**PUBLIC UTILITIES COMMISSION**
**505 Van Ness Avenue**
**San Francisco CA 94102-3298**

# Pacific Gas & Electric Company
# ELC (Corp ID 39)
# Status of Advice Letter 6612E
**As of May 20, 2024**

Subject: Operational Flexibility Pilot Proposal Pursuant to R. 17-07-007 Rule 21 Working Group 4 Decision 21-06-006 Ordering Paragraph 18

Division Assigned: Energy

Date Filed: 06-01-2022

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|---|---|
| **Disposition:** | **Signed** |
| **Effective Date:** | **05-09-2024** |

Resolution Required: Yes

Resolution Number: E-5260

Commission Meeting Date: None

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**PUBLIC UTILITIES COMMISSION**
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To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

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February 17, 2023

**Advice 6612-E-A**
(Pacific Gas and Electric Company U 39 E)

Public Utilities Commission of the State of California

**Subject:** **Supplemental: Operational Flexibility Pilot Proposal Pursuant to R. 17-07-007 Rule 21 Working Group 4 Decision 21-06-002 Ordering Paragraph 18**

## Purpose

Pacific Gas and Electric Company (PG&E) hereby submits this supplemental Tier 3 advice letter to propose an "Operational Flexibility" pilot, or OpFlex pilot, pursuant to California Public Utilities Commission (CPUC, Commission) Decision (D.) 21-06-002, Ordering Paragraph (OP) 18. The OpFlex pilot is intended to determine whether a distributed energy resource (DER) operational alternative would be sufficient mitigation for operational flexibility constraints.

At the Commission Energy Division's request, this advice letter supplements PG&E Advice Letter (AL) 6612-E by providing an update on the progress of the Operational Flexibility pilot proposal submitted in AL 6612-E, and resolves typographical errors in the Decision number provided in the original advice letter.

## Background

### Rulemaking 17-07-007

Rulemaking 17-07-007 the *Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21,* was initiated in late 2017 where "the primary objective in this proceeding is to streamline the interconnection application process, which the adopted proposals aim to accomplish.[1]"

In the original scoping memo and subsequent refinements, the proceeding was broken into two phases. The issues to be addressed in the first phase was further divvied up between four working groups. Each Working Group convened with the Commission, the IOUs[2] and various other parties over a period, culminating in a final working group

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[1] D. 21-06-002 Background, p2.

[2] The IOUs, or investor-owned utilities, consist of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.

report. That report was then used to inform the Commission in the preparation of a final decision addressing implementation of the various working group's issues.

Pertinent to this advice letter, the November 16, 2018, Assigned Commissioner's Amended Scoping Memo and Joint Administrative Law Judge Ruling (Amended Scoping Memo) revised the scope and schedule for this proceeding in response to the Motion of the California Solar & Storage Association (CALSSA).

Issue F, which was identified in the Amended Scoping Memo is pertinent to this advice letter. It addresses the question of "what interconnection rules should the Commission adopt to account for the ability of DERMS and aggregator commands to address operational flexibility need?"[3] The Amended Scoping Memo assigned Issue F (as well as other issues) to Working Group Four.

**Working Group Four**

Working Group Four first convened February 12, 2020, with twelve subsequent in-person and virtual meetings. On August 13, 2020, representatives of Working Group Four filed the final Working Group Four Report (Report). As noted in the Report, parties and other stakeholders participated in discussion of and developed proposals on the issues, including Issue F.[4]

In its background it explains:

> *During the Integration Capacity Analysis (ICA) Working Group in 2016-2017, participants developed methodology for the Integration Capacity Analysis. The Working Group agreed that ICA should be based on five constraints – thermal limits, steady state voltage, voltage fluctuation, protection, and operational flexibility*.
>
> *The operational flexibility constraint was particularly difficult. The concept of operational flexibility with the ICA context is that utilities need the flexibility to reconfigure circuits during maintenance or unplanned outages. Because customers sometimes get switched to adjacent circuits, the impact of DERS on circuits that they might be connected to must be studied, even if they are not connected to those circuits in normal circumstances.*

Five proposals to address Issue F were included in the report. This advice letter addresses Proposal F-1. Proposal F-1, as described in the Working Group Four Report, requires:

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[3] IBID p-6.
[4] IBID p-4.

