholders of ongoing and upcoming utility pilot projects related to a High DER Future. The Energy Division requested information on pilots related to the following topics:

1. flexible interconnection (generation)
2. flexible energization (load)
3. virtual power plants, (VPP) vehicle to grid integration
4. dynamic and real-time rates (e.g., CALFUSE),
5. Load Control Management Systems (LCMS) and Automated load control
6. power control systems (PCS)
7. data sharing,
8. Distributed Energy Resource (DER) Orchestration
9. Distributed Energy Resource Management System (DERMS), Automated Distribution Management Systems (ADMS), and DER visibility (to DSO & to CAISO), and
10. any other pilots deemed relevant by your organization.

For each pilot, the Energy Division requested the following details:

- Pilot Topic (from above list): Description of what gap or grid need is being addressed.
- Pilot Name: Official and colloquial names of the pilot
- Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: Indicate procedural home for the pilot. Include relative ordering paragraphs and/or directives.
- Pilot Objective: What does the pilot aim to do.
- Target Population: Who is the pilot directly affecting.
- Pilot Action/Description: What does the pilot actually do
- Pilot Dates Effective: Begin and end dates of pilot.
- Was the Pilot Derived from the Energy Program Investment Charge (EPIC)
- Pilot Budget: Dollar amount approved for pilot
- Subject Matter Expert Contact: Utility Contact
- CPUC Energy Division Contact: ED Contact
- Results of any evaluations and/or dates of future planned evaluation

Each IOU's response is provided below.

# Pacific Gas & Electric (PG&E) Related Pilots

**Energy Division Data Request for Information on Ongoing and Planned Pilot Programs.**

The following section complies with the data request requirements for topics and subtopics cataloguing Pacific Gas and Electric Companies (PG&E) portfolio of 2023 on going and planned pilots relative to Future Grid Workshop Series, high DER Future track 2 phase 1. The following pilots within this data request are in various stages of approval and or modification for approval. In some cases, pilots may not be approved, pursued, or canceled for any reason PG&E should deem necessary and appropriate. Each section has a description relative to the specific topic requested. An attached spreadsheet captures all the relative pilots and the required sub-categories. Below is an 'At a Glance' table of the pilots described in the summary and in the detailed spreadsheet. Included at the end of this master description of current pilots are a compilation of pilots from past EPIC projects relative to the topic.

"At a Glance" Summary Table:

| Pilot Topic | Pilot Name | Pilot Objective |
|---|---|---|
| **Any other pilots deemed relevant by your organization.** | EPIC 4.01 - Propensity Modeling for EV Adoption | Maximize EV adoption |
| | EPIC 4.03 - Residential Mulit-Family Housing (MFH) EV | Make EV adoption feasible for multi-family housing |
| | Ford Pre-Pilot | Bi-directional proof of concept |
| | EPIC 4.08 - Non-Wires Alternatives (NWA) Integration into Distribution Planning | DER and Non-Wires modeling tools for infrastructure forecasting and planning |
| | EPIC 4.21 T&D Co-Simulation Modeling | Platform for modeling distribution and transmission leveraging EPIC 4.08 outputs |
| | EPIC 4.11 - Service Transformer Sited Energy Storage | Utility owned BESS for local capacity and resilience |
| | Form Energy - Iron-Air Battery | Demo CEC partnership for long duration storage and grid management |
| | EV Flexible Load Analysis | EV adoption with and without load management and utilization impacts |
| | Tariff on-bill for residential | Finance mechanism enabling DER adoption |

| | | |
|---|---|---|
| | EPIC 4.09 - Advanced Load Management Analysis (ALMA) Pilots | Analytical platform to integrate load management solutions into planning (linked to EPIC 4.08) |
| | EPIC 3.11 - Location Targeted DERs - AKA Redwood Coast Airport Microgrid | Demonstrate a community scale microgrid w/greater penetration of PV/BESS |
| | EPIC 3.11B - Location Targeted DERs - AKA Leveraging BTM DERs in Microgrids | Operational processes for DER management within microgrids |
| **Data Sharing** | Load ICA | Prepares grid for high electrification guiding customers |
| **Distributed Energy Resource (DER) Orchestration** | EPIC 4.02 - Socket of the Future & Residential Single-Family Housing (SFH) EV | Remove barriers to electrification and EV adoption |
| | EPIC 4.07 - Battery Energy Storage System (BESS) Voltage Support on Radial Feeders | Enables increased capacity and voltage control on constrained distribution. |
| | EPIC 4.10 - Local DER Orchestration | Manage local grid constraints through DER coordination |
| | ResCEO | Study the customer experience through DER orchestration |
| **Distributed Energy Resource Management (DERMS), Advanced Distribution Management Systems (ADMS), and DER visibility (to DSO & to CAISO)** | Flex Service Connection, Flex Gen Connection & DIDF/NWA Apps | Use DERMS to manage grid capacity via dynamic controls and operating limits |
| **Dynamic and real-time rates (e.g. CALFUSE),** | Real Time Pricing | Pilots to support full scale roll out of RTP |
| **Load Control Management Systems (LCMS) and Automated load control** | Automated Response Technologies (ART) | Market and distribution capacity through automated technologies |

| | | |
|---|---|---|
| **Virtual power plants, (VPP) vehicle to grid integration** | Vehicle-Grid Integration Decision Pilot - V2X Commercial Pilot | Evaluates benefits of bi-directional charging via commercial vehicles |
| | Vehicle-Grid Integration Decision Pilot - V2X Microgrid Pilot | Evaluates benefits of bi-directional charging within microgrids |
| | Vehicle-Grid Integration Decision Pilot - V2X Residential Pilot | Evaluates benefits of bi-directional charging via light duty vehicles |
| | EPIC 4.12 - AC V2G and EV Virtual Power Plant (VPP) | VPPs for customer resiliency |
| | EPIC 4.04 - Home Charging, Distribution – Managed Charging | Develops managed charging orchestrated with grid need |

1) Flexible interconnection (generation)

Flexible service connections are intended to serve both new generation and new energization. Therefore, pilots described in this section will be a combination of both number one and two. PG&E is enabling our DERMs system as per our grid modernization plan. One of the initial use cases in development through current pilot activity is leveraging the system to allow for generation and energization of new facilities providing a day ahead forecast available for export or capacity. A second DERMS use case is to support and enable DIDF non-wires projects under development.

Pilots supporting flexible interconnection include:

a. DERMS Platform + Flex Service Connection, Flex Gen Connection & DIDF/NWA Apps

2) Flexible energization (load)

See above response in number one: Flexible Interconnection (generation)- PG&E treats both topics under the same technology and process.

3) Virtual power plants, (VPP) vehicle to grid integration

PG&E views virtual power plants as not limited to vehicle to grid integration, as the title suggests, and more inclusive of many different load modifying, generation, and storage sources contributing to an aggregated set of resources resulting in a total volume of load shape modification or bulk system peak reduction contribution. Therefore, we have identified pilots that contribute to VPP more holistically (distribution, transmission, generation supply) while also including those specific to vehicle to grid integration. Some pilots identified under other subheadings also apply to the technology enablement resulting in VPP type results but are not included under this specific list and called out under other categories.

Pilots supporting virtual power plants include:

a. Vehicle-Grid Integration Decision Pilot - V2X Commercial Pilot
b. Vehicle-Grid Integration Decision Pilot - V2X Microgrid Pilot
c. Vehicle-Grid Integration Decision Pilot - V2X Residential Pilot
d. EPIC 4.12 - AC V2G and EV Virtual Power Plant (VPP)
e. EPIC 4.04 - Home Charging, Distribution – Managed Charging
f. EV: Flexible Service Connect ("Flex Connect") for EV

4) Dynamic and real-time rates (e.g. CALFUSE)

Aligned with regulatory and IOU roll out of real-time rates through Calfuse, PG&E has a program roll out plan through 2027. PG&E's primary goal for the program phases are to test and learn how to expand RTP rates to more customer segments and end uses to support grid reliability and ensure adequate electric power during times of greatest need.

Pilots supporting dynamic and real-time rates include:

a. Real Time Pricing, DFOIR (note: RTP is a program, not a pilot)

5) Load Control Management Systems (LCMS) and Automated load control

PG&E is transitioning to a new program deployment strategy simplifying program enrollment and participation using automation technologies for demand response and load shifting. The program implementation will proceed through the DR proceeding period of 2024-2027. The use of PG&E's Distributed Energy Resource Management System (DERMS) will provide coordination on the grid with the end use DER's, providers, and aggregators.

Pilots supporting Load Control Management Systems and Automated Load Control are:

a. Automated Response Technologies (ART)

6) Power control systems (PCS)

No active pilots under this category.

7) Data sharing

PG&E views data sharing as in alignment with CPUC and IOU processes for understanding interconnection of generation and load allowing for visibility into system capacity and constraints. However, some requested information could be confidential in nature, including, but not limited to, customers-specific personally identifiable information (PII), third-party owned, or proprietary, and cannot be released to the public.

Pilots supporting data sharing include:

a. Load ICA

8) Distributed Energy Resource (DER) Orchestration

As part of our Grid Modernization process, PG&E is implementing DERMs, ADMS, SCADA, and IT infrastructure to support orchestration of DER's at the grid edge. Initial use cases include flexible service connections, support for a Distribution Infrastructure Deferral Framework projects (DIDF), and several EPIC projects associated with VPPs, EV's, and orchestration. DER Orchestration outcomes are aimed at understanding the customer interaction, the enabling orchestration and end use technology, and the effect of various pricing strategies and resulting engagement.

Pilots supporting Distribution Energy Resources Orchestration include:

a. EPIC 4.02 - Socket of the Future & Residential Single-Family Housing (SFH) EV
b. EPIC 4.07 - Battery Energy Storage System (BESS) Voltage Support on Radial Feeders
c. EPIC 4.10 - Local DER Orchestration
d. ResCEO

9) Distributed Energy Resource Management (DERMS), Automated Distribution Management Systems (ADMS), and DER visibility (to DSO & to CAISO)

As part of our Grid Modernization process, PG&E is implementing DERMs, ADMS, SCADA, and IT infrastructure to support orchestration of DER's at the grid edge.

Pilots supporting Distributed Energy Resource Management (DERMS), Automated Distribution Management Systems (ADMS), and DER visibility (to DSO & to CAISO)include:

a. Flex Service Connection, Flex Gen Connection & DIDF/NWA Apps

10) Any other pilots deemed relevant by your organization.

Several pilots fall outside the formatted categories within the request, however pertain to High DER enablement, orchestration, DSO, markets, and data supporting pilots, initiatives, and planning for DER's and could be of interest to the request.

