STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

October 18, 2022

Advice Letter 6350-E-B

Sidney Bob Dietz II
Director, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street
San Francisco, California 94177
E-mail: PGETariffs@pge.com

SUBJECT: Proposal to Implement Specific Technical Requirements for Telemetering of Distribution-Connected Systems 1 Megawatt (MW) or Greater, and Less Than 10 MW, Pursuant to Resolution E-5038

Dear Mr. Dietz:

Advice Letter 6350-E-B is effective as of October 4, 2021.

Sincerely,

Leuwam Tesfai

Leuwam Tesfai
Deputy Executive Director for Energy and Climate Policy
Director, Energy Division
California Public Utilities Commission

Pacific Gas and Electric Company

Sidney Bob Dietz II
Director
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Fax: 415-973-3582

July 12, 2022

Advice 6350-E-B
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Second Supplemental: Proposal to Implement Specific Technical Requirements for Telemetering of Distribution-Connected Systems 1 Megawatt (MW) or Greater, and Less Than 10 MW, Pursuant to Resolution E-5038**

Purpose

Pursuant to Ordering Paragraph (OP) 2 of California Public Utilities Commission (Commission or CPUC) Resolution E-5038, Pacific Gas and Electric Company (PG&E) hereby submits this advice letter to implement specific technical requirements for telemetering of distribution-connected systems 1 Megawatt (MW) or greater and less than 10 MW.

This advice letter addresses additional topics raised by Commission Staff (e.g., E-5038 OP 3, items 1 and 4) and provides an update on PG&E's production implementation of its Customer-Owned Telemetry solution. This supplemental advice letter supersedes both Advice Letter (AL) 6350-E and AL 6350-E-A in their entirety.

Background

On April 5, 2019, the CPUC issued D.19-03-013 that[1] requires the Utilities to file Tier 3 ALs:

(1) proposing technical specifications for telemetry,
(2) including a cost-benefit analysis of the telemetry as a means of collecting data on the distribution system, and
(3) providing information to indicate that Supervisory Control and Data Acquisition System (SCADA) and smart inverter data would not be able to provide sufficient data to satisfy the Utilities' needs.

1 D.19-03-013 *Decision Adopting Proposals From March 15, 2018 Working Group One Report -* date of issuance April 5, 2019.

OP 9 also directs that the ensuing resolution should seek to implement **Proposal 1,** and it requires that the Utilities publish technical requirements rather than requiring specific equipment if the telemetry is deemed necessary.

On July 26, 2019, PG&E submitted AL 5595-E pursuant to D.19-03-013 OP 9.

In AL 5595-E PG&E:

- Seeks telemetry based on IEEE 2030.5 communication standards and the Common Smart Inverter Profile (CSIP) to retrieve measurements from smart inverters or site monitoring equipment.
- Compares the IEEE 2030.5 solution with existing Advanced Metering Infrastructure (AMI) and indicates that an AMI-based solution cannot meet operational needs.
- Notes both SCADA and AMI do not help with the masked load issues.
- Asserts that an IEEE 2030.5 telemetry solution "will address the challenges with the existing solutions by identifying masked load effects, creating a near real-time system integrated with PG&E Operations, and reducing costs for customers."
- Will carry out a pilot to:
  (i) prove out the target of lowering utility-related telemetry costs below $20,000, and
  (ii) enable design around future IEEE 2030.5 standards that will provide a way to monitor and control smart inverter based DERs.

  The pilot is ongoing, and field testing is set to be completed in 2021.
- Proposes to transition towards an in-production system for widescale field deployment, following the pilot.
- Will roll out the IEEE 2030.5-based solution for systems greater than 1 MW before considering whether to expand to systems between 250 kW and 1 MW.
- Notes that requirements will be further refined through the pilot.

Resolution E-5038

On August 20, 2021, Resolution E-5038 was issued approving AL 5595-E. E-5038 "*approves maintaining the threshold for requiring telemetry for projects sized one (1) megawatt (MW) or greater, requires the implementation of certain technical requirements for telemetry, and directs the utilities to continue development of a telemetry solution using the IEEE 2030.5 communications standards*."[2]

[2] Resolution E-5038, page 1

Advice Letter 6350-E
Advice letter 6350-E[3] addresses E-5038 OP 2 that requires:

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall implement specific technical requirements for telemetering of distribution-connected systems 1 MW or greater and less than 10 MW. The adopted technical specifications for these systems are as follows:

1) ***facilities can report measurements in 15-minute increments using customer-owned, nonrevenue-grade metering and a data aggregation device*** *comparable to the serial device server that SCE[4] has historically required,*

2) *customers can choose to connect the reporting device to the utility Energy Management System via cellular modem or dedicated internet connection, and*

3) *measurements do not have to be made from revenue grade equipment.*

The Utilities shall submit Tier 1 Advice Letters to implement these requirements no later than October 4.

These Advice Letters may also suggest an alternative polling rate following a discussion of the need for more frequent data polling and what an appropriate polling rate would be within a meeting of the Smart Inverter Working Group.

Advice Letter 6350-E-A
AL 6350-E-A[5] was submitted as agreed to in PG&E's protest response and following discussions with Commission staff to clarify the requirements of Resolution E-5038. The purpose of the supplemental advice letter was to provide additional specifications to implement a customer-owned telemetry solution via PG&E's pilot project for those customers who are unable to be granted conditional permission to operate until a production IEEE 2030.5 system is available at PG&E.

This Second Supplemental Advice Letter
The purpose of this advice letter is to provide an updated status of the telemetry solution, as required by E-5038 OP 2, clarify new cybersecurity terms included with the other requirements published in the Distribution Interconnection Handbook (Attachment A), and provide commentary on E-5038 items 1 and 4 of OP 3 that states:

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company may request, via Tier 3 Advice Letters, a

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3 AL 6350-E submitted October 4, 2021.
4 Southern California Edison
5 AL 6350-E-A submitted November 15, 2021.

modification to the telemetry rules to require an IEEE 2030.5-based solution, with or without an accompanying request to reduce the telemetry threshold from 1 MW to 250 kW at a future date. Such a request must

1) ***Report on the actual utility-related costs and non-utility-related costs incurred, over a period of at least 6 months, by systems providing IEEE 2030.5-based telemetry****,*
2) *discuss the specific operational needs that would be met via a reduced telemetry threshold at a level of detail beyond that available in the Working Group One Final Report filed on March 15,*
3) *quantify the benefit provided by meeting those needs,*
4) ***provide detail on any implementation differences between communications directly to the inverter versus an aggregator or gateway****.*

[formatting added]

PG&E is not requesting a change to the "telemetry rules" in Rule 21 through this supplemental advice letter to require an IEEE 2030.5-based solution or to lower the telemetry threshold to 250 kW but is rather providing a customer-owned option using CSIP IEEE 2030.5 as the communication standard. As such, PG&E submits this Tier 1 advice letter. Since PG&E is deploying this customer-owned option using IEEE 2030.5, PG&E is providing commentary on the cost, to the best of our ability, as well as the implementation differences between communications directly to inverter versus an aggregator or gateway.

In the future, if IEEE 2030.5 communications becomes the only option to meet PG&E telemetry requirements, or there is a need to lower the telemetry threshold to 250 kW, PG&E will file a Tier 3 advice letter to propose a change to the telemetry rules to do so.