*Proposal F-1. Determine Whether a DER Operational Alternative Would Be a Sufficient Mitigation for Operational Flexibility Constraints*[5]*.*

Following the resolution of Working Group Two issues 8 (Incorporating the Integration Capacity Analysis Results into Rule 21) and 9 (Conditions that allow Distributed Energy Resources to perform while avoiding upgrades) with Decision 20-09-035, Proposal F-1 in essence becomes:

*If the output of a generating facility being interconnected is larger than the ICA values for that location with operating flexibility constraints taken into account (ICA-OF), but smaller than the ICA values without operational flexibility constraints taken into account (ICA-SG), then the distribution provider shall determine whether a DER operational alternative would be sufficient mitigation for operational flexibility constraints, consistent with the Commission decision on operationalizing ICA values within Rule 21*.[6]

The Report goes on to explain:

*This proposal will potentially allow more DER capacity to be added to a circuit while remaining within hosting capacity limits. The proposal addresses the problem that the ICA operational flexibility constraints may be severely limiting for many locations even if circuit reconfiguration at that location are rare. This leads to underutilization of existing hosting capacity. Also, DERs may be able to provide some grid support more effectively and/or at a cheaper cost than traditional approaches, but systems have not been established to make use of those opportunities*.

**Smart Inverter Operationalization Working Group (SIOWG)**
Proposal F-5 and Annex 4 of the Working Group Four Report, provides the Working Group Objectives, Scope, Formation, Oversight, and Timing.[7] Further discussion of proposal F-1 were held at the SIOWG.

**Decision 21-06-002**[8]
Decision 21-06-002 was issued to address the remaining Phase 1 issues including those from Working Group 4. Pertinent to this advice letter, it address Proposal F-1.

**Proposal F-1**,
Section 5.4.2. of D. 21-06-002 addresses Issue F, and regarding this advice letter, Proposal F-1. In the summary discussion it concludes:

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5 Working Group 4 Final Report p. 86.
6 IBID p86.
7 IBID p98 and p121 respectively.
8 D. 21-06-002 - *Decision Addressing Remaining Phase I Issues* - Issued June 4, 2021.

*... we are concerned with statements from PG&E and SDG&E that neither have a system in place at this time to accommodate the operational alternatives anticipated in this proposal. Further, we agree that the evolution of operational alternatives may require re-evaluation, testing, or pilots. Accordingly, we adopt Proposal F-1, but find it prudent to initially pilot it. Further, we delay such piloting until utilities have implemented necessary equipment allowing the proposal capabilities.*[9]

**Ordering Paragraph 18**

D. 21-06-002, in OP 18, the Commission directs that:

*18. Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company (Utilities) shall develop a proposal for a pilot of Proposal F-1, which would determine whether a distributed energy resource operational alternative would be a sufficient mitigation for operational flexibility constraints.* ***Six months after Utilities have implemented IEEE 2030.5 CSIP compliant production servers but not later than June 1, 2022, Utilities shall submit a Tier 3 Advice Letter seeking approval of the Proposal F-1 pilot; the Advice Letter shall include implementation timelines.***
[emphasis added]

**Advice Letter 6612-E**

PG&E filed Advice Letter 6612-E on June 1, 2022 outlining a proposal and timeline for an Operational Flexibility Pilot. This supplemental advice letter is in response to a request from the CPUC's Energy Division to provide an update on the progress of the Operational Flexibility pilot proposal submitted in AL 6612-E as well as resolve typographical errors in the Decision number provided in the original advice letter.

**Background and Updates**

In AL 6612-E, PG&E proposed a three-stage approach to piloting Operational Flexibility. The proposal aligned with the projected readiness of technology at PG&E to address the different aspects of Operational Flexibility to curtail generation to maintain the safety and reliability of the grid during abnormal or emergency scenarios. The proposal builds on the significant learnings from PG&E's EPIC 2.02 DERMS project[10]. The following provides a summary of the proposal stages, and relevant progress or updates in each area.