Pilots relevant to HighDER Track 2, Workshop 3 include:

a. EPIC 4.01 - Propensity Modeling for EV Adoption
b. EPIC 4.03 - Residential Multi-Family Housing (MFH) EV
c. Ford Pre-Pilot
d. EPIC 4.08 - Non-Wires Alternatives (NWA) Integration into Distribution Planning
e. EPIC 4.21 T&D Co-Simulation Modeling
f. EPIC 4.11 - Service Transformer Sited Energy Storage
g. Form Energy - Iron-Air Battery
h. EV Flexible Load Analysis
i. Tariff on-bill for residential [DER Adpotion].
j. EPIC 4.09 - Advanced Load Management Analysis (ALMA) Pilots
k. EPIC 3.11 - Location Targeted DERs - AKA Redwood Coast Airport Microgrid
l. EPIC 3.11B - Location Targeted DERs - Leveraging BTM DERs in Microgrids

Publicly available EPIC project details can be found at; Emerging Electric Technology Programs (pge.com)

Below are select completed EPIC projects from past portfolios relative to High DER. These projects provide foundations to current pilots. Note- these pilots provide valuable information however may be outdated due to a rapidly changing landscape. Specific aspects may be considered useful however outdated content has not been modernized, modified, or redacted and are in the original form of the completed outcomes and their associated final reports. Therefore costs, data, and technology may or may not be current:

- **EPIC 1.01 - Energy Storage End Uses**
  This project successfully utilized PG&E's Vaca-Dixon and Yerba Buena Battery Energy Storage Systems (BESSs) to gain experience and data by participating in CAISO's Non-Generator Resource (NGR) market model. PG&E developed and deployed an automated communications and control solution to fully utilize and evaluate BESS fast-response functionalities.
  Download Pacific Gas and Electric Company EPIC 1.01 (PDF)
- **EPIC 1.02 - Demonstrate Use of Distributed Energy Storage for Transmission and Distribution Cost Reduction**
  This project demonstrated the ability of a utility-owned and controlled energy storage resource to deliver autonomous distribution peak shaving functionality. Energy storage resources hold significant promise to help California address a variety of grid planning and operations challenges, both today and in the future, and can be used to provide more reliable and clean power to customers for lower overall costs. The learnings from this project can help inform utility procurement and operation of future energy storage resources, both utility-owned and utility-contracted, through compliance with the IOU energy procurement targets as set forth in CPUC D. 10-03-040 and beyond.
  Download Pacific Gas and Electric Company EPIC 1.02 (PDF)
- **EPIC 1.05 - Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output**
  This project successfully developed and demonstrated a new mesoscale meteorological model to provide more granular and accurate weather forecasting input to PG&E's storm damage prediction model and to other PG&E forecasting applications, such as catastrophic wildfire risk, large storms and photovoltaic (PV) generation. This model has improved the accuracy of forecasting for large storms, allowing for increased efficiencies in storm preparation, as well as enhanced the accuracy of identifying fire risks, helping enable improved reliability and safety. Finally, leveraging granular solar irradiance data in a new framework has improved PG&E's ability to understand the impacts of PV generation for grid management.
  Download Pacific Gas and Electric Company EPIC 1.05 (PDF)
- **EPIC 1.24 - Demonstrate Demand-Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction**
  This project successfully provided and tested the performance of a near real-time window of PG&E's Air Conditioning (AC) Direct Load Control (DLC) system, which utilizes one-way switch control devices. This allowed us to improve our ability to estimate AC DLC impacts at the distribution system level to better understand the localized impact of AC direct load control devices on meeting distribution feeder level reliability concerns. It also enabled near real-time visibility of AC direct load control installations to support Transmission and Distribution (T&D) Operations and provided Demand Response (DR) program administrators with near real-time feedback on any problems with direct load

control devices before, during or after an event is called, which supports T&D operational improvements.
Download Pacific Gas and Electric Company EPIC 1.24 (PDF)

- **EPIC 2.02 – Distributed Energy Resource Management System**
  This project provided an opportunity for PG&E to define and deploy a DERMS and supporting technology to uncover barriers and specify requirements to prepare for the increasing challenges and opportunities of DERs at scale. The DERMS Demo was a ground-breaking field demonstration of optimal control of a portfolio of 3rd party aggregated behind-the-meter (BTM) solar and energy storage and utility front-of-the-meter (FTM) energy storage to provide distribution capacity and voltage support services while also allowing for participation of these same DERs in the CAISO wholesale market.
  Download Pacific Gas and Electric Company EPIC 2.02 (PDF)
  Download Appendix L (PDF)
- **EPIC 2.03A Smart Inverters**
  - Project Final Report:
    This final project report documents field demonstration of commercial Smart Inverters on a high PV-penetration distribution feeder ("Location 2"), the evaluation of a vendor-agnostic Smart Inverter aggregation platform, and lab testing of multiple Smart Inverter models. The project established that there is significant potential for local voltage support from SIs to help mitigate local secondary voltage challenges caused by high PV penetration in a cost-effective manner. Efforts undertaken within the project were not able to establish that individual or aggregations of SIs were able to substantially affect primary voltage.
    Download Pacific Gas and Electric Company EPIC 2.03A Final Report (PDF)
  - Project Interim Report:
    This interim report documents the field demonstration of Smart Inverters complete to date, with results of ongoing evaluations to be released in a separate publication. To date, this project demonstrated the ability of residential Smart Inverters to influence local voltage on two electrical distribution feeders in PG&E's territory. The project evaluated a vendor-specific Smart Inverter aggregation platform, communications reliability to the Smart Inverter assets, and feasibility of targeted customer acquisition for DER deployment.
    Download Pacific Gas and Electric Company EPIC 2.03A Interim Report (PDF)
  - Joint IOU White Paper - Enabling Smart Inverters for Distribution Grid Services:
    This white paper is a joint collaborative effort of Pacific Gas & Electric (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison (SCE), collectively the California investor-owned utilities (IOUs), and member utilities in the Association of Edison Illuminating Companies (AEIC) Distributed Energy Resource (DER) Sub-Committee. It is intended to inform electric utilities, regulators and DER industry stakeholders nationwide on key learnings that the IOUs have gained on Smart Inverters through demonstration projects and key considerations for enabling Smart Inverter-enabled DERs to provide distribution grid services.
    Joint IOU White Paper - "Enabling smart inverters for distribution grid services" (PDF)
    Joint IOU White Paper - "Enabling smart inverters for distribution grid services" Appendix(PDF)
  - EPRI Smart Inverter Modeling Report:
    This modeling effort, performed for PG&E by the Electric Power Research

Institute (EPRI), analyzed the technical and economic impacts of growing densities of Smart Inverters connected to PG&E's distribution grid. The focus was placed on residential PV and PV + storage systems. An analysis of the economic impacts on six PG&E distribution feeders was conducted, comparing traditional network re-enforcement strategies involving distribution upgrades to scenarios leveraging grid support provided by Smart Inverters.
Download Pacific Gas and Electric Company EPIC 2.03A EPRI Smart Inverter Modeling Report (PDF)

- **EPIC 2.03B - Test Smart Inverter Enhanced Capabilities – Vehicle to Home**
This project assessed the technical feasibility and potential benefits to individual customers and to ratepayers of vehicle to home (V2H) technology which can be utilized for resiliency and reliability. V2H is technically capable of islanding and supporting household load in outage and demand response events and customers reported high initial interest. However, the technology is not yet commercially available and vehicle warranties must be modified to allow for discharge, the cost to customers exceed their perceived benefits, and the net benefits to the utility and ratepayers are likely not sufficient to surmount the low cost-effectiveness for customers. The V2H market is nascent and requires further investigation ahead of PG&E commercialization activities.
Download Pacific Gas and Electric Company EPIC 2.03 (PDF)
- **EPIC 2.19 - Enable Distributed Demand-Side Strategies & Technologies**
This project evaluated the performance and efficacy of using customer-sited behind-the-meter storage for grid and reliability services. The project utilized both residential and commercial assets via two vendor platforms. BTM Energy storage is technically feasible for the use cases evaluated, but before a full program is pursued there are opportunities for improvement.
Download Pacific Gas and Electric Company EPIC 2.19 (PDF)
- **EPIC 2.22 - Demand Reduction through Targeted Data Analytics**
This project developed a tool that leverages customer level data along with grid information and forecasts to create a robust optimization engine for identification of the lowest cost solution capable of deferring or mitigating the need for an asset upgrade due to capacity limitations. The tool considers both traditional wires solutions and DER portfolios and allows Distribution Planners to complete advanced scenario analysis.
Download Pacific Gas and Electric Company EPIC 2.22 (PDF)
- **EPIC 3.03 - Distributed Energy Resource Management System (DERMS) and Advanced Distribution Management System (ADMS) Advanced Functionality**
This project aimed to 1) advance the adoption of the Common Smart Inverter Profile (CSIP) and the IEEE 2030.5 protocol standard and contribute to its enhancement, 2) meet customer requests and regulatory mandates to lower the cost of telemetry using a customer-owned telemetry system, and 3) act as a foundational step to leveraging large volumes of DERs for monitoring and controlling DERs using a DERMS and ADMS.
Download Pacific Gas and Electric Company EPIC 3.03 (PDF)