Proposal

PG&E has conducted a pilot demonstration of a CSIP-certified, IEEE 2030.5 DER Headend System connected to customer-owned telemetry as part of its EPIC 3.03 project. This proposal is to make PG&E's CSIP IEEE 2030.5 DER Headend System broadly available for telemetering of Distribution-connected customers with DERs 1 MW and greater and less than 10 MW. The system is designed to fulfill the defined requirements stated in E-5038 OP 2 for using customer-owned equipment, the use of cellular or dedicated internet connection, measurements allowed to come from non-revenue grade equipment, and to implement telemetry using an IEEE 2030.5-based solution.

However, PG&E suggests an alternative reporting rate[6] to be used in the order of seconds versus the prescribed 15 minutes by Resolution E-5038. PG&E's IEEE 2030.5 DER Headend is implementing a reporting rate in seconds to better reflect the need for real-time data. At the Smart Inverter Working Group (SIWG) meeting to discuss alternative reporting rates held on September 16, 2021, the three IOUs explained the rationale for requiring real-time data in the realm of seconds versus the 15-minute requirement. A summary of the points discussed is made below:

1. **Resolution E-5038 seemed to be based on a misunderstanding of the capabilities of SCE's serial device server.** SCE's serial device server is referenced in the resolution as the basis for the 15-minute requirement. However, during the September 16, 2021 SIWG meeting, SCE clarified that this device actually provided real-time data in seconds versus a 15-minute refresh rate.

2. **The IOUs and other applicable jurisdictions (e.g. California Independent System Operator [CAISO]) rely on near-real time data on the order of seconds to make decisions to operate the grid.** PG&E's internal systems and Operations rely on data in the seconds range. Transmission systems are polled every 2-3 seconds. PG&E Distribution reporting rates depend on technology, with cellular and Operational Data Network connections polled within 5 seconds, and radio systems having a maximum of 30 seconds, although generally faster than 30 seconds. The other IOUs provided similar data showing existing data needs in the realm of seconds, not minutes.

3. **The need for real-time telemetry in seconds is based on the high variability of DER resources and their ability to negatively impact grid restoration activities during abnormal conditions.** Grid Operators rely on visibility from various points in the system to create operational switching plans to safely and reliably energize as many customers as possible during abnormal conditions. With the increased penetrations of DERs, DERs become a larger and more impactful presence on the grid that needs to be properly analyzed. Operators need to fully understand the real-time gross load profiles, as well as generation and load impacts of DERS, to properly configure sections of the grid.

   As described in PG&E's Electric Program Investment Charge (EPIC) 2.02 Distributed Energy Resource Management System (DERMS) Report[7], large DERs connected to the Distribution system can have an outsized impact on feeder load profiles. Figure 1 shows the impact of a 4MW DER participating in the CAISO frequency regulation market, with a before and after load profile of the Distribution

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[6] PG&E is using "reporting" rate throughout this document rather than "polling" rate because depending on the communication technology the data may be transmitted via a poll or a post (as in IEEE 2030.5).

[7] Pacific Gas and Electric Company EPIC 2.02 – Distributed Energy Resource Management System (pge.com)

feeder to which it was connected. This battery could swing a total of almost 8MW in a 4 second period depending on market signals.

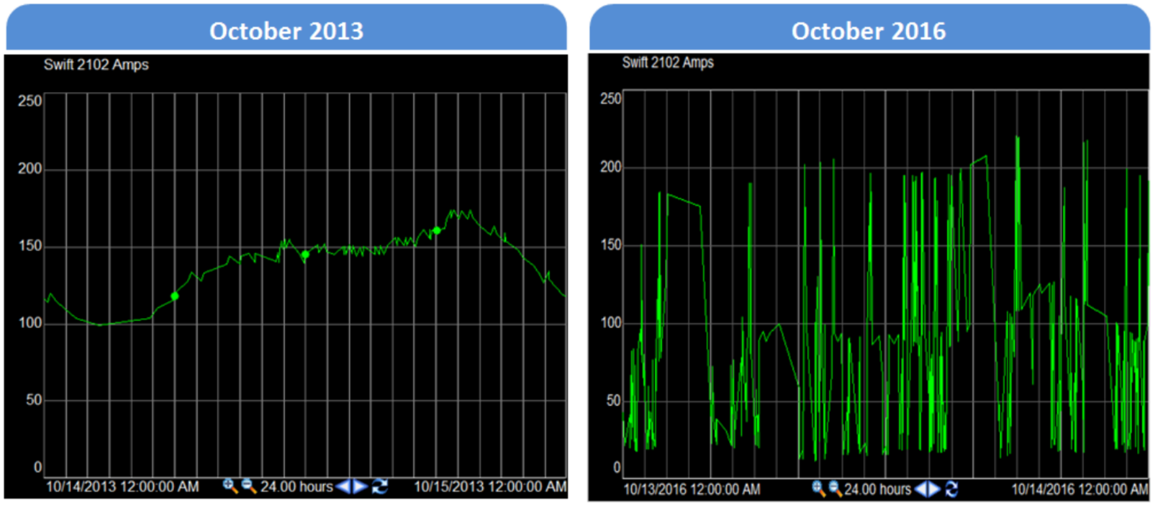

Figure 1: Impact of a Large Distribution-connected DER Participating in the Wholesale Market

In the past, the relatively smooth load profile prior to the large DER installation would have allowed for less frequent SCADA measurements to be adequate for performing switching or other analyses during abnormal conditions. However, after the installation of the large DER on this Distribution feeder, the rapid and large swings in DER generation and load made it difficult to properly assess the actual gross load of the feeder if the DER were to shut-down or be switched. Figure 2 shows the difference in trying to determine the gross load on the feeder (i.e. load profile without the impact of the large DER) using faster sampled data (in this case via a phasor measurement unit) versus slower non-temporally aligned existing SCADA data.

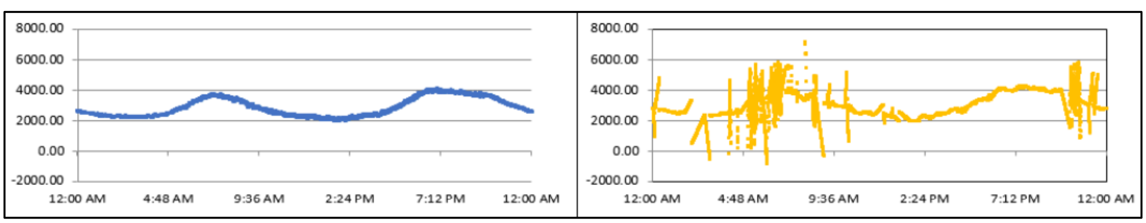

Figure 2: Comparison of Calculating Gross Load (Amps) on a Distribution Feeder with a Large Market-Participating DER using Faster and Slower Sampling Rates during the Same Time Period

The inadequate sampling rate and temporal alignment of data had a direct impact on the ability for more advanced systems, particularly the Advanced Distribution Management System (ADMS) and DERMS in the EPIC 2.02 DERMS project, to operate by creating failures of convergence in the real-time load flow models.