[9] IBID, p71.
[10] https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-2.02.pdf.

**Stage 1: Redwood Coast Airport Microgrid (RCAM) – Q3 2022 – Q2 2023**

For Stage 1, PG&E leveraged the Battery Energy Storage System (BESS) of the Redwood Coast Airport Microgrid, which is owned and operated by the Redwood Coast Energy Authority (RCEA), to evaluate the manual process and implementation of control during abnormal switching.
The goal was for PG&E to gain insight into:

- Dispatch of Curtailment – Evaluate the reliability of dispatch communications and Operator ability and comfort level to perform dispatch under the defined processes.
- Triggers for OpFlex curtailment – Evaluate the situations that trigger a curtailment, and how Operators are informed.
- Curtailment Amount Determination – Evaluate the process steps and manual studies required to determine the amount of curtailment.
- Operational Process Impacts – Evaluate how well does the initially defined RCAM process work for the OpFlex use case and identify any improvements in the current process.

**Progress with Stage 1:**
RCAM has been in operation since June of 2022, during which time PG&E Operators have needed to modify the charge or discharge settings of the RCEA owned BESS multiple times based on abnormal or emergency conditions.

**Key Lessons Learned:**

- PG&E Operators were successfully able to manually modify the charge and discharge limits of the BESS in response to multiple planned and unplanned abnormal events.
- The operational coordination process for the BESS is still very manual and would be difficult to scale until new and more automated tools like ADMS and DERMS are available for PG&E Operators.
- Prior to putting the system in production, Operators required significant procedural documentation and training to ensure comfort with the system.
    - The documentation and training were updated promptly when issues were experienced in the field.
    - The documentation and training requirements highlighted the need to standardize the operational approach for future systems.
- The 24/7 support provided by RCEA, and their agents, was instrumental in coordination and troubleshooting of the system to ensure limits were properly administered.
- Overshoot by the BESS dispatch caused the power to go beyond the protection settings at the site for over 2 seconds, triggering nuisance trips for the customer.
    - While this system was tested in the PG&E lab, it was not certified to UL 1741 Power Control System (PCS) or another like standard. The issues experienced strengthen the case for having such a certification for similar applications.

**PG&E Operator Training and Experience**

In order to ensure the safe operation of RCAM with PG&E's Operations team, formal documentation and training was conducted prior to allowing RCAM to energize as a microgrid. Over 20 reference documents were created for both Operators and field personnel to be able to properly operate the system and respond to issues. In-person and online training was developed to ensure the material was effectively communicated to, and understood by, affected parties. In addition, PG&E Operators are provided with RCEA's 24/7 operational contact information so Operators can coordinate any updates or actions required.

As part of this training and documentation, particular sections describe the process for abnormal switching conditions that may require RCAM to be curtailed beyond the initial charge/discharge limits established during the interconnection process and delineated in the interconnection agreement.

Furthermore, instructions are provided for previously unstudied conditions via planned or unplanned work for PG&E to study the impact of the work on RCAM and, if possible, notify RCEA in advance of any planned shutdowns or curtailments.

PG&E engineers also identified known alternate grid configurations impacting RCAM including when the Humboldt Bay Transmission Source is islanded during emergency conditions. PG&E's current policy prohibits large generating facilities (>1MW nameplate) from discharging into the Humboldt Bay Regional Island. The 1MW curtailment threshold considers the capacity of the PG&E Grid Operations team to manage complex curtailment calculations and rules during emergency conditions.

The strict limit on generation is enforced to maintain stability of the Humboldt Bay Regional Island. PG&E sought to leverage the BESS's unique capabilities for visibility and constraint controls to allow for more operational flexibility of the BESS during this type of emergency grid configuration. PG&E performed a study and considered modified import/export settings that varied based on time of day, ensuring exports were limited during non-peak periods. However, operationalizing this proposal was infeasible due to the added manual complexity to monitor and manage constraints by the Grid Operations Team which would have detracted from their primary responsibilities when responding to the emergency events that created the abnormal grid configuration.