| Pilot Topic (CPUC) | Pilot Name | Relevant Proceeding | Pilot Objective | Target Population | Pilot Action/Description What will the pilot actually do | Pilot Dates Effective | Pilot Budget ($M)_ | Subject Matter Expert | CPUC Contact | Results |
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| Any other pilots deemed relevant by your organization. | EPIC 4.01 - Propensity Modeling for EV Adoption | EPIC 4 | To maximize EV adoptions and optimize the new grid load using EVs as energy storage, we require an estimate of where and when EVs come online. This can be achieved by predicting the likelihood a PG&E customer adopting an Electric Vehicle using machine learning algorithm. | Residential | • Identify and map current Res customers with EV in PGE data system as ground truth (i.e. DMV sales and registeration data). At the absence of plan A levarage other approaches as a proxy for current EV ownerships i.e. AMI disaggregation, rates, EV program sign ups.<br>• Build a predictive model levaraging current adoption to predict potential EV adopters at customer premise level to the grid (feeder or transformer). Include heatmap for current and future EV adoptions at granular level. | Planned 2024 | $ 3.0 | Shareghe Mehraeen | NA | upon successfull build and test, results will inform the future load shift as a result of residential EV integration at a localized grid level as well as inform the load management and vehicle-to-grid integration strategies. |
| Any other pilots deemed relevant by your organization. | EPIC 4.03 - Residential Mulit-Family Housing (MFH) EV | EPIC 4 | Test a variety of EV charging solutions to address the lack of accessible charging at MFHs and single-family housing without dedicated access to parking.<br>o On-site solutions might include but are not limited to: 1) plug/smart outlet 2) smart breaker, 3) L2 charging w/ load management<br>o Off-site solutions might include, but are not limited to: 4) streetlight L1 & L2 5) curbside L1 & L2 with bring your own (BYO) cable<br>• Identify which solution or portfolio of solutions can be scaled for deployment | EV drivers living in parking-constrained residences | Phase 1: Project Discovery<br>• Activities: Conduct customer and product solution research. Develop common framework to assess solutions in Demonstration stage<br>• Outcomes: Publish white paper to generate industry interest & communicate PG&E's objectives. Use learnings to inform Demonstration plan.<br>Phase 2: Demonstration<br>• Activities: Design, test, execute, and assess demonstration projects<br>• Outcomes: Learn and confirm or disprove hypotheses. Use learnings to inform PG&E strategy & create list of selected solutions | Planned 2024 | $ 6.0 | Maya Wolf | | The output of this pilot will inform the commercialization strategy for solutions to reduce the barriers to provide reliable charging to parking-constrained customers. |
| Any other pilots deemed relevant by your organization. | Ford Pre-Pilot | N/A | Proof of concept field demonstration of Ford Charge Station Pro with Delta Electronics E8-BDI Bi-directional Inverter EV charger to test and report performance of providing back-up power to a home improving during PSPS and other power outages. | Residential | Phase 1: Installation<br>• Activities: Recruit employee-customers with the Ford F-150 Lightning. Work closely with Sunrun to permit and install the system.<br>• Outcomes: Approve system for installation and energization as an emergency backup-only "Break-before-make" generator without need for R21 Interconnection. Use learnings to inform CPUC Decision Vehicle-to-Everything Pilots.<br>Phase 2: Testing<br>• Activities: Commisssion the 2 installations, test transition to islanded mode and response to overloading, and monitor for 12 months.<br>• Outcomes: Learn and review results with Ford and Sunrun. Use learnings to inform PG&E strategy & CPUC Decision Vehicle to-Everything Pilots. | 2023-2024 | | Kristin Landry<br>Chris Moris | N/A | • Recruited 2 employee-customers with Ford F-150 Lightning trucks<br>• Review system design and operational flow for transitions to island and back to grid<br>• Proceed with permitting and install the Ford 80 Amp Charge Station Pro and Sunrun Home Integration System at field demonstration sites<br>• Test to confirm safety and islanding capabilities.<br>• Measure performance and record learnings from outage testing<br>• Conduct 12 months of monitoring and enroll sites in the CPUC Decision Vehicle-to-Everything Pilots<br>• Follow up with customers to evaluated customer experience |
| Any other pilots deemed relevant by your organization. | EPIC 4.08 - Non-Wires Alternatives (NWA) Integration into Distribution Planning | EPIC 4 | Expand capabilities of existing planning tools to improve the forecasting and use of nonwires alternatives (NWA), including load flexibility and distributed energy resources (DERs). | Utility DER Grid Planning | 1. Incorporate load flexibility, load management, and dynamic rating directly into distribution forecast and distribution tools used by distribution planners to reduce grid needs.<br>2. Identify opportunities for various DER technologies and customer flexible load interconnection as an alternative or bridge to conventional upgrades (NWA).<br>• Determines limited load/generation profiles and locations. | Planned 2024 | $ 2.0 | Gabriel Jew/Ahmed Bekhit | | |
| Any other pilots deemed relevant by your organization. | EPIC 4.21 T&D Co-Simulation Modeling | EPIC 4 | This project is to provide a wholistic approach for Transmission Planning and Distribution Planning engineers to study the capacity needs from both systems, develop optimized capacity upgrades on T&D and make more use of the existing capacities. This project is also to further align the inputs, assumptions, and methodologies of Transmission and Distribution planning load forecast. And implement the Transmission planning load forecast into standard software such as Load SEER. | Utility DER Grid Planning | 1. Build a new application which will make utility T&D co-simulation possible to provide enhanced support for the existing transmission planning processes.<br>2. Build an optimization engine to run T&D wholistic planning optimizations by user defined goals.<br>3. Load forecast for transmission planning will be further aligened with distribution forecast in this project. | Planned 2024 | $ 6.5 | Marco Rios | | If successful, the results can help optimize the future buildout of transmission and distribution, reduce cost on capital investment and interconnect load customers sooner. |

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| Any other pilots deemed relevant by your organization. | EPIC 4.11 - Service Transformer Sited Energy Storage | EPIC 4 | Develop front-of-the-meter (FTM) grid management assets and provide hyper-local capacity and microgrid capabilities. This provides an opportunity to improve reliability for customers frequently impacted by EPSS/PSPS, and other outage events while providing an opportunity for utilities to leverage these assets for local capacity and grid smoothening at scale. | Customer/Utility DER Grid Planning | •Issue Request for Proposal for distributed battery solution and enclosure (e.g. pad-mounted) to serve common sized distribution transformers<br>• PG&E testing to confirm safety, cost-effectiveness, and control/islanding capabilities.<br>• Enroll customers in disadvantaged and low-income communities to extent feasible and customers in high fire threat districts frequently impacted by EPSS to enable field demonstration<br>• Measure performance, impact, and record learnings from outage and capacity management in relation to alternatives<br>• Integrate battery monitoring and controls into utility systems (e.g. Advanced Distribution Management Systems, Distributed Energy Resources Management Systems (DERMS))<br>• Aggregate batteries into virtual power plants (VPP) and evaluate VPP use cases<br>• Determine processes for scaling as a program for disadvantaged, vulnerable communities, low-income communities, EPSS and PSPS affected customers, and capacity constraints | Planned 2024-2026 | $ 4.0 | Nicole Collette | | |
| Any other pilots deemed relevant by your organization. | Form Energy - Iron-Air Battery | CEC | PG&E is matching the funding and providing land outside a substation in Medocino. PG&E is not leading this project (Form Energy is) and we are not the grant awardee (the CEC is); PG&E is considered a sub-contractor in this arrangement. We have an interconnection agreement to allow Form to connect to the system. Form would lease the land from PG&E for no cost, which would essentially count as the match funding. This would be a long-duration energy storage for potentially seasonal storage. | Technology OEM/CEC | | Planned 2024 | | Marco Rios<br>Gina Kathuria | | |
| Any other pilots deemed relevant by your organization. | EV Flexible Load Analysis | N/A | Primary bank, circuit, and secondary service transformer utilization capacity analysis to understand the impact of EV electrification with and without load management through the year 2035. | Utility DER Grid Planning | Model the 2024 today, 2035 no load management, and 2035 full EV load management scenarios to understand the state of the primary and secondary network in each scenario. | 2023-2024 | $ 0.2 | Chris Moris<br>Claire Wu | N/A | in progress |
| Any other pilots deemed relevant by your organization. | Tariff on-bill for residential | Clean Energy Finance Options (R.20-08-022) | PG&E's pilot in the Tariff On-Bill (TOB) proposal will have PG&E work with SVCE/TECH as they leverage their existing CCA billing functionality (on the PG&E consolidated bill) to implement their field trial. PG&E will also explore working with other CCAs that are exploring leveraging the CCA billing functionality in advance of the availability of PG&E's billing modernization project.<br>PG&E will leverage this work and input from other stakeholders to develop use cases for the billing functionality and other costs required to implement a full TOB proposal using either non-ratepayer or potentially enable the deployment of IOU capital for site specific investments in BTM technologies to support grid needs and state policy objectives. | DAC, All customers | The TOB pilot is evaluating the ability of the IOUs adding a fixed charge to participating customers bill based on the projected retail rates savings for decarbonization projects, including solar and storage. The use cases will need to demonstrate the ability of the TOB functionality to support equitable adoption of decarbonization measures for residential customers. PG&E will continue to evaluate the opportunities to improve the customer economics of these projects for targeted decarbonization projects in coordination with state programs. | Planned 2024-2027 | 5.3 (tentative to be updated) | Al Gaspari | Hal Kane | in progress |
| Any other pilots deemed relevant by your organization. | EPIC 4.09 - Advanced Load Management Analysis (ALMA) Pilots | EPIC 4 | Build an analytical platform to integrate load management (LM) solutions with generation, transmission, and distribution planning.<br>Design and implement customer pilot programs to refine LM program design, available potential, and cost. | Utility DER Grid Planning | To address these gaps, this project will develop analytical approaches, modelling assumptions, and tools to enable a wide range of LM solutions to function as candidate resources, which allows them to be:<br>• Co-optimized with supply side resources to understand the interaction between alternatives (e.g., traditional supply side resources, new technologies such as hydrogen, carbon capture, etc.)<br>• Evaluated as alternatives to identified T&D upgrades<br>• Tested for effectiveness in addressing reliability requirements and achieving greenhouse gas emission reduction goals to develop a portfolio of cost effective LM solutions | Planned 2024 | $ 6.0 | Trevor Udwin<br>Neda Assadi | | |
| Any other pilots deemed relevant by your organization. | EPIC 3.11 - Location Targeted DERs - AKA Redwood Coast Airport Microgrid | EPIC 3 | Demonstrate a viable, replicable business model for a community-scale microgrid that provides resilience to critical community services (airport and coast guard station) and allows for greater penetration of distributed renewables (powered by solar + BESS)<br>Develop standard processes to integrate multi-customer microgrids into utility operations | Utility DER Grid Planning, Vulnerable communities seeking resilience | Develop, construct and operation CA's first 100% renewable, front-of-meter, multi-customer microgrid<br>2.2 MW PV array DC-coupled to 2.2 MW/8.8 MWh battery storage ⍰ WDT interconnection, CAISO wholesale market participation<br>320 kWAC net-metered PV array ⍰ reduce airport electric bills<br>Microgrid controls ⍰ will allow the system to island and provide uninterruptible power for long periods | 2021-2024 | $ 3.0 | Alex Portilla | N/A | RCAM system was successfully commissioned in 2022 has successfully been providing resiliency to critical facilities in Humboldt County. Project formed the basis for PG&E's Community Microgrid Enablement Program and Tariff |