There continues to be an increase, not decrease, in the need and use of data as technology and automation advances. PG&E is proposing investments via the General Rate Case for communication infrastructure in direct response to the increased importance and abundance of data to operate the grid. These improvements via projects like the field area network, help improve existing SCADA polling rates and allow more data to be captured across the system. Constraining polling to 15 minutes as Resolution E-5038 initially suggests, would be a backwards step and only exacerbate the types of problems faced with automation as shown in the EPIC 2.02 DERMS project. As the industry moves toward more automation, and more grid services, inadequate telemetry across the system will lead to these automated systems not providing the situational awareness nor automated capabilities that they are designed and funded to perform.

4. **There is expected to be little to no impact on cost between a reporting rate in seconds versus 15 minutes.** The motivations for this telemetry discussion are primarily driven by cost. Customer ownership, internet-based communication, and the need for non-revenue grade equipment are the main drivers for the cost reduction for customers using the planned CSIP IEEE 2030.5 interface when compared to PG&E's existing telemetry methods of either a miniRTU or line recloser. The data rate also does not impact the other major expenses of a telemetry installation including the installation labor, equipment used, communication hardware, and maintenance activities.

   A preliminary analysis indicates that the difference between reporting in seconds versus minutes should have little effect on cost. While it would impact the amount of data being exchanged between the utility and customer, the cost would depend on the base data plan the customer chooses and any modifications they may or may not need to have adequate capabilities for 30 second data. With network capabilities ever improving, this suggests sufficient data plans should be less expensive as time goes on. For customers with an adequate baseline data plan, PG&E does not expect any additional costs. For a customer with a low baseline data plan, PG&E estimates a potential maximum of an extra $25 per month. As PG&E implements more customer owned telemetry sites, there will be an analysis done on the amount of data required at different types of sites to have a more quantitative analysis on this subject.

5. **The CSIP Standard acknowledges that Utilities' Interconnection Handbooks should define the ultimate reporting rate.** CSIP actually defines the default for posting monitoring information more stringently than Resolution E-5038, as every 5 minutes, but provides for the utilities to make the final determination via their Interconnection Handbooks or programs/contracts because of the understanding that telemetry requirements are based on the needs of the utility or program:

   > "Unless specified in each utility's Interconnection Handbook or programs/contracts, default polling and posting rates SHALL be as follows:
   > - Polling of DERControls and DefaultDERControls (Direct DER Communication)– every 10 minutes

- Posting monitoring information (Direct and Aggregator Mediated Communications)– every 5 minutes

For DERs with an external SMCU [Smart Inverter Control Unit], the SMCU SHALL transfer the DER control to the DER within 10 minutes of receiving the control from the server.

For DERs with a GFEMS [Generating Facility Energy Management System], the GFEMS SHALL transfer the DER control to the DERs within 10 minutes of receiving the control from the server.

For DERs mediated by Aggregators, the Aggregator SHALL transfer the DER control to the DERs within 15 minutes of receiving the control from the server."[8]

PG&E's EPIC 3.03 pilot demonstrated a 30 second rate for acquiring monitoring data. This rate was chosen to align with PG&E's worst-case scenario on Distribution and what was considered to be an achievable starting point while testing a new technology in IEEE 2030.5. For the near-term, PG&E proposes a 30 second rate for acquiring monitoring data, however as technology, use cases, or programs change, PG&E may modify this in the future following an analysis to not create a significant additional burden to customers. As described during the SIWG presentation, PG&E already receives data in about 5 seconds for cellular or Operational Data Network connections, and even faster for Transmission related SCADA.

Implementation Plan

As previously described, PG&E has tested and deployed a CSIP-Certified IEEE 2030.5 DER Headend System that allows customers to fulfill the telemetry requirement more affordably for Distribution-connected DERs greater than or equal to 1MW and less than 10MW using customer-owned equipment, a cellular or other public internet connection, and non-revenue grade metering as required by Resolution E-5038 and described below:

1. **Customer-Owned Equipment:** PG&E provides customers with at least two 3rd-party vendor options for a CSIP certified gateway that can interoperate with PG&E's CSIP-certified 2030.5 Headend. This gateway would be installed and maintained by the customer to provide monitoring information from other customer-owned devices for generation information from the site. These gateways will be able to translate information coming from customer-owned metering, data concentrators, or energy management systems from protocols such as Modbus into IEEE 2030.5 to send to the utility. By providing the customer-owned option,

[8] Common Smart Inverter Profile, March 2018, Version 2.1, Section 4.5 Communication Interactions, page 10.

customers avoid paying PG&E Income Tax Component of Contribution (ITCC) and Utility Cost of Ownership (COO) thus reducing costs further for customers.

2. **Cellular or Other Public Internet Connection:** The customer will be responsible for obtaining and maintaining an internet connection for the gateway device to send data to PG&E. Current deployment of the solution at PG&E is aligned with the IEEE 2030.5 description of an additional static IP based Access Control List (ACL) implementation. However, PG&E is open to develop and implement suitable alternate solutions to support dynamic IP in future iterations of the platform via the process described in the “Options for Customer-Owned Telemetry Solutions” section of this document.

3. **Non-Revenue Grade Metering:** PG&E does not require the customer to provide telemetry data via revenue grade metering.

After successfully piloting the system, PG&E’s CSIP IEEE 2030.5 DER Headend has recently been deployed into production and interoperability with two CSIP certified client gateways has been tested and demonstrated. Updates to PG&E’s front-end interconnection processes and the Distribution Interconnection Handbook have been completed to make this low cost, customer-owned telemetry option available to eligible interconnecting customers.

Specifications and Technical Requirements

The Customer-Owned Telemetry Procedure (Attachment A) was recently posted online as part of PG&E’s Distribution Interconnection Handbook. Attachment A provides the detailed specifications for customer-owned telemetry connecting to the PG&E CSIP-certified IEEE 2030.5 headend server for telemetry of Distribution-connected sites 1MW or greater that have no other protection requirements (e.g. recloser required). These are the initial specifications based on experience in PG&E’s DER Headend pilot and on standards such as the new draft of IEEE 1547.3 (Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems) but may be refined as PG&E and the industry continue to mature in the CSIP and IEEE 2030.5 space.

Options for Customer-Owned Telemetry Solutions

To date, PG&E has successfully tested two gateway solutions for interoperability as part of the EPIC 3.03 project to provide customers a minimum of two initial vendor options. Additionally, PG&E is currently testing two additional IEEE 2030.5 aggregator platforms for interoperability. An updated list of approved vendors solutions will be maintained in the Distribution Interconnection Handbook (Attachment B). Interconnection Customers may select other customer-owned telemetry vendors; however, these alternatives would be required to be tested and configured for interoperability with PG&E’s CSIP-certified IEEE 2030.5 headend server, which could result in additional cost and time. If customers wish to use a customer-owned telemetry platform not yet tested by PG&E, PG&E will provide a cost estimate and timeline to complete an evaluation of the requested solution.

Commentary Relevant to Items 1 and 4 of OP 3

PG&E provides additional comments relevant to items 1 and 4 of OP 3 for the Commission's consideration. PG&E is not proposing changes to the specific telemetry requirements set forth in Resolution E-5038.