While it is technically possible to execute the operational flexibility use case at RCAM, this example does not yet prove out a model for scaling such types of curtailment control to large numbers of DER customers. The process for coordinating with RCEA and the BESS is still very manual in terms of needing to apply specific settings for each abnormal condition, creating the proper switch logs, having engineering review of planned work, and anticipating the curtailment limits required. To automate these types of processes ADMS and DERMS functionality is required to be built out and verified before a more scaled approach can take hold. Moreover, the 24/7 support PG&E required of RCEA could be difficult to scale but is important in ensuring the proper operation of these new systems.

**Battery Overshoot Issues**

The initial charge/discharge limits were based on the results of the interconnection study for the site and are codified within the Small Generator Interconnection Agreement of the generation owner. The full 2.3MW system could not safely be interconnected without limits due to generation and load capacity constraints on the line feeding the system. Because the costs of upgrading the PG&E facilities would have been borne by the customer in this case, and the expenditures were large, the customer opted for a constrained interconnection instead. The initial constraints were 1480kW for charging and 1778kW for discharging.

There are two levels of protection to ensure the BESS does not exceed its given limits. The first is soft control via communications to PG&E's Distribution Control Center where PG&E Operators can change the settings via their Supervisory Control and Data Acquisition (SCADA) system. The second is a physical control on site within the settings of RCEA's generation circuit breaker.

The BESS at RCAM normally participates in the whole sale market via CAISO. RCEA found that although the dispatches were set to the maximum settings (1480kW / 1778kW) the BESS would actually slightly overshoot those values for over 2 seconds when set to dispatch to those levels. This in turn caused the generation owner's circuit breaker to open, thus disconnecting the generator from the system. RCEA analyzed the events and asked PG&E to change the default soft control settings to allow a buffer for the known overshoot so as not to create nuisance trips for their generation circuit breaker. PG&E updated the settings and related Operator training documentation to accommodate the change to 1450kW charging and 1750kW discharging.

Although the system had gone through limited testing in the PG&E lab, there was no certification of the output control based on standards like the UL 1741 Power Control Systems (PCS). In RCAM's case, there was redundancy via the required protection settings in the customer breaker, but for sites without this type of physical redundancy, this finding further supports the value of PCS type certification of equipment required to perform strict control limits for constrained interconnections.

**Abnormal Conditions**

There was a total of 5 unplanned or planned events since RCAM became operational that required PG&E Operators to modify the charge and/or discharge limits. For these events, PG&E was able to coordinate with RCEA and update the limits appropriately using PG&E SCADA screens. If there were any issues via SCADA, PG&E would work with the local RCEA staff to update the limits. For example, during the first event on 8/8/22 there were issues changing the limit from the PG&E SCADA Screens. PG&E Operators worked with the 24/7 RCEA support staff to update the settings locally and uncovered a gap in the process. Operator training and documentation were updated accordingly.

A summary of the limit changes and events are below for reference.

| # | Date | Duration (H:M) | Limit Change | Summary |
|---|---|---|---|---|
| 1 | 8/8/22 | 5:13 | Charge Limit Reduced to 0 | An unplanned transmission event created outages for neighboring substations. Asked RCEA to reduce charging to 0 to be able to pick up additional load. |
| 2 | 10/11/22 | 11:23 | Charge and Discharge Limits Reduced to 0 | Planned work to replace a recloser on the Janes Creek circuit required RCEA to limit charging and discharging. |
| 3 | 11/10/22 | 208:41 | Charge Limit Reduced to 0 | Planned work for the substation needed abnormal switching, which required RCEA to limit charging. |
| 4 | 11/21/22 | 13:10 | Charge Limit Reduced to 0 | Planned work for the substation needed abnormal switching, which required RCEA to limit charging. |
| 5 | 1/1/23 | 8:24 | Charge and Discharge Limits Reduced to 0 | Unplanned event where a car hit a PG&E pole on the RCAM Janes Creek circuit, requiring switching to do repairs. |

In addition to the approximately 247 hours of curtailment from the PG&E Distribution Operations team, there were also curtailments or non-dispatches done by the generation owner via CAISO for events on the Transmission system, specifically related to the Humboldt Bay Transmission Island. PG&E does not have direct information regarding CAISO related curtailments and durations, but Transmission related events can have a significant effect on the operations for RCAM as discussed above.