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| Any other pilots deemed relevant by your organization. | EPIC 3.11B - Location Targeted DERs - AKA Leveraging BTM DERs in Microgrids | EPIC 3 | Develop the technical capabilities and the production ready operational processes to utilize BTM DERs to support resiliency within multicustomer community microgrids | Vulnerable communities seeking resilience | • Test frequency droop settings for managing generation/load on a medium voltage distribution circuit<br>• Prove out energy storage as a grid forming source and test it in the field at a site with excess solar generation during islanded operations<br>• Study the theoretical limits of control for such a system<br>• Leave behind reusable processes for leveraging DERs via frequency signals during microgrid islanding events | 2022-2024 | $ 2.7 | Chris Moris | | |
| Data sharing, | Load ICA | High DER | Incorporate Load ICA Results into Internal IOU Energization.<br>Business Processes PG&E shall use Load ICA to improve its load energization process to help prepare the grid for a high electrification future. Load ICA shall be used by PG&E's service planning representatives to guide customers during this Intake process to help customers beter understand and navigate the energization process. | Internal: SP&D<br>External: Applicants for load energization | Customers applying for load interconnection must endure several months of back-and-forth with PG&E only to be told that there's no capacity for their project. There are hundreds of applications stuck in the Design backlog that will end up with this outcome.<br><br>Load ICA can be used to screen applications for capacity constraints significantly earlier in the process with minimal information gathering, leading to more efficient use of internal resources and a better customer experience. | End of 2024 | Funded through DRPTMA | Gabriel Jew | | |
| Distributed Energy Resource (DER) Orchestration | EPIC 4.02 - Socket of the Future & Residential Single-Family Housing (SFH) EV | EPIC 4 | Ensure affordable and timely connection for every Residential Single-Family Home (SFH) customer (note there is a separate Multi-Family Home Project)<br>• Enable a <$1,000/site home EV charging solution that connects a Smart Meter via Wi-Fi to customer owned EV charger over OCPP to avoid a customer panel and/or service upgrade | Residential Customers w/Evs | • Deploy updated AMI meter software platform (head end) that enables edge computing<br>• Lab and limited field test the meter application with a few EVSE charging partners and confirm it meets the requirements of electric code and utility standards to avoid an upgrade<br>• Extended pilot (in production) up to 1,000 sites as an option for customers to avoid a panel/service upgrade<br>• Design/develop/explore pathway for standard process scaling past 1,000 units | 2024-2025 | $ 6.0 | Chris Moris | | |
| Distributed Energy Resource (DER) Orchestration | EPIC 4.07 - Battery Energy Storage System (BESS) Voltage Support on Radial Feeders | EPIC 4 | Develop controls for Battery Energy Storage System (BESS) to enable increased capacity and voltage control on constrained distribution lines. | Residential/Commercial/Utility /rate payers | • Develop new controls layer for battery energy storage system for stacked benefits of feeder capacity, voltage support, and short circuit ratio • Perform power system simulations and power/control hardware-in-the-loop • Implement and commission on one distribution circuit | 2024-2025 | 0.4 | Franz Stadtmueller | N/A | |
| Distributed Energy Resource (DER) Orchestration | EPIC 4.10 - Local DER Orchestration | EPIC 4 | Evaluate and demonstrate distribution mechanisms and the technical capabilities required to efficiently and reliability interact with multiple DERs to manage local grid constraints, as a foundation to a future local grid orchestration, that efficiently allocates available capacity among flexible loads and DERs and sets the value for grid services while providing strict limits to avoid grid issues. Determine cost effective mechanism(s) as an alternative to traditional grid upgrades and other methods for providing local capacity such as the Distribution Investment Deferral Framework. | DER Customer/Grid Benefits | • Develop, model and evaluate enrollment and compensation schemes for participation local distribution orchestration such as a local capacity auction (e.g. flexibility market similar to UK), a flat or time-of-use rate with reduced $/kWh in exchange for dispatch rights, peer to peer transactive energy market, real time<br>pricing, upfront payment + performance or other distribution plus transmission-based mechanism for the purposes of evaluating technical feasibility, customer<br>experience and compensation models at the distribution level.<br>• Based on initial study/evaluation determine preferred model to demonstration in the field (go / no go stage gate)<br>• Create Distributed Energy Resource Management System (DERMS) integrations and capabilities as needed for demonstration purposes<br>• Select demonstration location with high penetrations of DERs and flexible loads<br>• Enroll multiple diverse customers and/or aggregators within a constrained area with flexible loads to participate in a local distribution orchestration mechanism<br>to address hourly capacity constraints<br>• Set a reduced feeder limit and call upon the resources and allocate capacity among participants in an automated fashion<br>• Measure performance, impact, and record learnings | Planned 2024 | $ 3.0 | Claire Wu<br>Chris Moris | N/A | Results will inform future mechanisms to engage with and orchestrate local DERs to provide distribution grid services |
| Distributed Energy Resource (DER) Orchestration | ResCEO | EE | This pilot is to study the customer experience associated with various residential DER orchestration strategies of interest. The pilot cohort will include residential customers with multiple DERs integrated with EE technologies. Study objectives include understanding current barriers that limit long-term program particiation and potenal new approaches to improve the DER orchestration customer experience. | Residential Single Family | • Determine local residential DER orchestration strategies to be tested.<br>• Identify/enroll cohorts of participating customers with EE technologies integrated with multiple DERs for orchestration.<br>• Study the customer experience associated with each orchestration approach | Planned 2025 | $ 5.7 | Matt Braunwarth | Jesse Levine | |

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| Distributed Energy Resource Management (DERMS), Advanced Distribution Management Systems (ADMS), and DER visibility (to DSO & to CAISO) | DERMS Platform +<br>Flex Service Connection,<br>Flex Gen Connection &<br>DIDF/NWA Apps | GRC | This project will implement a Distributed Energy Resource Management System (DERMS) to complement the foundational technology improvements and grid management tools built by the Advanced Distribution Management System (ADMS) program. The DERMS will allow PG&E to manage the added operational and programmatic complexity of ever-growing Distributed Energy Resources (DERs) and DER Programs on the PG&E grid.<br><br>PG&E's Enterprise DERMS will have the foundational capabilities to improve visibility and forecasting of the distribution grid and DERs and will enable initial use cases to manage grid capacity via dynamic controls and/or operating limits of DERs and flexible loads. | All customers | Initial DERMS use cases include:<br>1. UC1 Operator Visibility of DER Telemetry (1MW+):<br>IEEE 2030.5 DER Headend to connect 1MW+ DERs integrated with standard operator tools and processes (ADMS)<br>2. UC2 Flexible Service Connection Pilot: Dynamic load limits to will allow customers with controllable loads to connect to the system without waiting for a service upgrade and increase the utilization of existing grid capacity.<br>3. UC3 Flexible Generation Interconnection Pilot: Dynamic generation limits to maximize hosting capacity and minimize interconnection costs on constrained circuits<br>4. UC4 Operation of Capacity Deferral Solutions (i.e. Non-Wires Alternatives) Dispatch DERs procured through the Distribution Investment Deferral Framework (DIDF). | 2024-2026 | N/A (pilots not seperately funded from the overall DERMS GRC initiative | Alex Portilla | N/A | |
| Dynamic and real-time rates (e.g. CALFUSE), | Real Time Pricing | DFOIR | PG&E's primary goal for the pilots is to test and learn how to expand RTP rates to more customer segments and end uses to support grid reliability and ensure adequate electric power during times of greatest need. The pilots will also help to inform full-scale rollout of RTP prior to the January 2027 California Energy Commission (CEC) mandate for hourly RTP to be available to all customer classes. In addition, the pilots will provide learning opportunities for informing wider rollout of RTP related to rate design, attracting customer participation, customer communications, targeting end-uses, coordination with CCAs, encouraging robust ASP participation, and other elements to support grid reliability. | All customers | 1. Plan for achieving the 50-megawatt enrollment target for each pilot. 2. Plan for conducting Marketing, Education, and Outreach (ME&O) to potential pilot participants, with additional details on outreach approach to enroll customers in Environmental and Social Justice (ESJ) communities, for each pilot.<br>3. Proposal for awarding up to $8,000,000 in customer automation incentives in the PG&E Ag Pilot. Proposal for how the kW-magnitude of customers will be assessed for each proposed end-use for this incentive.<br>4. Proposal for awarding up to $3,600,000 in incentives to Automation Service Providers (ASPs) for Expanded Pilot 2 for automation technology and software to manage customer end-use load response to RTP price signals. Proposal for how the kW-magnitude of customers will be assessed for each proposed end-use for this incentive.<br>5. Implementation process for awarding up to $1,800,000 in CCA incentives of $20 per unbundled kW-year, for each pilot. | 6/1/24 - 12/31/27 | $36.7M | Andrew Au | | n/a |
| Load Control Management Systems (LCMS) and Automated load control | Automated Response Technologies (ART) | DR 2024-2027 Proceeding | Provide DR market integrated capacity and distribution relief through residential automated technologies along with load-shifting through daily automated response. | Customer/Grid Benefits | The technologies will include, but are not limited to: smart thermostats, smart appliances, HPWHs, EV chargers, and battery—all for load management purposes. An overarching objective of the program will be to promote the use of these technologies to automatically curtail or shift energy use away from the higher cost periods in the customer's TOU rate plan as well as to help mitigate periods of high electric demand on the grid. | Planned 2024 | $43.8M | Albert Chiu<br>Wendy Brummer | Maryam Mozafari | |
| Virtual power plants, (VPP) vehicle to grid integration | Vehicle-Grid Integration Decision Pilot - V2X Commercial Pilot | Rulemaking 18-12-006 | PG&E proposed two V2X pilots and one V2Microgrid to evaluate the benefits of bidirectional EV technology to both customer and the utility and inform full-scale programs. | EV Commercial Fleets | The V2X pilots will pay to incentivize customers to purchase and install V2X technology and test use cases including a dynamic rate through a cloud platform. | 2023-2026 | $ 2.7 | Rudi Halbright | Meschelle Thatcher | |
| Virtual power plants, (VPP) vehicle to grid integration | Vehicle-Grid Integration Decision Pilot - V2X Microgrid Pilot | Rulemaking 18-12-006 | PG&E proposed two V2X pilots and one V2Microgrid to test inverter settings to enable bidirectional EVs to support a microgrid. | Resilience needs | The V2M pilot will provide additional incentives for bidirectional EVs to participate in distribution microgrids and community microgrids. | 2022-2026 | $ 1.5 | Abel Levin | Meschelle Thatcher | |
| Virtual power plants, (VPP) vehicle to grid integration | Vehicle-Grid Integration Decision Pilot - V2X Residential Pilot | Rulemaking 18-12-006 | PG&E proposed two V2X pilots and one V2Microgrid to evaluate the benefits of bidirectional EV technology to both customer and the utility and inform full-scale programs. | Residential | The V2X pilots will pay to incentivize customers to purchase and install V2X technology and test use cases including a dynamic rate through a cloud platform. | 2022-2026 | $ 7.5 | Kristin Landry | Meschelle Thatcher | |

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| Virtual power plants, (VPP) vehicle to grid integration | EPIC 4.12 - AC V2G and EV Virtual Power Plant (VPP) | EPIC 4 | This EPIC Project demonstrates AC V2G and EV VPP capabilities as opportunities to increase availability of clean mobile and stationary distributed energy resources (DERs) that can be used to support individual customer resiliency. | AC V2G capable vehicle owners (limited to Tesla vehicles due to OEM technology availability) | Phase 1: Accelerate a pathway to scale interconnection<br>• Develop standardized pathway(s) for AC V2G to inform enhancements to Rule 21<br>• Supporting existing longer-term UL 1741 SC effort<br>• Provide the option to explore a nearer-term UL 1741 SB "QIKP" pathway<br>• Test AC V2G in the lab and demo with 2-3 field installations<br>• ID opportunities to reduce cost by optimizing bill of materials or removal of protective relays (if/when possible; reference PG&E AL 7125-E filed 1/5/24)<br>Phase 2: Demonstrate an at scale VPP (potential up to 100s to 1,000s of units)<br>• Scale beyond 2-3 field installations to create an EV VPP with a focus on testing and refining a least-friction highest-value customer experience<br>• Integrate to DERMS/Demand Response headend<br>• Analyze economics of the VPP and lay framework for future scaling<br>• Advocate at the CPUC for frameworks that enable EV VPPs | Planned 2024 | $ 2.0 | Sarah Swickard<br>Chris Moris | | |
| Virtual power plants, (VPP) vehicle to grid integration | EPIC 4.04 - Home Charging, Distribution – Managed Charging | EPIC 4 | This project tests if PG&E can manage EV charging (using Vendor software) to mitigate service transformer overloading and potentially defer an upgrade. This saves costs for PG&E (and therefore ratepayers) and increases reliability while providing value to EV customers. The vendor software will ensure that EV customers participating in the pilot will charge off peak or at the best time for the rate they are on. | Residential | • Project Set up: 1) Identify candidate transformers, 2) use historical and forecasted data to determine time-varying capacity availability on a given asset and 3) develop load shapes for electric vehicle service providers (EVSPs).<br>• Seek partnership with a vendor willing to respond to PG&E load shapes<br>• Orchestrate load limiting level 2 charging or load shifting based on available capacity on constrained assets.<br>• Deliver load shapes for electric vehicle service providers to follow, thus remaining under asset limitations.<br>• Develop framework to quantify avoided cost of an upgraded asset to inform cost-effective/optimal customer incentive design for managed charging programs.<br>• Develop framework to scale | 2024 - 2025 | $ 3.6 | Amy Costadone<br>Amy Wu | | |
| End | End | End | End | End | End | End | End | End | End | End |

# San Diego Gas & Electric (SDG&E) Related Pilots

**ENERGY DIVISION DATA REQUEST – PILOT PROGRAMS FUTURE GRID STUDY**
**SDG&E RESPONSE**
**DATE RECEIVED: MAY 17, 2024**
**DATE RESPONDED: JUNE 10, 2024**

**REQUEST:**

The Energy Division at the California Public Utilities Commission is submitting a data request for information on ongoing and planned pilot programs.