OP 3 Item 1: Cost of Installation

CPUC Resolution E-5038 mandates that IOUs provide Distributed Energy Resource projects a customer-owned telemetry option with the goal of lowering utility-related costs to less than $20,000. Item 1 of OP 3 of the resolution requests a report on the actual utility-related costs and non-utility related costs incurred, over a period of at least 6 months, by systems providing IEEE 2030.5-based telemetry. While PG&E is not proposing to change the "telemetry rules", PG&E would like to provide its observations on the cost of the IEEE 2030.5-based solution for telemetry.

The cost for PG&E to configure and commission the customer-owned system onto PG&E's DER headend server is estimated to be $4,000.

The Interconnecting Customer (IC) is also responsible for the purchase, installation, operation and management of the customer-owned communication equipment. In an effort to drive down costs and increase competition between device manufacturers, PG&E has completed interoperability testing with two CSIP-Certified client gateway vendors.

From discussions with the approved vendors, IC costs for purchase and installation of the gateway(s), configuration to PG&E servers and annual maintenance are expected to be near the target of $20,000 for utility-related costs depending on service options. The total cost associated with purchase and installation of the gateway device and its ongoing operations are variable depending on the offerings from vendors and customer choices and, to the best of PG&E's knowledge, range from $12,000-$23,000 over a ten-year period depending on configuration options and optional support packages. This range includes the $4,000 PG&E costs for configuration and commissioning.

Additionally, PG&E is currently testing two different IEEE 2030.5 aggregator platforms. Aggregator implementation is expected to further reduce telemetry costs by leveraging the existing network connections that customers might already have with their developer's systems.

PG&E has not yet had any production systems installed for a period of 6 months as of this filing. PG&E's initial pilot site that was installed over 6 months ago utilized a network architecture that is no longer being used for today's production systems. The first pilot site using the latest network architecture was completed in April 2022.

OP 3 Item 4: Direct-to-Inverter Communications vs Gateway or Aggregator

There are no implementation differences on PG&E's end if a customer wants to do direct-to-inverter communication though PG&E has not tested any direct-to-inverter communications with PG&E's IEEE 2030.5 CSIP-certified platform at this time. However, an inverter vendor can apply to be tested at PG&E similar to any other gateway or aggregator vendor that adheres to PG&E's specifications as described above and in the Distribution Interconnection Handbook. PG&E anticipates that gateway and aggregator implementations will be the primary method of communication to the utility, and likely the most cost-effective method to ensure ongoing compatibility with existing inverters. As a sign of the industry gravitating toward gateways and/or aggregators, currently 99% of the smart inverters that received CSIP-certification did so using a gateway according to the California Energy Commission inverter list[9].

Protests

Anyone wishing to protest this submittal may do so by letter sent electronically via E-mail, no later than August 1, 2022, which is 20 days after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
E-mail: EDTariffUnit@cpuc.ca.gov

The protest shall also be electronically sent to PG&E via E-mail at the address shown below on the same date it is electronically delivered to the Commission:

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name and e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

[9] California Energy Commission inverter list; last updated June 21, 2022.

Effective Date

Pursuant to General Order (GO) 96-B, Rule 5.2, and OP 2 of E-5038, this advice letter is submitted with a Tier 1 designation. PG&E requests that this Tier 1 advice submittal become effective on October 4, 2021, which is 45 days after the issuance of E-5038.

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

Attachments:
Attachment A – Customer-Owned Telemetry Requirements and Guidance Document
Attachment B – Approved Customer-Owned Telemetry Vendors
Attachment C – PG&E IEEE 2030.5 LogEvent Descriptions

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 (ID U39 E)

Utility type:
- ☑ ELC
- ☐ GAS
- ☐ WATER
- ☐ PLC
- ☐ HEAT

Contact Person: Kimberly Loo
Phone #: (415)973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: KELM@pge.com

EXPLANATION OF UTILITY TYPE

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

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6350-E-B

Tier Designation: 1

Subject of AL: Second Supplemental: Proposal to Implement Specific Technical Requirements for Telemetering of Distribution-Connected Systems 1 Megawatt (MW) or Greater, and Less Than 10 MW, Pursuant to Resolution E-5038

Keywords (choose from CPUC listing): Compliance

AL Type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Resolution E-5038

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:

Confidential treatment requested? ☐ Yes ☑ 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? ☐ Yes ☑ No

Requested effective date: 10/4/21

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

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

Clear Form

Advice 6350-E-B
July 12, 2022

Attachment A

Customer-Owned Telemetry Requirements and Guidance Document

Customer-Owned Telemetry (COT) Procedure

SUMMARY

As required by California Public Utilities Commission (CPUC) Resolution E-5038 Ordering Paragraph 2, PG&E approves of the use of customer-owned telemetry (COT) to support distribution-connected generating facilities' telemetry requirements, effective October 4, 2021.

PG&E's telemetry system uses IEEE 2030.5 and California Rule 21 specified Common Smart Inverter Profile (CSIP) requirements to communicate with the generating facility's COT available for purchase from approved vendors.

Approved vendors' COT have been tested to be compatible within PG&E's IEEE 2030.5 infrastructure and to meet PG&E requirements for the equipment. See Attachment 1 for the list of approved vendors.

Level of Use: Information Use

TARGET AUDIENCE

The target audience is PG&E electric grid interconnection (EGI) interconnection customers (ICs) who use customer-owned telemetry that communicates using IEEE 2030.5 protocol to PG&E to fulfill their telemetry requirements. The telemetry requirement is typically for ICs with generation or storage devices with a total aggregate generation of 1 Megawatt (MW) or larger. COT is approved only for distribution-connected ICs with a telemetry requirement and no other protection requirements.

SAFETY

This utility procedure describes administrative tasks that do not expose personnel to any significant hazards.

BEFORE YOU START

NA

TABLE OF CONTENTS

Customer-Owned Telemetry (COT) Procedure

PROCEDURE STEPS

CUSTOMER-OWNED TELEMETRY PROCESS

1 Process Overview

1.1 IC Application to Interconnect – YourProjects Application

1. The IC APPLIES to interconnect their proposed generation via the YourProjects application portal.

2. IF the IC has a project interconnecting onto the distribution grid that is 1 megawatt (MW) or greater (according to the system nameplate),

   THEN the customer SELECTS one of the following three options:

   - Customer-owned telemetry – remote site gateway
   - Customer-owned telemetry – aggregator
   - PG&E MiniRTU

3. PG&E personnel STUDY proposed generation AND PROVIDE a study report to the IC.

4. The IC REVIEWS the study report AND REQUESTS an interconnection agreement (IA) from PG&E.

5. The EGI contact PERFORMS the following tasks:

   a. TENDERS IA to IC.

   b. REQUESTS a choice in vendor. (SEE Attachment 1, "Approved Customer-Owned Telemetry Vendors.")

   c. TENDERS Work at the Request of Others (WRO) agreement, based on a $4,000 flat cost for configuring the COT solution.

6. The IC PROCEEDS as follows:

   a. CHOOSES a vendor.

   b. SIGNS the IA.

   c. RETURNS the IA AND REPLIES with their vendor choice to the EGI contact.

   d. RETURNS the WRO agreement signed by the customer.

1.1 (continued)

7. Once the WRO agreement is signed AND payment is received, the EGI contact ASSIGNS an IT project manager for the proposed generation site.

   a. The IT project manager ASSISTS with coordinating the configuration of the COT to PG&E's system.