**Summary of Findings related to Operational Flexibility Points of Interest for RCAM:**

- Dispatch of Curtailment
    a. Dispatch of curtailment via PG&E SCADA worked reliably after the initial challenges were resolved
    b. Training, documentation, and Operator involvement in the user interface were important for uptake, and Operators have shown comfort in using the system
    c. Based on the issues seen with potential overshoot, it is recommended the systems using constraints be certified to UL 1741 PCS or a similar standard to avoid potential issues with compliance or protection when no other physical assurance is in place

- Triggers for OpFlex curtailment
    a. Triggers for curtailment were identified upfront and built into the Operators' procedure and training
    b. For planned work, engineers decide in advance if curtailment is required and RCEA is notified in advance via phone call
    c. For unplanned work, Operators and Engineers must decide in real-time if any action is required of the RCEA generation
    d. RCAM was integrated into PG&E Operations' existing tools to provide a more seamless experience for Operators within their normal toolset
- Curtailment Amount Determination
    a. Curtailment amount determination for RCAM so far has only been either full output (up to existing limits) or full curtailment.
    b. Dynamic curtailment values based on time of day during abnormal configurations, specifically the Humboldt Bay Island, were determined to be operationally infeasible
    c. Further research and possibly new automation tools are required to determine how to make the curtailment more granular, however during unplanned situations, running manual studies can be difficult under the given time pressure when the primary operational objective is to safely minimize customer outages
- Operational Process Impacts
    a. The operational process works well for RCAM, but is very manual and not easily scalable
    b. Likely not until new tools like ADMS and DERMS will the operational process be able to scale more effectively

**Stage 2: CSIP-certified IEEE 2030.5 Controls Testing – Q2 2022 – Q4 2022**

The PG&E EPIC 3.03 DER Headend project deployed a production Common Smart Inverter Profile (CSIP)-certified IEEE 2030.5 server for DER telemetry, completed interoperability testing with two CSIP-certified gateways from different manufacturers for the telemetry-only use case, with three additional aggregators soon to be certified as interoperable. There were significant challenges overcome through the EPIC 3.03 project particularly related to vendor maturity with a new standard and interoperability between the DER Headend and CSIP-certified end devices and aggregators. Based on this experience, PG&E believes that it is essential to test control functionality with each new technology vendor in a lab environment prior to any field deployment of these capabilities and perform a technical assessment of the CSIP-certified equipment's ability to dispatch curtailment control commands.

**Progress with Stage 2:**

Stage 2 leveraged the existing DER Headend platform to further test control functionality related to curtailment. Based on the extended time and cost for making telemetry with IEEE 2030.5 functional for the initial IEEE 2030.5 server and connected devices, only limited control testing was possible within the scope of the EPIC 3.03 project. In addition, the DER Headend system developed as part of the EPIC 3.03 pilot project will soon be retired and replaced with PG&E's ADMS vendor, currently scoped for deployment starting in 2023. Therefore, the learnings from the Stage 2 testing will be incorporated into the production ADMS rollout versus trying to resolve any found issues in the existing legacy server. The EPIC team has already performed a similar transfer of knowledge involving CSIP IEEE 2030.5 telemetry, transferring lessons learned from EPIC and being involved in the ADMS testing of telemetry-related functions to implement that technology more efficiently.