As an extension of the Future Grid Study Workshop Series, CPUC staff presents this data request. The Future Grid Study Workshop series, hosted by the CPUC and consultant Gridworks under track 2 phase 1 of the High DER Future Proceeding R.21-06-017, brought together Investor-Owned Utilities and stakeholder to identify operational needs, assess gaps and develop recommendations to address gaps, and provide an opportunity for parties to collaborate to modernize the electric grid for a high DER future. These efforts will culminate in a report produced by Gridworks which summarizes the series. The requested information will be used as an appendix to the Future Grid Study Report to inform stakeholders of ongoing and upcoming utility pilot projects. Relevant pilot topics include:

1) flexible interconnection (generation),
2) flexible energization (load),
3) virtual power plants, (VPP) vehicle to grid integration
4) dynamic and real-time rates (e.g., CALFUSE),
5) Load Control Management Systems (LCMS) and Automated load control
6) power control systems (PCS)
7) data sharing,
8) Distributed Energy Resource (DER) Orchestration
9) Distributed Energy Resource Management (DERMS), Automated Distribution Management Systems (ADMS), and DER visibility (to DSO & to CAISO), and
10) any other pilots deemed relevant by your organization.

For all relevant pilot topics discussed above please provide the following information for any ongoing or planned pilots associated with SDG&E:

- Pilot Topic (from above list): Description of what gap or grid need is being addressed.
- Pilot Name: Official and colloquial names of the pilot
- Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: Indicate procedural home for the pilot. Include relative ordering paragraphs and/or directives.
- Pilot Objective: What does the pilot aim to do.
- Target Population: Who is the pilot directly affecting.
- Pilot Action/Description: What does the pilot actually do
- Pilot Dates Effective: Begin and end dates of pilot.
- Was the Pilot Derived from the Energy Program Investment Charge (EPIC):
- Pilot Budget: Dollar amount approved for pilot
- Subject Matter Expert Contact: Utility Contact
- CPUC Energy Division Contact: ED Contact
- Results of any evaluations and/or dates of future planned evaluation:

SDG&E should provide one primary narrative response as a word document with a section for each pilot category described above that includes the relevant pilots within that category, additional documents can be attached to the master narrative along with a list of all attachments. SDG&E should also attach a summary "at a glance" table for the all the pilots to provide an overview.

**RESPONSE:**

| Pilot Topic: | Virtual power plants, (VPP) vehicle to grid integration |
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| Pilot Name: | Toyota V2G (on campus - Fermata Energy charger) |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | N/A |
| Pilot Objective: | To test use cases of smart charging, EV off-peak, Vehicle to Home, V2G export, dispatching energy as stationary storage device, credits on energy bill, V1G demand response, curtailing charging, aggregator charging, V2B – Backup power. |
| Target Population: | SDG&E employees at Century Park |
| Pilot Action/Description: | Testing technical capabilities for use cases, collect data on use cases (power quality monitoring), feedback on use cases. Info will be captured through Fermata charger. |
| Pilot Dates Effective: | In development<br><br>Each objective will be tested for 3 months.<br><br>Export pilot rate goes live. |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | No |
| Pilot Budget: | TBD |
| Subject Matter Expert Contact: | Nick Fiore - NFiore@sdge.com |
| CPUC Energy Division Contact: | |

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| Results of any evaluations and/or dates of future planned evaluation: | Highly restrictive rates depending on customer qualifications leading to primarily commercial use at first.<br><br>Standards and certifications for qualifying hardware led to limitations. |

| Pilot Topic: | Virtual power plants, (VPP) vehicle to grid integration |
|---|---|
| Pilot Name: | Residential V2X Pilot & GM Energy Partnership |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | N/A |
| Pilot Objective: | Field-test residential V2X customer experience and technical capabilities in phased approach with V2H, DR, V2G, and VPP applications through GM's bidirectional hardware and software in partnership with SDG&E emerging tech group. |
| Target Population: | SDG&E Customers with GM V2G Capable EVs. |
| Pilot Action/Description: | Evaluate the technical performance across various scenarios (V1G, V2G, VPP, DR events).<br><br>Assess the grid impact of V2X systems in a real-world residential context (i.e., additional energy capacity as a result of V2X discharge events)<br><br>Understand and enhance the customer experience, acceptance, and impact related to V2X technology adoption.<br><br>Understand and enhance the customer experience, acceptance, and impact related to using EVs as grid-connected DERs. This may include developing a variety of reward mechanisms and charge management strategies to study customer response.<br><br>Create a blueprint for educational and marketing strategies.<br><br>-Build a dataset to inform future customer programs and influence customer behaviors. |

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| Pilot Dates Effective: | Initial negotiations started in November of 2022 followed by a feasibility study.<br><br>Tentative start date: Q2 2024<br><br>Tentative end date: Flexible, conservatively EOY 2026 |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | No |
| Pilot Budget: | TBD |
| Subject Matter Expert Contact: | Nick Fiore - NFiore@sdge.com |
| CPUC Energy Division Contact: | |
| Results of any evaluations and/or dates of future planned evaluation: | Hardware not certified for commercial viability. |

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| Pilot Topic: | Virtual power plants, (VPP) vehicle to grid integration |
| Pilot Name: | Grid Resilience and Sustainability through integrated vehicle-to-grid (V2G) and Renewable Energy at Community Resource Centers (CRCs) |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | Decision 23-11-086. Currently being considered within the scope of EPIC. |
| Pilot Objective: | Increase the Value Proposition of Distributed Energy Resources to Customers and the Grid |
| Target Population: | SDG&E customers |
| Pilot Action/Description: | SDG&E is currently considering this pilot project: This project will showcase a groundbreaking integration of electric vehicles (EVs) with Vehicle-to-Building (V2B) and Vehicle-to-Grid (V2G) technologies alongside planned solar installations and a Battery Energy Storage System (BESS). This project will install two V2G capable EV chargers at the CRC site, incorporate on-site V2G |

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| | capable EVs, and optimize the use of the vehicle batteries through predictive software that most efficiently integrates the renewables and energy management systems both at this site and on the grid. |
| Pilot Dates Effective: | 24-month duration (dates TBD) |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | Yes |
| Pilot Budget: | TBD |
| Subject Matter Expert Contact: | Nick Fiore - NFiore@sdge.com |
| CPUC Energy Division Contact: | |
| Results of any evaluations and/or dates of future planned evaluation: | TBD |

| Pilot Topic: | Virtual power plants, (VPP) vehicle to grid integration |
|---|---|
| Pilot Name: | Shelter Valley VPP Project |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | The different tariff schedules at the Shelter Valley sites are TDR1NME, TOU DR1NM, TOU-DR1, TOU-ANM, DR-SESNM and DR-NM. |
| Pilot Objective: | The purpose of this project was to test the real-world impacts of a VPP on SDG&E's grid and analyze its operational performance. |
| Target Population: | 16 SDG&E customers in the Shelter Valley of San Diego. |
| Pilot Action/Description: | Build out a VPP Project Team to implement a standalone VPP, test the VPP with BTM resources, operate the VPP and send out DR signals based on test, experiment for other grid services, analyze operational performance of the VPP and document results that can be used for future VPP endeavors. |
| Pilot Dates Effective: | Testing started in December of 2022.<br><br>Project ended in December of 2023. |
| Was the Pilot Derived from the | No |

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| Energy Program Investment Charge (EPIC): | |
| Pilot Budget: | N/A |
| Subject Matter Expert Contact: | Jeff Barnes - JBarnes@sdge.com<br>Brad Mantz - BMantz@sdge.com |
| CPUC Energy Division Contact: | |
| Results of any evaluations and/or dates of future planned evaluation: | Low customer participation, BTM resource installation issues, hardware failures, and testing challenges requiring modifications. |

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| Pilot Topic: | Distributed Energy Resource Management (DERMS), Automated Distribution Management Systems (ADMS), and DER visibility (to DSO & to CAISO) |
| Pilot Name: | PV Integration using a Virtual Airgap (PIVA) |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | N/A |
| Pilot Objective: | The objective of the PIVA (PV Integration using a 'Virtual Airgap') project is to develop and demonstrate a cloud-based integration layer that decouples PV data collection from mission critical Operations Technology (OT) systems like EMS or ADMS. This improves usability, reliability, and security by neutralizing the operational impacts of both benign and malicious cyber-risks. Bad data is naturally filtered out, missing data is automatically filled in, and sensitive data is mathematically de-identified. It would also help solve an emerging challenge of TSO-DSO-Aggregator-Retailer coordination of DER. |
| Target Population: | |
| Pilot Action/Description: | The expected outcomes and performance targets have been defined in 6 key dimensions –<br>**1. PV data acquisition interfaces:** Open support for at least 3 PV data acquisition protocols<br>**2. IT/OT data publication interfaces:** Open support at least 2 IT/OT integration protocols |

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| | 3. **Performance latency:** Add no more than 5 seconds to overall roundtrip latency from the PV data source interface to a utility control room system (e.g., ADMS)<br>4. **Estimation accuracy:** Ability to estimate (in near real time) missing or non-telemetered PV generation within 5% error.<br>5. **Value proposition cost savings:** Demonstrate Total Cost of Ownership with 50% cost savings over comparable on-premise utility solutions.<br>6. **Industry outreach and technology transfer:** Engage the industry as stakeholders during the project, and sign at least one Letter of Intent with a potential customer or vendor partner to help fund ongoing commercialization and/or pilot the solution. |
| Pilot Dates Effective: | 2022-2026 |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | No, but in partnership with the DOE and Gridbright. |
| Pilot Budget: | |
| Subject Matter Expert Contact: | Kirsten Petersen - KPetersen@sdge.com |
| CPUC Energy Division Contact: | |
| Results of any evaluations and/or dates of future planned evaluation: | Budget Period 1 – Requirements, Development, and CHIL Preparation<br><br>Budget Period 2 – CHIL Testing, Security Testing, and Pilot Preparation<br><br>Budget Period 3 – Performance Validation and Field Demonstration Pilot |