8. The IC WORKS with the vendor to install the COT at their site, per required metering points set in Section 3, "Required Data Points," on Page 4.

9. The IT project manager COORDINATES the configuration of the COT onto PG&E's system.

10. When all systems are working correctly and other required site work and testing is successfully completed, the EGI contact PROVIDES the Permission to Operate (PTO) to the IC.

REQUIREMENTS

2 Metering Configuration

2.1 To uncover masked load and support PG&E distribution control center (DCC) switching operations, sites requiring telemetry (typically 1 MW or larger) must PROVIDE aggregate metering of each distributed energy resource (DER) type (e.g., the sum of all individual solar onsite).

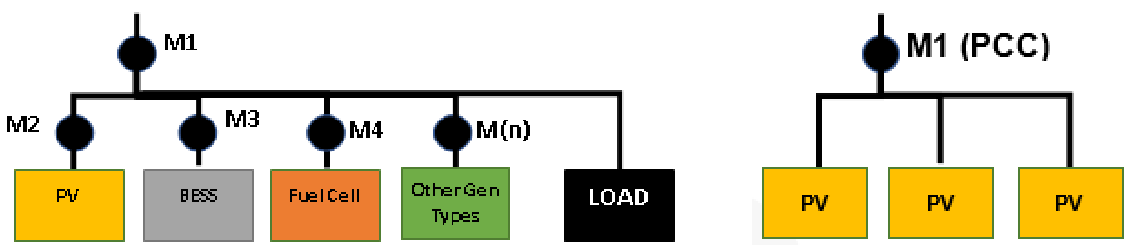

Figure 1. Required Site Metering Examples

2.2 The following data points are required at each point shown in Figure 1 above for the customer-owned telemetry solution, depending on installed generation resources:

- M1: Site (Point of common coupling measurements). **Optional to provide PG&E additional information OR may be used as monitoring point if there is only one generator fuel type AND no other load onsite.**

- M2: Photo-voltaic (PV) Solar (aggregate of all PV on site)

- M3: Battery Energy Storage System (BESS) (aggregate of all storage onsite)

Customer-Owned Telemetry (COT) Procedure

2.2 (continued)

- M4: Fuel Cell (aggregate of all fuel cell generation on site)
- M(n): Any other Generation Type (aggregate of any other generation type not listed above)

3 Required Data Points

3.1 Program Description

1. As a condition to PG&E issuing the final Permission to Operate for generator interconnection projects requiring telemetry (typically 1 MW or larger), the IC SUPPORTS PG&E's implementation of COT to provide the following real-time data from the generating facility to PG&E to satisfy Producer's Rule 21 DER telemetry requirements:
   - 3-phase and total watts (W)
   - 3-phase and total volt-amperes-reactive (VAR)
   - 3-phase voltage (V)
   - 3-phase amperes (Amps)
2. TEST monitoring functionality at the generating facility. The day and time for testing functionality is decided in coordination with the IC to ensure minimal to no impact to existing operations.
3. During the Operational Period, the IC must MAINTAIN the following items:
   a. The connection between the COT and its equipment.
   b. The accurate scaling of watts, VARs, volts, and amps values.
      (1) IF the IC CHANGES Item a or Item b above and such change results in inaccurate values that do not accurately reflect local conditions,

      THEN the IC must RESOLVE the issue within 2 weeks of notice or discovery of the issue. Parties AGREE that the IC remains solely responsible for its obligations under these requirements and the Generating Facility Interconnection Agreement (GFIA).
4. During the Operational Period, the IC must NOTIFY PG&E 10 days in advance of making any changes to the telemetering devices connected to the COT, along with the proposed change at: DERComms@pge.com

3.1 (continued)

5. During the Operational Period, the IC is RESPONSIBLE for connections with the COT equipment.

6. Table 1 below describes the required data points for locations M2, M3, M4…M(n), as applicable. Table 2 on Page 6 describes data points for M1, as applicable (M1 is optional to provide PG&E additional information OR may be used as a monitoring point if there is only one generator fuel type AND no other load onsite).

Table 1. Directly Monitored Telemetry Points by Generation Type from the DER Site

Telemetry	Accumulation Behavior Type	Comm-odity Type	Data Qualifier Type	Flow Direction Type	Kind Type	Phase Code	Uom Type	Unit and Precision	Note
Current A	12	0	0	0	0	128	5	1 A	Always Positive
Current B	12	0	0	0	0	64	5	1 A	Always Positive
Current C	12	0	0	0	0	32	5	1 A	Always Positive
Voltage AN	12	0	0	0	0	129	29	0.1 V	Use for Wye connected meter. Omit for Delta connected meter.
Voltage BN	12	0	0	0	0	65	29	0.1 V	Use for Wye connected meter. Omit for Delta connected meter.
Voltage CN	12	0	0	0	0	33	29	0.1 V	Use for Wye connected meter. Omit for Delta connected meter.
Voltage AB	12	0	0	0	0	132	29	0.1 V	Use for Delta connected meter. Omit for Wye connected meter.
Voltage BC	12	0	0	0	0	66	29	0.1 V	Use for Delta connected meter. Omit for Wye connected meter.
Voltage CA	12	0	0	0	0	40	29	0.1 V	Use for Delta connected meter. Omit for Wye connected meter.
Active Power Total	12	0	0	0	0	224	38	1 W	Negative = Export to Grid
Active Power A	12	0	0	0	0	128	38	1 W	Negative = Export to Grid
Active Power B	12	0	0	0	0	64	38	1 W	Negative = Export to Grid
Active Power C	12	0	0	0	0	32	38	1 W	Negative = Export to Grid
Reactive Power Total	12	0	0	0	0	224	63	1 VAR	Negative = Capacitive Load
Reactive Power A	12	0	0	0	0	128	63	1 VAR	Negative = Capacitive Load
Reactive Power B	12	0	0	0	0	64	63	1 VAR	Negative = Capacitive Load
Reactive Power C	12	0	0	0	0	32	63	1 VAR	Negative = Capacitive Load

3.1 (continued)

Table 2. Directly Monitored Telemetry Points for the Point of Common Coupling (PCC) from the DER Site (PCC metering only required for sites seeking control)

Telemetry	Accumulation Behavior Type	Commodity Type	Data Qualifier Type	Flow Direction Type	Kind Type	Phase Code	Uom Type	Unit and Precision	Note
Current A	12	0	0	0	0	128	5	1 A	Always Positive
Current B	12	0	0	0	0	64	5	1 A	Always Positive
Current C	12	0	0	0	0	32	5	1 A	Always Positive
Voltage AN	12	0	0	0	0	129	29	0.1 V	Use for Wye connected meter. Omit for Delta connected meter.
Voltage BN	12	0	0	0	0	65	29	0.1 V	Use for Wye connected meter. Omit for Delta connected meter.
Voltage CN	12	0	0	0	0	33	29	0.1 V	Use for Wye connected meter. Omit for Delta connected meter.
Voltage AB	12	0	0	0	0	132	29	0.1 V	Use for Delta connected meter. Omit for Wye connected meter.
Voltage BC	12	0	0	0	0	66	29	0.1 V	Use for Delta connected meter. Omit for Wye connected meter.
Voltage CA	12	0	0	0	0	40	29	0.1 V	Use for Delta connected meter. Omit for Wye connected meter.
Active Power Total	12	0	0	0	0	224	38	1 W	Negative = Export to Grid
Active Power A	12	0	0	0	0	128	38	1 W	Negative = Export to Grid
Active Power B	12	0	0	0	0	64	38	1 W	Negative = Export to Grid
Active Power C	12	0	0	0	0	32	38	1 W	Negative = Export to Grid
Reactive Power Total	12	0	0	0	0	224	63	1 VAR	Negative = Capacitive Load
Reactive Power A	12	0	0	0	0	128	63	1 VAR	Negative = Capacitive Load
Reactive Power B	12	0	0	0	0	64	63	1 VAR	Negative = Capacitive Load
Reactive Power C	12	0	0	0	0	32	63	1 VAR	Negative = Capacitive Load