**Key Lessons Learned:**

- PG&E observed the inverter firmware representation of the nameplate capacity did not match the actual capacity, resulting in incorrect controls for commands based on percentages of the nameplate rating. Therefore, PG&E recommends the smart inverter firmware needs to be verified during a commissioning process for any field installations.
- Loss of communication scenarios need to be properly characterized with the expected response from the gateway, aggregator, or smart inverter precisely specified. Further alignment is needed with industry partners because of limitations in energy devices to retain settings and revert to defaults.
- Interoperability between gateways/aggregators and different smart inverters is not guaranteed even if CSIP-certified. All required control functions need to be tested during site commissioning at this time.
- Performing more advanced scheduling requires additional testing beyond CSIP certification. PG&E was unable to implement a constraint profile similar to a limited generation profile because the CSIP-certified server user interface only allowed one scheduled event to be set.

PG&E currently anticipates that the final report for the EPIC 3.03 project will be publicly available by the second quarter of 2023.

**Control Test Setup:**

PG&E tested controls using CSIP-certified devices, including the PG&E Headend server, a gateway device, and a smart inverter in the PG&E lab as shown in Figure 1. The gateway communicated with the headend server via IEEE 2030.5, with the gateway polling the server every 30 seconds for new controls (via changes to DERControl or DefaultDERControl). The gateway communicated with the smart inverter via SunSpec Modbus over TCP/IP, translating between 2030.5 and Modbus.

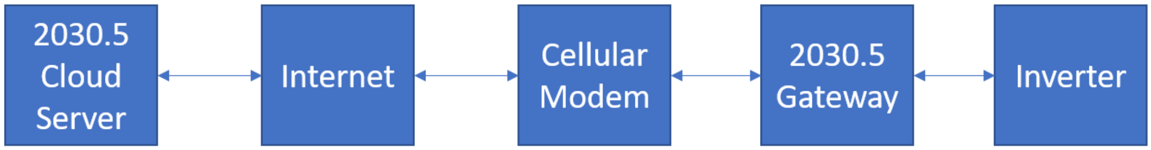


*Figure 1: PG&E IEEE 2030.5 Control Testing Setup*

**Test Cases and Results:**

The following test cases and results are separated between functional control testing and communication loss testing. Criteria for passing a test is clear for the functional control testing. However, for communication loss testing, the goal was more exploratory because the standards for how the system should react under different scenarios are less clear, therefore the results for those tests are not marked with a pass or fail. The communication loss testing still helped define gaps and where to focus discussions with industry as these standards progress.

**Functional Control Testing**

| # | Objective | Results |
|---|---|---|
| 1 | Confirm the gateway polls and acts on changes from the server within the defined 30 second interval. | **Passed** – Confirmed the gateway picked up the changes and acted on them within the 30 second interval. |
| 2 | Confirm the gateway and smart inverter properly respond to a connect/disconnect control via opModConnect changes to the DefaultDERControl function. | **Passed** – Confirmed the gateway picked up the changes to the DefaultDERControl and the smart invert output changed accordingly for both the connect and disconnect functions. For the reconnect function, the smart inverter observed a 5-minute grid monitoring time before power output started. |
| 3 | Confirm the gateway and smart inverter properly respond to a fixed watt (used max watt for solar inverter) control via OpModFixedW changes to the DefaultDERControl function. | **Failed** - Control is a percentage value and should be based on the smart inverter name plate of 33.3kW. However, when sent a command to set the output at 10% (3.3kW), the output was set to 5kW. The issue was that the smart inverter firmware incorrectly assigned the smart inverter max output to 50kW instead of the actual 33.3kW. Therefore, while the communications and command worked appropriately, settings within the inverter caused the output to be incorrect. |
| 4 | Confirm the gateway and smart inverter properly respond to a | **Failed** – The gateway received the curve points, but they were not applied to the |

| | | |
|---|---|---|
| | volt/watt curve change to the DefaultDERControl function. | smart inverter. It is suspected that there could be an error in the Modbus mapping, but this issue was not debugged to confirm based on funding/timing issues. |
| 5 | Confirm the gateway and smart inverter properly respond to a single scheduled control change, and after completion of the schedule the smart inverter returns to the DefaultDERControl. | **Passed** – OpModFixedW (mapped to maxW in the smart inverter) and OpModConnect were both able to be scheduled separately with a start time and duration. |
| 6 | Confirm the gateway and smart inverter properly respond to multiple scheduled control changes, and after completion of the schedule the smart inverter returns to the DefaultDERControl. | **Failed** - Only one control schedule is able to be executed at a time. The UI of the server had no way to implement multiple schedules, and therefore is unable to implement a changing constraint profile or multiple scheduled controls. |

Recommendations from Functional Control Testing:

- The smart inverter nameplate specified in the firmware needs to be verified during commissioning for any production systems.