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| Pilot Topic: | Flexible interconnection (generation), |
| Pilot Name: | Maximizing BESS Asset Utilization – Dynamic Charging Constraints |
| Relevant Proceeding(s), | N/A |

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| Advice Letters, Decisions, Resolutions and Rules and Tariffs: | |
| Pilot Objective: | Maximizing BESS Asset Utilization by evaluating impact of utilizing dynamic charging constraints based on day-ahead forecasts. Evaluate accuracy of day-ahead forecasting capabilities. |
| Target Population: | |
| Pilot Action/Description: | **Deliverable #1** - Modification of SGIA/LGIA Charging Table Customer Generation periodic engineering study improvement to limits.<br>**Deliverable #2** - PI Vision Complete Operational Picture Screen. Adjust/Improve/Enhance existing PI Vision screens to begin measuring unutilized circuit capacities.<br>Show forecast limit line above or below the existing SGIA Red limit line.<br>**Deliverable #3 -** Day ahead Forecasting<br>Utilize day ahead forecasting tool in NMS to produce Day ahead forecast that will be provided to Generation Operations. Optional for Generation team to use based on predetermined thresholds.<br>**Deliverable #4 -** DCC Signal +/- analog value MW scale with single decimal precision<br>Send signal of new charging constraints to maximize charging.<br>Develop/Test signal to protect circuit from overload.<br>Add automated notifications that loading is above 90% |
| Pilot Dates Effective: | In Development |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | No |
| Pilot Budget: | N/A |
| Subject Matter Expert Contact: | Alex Kilmer; AKilmer@sdge.com<br>Ram Dhanekula; RDhanekula@sdge.com<br>Kirsten Petersen; KPetersen@sdge.com |
| CPUC Energy Division Contact: | |
| Results of any evaluations and/or dates of future planned evaluation: | N/A |

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| Pilot Topic: | Distributed Energy Resource (DER) Orchestration |
| Pilot Name: | Zonal Electrification with Integrated Distributed Energy Resources (IDER) Operational Flexibility |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | N/A |
| Pilot Objective: | SDG&E is currently considering this pilot project: SDG&E's zonal electrification project seeks to capture and understand customer's decision-making process by integrating DER flexibility and enabling electrification for customers (including underserved customers).<br><br>Part of our roadmap to establish our production DERMS integration requirements including the coexistence of DERMS with existing SDG&E technology components to leading to the optimization of our overall distribution system operator environment. |
| Target Population: | With a lens on Disadvantages Communities (DACs), customers will be identified using defined internal and external metrics. Potential to overlay prospective target audiences with:<br>• Existing and future programs that target similar markets.<br>• Customers who do not typically qualify for AMI/CARE programs.<br>• Less dense geographical locations |
| Pilot Action/Description: | This project is divided into two parts, part 1 focuses on electrifying selected customers' homes and businesses. The customers will be selected based on our gas and electric infrastructure maps and disadvantaged community designation. Once the customers are enrolled, we will be installation a wide range of electric appliances and distributed energy resources on their premises. These behind the meter assets may include solar panels, battery storage, EV charger, HP furnace/AC, EE washer, HP dryer, HP water heater, electric range. Once the assets are installed, we will conduct our IDER operational flexibility research. Many of SDG&E's customers reside in climate zone 7, along the temperate Southern California coast, requiring less heating and cooling. SDG&E currently does not have an analytical tool that produce ideal zonal electrification sites, this project will help fund that initiative. The technologies used in this |

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| | project will be compatible with the state's required 2030.5 Communication Protocol, which will allow us to further test the technologies in the real world. |
| Pilot Dates Effective: | • Zonal electrification portion of the project is estimated to take 36 to 48 months.<br>• IDER research on operational flexibility is estimated to take up to 18 months.<br>• Some activities will happen concurrently. |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | Yes – Currently in the planning phase. |
| Pilot Budget: | $2.6M - $4.7M |
| Subject Matter Expert Contact: | Alton Kwok CKwok@sdge.com<br>Bill O'Brien WOBrien@sdge.com<br>Kirsten Petersen KPetersen@sdge.com |
| CPUC Energy Division Contact: | |
| Results of any evaluations and/or dates of future planned evaluation: | TBD |

| Pilot Topic: | Dynamic & Real-Time Rates |
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| Pilot Name: | Dynamic Export Rate Pilot |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | A.21-12-008<br>D.23-11-006<br>Advice Letters 4407-E (pending) and 4408-E (effective)<br>Proposed "Schedule Dynamic Export Rate" |
| Pilot Objective: | To advance demand flexibility through electric rates |
| Target Population: | Bundled commercial customers on Schedules EV-HP, AL-TOU, TOU-A |
| Pilot Action/Description: | • This is a one-stage pilot. Bundled commercial customers on Schedules EV-HP, AL-TOU, and TOU-A are eligible to participate.<br>• The Dynamic Export Rate will use the California Independent System Operator ("CAISO") day-ahead hourly commodity market price, and a Generation Capacity Component, ("GCC") similar to the Critical Peak Pricing ("CPP") Commodity |

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| | Capacity Adder approach used in SDG&E's Schedules Vehicle-Grid Integration and Public-Grid Integration Rate, with the main difference being the GCC for the Pilot is based on marginal generation capacity costs only.<br>• At this time, the Pilot will include generation rate components only. |
| Pilot Dates Effective: | Enrollment beginning on January 1, 2025, and the pilot concluding after two years |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | No |
| Pilot Budget: | $2,361,259 |
| Subject Matter Expert Contact: | Jeff DeTuri, jdeturi@sdge.com |
| CPUC Energy Division Contact: | |
| Results of any evaluations and/or dates of future planned evaluation: | • SDG&E will begin data collection approximately 11 months after pilot implementation commences;<br>• SDG&E will serve an interim report with data from the first year of the Pilot and any survey results that were conducted during the first year;<br>• SDG&E will administer a survey 24 months after pilot implementation commences;<br>• SDG&E will complete M&E activities and reporting for the final report six months following data collection; and<br>• SDG&E will file a final M&E report on a date 30 months after pilot implementation commences.<br>• SDG&E will file a Tier 2 advice letter within 30 days of the completion of the final M&E report to propose to continue, modify, or discontinue the dynamic export rate pilot. |

| Pilot Topic: | Demand Flexibility |
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| Pilot Name: | Smart Pool Control Systems |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | TBD |
| Pilot Objective: | Demand flexibility. Benefit to customer, utility, and grid. |

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| Target Population: | SDG&E Customers |
| Pilot Action/Description: | To demonstrate the ability of pool pumps to be used as flexibility assets. Explore using other pool technologies (heaters, LEDs, water fountain systems, chlorination systems etc.) as flexibility resources in future study phases. |
| Pilot Dates Effective: | TBD:<br><br>Tentative launch Q3 2024<br><br>Tentative end Q1 2025 |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | No |
| Pilot Budget: | TBD |
| Subject Matter Expert Contact: | Jeff Barnes - JBarnes@sdge.com |
| CPUC Energy Division Contact: | |
| Results of any evaluations and/or dates of future planned evaluation: | TBD |

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| Pilot Topic: | Demand Flexibility, Demand Response, Energy Efficiency |
| Pilot Name: | Smart Panel Study |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | TBD |
| Pilot Objective: | Energy efficiency, demand response electrification. |
| Target Population: | SDG&E Customers who have already begun electrification (Solar, Energy Storage, etc.). |
| Pilot Action/Description: | Field demonstration project aiming for 3-5 panels installed at customer sites. Determine if panels can allow for real time non-critical loads while critical loads remain untouched. Determine if metering can take place on individual circuits. |

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| Pilot Dates Effective: | TBD:<br><br>Tentative launch Q3 2024<br><br>Tentative end Q4 2025 |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | No |
| Pilot Budget: | TBD |
| Subject Matter Expert Contact: | Jeff Barnes - JBarnes@sdge.com |
| CPUC Energy Division Contact: | |
| Results of any evaluations and/or dates of future planned evaluation: | Understanding functionality of smart panels.<br>Enabling electrification.<br><br>Gaps w/ technology as information is gathered. |

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| Pilot Topic: | Flexible Energization (load) and Distributed Energy Resource (DER) Orchestration |
| Pilot Name: | **Demonstration of Multi-Purpose Mobile Battery and IEEE 2030.5 Operational Flexibility** |
| Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: | Decision 18-01-008 and Application 17-05-009. Resolution E-5260 (Operational Flexibility Pilots). |
| Pilot Objective: | Increase the Value Proposition of Distributed Energy Resources to Customers and the Grid |
| Target Population: | SDG&E customers |
| Pilot Action/Description: | The objective of this project is to undertake a pre-commercial demonstration of a mobile battery energy storage system (MBESS). The project will examine the possibilities for using a mobile battery at multiple locations within SDG&E's service area. An MBESS is a battery energy storage system on wheels that can provide multiple use cases based on a single MBESS application or a combination of |

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| | several applications (stacking of applications) to provide grid support and reliability/resiliency solutions for utility projects and/or customers at different sites. Included in the project are trials of IEEE 2030.5 to highlight the benefit and challenges associated with the communication protocol. Test cases will leverage 2030.5 as a means of controlling the MBESS to provide a demonstration of alleviating constraints on Operational Flexibility under specific scenarios. The objective is to evaluate the effectiveness of mobile batteries when rotated between applications and identify preferred applications and strategy for the rotation. |
| Pilot Dates Effective: | Commenced 2020-present |
| Was the Pilot Derived from the Energy Program Investment Charge (EPIC): | Yes |
| Pilot Budget: | $4.6 M |
| Subject Matter Expert Contact: | Stephanie Lomeli, slomeli@sdge.com |
| CPUC Energy Division Contact: | Fredric Beck, Fredric.Beck@cpuc.ca.gov |
| Results of any evaluations and/or dates of future planned evaluation: | TBD – preliminary reports for the other Project's Modules can be reviewed here: https://database.epicpartnership.org/project/32509 |

# Southern California Edison (SCE) Related Pilots

*Southern California Edison*
*R.21-06-017 – DER Integration OIR*

**DATA REQUEST SET ED-SCE-GridMod2024-1**

**To: Energy Division**
**Prepared by: Belinda Vivas**
**Job Title: Sr. Advisor**
**Received Date: 5/17/2024**

**Response Date: 6/14/2024**

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**Question 01:**

- Pilot Topic (from above list): Description of what gap or grid need is being addressed.
- Pilot Name: Official and colloquial names of the pilot
- Relevant Proceeding(s), Advice Letters, Decisions, Resolutions and Rules and Tariffs: Indicate procedural home for the pilot. Include relative ordering paragraphs and/or directives.
- Pilot Objective: What does the pilot aim to do.
- Target Population: Who is the pilot directly affecting.
- Pilot Action/Description: What does the pilot actually do
- Pilot Dates Effective: Begin and end dates of pilot.
- Was the Pilot Derived from the Energy Program Investment Charge (EPIC):
- Pilot Budget: Dollar amount approved for pilot
- Subject Matter Expert Contact: Utility Contact
- CPUC Energy Division Contact: ED Contact
- Results of any evaluations and/or dates of future planned evaluation:

"SCE should provide one primary narrative response as a word document with a section for each pilot category described above that includes the relevant pilots within that category, additional documents can be attached to the master narrative along with a list of all attachments. SCE should also attach a summary "at a glance" table for the all the pilots to provide an overview."