4 COT Functional Specifications

4.1 The following are the functional specifications for the COT equipment:

1. COT must be CSIP certified for IEEE 2030.5.

2. COT must run the latest version of CSIP implementation of 2030.5 (Currently CSIP 2.1 – March 2018).

4.1 (continued)

3. COT must be able to update the CSIP 2030.5 version and the version should be verifiable.

4. COT must have proven interoperability with the PG&E CSIP-certified IEEE 2030.5 Head-end system.

5. COT must be able to translate between the CSIP implementation of IEEE 2030.5 and the local device protocol for providing telemetry information.

6. Gateway must be able to provide the LogEvents as described in Attachment 2, "PG&E IEEE 2030.5 LogEvent Descriptions."

7. COT must be able to provide metering point values (e.g., W per phase and total, VAR per phase and total, Voltage per phase, Amps per phase) at any uniquely identified input with the appropriate CSIP characteristics (RoleFlags, ServiceCategoryKind, AccumulationBehaviour, Commodity, DataQualifier, FlowDirection, PowerOfTenMultiplier, Qualityflags, etc.).

8. COT must monitor status values (e.g., alarm or status points) at any uniquely identified input.

9. COT must post data at a minimum of every 30 seconds, as defined by the posting rate given by the PG&E 2030.5 Headend server.

10. Data must be scaled appropriately based on units of measure (kW, MW, etc.).

11. COT must have the ability to determine the average, minimum, and maximum from a set of values.

12. COT must be able to receive input signals from one or more serial and IP connections.

13. COT must have methods to configure the site and site DER/load identification information.

14. COT must have methods to configure data values as required for each measurement location within a site.

15. COT must have methods to configure protocol parameters as required.

16. COT must have methods to configure security parameters as required, including user access management.

17. COT must have methods to configure communication and network parameters as required.

18. COT must have methods to configure alarm parameters as required.

4.1 (continued)

19. COT must provide continuous monitoring of connections to local DER or metering interfaces.

20. The device must automatically restart to full functionality after power is restored following the complete loss of power to the COT equipment.

5 COT Equipment Non-Functional Specifications

5.1 The following are the functional specifications for the COT equipment:

1. Gateway should be an OS embedded type of device. Currently, PG&E does not accept Windows 10 Enterprise operating system for a Gateway. The vendor must indicate what security certification, such as ISO/IEC 15408 Common Criteria (CC) and Evaluation Assurance Level (EAL), the OS has achieved from an external-auditing organization.

2. Minimum operating temperature range: -20° C to +70° C

    a. Preferred operating temperature range: -40° C to + 85° C

3. Gateway is capable of being installed inside an outdoor cabinet.

4. COT must meet all IEEE 2030.5 mandatory requirements described in the standard and must follow the IEEE 2030.5 Implementation Guide for the Common Smart Inverter Profile (CSIP 2.1), acting as a DER Client or Aggregator when communicating with the PG&E DER Headend server using CSIP IEEE 2030.5.

5. COT must initiate all communications with the PG&E DER Headend Server according to polling and posting intervals provided by the server to ensure the Gateway has up to date settings and PG&E understands the operational state of the Gateway.

6. The default posting rate must be every 30 seconds and must be configurable.

7. TLS must be used for all HTTPS transaction and the Gateway must support the following cipher suite, in addition to the CSIP specified cipher suites: TLS_ECDHE-ECDSA-AES128-GCM-SHA256 (oxc02d) GCM cipher suite

8. A valid certificate must be used in IEEE 2030.5 TLS transactions. The COT must have a 'SunSpec PKI' issued device certificate and store key files using secure methods.

9. COT must perform mutual authentication (Two-Way Authentication) during the TLS handshake by exchanging and authenticating with the DER Headend Server's certificate. The DER Headend server will hash the COT certificate and validate it with the pre-registered SFDI/LFDI of the COT.

Customer-Owned Telemetry (COT) Procedure

5.1 (continued)

10. COT must provide a stable communication path via public internet with Public Static (fixed) IP addresses to communicate with PG&E DER Headend Servers. The Public Static IP addresses will be submitted to add to the White List of the edge Load Balancer for Access Control List (ACL) management.

11. COT must support access control functions, including Gateway applications checking the 'PIN' code from the registration message.

12. COT must support the following methods to get the PG&E IEEE 2030.5 DER Headend Server's 'DeviceCapability' resource:

    a. Out-of-Band Discovery: Gateway can be provisioned with all the DER Headend information by an out-of-band method.

    b. Unicast-DNS and DNS-SD: Gateway is provisioned with the DNS name of the PG&E Headend server. The Gateway must perform name resolution using DNS and using DNS based Service Discovery (DNS-SD) to get the PG&E DER Headend Server IP address and port, scheme (HTTPS), and the path to the 'DeviceCapability' resource.

13. Once the COT gets its EndDevice instance, it finds its group assignments by following the 'FunctionSetAssignmentListLink'. The COT periodically polls these resources at a rate specified by the DERProgramList:pollRate setting.

    a. COT must also support operating with no Function Set Assignment for telemetry only installations.

14. The PG&E DER Headend server will use the 'Time' function set (IEEE 2030.5) to distribute the current time to the Gateway. The Gateway must update the local time of the device to this time.

15. Communication performance requirements for the interfaces to the DER Headend Server are listed below. These requirements do not constrain or define the performance of various communication systems.

    a. Availability of Communication: Must be active and responsive whenever the end device is operating and in a continuous operating region or mandatory operating region.

    b. Reporting Telemetry Data: Post data every 30 seconds. This is based on the default posting interval from the PG&E DER Headend Server.

    c. Reporting Status Information: <=2 seconds. This is based on the maximum amount of time to report status information after receiving status information from an end device.

5.1 (continued)

d. Reporting Alarm: <=2 seconds. This is based on the maximum amount of time to report alarms after detecting and/or receiving alarms from an end device.

16. COT must have sufficient public documentation regarding the following:

a. System Installation Guide

b. System Administrator Guide

c. User (Operator) Guide

d. Functional Specifications and Related Technical Specifications

e. System Configuration Hardening Guide

6 Cybersecurity Requirements

6.1 PG&E PROVIDES network access to ICs to supply power and related telemetry data originating from an IC's DER system.

1. Access is governed by the security requirements defined in this procedure.

2. PG&E may REVOKE access if the IC violates any terms of this agreement as described in Section 6.2 below.

6.2 Any IC connecting to PG&E networks must COMPLY with the security requirements described in this procedure to ensure the confidentiality, integrity, and availability of PG&E networks, systems, and data.