- If change of curve points is required in a production application, the specific gateway/smart inverter combination should be tested during commissioning of the system.

- PG&E's existing legacy DER Headend is not currently capable of issuing multiple scheduled controls. The new IEEE 2030.5 system currently in development should be designed upfront to do multiple controls. If doing multiple controls in production, this should also be tested using a customer specified smart inverter and gateway combination prior to deployment.

- For the reconnect function, the operator should be aware that local controls may have a delay similar to the 5-minute grid monitoring that was seen during testing, so operators may not see the DER come online instantaneously after commanded.

**Loss of Communication Testing**

| # | Objective | Results Observed |
|---|---|---|
| 1 | Confirm failsafe scenarios in case of loss of communication between the **server and the gateway** (disconnecting gateway from internet) during different times in the control communication process | |
| 1.a | Loss of communications after the scheduled control starts | Control persists until scheduled duration ends, and gateway reverts to DefaultDERControl |

| | | |
|---|---|---|
| 1.b | Loss of communications after the gateway receives the scheduled control, but before the start time | Schedule not followed |
| 1.c | Loss of communications after the gateway receives the scheduled control but before the start time, but then communications returns prior to the event duration elapsing. | Schedule not initially followed, but when communications returns the control starts until the originally scheduled duration elapses. |
| 2 | Confirm failsafe scenarios in case of loss of communication between the **gateway and the smart inverter** | |
| 2.a | DefaultDERControl changed during temporary loss of communication between gateway and smart inverter | When communications returns between the gateway and smart inverter, the smart inverter did not change its output based on the most recent DefaultDERControl |
| 2.b | Loss of communications after the gateway receives a scheduled control but before the start time | Schedule not followed |
| 2.c | Loss of communications after the gateway receives the schedule but before the start time, but then communications returns prior to the event duration elapsing | Schedule not initially followed, but when communications returns the control starts until the duration elapses. |
| 2.d | Loss of communications after the smart inverter receives a DefaultDERControl setting, and the smart inverter loses both DC and AC power | Smart inverter maintained DefaultDERControl opModFixedW setting through all scenarios |

Recommendations from Communication Loss Testing:

- Results of PG&E testing is to be shared with the other IOUs and industry stakeholders to help align on expected and desired responses from the gateway and smart inverter for various loss of communication scenarios.

**Stage 3: ADMS Rollout (CSIP IEEE 2030.5) – Q1 2023 – Q4 2024**

The ADMS program at PG&E is in the final stages of preparing for the initial go-live for SCADA replacement. The full rollout is currently expected to last until Q4 2024 as it is systematically deployed to different areas of the PG&E territory. This timeline has expanded since the writing of AL 6612-E. PG&E is also finalizing the contract with the ADMS vendor for the CSIP-certified IEEE 2030.5 headend server and initial DERMS functionality which is separate from the larger ADMS deployment. However, the IEEE

2030.5/DERMS functionality has dependencies on the ADMS SCADA deployment and is therefore tied to the timeline of the larger system.

As part of the scope of work for the initial DERMS and IEEE 2030.5 deployment, PG&E is planning a small-scale pilot to test communication and constraint management functions based on the real time and forecasted state of the grid, in line with goals of the Operational Flexibility Pilot.

As stated in AL 6612-E, PG&E's OpFlex Pilot intends to demonstrate capabilities to curtail generating facilities in the case of abnormal switching conditions to avoid safety and/or reliability issues and to evaluate whether the operationalization of these capabilities could allow participating interconnecting customers to bypass the supplemental review, and any associated costs and delays, while connecting to the as-built system at the ICA-SG value. This assumes that switching scenarios that impact the customer are infrequent, and therefore connecting up to the ICA-SG would allow for a better utilization of hosting capacity.