**Response to Question 01:**

The number and breadth of the pilots detailed in the attached spreadsheet indicates how much we can still learn about effectively leveraging DERs to provide grid services. We expect to gather information from these pilots in the following three broad categories:

- Technical validation: Did all technical systems work as anticipated? Was the right data shared with the right entities? Did the IOUs receive the expected data (from IOU devices or from third parties)? Did communication happen as planned? Were the right signals sent to the DERs? Were those signals received and did the DER behave as intended?
- Customer participation and experience: Will customers participate? Are they satisfied with the structure of the program and willing/eager to participate again? Did DER performance

meet or exceed expectations? Did the incentive levels seem appropriate given customer benefits and grid benefits?
- Benefits and cost-effectiveness: Did the pilot result in actual benefits to the grid? Can these benefits be quantified? How did the quantified benefits, if any, compare with the expected costs (considered capital costs to deploy DERs and/or customer incentive costs as applicable)?

Based on the answers to these questions, we hope to inform broader questions related to the specific use case tested by the pilots:

- Overall, did we achieve the expected technical results, customer participation, benefits and cost-effectiveness?
- If so, how much can we scale this? If not, what needs to change prior to expanding the pilot into a full program? Is further piloting necessary prior to full-scale implementation across the system?
- And most critically, given the experience, do we believe the approach tested in the pilot is the *right approach*? Or should any alternative approaches be piloted before moving into broad, system-wide implementation?

Technical, Customer Experience, and Cost-Effectiveness Pilots

The first four pilots detailed in the excel sheet seek broad customer participation and will therefore provide validation of all three categories above. As such, we expect to learn about customer experience and interest, validation of technical capabilities, and relative costs and benefits.

Technical-Focused Pilots

The remaining pilots in the excel sheet are primarily testing technical capabilities across a wide variety of use cases, and thus will provide technical validation. These pilots will help indicate where DER grid services are truly valuable and effective at the local (circuit) or hyper-local (sub-circuit) level. These pilots will help answer the critical question of "where will DERs actually be valuable to provide grid services;" without these data, we really do not know the answer. While we believe the use cases tested in these pilots will have real world, scalable benefits, we do not know that yet, which is precisely why we are implementing these pilots. Some of these pilots focus on utility equipment and systems, and some are intended to test use cases that will eventually leverage customer participation. Importantly, the technical pilots that aim to leverage customer resources may need additional piloting to better validate and understand customer participation in these use cases.

We still *do not* have any pilots that test out local (circuit level) dispatch across a wide variety of DERs. This remains a substantial gap. Many of the discussions assume that this happens at a wide scale, across many customer types and DER types, with local (or hyper-local) dispatch precision and high levels of performance and dependability. We hope this is the future, but as of now, we don't have real-world experience to validate it. Many of the technology pilots will validate the technical capabilities to achieve this, but they will not validate the customer side: will customers participate, will they accept a reasonable incentive to perform, will they perform at a high level and dependably?

To summarize, there are many pilots in progress, and we expect to learn through the current and planned pilots, and a lot of additional experience we will need even beyond the current set of pilots before we are ready to determine the end-state “market” vision. Therefore, SCE recommends the focus of this proceeding be to further capture and describe this incremental need for further understanding, through incremental pilots, that will be necessary to establish the end-state vision. Additionally, it will be important for this proceeding to consider the interactive effect across each of the techniques tested in discrete pilots. Similar to the bulk power system, it is reasonable to expect that all techniques will be options for customers and utilities, so it is important to understand how one approach impacts the deliverability of another approach, as there is likely some cannibalization of benefits across approaches.

| Category/Topic (From CPUC list) | Pilot Name | Relevant Proceedings | Objectives | Target Population | Action/Description | "Future Grid" Capability Gaps Addressed (how does this advance the future grid vision) | Dates | EPIC (Y/N) | Pilot Budget | Utility Contact | ED Contact | Results of Any Evaluations |
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| 5) LCMS and Automated Load Control<br>2) flexible energization (load), | **Load Control Management System (LCMS)** | Advice Letters 5138-E and 5138-E-A | Objective to allow customers to interconnect into a grid constrained area ahead of SCE utility upgrades by managing their load to limits set by SCE. The LCMS pilot provides capacity to customers that are waiting on long energization requests | This pilot is not specific for a certain target. | Customer installs control system to limit load based on SCE-provided maximum load schedule. Enables customers to partially energize while awaiting grid upgrades. | Validate load constraints as "bridging solution" to enable partial energization while waiting for grid upgrades. Validate customer interest/willingness to particpate in this soution. | Dates Nov 2023 - Dec 2025 | N | None (funded out of operating budget) | Ari Altman | Audrey Neuman (TE) | One vendor and two sites in operation since November 2023 with no adverse operations. |
| 3) virtual power plants, (VPP) vehicle to grid integration<br>7) data sharing,<br>8) Distributed Energy Resource (DER) Orchestration | **Charge Ready Demand Response Pilot** | Application (A.) 14-10-014, Decision (D.) 16-01-023, Application (A.)17-01-018, Decision (D.)17-12-003, Advice Letter 3773-E,<br>Advice Letter 3773-E-A, Advice Letter 4244-E | Demonstrate V1G capabilities to manage changing based on utility signals. | All active Charge Ready Pilot, Bridge and School sites participate in the Charge Ready DR Pilot, which began in 2018. Charge Ready DR did not enroll specific vehicles, but rather the EVSEs, and has 138 sites participating with 2426 ports | The Charge Ready DR Pilot sends control signals on bulk system level from the utility to the EVSP, who can then communicate with the EVSEs to stop or start charging or to throttle charging current. | Validate technical capabilities of V1G. Validate customer interest/willingness to participate in V1G (allow managed charging. | 2018-2022 | N | $429,953 | Ari Altman | Audrey Neuman (TE) | Ongoing |
| 4) dynamic and real-time rates (e.g. CALFUSE),<br>7) data sharing | **Expanded Dynamic Rate Pilot** | Rulemaking (R.) 22-07-005, Decision (D.) 24-01-032 (Latest Decision) | Offers a new rate based on real-time energy market prices with the objective of reducing grid constraints | Non-residential, non-demand response customers (A.1)<br>Non-residential aggregators (A.2)<br>Rule 21 Exporting Distributed Energy Resources (A.3)<br>Virtual Power Plant Aggregators (A.4)<br>EV and VGI Aggregators (A.5)<br>Residential customers (A.6) - Power Saver Rewards<br><br>Third Party Demand Response Providers (B.1)<br>Capacity Vidding Program Aggregators (B.2) | Makes more efficient use of the grid by raising the price during high utilization. May result in sigificantly lower cost for operating shiftable loads (especially EV charging). Pricing is anticipated to be at the A-Bank level, so it will be geographically differentiated but not down to the circuit level. | Validate technical capabilities of dyanmic rates. Validate customer interest/willingnes to particiapte/accpet dyuamic rates. Validate cost-effectiveness of using dynamic rates to effect load shifts. | Current pilot ending 12/2024<br>New expanded pilot will operate from 6/2024 to 12/2027 | N | $17,250,000 (see D.24-01-032) | Ari Altman | Masoud Foudeh | On-going. First results from Original Dynamic Rate Pilot available Q4 2024. |
| 7) data sharing,<br>8) Distributed Energy Resource (DER) Orchestration | **Emergency Load Response Program (ELRP)** | Applicaiton (A.) 22-05-004, Decision (D.) 23-12-005 (Latest Decision) | Demand Response program designed to provide incremental load reduction during times of high grid stress and emergencies. Emergency Demand Response (DR) program designed as a last line of defense to prevent rolling blackouts. | Non-residential, non-demand response customers (A.1)<br>Non-residential aggregators (A.2)<br>Rule 21 Exporting Distributed Energy Resources (A.3)<br>Virtual Power Plant Aggregators (A.4)<br>EV and VGI Aggregators (A.5)<br>Residential customers (A.6) - Power Saver Rewards<br><br>Third Party Demand Response Providers (B.1)<br>Capacity Vidding Program Aggregators (B.2) | Statewide emergency demand response program that serves as a last line of defense to help prevent rotating outages. When CAISO declares a grid emergency, SCE will signal program participants. Participants include a wide variety of entities: aggregators, individual resources, etc | Validate ability to deploy large quanities of DR to resolve grid emergencies.<br>Validate performance of wide variety of resource/aggregator types to provide emergency DR service.<br>Validate cost-effectiveness of the program. | Funded through 2027<br>Group A.6 ends 2025 | N | $194M (Through 2027) | Ari Altman | Daniel Horan | Ongoing |
| 3) virtual power plants, (VPP) vehicle to grid integration<br>9) Distributed Energy Resource Management (DERMS), Automated Distribution Management Systems (ADMS), and DER visibility (to DSO & to CAISO), and | **V2G With On-Board and Off-Board Inverter (EPIC)** | EPIC III | Demonstrate V2G AC interconnection method and DERMS functionality for VGI use cases | Lab demonstration and standards advancement | To conduct a lab demonstration of the use of EV battery/inverter systems to support customers and the grid using V1G and V2G.<br>Demonstrate the secure integration of project 3rd party aggregators with SCE's Grid Management System (GMS)/DER Management Systems (DERMS) and the use of the Institute of Electrical and Electronis Engineers (IEEE) 2023.5 communications protocol for aggregator-based monitoring and management of EVs and EV Control systems.<br>Demonstrate the use of EV battery systems and related applications to support and related applications to support customer resiliency during grid outage conditions.<br>Develop and disseminate recommendations for updates to Rule 21 Interconnections, Society of Automotive Engineers (SAE), United Laboratories (UL), SunSpecand other V2G-related standards, tariffs, and techonologies. | Validate technical capabilities to support widepread V2G/V1G implementation. | 2019 through 2024 | Y | $3M | Ari Altman | None | Ongoing |

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| 3) virtual power plants, (VPP) vehicle to grid integration<br>9) Distributed Energy Resource Management (DERMS), Automated Distribution Management Systems (ADMS), and DER visibility (to DSO & to CAISO), and | **Service Center of the Future (EPIC)** | EPIC III | Demonstrate utility microgrid controls and DERMS interface with FTM battery for heavy EV fleet depot | Lab demonstration preparing for following field pilot. | A pilot to establish SCE's standards to support charging infrastructure for a fleet depot. | Validate new capabilities to utilize DER management to manage high load concentration in constrained area, | 2019 through 2025 | Y | $4M | Ari Altman | None | Ongoing |
| 3) virtual power plants, (VPP) vehicle to grid integration<br>8) Distributed Energy Resource (DER) Orchestration | **Distributed Plug-In Resources (EPIC)** | EPIC III | Demonstrate energy storage integration with high power EV charger for grid impact and grid services, customer bill management | Lab demonstration | Demonstrate the use of energy storage systems to reduce grid impact and to provide grid support. Try to demonstrate the benefits of V2G prior to wide scale adoption of V2G capable vehicles. | Validate new capability to use distributed DER grid resources to manage high peak impact of DC fast charge, | 2019 through 2024 | Y | $2M | Ari Altman | None | Ongoing |
| 8) Distributed Energy Resource (DER) Orchestration | **Smart City (EPIC)** | EPIC III | Demonstrate utility provided microgrid for city customer; utility owned storage, control of | Lab demonstration preparing for following field pilot. | A microgrid pilot to establish SCE's standards around microgrids, while supporting some the city of Porterville's critical infrastructure. | Validate migrod controls to support essential city services | 2019 through 2025 | Y | $4M | Ari Altman | None | Ongoing |
| 2) flexible energization (load),<br>8) Distributed Energy Resource (DER) Orchestration | **Swift Electrification of Transit (EPIC)** | EPIC IV | Demonstrate DERs, long duration energy storage, VGI in heavy transit depot | Lab demonstration followed by field implementation in DVC | The EPIC 4 SET Project will demonstrate technology solutions to improve large scale (>1MW) transportation electrification interconnections by reducing planning complexity/uncertainty, deployment time, footprint and cost while meeting their the projects resiliency expectations. Some of the key technologies to be demonstrated are Energy Buffering (non li-ion energy storage) and Islanding and Reconfigurability. | Validate use of DERs to support Resilience for heavy transit, load management service options | 2024 through 2028 | Y | $10M | Ari Altman | None | In Planning |
| 8) Distributed Energy Resource (DER) Orchestration | **Stability Improvement with DERs (EPIC)** | EPIC IV | Demonstrate DERs and inverter based technology in a community approach to serve customers and manage the grid | Lab demonstration followed by field implementation in DVC | This project will showcase new grid stablizing techonologies to aggregate DERs and Evs to optimize their utilization and enhance load flexibility. The programs' main objectives are to (1) identify the grid's current and future stability needs, (2) improve DER registrations and monitor control capabilities, (3) increase flexible load and EV energy storage capabilities and, (4) partner with local educational institutions. | Validate capability to manage DERs to provide grid stability and inertia | 2024 through 2028 | Y | $9M | Ari Altman | None | In Planning |
| 8) Distributed Energy Resource (DER) Orchestration | **Storage-Based Distribution DC Link (EPIC)** | EPIC III | Demonstrate energy storage and inverter technology for phase balance, circuit transfer | Lab demonstration preparing for following field pilot. | Proposes an architecture that will allow an energy storage system to connect to two unique distribution circuits, through the use of two power conversion systems, tied to a single storage medium. This approach will allow the storage system to support both circuits, individually or simultaneously, and it will also provide a means of dynamically exchanging power between the two circuits. | Validate advanced capbilities to utilize DERs to provide grid capacity for mulitple circuits | 2019 through 2025 | Y | $3M | Ari Altman | None | Ongoing |
| 8) Distributed Energy Resource (DER) Orchestration | **Energy Storage Integration Program** | 2013 CPUC Decision - Adopting Energy Storage Procurement Framework and Design Program 2015 GRC, 2018 GRC, 2025 GRC | Deploy energy storage systems to address grid needs; includes mobile energy storage system. 12 Pilots. | Deployment of energy storage systems in several areas based on grid needs and including PSPS support with mobile energy storage. | The Program includes several pilots which support learnings related to integrating standard lithium -ion storage, as well as the post-pilot operations of the BESS. These pilots are connected to the distribution grid to determine how these systems can defer traditional distribution circuit upgrades, provide operational flexibility as the operating environment changes, and potentially increase the value of Distributed Energy Resources. Learnings from these pilots include helping SCE safely and reliably integrate energy storage systems.<br>For details on the 12 ESIP pilots plese go to tab titled "ESIP Pilots" | Validate varity of use cases for energy storage, including grid asset/resource; microgrid, PSPS | 2018 through 2028 | N | $60M | Ari Altman | None | Ongoing. Seven battery systems deployed. |
| 7) data sharing,<br>8) Distributed Energy Resource (DER) Orchestration | **eTRUC – Electric Truck Research and Utilization Center (CEC EPIC)** | CEC EPIC 2018 GRC, 2025 GRC | EPRI-led CEC funded project focused on advancing electric truck charging infrastructure. SCE hosts the Advanced Research Hub Facility, demonstrating megawatt charging and DER integration; two pilot sites for heavy trucks | Pilot sites in Ontario and near ports of LA and Long Beach | eTRUC is a stakeholder-driven consortium of industry, government, academia, and community partners committed to the development, advancement, and deployment of innovative heavy-duty (HD) high-power charging infrastructure along key freight corridors that promote the adoption of Class 7 and 8 battery-electric zero-emission (ZE) trucks.<br>eTRUC follows a "Community First" approach to 1) engage stakeholders, 2) advance technology, and 3) create ZE freight corridors<br>eTRUC's principal responsibility is to support technology development that will address core market barriers to zero-emission truck adoption. eTRUC will work with equipment manufacturers to develop prototypes of high-power charging systems that can meet the following performance targets:<br>(1)Capable of providing 100 miles of range for a Heavy-Duty Battery-Electric Vehicle drayage truck in less than 10 minutes; (2)uses only open standards for connectors and communications to increase interoperability across different vehicles and control systems; (3)research and data gathered from eTRUC engagement and pilot site demonstrations will inform statewide corridor planning and development along key freight corridors that reside nearby and within low-income and disadvantaged communities (DAC).<br>Corridor planning will factor the following data to support strategic deployment:<br>Benefits to priority populations, environmental justice considerations, travel volume estimates, grid connection and optimized control, site location and cost estimates, distributed energy resources and on-site storage integration, business model solutions<br>Securely controllable from a cloud-based network and can be integrated with a local energy management system;<br>High efficiency from input to delivery to vehicle (≥97% at full load);<br>Modular design that can be scaled up with future Battery-Electric Vehicle truck deployment;<br>Delivered at a total cost below 500 $/kW. | Validate utilization of DER integration to minimize grid impact of High power charging, | 2019 through 2026 | Y | $13M total. SCE contributing $600K in-kind. | Ari Altman | None | Project is currently executing on Budget Period 1; SCE's technical advisory commitments are supporting SunPower with developing the microgrid requirements specifications. |
| 8) Distributed Energy Resource (DER) Orchestration | **Shadow Mountain Community Microgrid (DOE)** | N/A | Serve DOE project with microgrid control system, customer PV, energy storage, and V2G | Menifee, KB Homes Shadow Mountain | Deploy community microgrid | Validate community microgrid leverage third party energy storage and utility control system | 2022 through 2028 | N | SCE is contributing $503,701 in in-kind contribution for this project | Ari Altman | None | Ongoing |

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| 8) Distributed Energy Resource (DER) Orchestration | **Remote Grid Stand-Alone Power System** | Resolution E-5189 for Advice Letter 4573-E | Reducing wildfire risk in all in High Fire Risk Areas (HFRAs), when compared to conventional service via overhead electric poles and wires. No PSPS impact. | Preliminary studies in SCE distribution circuits determined Remote Grid opportunities can reach well above 600 sites with small load to line length ratio | Deploy remote grid (fully isolated system with no grid connection) in high fire risk areas as alternative to overhead line. | Demonstrate alterantive to grid connection when grid connection is challenging or impossible | 2021 through 2025 | N | ~$10M. However, no explicit budget; costs will be offset by savings due to avoided traditional wires infrastructure. | Ari Altman | None | Ongoing |
| 5) Load Control Management Systems (LCMS) and Automated load control | **Virtual Programmable Automation Controller** | 2025 GRC | Pilot instalation of a virtual IEC 61850 capable programmable automation controller to develop the programming and interface standards needed to deploy vPAC in SCE's system | N/A | Similar to objective, the pilot is a first deployment on the system to develop the standards, training, and processes required to deploy the technology at scale to the broader system. | 1. This pilot fills the gaps between technology feasibility assessment and deployment. The EPIC funded predecessor demonstrates the technical feasibility of the technology. Before the technology can be deployed broadly in SCE's systems, standards and processes need to be developed.<br>2. Virtualizing programmable automation controllers advances SCE path as part of the clean energy transition by itself advancing alignment with IEC 61850 for interoperability, reduction in obsolescence, automate configuration, and advance cybersecurity | 2025 through 2027 | Y | $3.9M | Ari Altman | None | If successful, would move this technology to become part of SCE's standard deployment for new substations and substation upgrades. |
| 5) Load Control Management Systems (LCMS) and Automated load control | **Virtual Relay Pilot** | 2025 GRC | Pilot the use of a Virtual Protection Relay at a distribution sub-station to develop the standards needed to deploy (VPR) in our system | N/A | The pilot is a first deployment on the system to develop the standards and training needed to scale the deployment to our broader system | The pilot will reduce cost, reduce footprint, and improve capabilities of a future low carbon grid. VPR will reduce the number of descrete components in the protection system, which will reduce the footprint in substations and reduce the cost of configuring and upgrading the system. Additionally it provides flexibility to adapt to changes in the grid that will be part of the transition to clean energy and high DER penetration. | 2025 through 2028 | Y | $8.8m | Ari Altman | None | If successful, would become part of our standard deployment for new substations and substation upgrades. |
| 8) Distributed Energy Resource (DER) Orchestration | **DC Link Project** | 2025 GRC | Demonstrate battery energy storage connectivity with DC Link to improve operational flexibility between load circuit transfers. | N/A | This project will implement one or more battery energy storage systems (BESS) capable of connecting to two adjacent circuits, referred to as a “DC Link.” The pilot is a first field deployment on the system to develop the standards, training, and processes required to deploy the technology at scale to the broader system | The DC Link can facilitate achieving greater economies of scale for Distribution connected storage capacity by allowing one system to be sized to the interconnection capacity of two adjacent circuits. Another high value opportunity is to use the Link to move load from a heavily loaded circuit to a lightly loaded circuit, thereby increasing utilization and cost effectiveness of the Distribution system | 2024 through 2028 | N | $14,607,000 | Ari Altman | None | The pilot will result in standardization of this DC Link to enhance the operational flexibility currently provided by the feeder parallel/tie switches by allowing the dynamic transfer of load from one circuit to another circuit. |