1. General Information

a. Approved gateway vendors must be ABLE to communicate with PG&E's IEEE 2030.5 system using the ECDHE-ECDSA-AES128-GCM-SHA256 (oxc02d) GCM cipher suite.

b. The IC connecting to PG&E networks and systems must FOLLOW security principles and guidance, based on the then-current NIST CSF framework, currently NIST 800 53 r4, OR similar security frameworks.

2. Identify and Access Management

a. The IC must ENSURE that individuals operating the DER or accessing assets connected to the PG&E network are properly authenticated and have documented roles and responsibilities governing their level of access.

6.2 (continued)

b. All IC devices accessing the PG&E networks and systems must have valid credentials identifying the asset and all assets and devices must be physically protected to prevent unauthorized access and use.

3. Network and Asset Protection

a. The IC DER systems or LAN(s) connecting to the PG&E IEEE 2030.5 systems must have adequate technical controls (perimeter firewalls, anti-virus protection, etc.).

b. The IC is RESPONSIBLE for safeguarding their internal networks (logically and physically) to protect the equipment and systems from unauthorized access and manipulation.

4. Cyber Event Detection

a. PG&E must EMPLOY tools AND techniques to detect and remediate cyber risks.

(1) The IC AGREES that in the event of detection of a cyber event, PG&E must PERFORM problem analysis including monitoring, scanning, and auditing of PG&E networks (and traffic to such PG&E networks). Such problem analysis must be coordinated with the IC in advance and must be initiated from PG&E sites or the IC site with the agreement of the IC.

(2) The IC is RESPONSIBLE for any tools and techniques to detect and remediate cyber risks within their networks or connections and is expected to perform their own analysis.

(3) The IC can REQUEST reporting or results of investigations or events.

b. The IC must PROVIDE, upon PG&E request, systems log and audit trails in support of PG&E cyber event detection and/or cyber event analysis or forensic analysis.

(1) PG&E can REQUEST additional data to support the analysis of IC infrastructure connections to PG&E networks to confirm that the connection is authorized and that the IC has implemented cyber safeguards and best practices, including having implemented appropriate firewall, patch, and anti-virus measures.

(2) The IC may also REQUEST that PG&E provide systems logs and audit trails in support of PG&E cyber event detection and/or cyber event analysis or forensic analysis.

6.2 (continued)

c. PG&E LIMITS the scope of their monitoring, scanning, and auditing activities to ensure compliance with these requirements AND COORDINATES with designated members of the IC information security staff in advance.

(1) The IC CONSENTS to such monitoring, scanning, and auditing.

(2) Any proprietary or other information of the IC obtained by PG&E as a result of such monitoring, scanning, and auditing will be kept in strict confidence, will not be disclosed to third parties, and will be used by PG&E only for the purposes set forth in this Section 6.2.4.c.

5. Cyber Event Response

a. The IC must HAVE a documented and tested Cyber Incident Response Plan (IRP) or a documented process so that in the event of a confirmed cyber event the IC can NOTIFY PG&E AND PROVIDE information and the scope of exposure.

(1) PG&E must HAVE a similar plan AND/OR process to notify the IC and provide information on the scope of exposure, extent of conditions, etc.

b. The IC is RESPONSIBLE for all network activities that originate from its facilities, systems, or networks that pass into PG&E networks.

(1) In the event of a cyber event, PG&E may REQUEST additional logical or administrative controls be deployed as precautionary and risk mitigation measures.

c. Upon completion of a cyber event investigation and indication of criminal activity, PG&E in conjunction with the IC, must PROVIDE evidence to appropriate law enforcement or regulatory agencies.

7 COT Maintenance Specifications

7.1 The customer or their contracted vendor IS RESPONSIBLE for maintaining customer-owned equipment in good working order

7.2 The customer or their contracted vendor IS RESPONSIBLE for all firmware and security patching of customer-sited telemetry equipment

7.3 The customer or their contracted vendor has 30 days to repair or replace malfunctioning equipment. Security-related patching may be required in a shorter time-frame.

7.4 Gateway must have an encrypted interface for remote management to upgrade software/firmware, install security patches, and reboot device remotely.

8 Cellular Signal Strength

8.1 To ensure PG&E is receiving quality data from the site, VERIFY the cellular signal strength is in the required range for the program.

8.2 IF the COT solution will be using a cellular connection to the internet,

THEN:

1. PG&E REQUIRES that Reference Signal Received Quality (RSRQ) values be greater than -14 dB with corresponding Reference Signal Received Power (RSRP) values, as listed in Figure 3 below. (PG&E USES the Berkeley Varitronics Systems – Octopus Cellular Signal Meter Pro Kit to measure cellular signal strength.)

2. DO NOT INSTALL anything less than RSRQ values of -14 dB.

    a. NOTE the negative signs and that greater than in relative terms means a smaller number.

If RSRQ (dB) is=	Then RSRP (dBm) must be:
≥ -9	≥ -105
-10	≥ -104
-11	≥ -103
-12	≥ -102
-13	≥ -91
-14	≥ -87
-15	NA - Do Not Install
-16	NA - Do Not Install
-17	NA - Do Not Install
-18	NA - Do Not Install
-19	NA - Do Not Install

Figure 3. Cellular Signal Strength Requirements Using Berkeley Varitronics Systems – Octopus Cellular Signal Meter Pro Kit

9 Frequently Asked Questions

9.1 What is the estimated cost of the new customer-owned telemetry solution?

Answers:

1. Costs for customer-owned telemetry include the following:
   - $4,000 for configuring the customer-owned gateway to the PG&E server
   - Any costs that vendors charge for the procurement, installation, and support of the COT solution
2. The goal of the system is to estimate utility-related costs for the new telemetry solution at less than $20k for ICs, including PG&E and vendor-related costs. This does not include recurring third-party telecom costs.

9.2 What is the best way to power the remote site gateway?

Answer:

1. POWER the COT from the utility side of any breaker or disconnect device and not from the DER side. This avoids requiring permission to operate for the DER before configuring and testing the COT with PG&E's network.

END of Instructions

DEFINITIONS

Distribution-connected: Connected to PG&E's distribution system, which is the portion of PG&E's power system that is at voltage less than 60 kilovolt (kV).

Point of Common Coupling (PCC): The transfer point for electricity between the electrical conductors of Distribution Provider and the electrical conductors of Producer.

Remote Site Gateway (RSG): IEEE 2030.5 site gateway device that communicates telemetry data points to PG&E's IEEE 2030.5 server.

Utility-related costs: The Smart Inverter Working Group One Final Report defines utility-related costs as: "charges for metering equipment (meters, circuit transformers (CT) and potential transformers (PT)), communications/telemetry equipment (Remote Terminal Unit (RTU) and a modem), and charges for labor, taxes, and maintenance."

IMPLEMENTATION RESPONSIBILITIES

The electric grid interconnection (EGI) manager for EGI retail is responsible for the front end processes.

The supervisor control and data acquisition (SCADA) operations supervisor for business applications is responsible for commissioning systems.

The integrated grid planning and innovation senior manager is responsible for overall system support.

The Applied Technology Services (ATS) grid technology engineering and evaluation team is responsible for evaluating new COT that are not included in the approved vendor list in Attachment 1.

GOVERNING DOCUMENT

NA

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Records and Information Management:

Information or records generated by this procedure must be managed in accordance with the Enterprise Records and Information (ERIM) program policy, standards, and Enterprise Records Retention Schedule (ERRS). REFER to GOV-7101S, "Enterprise Records and Information Management Standard," and related standards. Management of records includes, but is not limited to:

- Integrity
- Storage
- Retention and Disposition
- Classification and Protection

REFERENCE DOCUMENTS

Developmental References:

NA

Supplemental References:

NA

Customer-Owned Telemetry (COT) Procedure

APPENDICES

NA

ATTACHMENTS

Attachment 1, "Approved Customer-Owned Telemetry Vendors"

Attachment 2, "PG&E IEEE 2030.5 LogEvent Descriptions"

DOCUMENT RECISION

NA

DOCUMENT APPROVER

Alex Portilla, Senior Manager, Grid Innovation

Brian Chabot, Senior Manager, Electric Business Systems

Shawnmarie Gonzalez, Manager, Electric Grid Interconnection Retail

DOCUMENT OWNER

Alex Portilla, Senior Manager, Grid Innovation

Kathy Graykowski, Principal, Electric Grid Interconnection

DOCUMENT CONTACT

Kathy Graykowski, Principal, Electric Grid Interconnection

Omid Sarvian, Expert, Grid Innovation

Rustom Dessai, Principal, Grid Innovation

REVISION NOTES

Where?	What Changed?
NA	This is a new utility procedure.

Advice 6350-E-B
July 12, 2022

Attachment B

Approved Customer-Owned Telemetry Vendors

Customer-Owned Telemetry Procedure

Attachment 1, Approved Customer-Owned Telemetry Vendors

PG&E has tested and approved the following customer-owned telemetry (COT) vendors for interoperability with PG&E's Common Smart Inverter Profile (CSIP)-certified IEEE 2030.5 solution.

The list of approved vendors is expected to expand as PG&E continues to work with vendors to provide COT solutions. Interconnection customers (ICs) are free to select other gateway or aggregator vendors; however, new solutions would be required to be tested and configured for interoperability with PG&E's CSIP-certified IEEE 2030.5 headend server, which could result in additional time and costs for the IC.

If ICs wish to use a gateway or aggregator platform not yet approved by PG&E, PG&E will provide a cost estimate and timeline to complete an evaluation of the requested device. For more information, CONTACT: DERComms@PGE.com

The following are approved COT vendors:

1. **Applied Systems Engineering Inc.**
   Website – https://www.ase-systems.com/california-rule-21-solutions/
   Contact: Catherine Hugoo, Sales Specialist
   Phone: 408-364-0500
   E-mails:
   Quotes/Ordering – sales@ase-systems.com
   Support/Engineering – support@ase-systems.com

2. **Kitu Systems Inc.**
   3760 Convoy Street, Suite 230
   San Diego, CA 92111
   Email: Gateway_Enquiries@kitu.io
   Phone: 619-569-2208 x7

REVISION NOTES

Where?	What Changed?
NA	This is a new attachment to new Utility Procedure TD-2306P-01.

Advice 6350-E-B
July 12, 2022

Attachment C

PG&E IEEE 2030.5 LogEvent Descriptions

Customer-Owned Telemetry Procedure

Attachment 2, PG&E IEEE 2030.5 LogEvent Descriptions

The following table provides the LogEvent information for PG&E.

Customized alarm notifications – LogEvent:functionSet

logEventPEN: 4816 (PG&E)

profileID: 1 (vendor defined)

Alarms	FunctionSet	LogEvent Name	LogEvent Code	Data Source	Notes
Local DER Interface Disconnected	DER (11)	DER_Fault_Local_INTERFACE_DISCONNECTED	100	Remote Site Gateway	Detect local interface communication down
Local DER Interface RTN	DER (11)	DER_Fault_Local_INTERFACE_RTN	101	Remote Site Gateway	Local interface communication RTN (Return to Normal)
Meter Failure	Metering (6)	UPT_Fault_Meter_Comm_Failure	102	EMS / Controller	Meter communication failure
Meter RTN	Metering (6)	UPT_Fault_Meter_Comm_RTN	103	EMS / Controller	Meter communication failure – RTN
Relay Failure	DER (11)	DER_Fault_Relay_Comm_Failure	104	EMS / Controller	Relay communication failure
Relay RTN	DER (11)	DER_Fault_Relay_Comm_RTN	105	EMS / Controller	Relay communication Failure – RTN
Loss of monitoring	DER (11)	DER_Fault_Loss_of_monitoring	106	DER Aggregator Server	The DER Site controller has stopped reporting data to the monitoring provider's servers for a certain duration of time. DER Headend server should define this alarm to notify for PG&E SCADA Masters as same as 'Comm. Failure' in DNP3 interface.
Loss of monitoring RTN	DER (11)	DER_Fault_Loss_of_monitoring_RTN	107	DER Aggregator Server	
Generator failed to start	DER (11)	DER_Fault_Generator_failed_to_start	108	EMS / Controller	The EMS/Controller has attempted to start the generator and it has not started for a certain duration of time. (Not used in the telemetry only use case)
Generator failed to start RTN	DER (11)	DER_Fault_Generator_failed_to_start_RTN	109	EMS / Controller	

Customer-Owned Telemetry Procedure

Attachment 2, PG&E IEEE 2030.5 LogEvent Descriptions

Low enclosure temperature*	DER (11)	DER_Fault_Low_Enclosure_temperature	110	EMS / Controller	An enclosure with active heating has fallen below its design minimum temperature.
Low enclosure temperature RTN*	DER (11)	DER_Fault_Low_Enclosure_temperature_RTN	111	EMS / Controller	Temperature RTN
High enclosure temperature*	DER (11)	DER_Fault_high_Enclosure_temperature	112	EMS / Controller	An enclosure with active cooling has risen above its design maximum temperature.
High enclosure temperature RTN*	DER (11)	DER_Fault_high_Enclosure_temperature_RTN	113	EMS / Controller	Temperature RTN
Door Open	DER (11)	DER_Fault_Enclosure_door_open	114	Remote Site Gateway	The Cabinet or Enclosure door is open.
Door Open RTN	DER (11)	DER_Fault_Enclosure_door_open_RTN	115	Remote Site Gateway	The Cabinet or Enclosure door is closed. (RTN)
Unauthorized Access	DER (11)	DER_Fault_unauthorized_access	116	Remote Site Gateway	A user tried to access the Remote Site Gateway.
Unauthorized Access RTN	DER (11)	DER_Fault_unauthorized_access_RTN	117	Remote Site Gateway	A user accesses the Remote Gateway successfully. (RTN)
Time Synchronization Failure	DER (11)	DER_Fault_Time_Synchronization	118	Remote Site Gateway	Failure to Time synchronization with DER Server's 'Time'
Time Synchronization Failure RTN	DER (11)	DER_Fault_Time_Synchronization_RTN	119	Remote Site Gateway	Time synchronization - RTN

REVISION NOTES

Where?	What Changed?
NA	This is a new attachment to new Utility Procedure TD-2306P-01.

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

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

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
International Power Technology

Intertie

Intestate Gas Services, Inc.
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.
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