The DERMS pilot should provide a platform to incorporate the four areas identified in AL 6612-E that PG&E feels is required to fully operationalize the OpFlex use case:

1. **Demonstrate Ability to Curtail Participating Generating Facilities:**

   The communications and curtailment control signals need to be tested to ensure PG&E can send control commands, limits, or schedules, and that end devices properly receive and interpret them, with a focus on using IEEE 2030.5.

2. **Identify Triggers for OpFlex Curtailment:**

   Determine how an ADMS measurement-based system tied with DERMS can help identify triggers for curtailment.

3. **Develop Curtailment Calculation and Allocation Methodology:**

   Develop processes with ADMS and DERMS to determine the amount of curtailment required at each generating facility during an OpFlex event. In addition, analyze potential issues of equity if multiple parties need to be curtailed on a certain section of line.

4. **Develop Operational Processes to Implement OpFlex:**

   Operational processes and engineering tools will need to be developed to implement the pilot. PG&E will need to evaluate the processes for safe operation of the system and ability to scale.

In addition to the internal development and processes required to enable this functionality, PG&E will continue to work to align with the other CA IOUs on 2030.5 and the industry in developing any new functionality, processes, and standards required for implementing Operational Flexibility.

**Funding**

No funding sources were specified for the OpFlex pilot. As previously stated, PG&E leveraged the scope and budget of existing EPIC funds through the EPIC 3.11 RCAM project and 3.03 DER Headend project for stages 1 and 2, respectively, and is using GRC funds for stage 3 to satisfy the objectives and timeline of the OpFlex pilot as defined in this proposal.

**Protests**

Pursuant to GO 96-B, General Rule 7.5.1, PG&E requests to maintain the original protest and comment period designated in Advice 6612-E and not reopen the protest period.

**Effective Date**

Pursuant to General Order (GO) 96-B, Rule 5.2, this advice letter is submitted with a Tier 3 designation. PG&E requests that this Tier 3 advice submittal become effective upon Commission approval.

**Notice**

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for R.17-07-007. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations

cc: Service List R.17-07-007

# ADVICE LETTER SUMMARY

## ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (U 39 E)

Utility type:

- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Stuart Rubio
Phone #: (951)965-8905
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: stuart.rubio@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6612-E-A

Tier Designation: 3

Subject of AL: Supplemental: Operational Flexibility Pilot Proposal Pursuant to R. 17-07-007 Rule 21 Working Group 4 Decision 21-06-006 Ordering Paragraph 18

Keywords (choose from CPUC listing): Compliance, Rule 21

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.21-06-006

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [x] Yes [ ] No

Requested effective date:

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

**Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:**

| | |
|---|---|
| California Public Utilities Commission<br>Energy Division Tariff Unit Email:<br>EDTariffUnit@cpuc.ca.gov | Contact Name: Sidney Bob Dietz II, c/o Megan Lawson<br>Title: Director, Regulatory Relations<br>Utility/Entity Name: Pacific Gas and Electric Company<br><br>Telephone (xxx) xxx-xxxx: (415)973-2093<br>Facsimile (xxx) xxx-xxxx:<br>Email: PGETariffs@pge.com |
| | Contact Name:<br>Title:<br>Utility/Entity Name:<br><br>Telephone (xxx) xxx-xxxx:<br>Facsimile (xxx) xxx-xxxx:<br>Email: |

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

**PG&E Gas and Electric**
**Advice Submittal List**
**General Order 96-B, Section IV**

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
Braun Blaising Smith Wynne, P.C.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell
Downey Brand LLP
Dish Wireless L.L.C.

East Bay Community Energy Ellison
Schneider & Harris LLP
Engineers and Scientists of California

GenOn Energy, Inc.
Green Power Institute
Hanna & Morton
ICF
iCommLaw
International Power Technology
Intertie

Intestate Gas Services, Inc.

Johnston, Kevin
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.

Resource Innovations

SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Stoel Rives LLP

Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead
Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy