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November 15, 2021

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

Public Utilities Commission of the State of California

Subject: **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, CPUC) Resolution E-5038, Pacific Gas and Electric Company (PG&E) hereby submits this Supplemental Tier 1 Advice Letter to implement specific technical requirements for telemetering of distribution-connected systems 1 Megawatt (MW) or greater and less than 10 MW.

This supplemental advice letter provides an update to the original Advice Letter 6350-E.

Background

Rulemaking 17-07-007

In July of 2017, Rulemaking (R.) 17-07-007 was initiated to "*consider a variety of refinements to the interconnection of distributed energy resources* [DERs] *under Electric Tariff Rule 21 of the Utilities and the equivalent tariff rules of the small and multi-jurisdictional electric utilities*[1]." Rule 21 addresses the safe and reliable interconnection of customer owned generation to the Investor Owned Utilities' (IOUs)[2] electric grid.

Scoping Memo and Issue 4

On October 2, 2017 the *Scoping Memo of Assigned Commissioner and Administrative Law Judge* was issued. Included in it was **Issue 4**, which posed the following question: "*As the penetration levels of distributed energy resources increase, what changes to telemetry requirements should the Commission adopt to ensure adequate visibility while minimizing cost?*"

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[1] Resolution E-5038, page 2

[2] The "IOUs", or "Utilities" consist of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.

Rule 21 Section J addresses the current telemetry requirements for DERs 1 Megawatt or greater.

Working Group 1
Working Group 1 (WG1) took up Issue 4 from the Scoping Memo and resulted in five proposals in the final report (in summary):

> **Proposal 1** allow the Utilities to require telemetry for systems between 250 kW and 9.9 MW if utility costs are less than $20,000.
>
> **Proposal 2** maintains the 1 MW threshold for requiring telemetry.
>
> **Proposal 3** implements specific technical requirements for systems larger than 1 MW.
>
> **Proposal 4** was found to be unnecessary and
>
> **Proposal 5** was adopted to allow customer owned telemetry where practicable.

Decision 19-03-013
On April 5, 2019 the CPUC issued D.19-03-013.[3]

Workshop
In considering **Proposal 1**, D.19-03-013 found that additional information was necessary for implementation and authorized a public workshop in which the Utilities would present, in detail, the telemetry requirements for systems between 250 kW and 9.9 MW, before filing Advice Letters (ALs) to resolve the issue.

On June 26, 2019, the CPUC's Energy Division hosted a public workshop during which the Utilities presented their proposed telemetry requirements.

OP 9
Ordering Paragraph (OP) 9 required 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.

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

[3] D.19-03-013 *Decision Adopting Proposals From March 15, 2018 Working Group One Report* - date of issuance 4/5/2019

requiring specific equipment if the telemetry is deemed necessary. However, if the Tier 3 ALs do not indicate that the Utilities' proposed approach is cost-effective, the resolution should instead adopt **Proposal 2** (maintain 1 MW threshold) and **Proposal 3** to implement specific technical requirements for systems larger than 1 MW.

Advice Letter 5595-E
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.

AL 5595-E Protests
On August 15, 2019, Advice Letter 5595-E was protested by:
(i) the Interstate Renewable Energy Council, Inc. (IREC),
(ii) the Public Advocates Office (PAO), and
(iii) The California Solar & Storage Association (CALSSA).

AL 5595-E Reply
On August 22, 2019, PG&E, and the other IOUs each replied to the protests they received to their respective advice letters.

Resolution E-5038
On August 20, 2021, Resolution E-5038 was issued to resolve the protests received to the Utilities' Advice Letters. 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."[4]

Advice Letter 6350-E
This advice letter 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[5] 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.***

[formatting added]

AL 6350-E was protested by CALSSA on October 25, 2021. PG&E submitted a protest response on November 1, 2021.

This Supplemental Advice Letter
This supplemental AL is being 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 this supplemental advice letter is to provide additional specifications

[4] Resolution E-5038, page 1
[5] Southern California Edison

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.

Proposal

Following the completion of PG&E's CSIP IEEE 2030.5 Pilot, PG&E plans to implement a production CSIP IEEE 2030.5 system for telemetering of Distribution-connected customers with DERs 1 MW and greater and less than 10 MW. This 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, and measurements allowed to come from non-revenue grade equipment.

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. The pilot 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

[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).

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

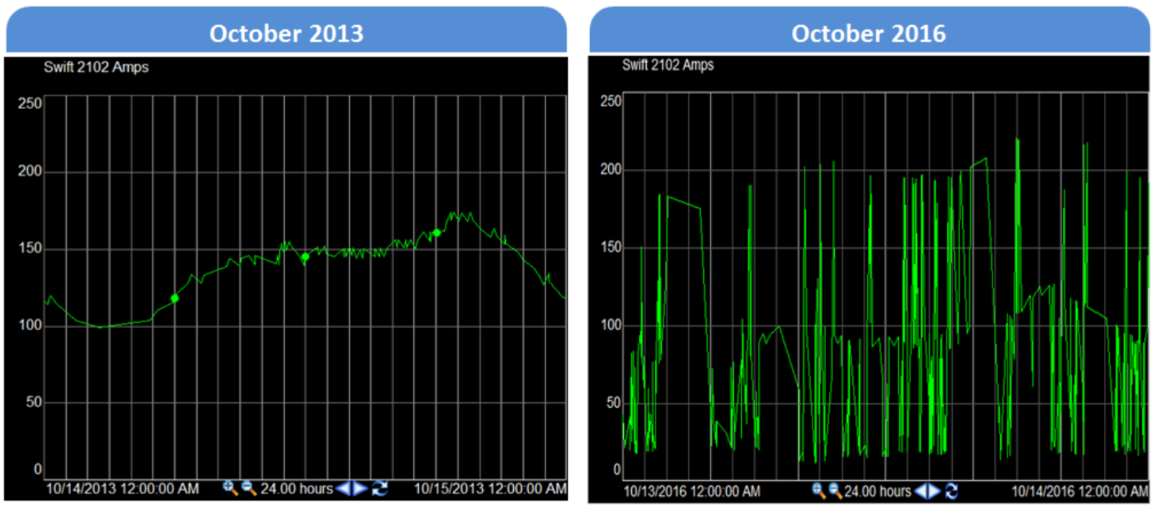

Figure 1: Impact of a Large Distribution-connected DER Participating in the Wholesale Market

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.

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

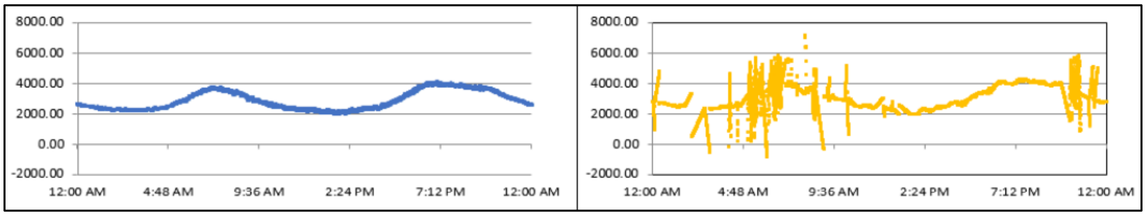

Figure 2: Comparison of Calculating Gross Load (Amps) on a Distribution Feeder with a Large Market-Participating DER using Faster and Slower Sampling Rates during the Same Time Period

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 pilot sites as part of the EPIC 3.03 project, 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 is testing 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.

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

Implementation Plan:

As previously described, PG&E is in the midst of the EPIC 3.03 pilot that is testing a future production CSIP Certified IEEE 2030.5 System that will allow customers to more affordably fulfill the telemetry requirement 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 plans to initially provide 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 net loading and 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 like Modbus into IEEE 2030.5 to send to the utility.

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.

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

PG&E does not currently have a production system in place that can meet the requirement for customer-owned equipment. Therefore, in order to comply with the Resolution, for interconnection applications[9] received after October 4th, 2021, those Distribution-connected DER customers that have a telemetry only requirement that are not issued a conditional permission to operate (PTO) by PG&E's Distribution Operations Team will be included in the EPIC 3.03 pilot until the IEEE 2030.5 production system is ready.

The pilot is currently working through interoperability issues between CSIP certified clients and the CSIP certified Headend Server. Once these issues are resolved, PG&E's goal is to have the CSIP IEEE 2030.5 ecosystem ready for non-pilot sites by early 2022. This assumes that all interoperability challenges will be resolved by that time. This

[9] Customers who submitted applications prior to October 4th may still be eligible to participate in the pilot depending on progress implementing an existing telemetry solution, but would need to discuss with PG&E.

timeline may be modified if additional challenges arise that cannot be addressed in that timeframe.

Specifications:
The following sections provide more detailed specifications by PG&E for clients 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 thus far in the 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 following the completion of the pilot and as the industry continues to mature in the CSIP and IEEE 2030.5 space.

Site Specifications:

1. Measurement Locations: To determine masked-load at a site, measurements are required at the point of common coupling (PCC) for net load, and the aggregate (i.e. sum) of generators by fuel source. If the site has no significant load and only one type of generator (e.g. only solar generation on site), then only net load (PCC) measurements are needed. Examples of Measurement Points (M[n]) are given in Figure 3 for two different sample sites: One with a photovoltaic (PV) system, battery energy storage system (BESS), and site load, and the other with only PV systems.

Figure 3: Example Required Measurement Points Based on Differing Site Layouts

2. Measurement Devices: PG&E does not require the customer to provide telemetry data via revenue grade metering. Based on PG&E's limited experience, customers are choosing to provide measurements by meters installed at the locations of interest either by directly connecting the individual meters separately to the IEEE 2030.5 gateway or via a data concentrator connected to the IEEE 2030.5 gateway. It is expected that many customers in the 1MW or greater space would already have existing metering of their site and generation facilities to connect to either individually or via an Energy Management System.

- At the PCC, the customer may leverage their own meter by either installing or using an existing customer meter. The customer may also work with PG&E to leverage certain PG&E meters to provide data to the Gateway. Options for providing PCC level data will vary for customers depending on what is already on site.

3. Measurement Data Points:
    - 3-phase and total MW
    - 3-phase and total MVAR
    - 3-phase Amps
    - 3-phase Volts

Gateway Client Equipment Functional Specifications:
As mentioned earlier, PG&E plans to initially provide 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. The following provide specifications for this type of equipment.

1. Gateway shall be CSIP certified for IEEE 2030.5 at the client level. Aggregator client certification is preferred for flexibility based on potential site layouts.
2. Gateway shall run latest version of CSIP implementation of 2030.5 (Currently CSIP 2.1 - March 2018)
3. Gateway shall be able to update CSIP 2030.5 version and version should be verifiable at the site gateway level
4. Gateway shall have proven interoperability with the PG&E CSIP-certified IEEE 2030.5 Head-end system[10]
5. Gateway shall be able to translate between the CSIP implementation of IEEE 2030.5 and the local device protocol for providing telemetry information
6. Gateway shall be able to provide the LogEvents as described in Appendix A.
7. Gateway shall be able to provide metering point values (e.g. kW per phase and total, kVAR per phase and total, Voltage per phase, Amps per phase) at any uniquely identified input with the appropriate CSIP characteristics (e.g. RoleFlags, ServiceCategoryKind, AccumulationBehaviour, Commodity, DataQualifier, FlowDirection, PowerOfTenMultiplier, Qualityflags etc.).

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[10] PG&E is already evaluating multiple gateway clients for interoperability as part of the EPIC 3.03 project to provide customers a minimum of two initial 3rd party options. PG&E plans to test and include aggregator clients in future portions of the pilot. If customers wish to use a platform not yet approved by PG&E, PG&E will provide a cost estimate and time to complete an evaluation of the requested device. CSIP 2.1 certification was determined to be insufficient in establishing interoperability among clients and servers via experience in the pilot. Therefore, at this time, there is no available certification process to ensure interoperability across various vendors. However, PG&E will continue to make recommendations to improve CSIP and certification strategies based on industry learnings. When a certification process is confirmed to ensure operability of/with PG&E's system, PG&E will rely on that certification versus in-house interoperability testing and evaluation.

8. Gateway shall monitor status values (e.g. alarm or status points) at any uniquely identified input
9. Gateway shall 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 shall be scaled appropriately based on units of measure (e.g. kW, MW, etc.)
11. Gateway shall have the ability to determine the average, minimum, and maximum from a set of values
12. Gateway shall be able to receive input signals from one or more serial and IP connections
13. Gateway shall have methods to configure the site and site DER/load identification information
14. Gateway shall have methods to configure data values as required for each measurement location within a site
15. Gateway shall have methods to configure protocol parameters as required
16. Gateway shall have methods to configure security parameters as required including user access management
17. Gateway shall have methods to configure communication and network parameters as required
18. Gateway shall have methods to configure alarm parameters as required
19. Gateway shall provide continuous monitoring of connections to local DER or metering interfaces
20. Device shall automatically restart to full functionality after power is restored following the complete loss of power to the gateway device

Gateway Client Equipment Non-Functional Specifications:

1. Gateway should be an OS embedded type of device. Currently PG&E doesn't 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. Gateway shall meet all IEEE 2030.5 mandatory requirements that are described in the standard and shall 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. Gateway shall 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 shall be every 30 seconds, and shall be configurable.

7. TLS shall be used for all HTTPS transaction and the Gateway shall support the following cipher suite in addition to the CSIP specified cipher suites: TLS_ECDHE-ECDSA-AES128-GCM-SHA256[11]
8. A valid certificate shall be used in IEEE 2030.5 TLS transactions. The Gateway shall have a 'SunSpec PKI' issued device certificate and store key files using secure methods
9. Gateway shall 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 Gateway certificate and validate it with the pre-registered SFDI/LFDI of the Gateway.
10. Gateway shall 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.[12]
11. Gateway shall support Access Control functions including Gateway applications checking the 'PIN' code from the Registration message
12. Gateway shall support the following methods to get the PG&E IEEE 2030.5 DER Headend Server's 'DeviceCapability' resource:

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[11] PG&E's internal Network Protection Services Team has not accepted the use of the aggregator CSIP specified cipher suite TLS_RSA_WITH_AES_256_CBC_SHA256 because of known security risks. However, CSIP states in section 5.2.1.1 that aggregators shall support "other cipher suites as specified by the utility…".

Also, PG&E's Load Balancer does not currently support the CSIP specified TLS_ECDHE_ECDSA_WITH 505 _AES_128_CCM_8 using the elliptic curve secp256r1. PG&E is in discussions with the Load Balancer vendor to see if they can support this cipher suite. The vendor's initial response was that GCM mode (as specified by PG&E) is considered superior to CCM in many ways (https://support.f5.com/csp/article/K55537702). PG&E understands that TLS_ECDHE-ECDSA-AES128-GCM-SHA256 was not one of the specified cipher suites in CSIP 2.1 but was chosen based on its common availability among the three vendors being tested by PG&E with an equivalent or better strength than what was prescribed by CSIP. Therefore, based on its common availability, PG&E believes this should not be an undue burden for vendors to comply with in the interim for telemetry to large sites, where it is expected that PG&E would not be connecting to individual DER devices, but rather gateways or aggregators where a deviation from the existing CSIP standard would be easier to accommodate.

[12] At this time, PG&E is requiring static IP addresses for Access Control Lists as described in IEEE 2030.5-2018 as part of a defense in depth cybersecurity strategy to prevent 3rd-party actors from malfeasance on PG&E's Operational Data Network. Static IP whitelisting allows PG&E greater access control to isolate internal networks and systems based on known IP addresses versus using dynamic IPs which would require PG&E to allow all IPs access to the system.

   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 shall 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 Gateway gets its EndDevice instance, it finds its group assignments by following the 'FunctionSetAssignmentListLink'. The Gateway periodically polls these resources at a rate specified by the DERProgramList:pollRate setting.
    a. Gateway 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 shall update the local time of the device to this time.
15. Communication performance requirements for the interfaces to the DER Headend Server are as below. These requirements do not constrain or define the performance of various communication systems.
    a. Availability of Communication: Shall 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.
    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. Gateway shall 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

Gateway Cybersecurity Specifications:

1. Gateway Vendor should be approved by the Third-Party Security Review (TSR) team at PG&E
2. All solution components are required to conform to applicable US manufacturing standards, cyber security controls, and privacy laws
3. Gateway should be secured in a way to block unauthorized physical access to the device
4. Gateway should provide a means necessary to apply physical security hardening measures

5. Gateway should include the means necessary to apply network connectivity management and control mechanisms
6. Gateway should enforce encrypted Identity and Access Management (IAM) mechanisms
7. Gateway should enforce Authentication, Authorization, and Accounting (AAA) and Role Based Access Control (RBAC)
8. Gateway should provide NIST compliant cryptographic mechanisms
9. Gateway should provide Secure Key management mechanisms
10. Gateway should provide Secure Boot mechanisms
11. Gateway should provide a Trusted Platform Module (TPM) or equivalent
12. Gateway should provide secure auditing and logging mechanisms
13. Gateway should provide secure session management mechanisms
14. Gateway should provide the ability to be scanned for vulnerabilities without significant impact on the performance and availability
15. Gateway should provide secure remote maintainability mechanisms
16. Cannot include devices on the National Defense Authorization Act (NDAA) Prohibited Manufacturers list

Gateway Maintenance Specifications:

1. Customer or their contracted vendor is responsible for maintaining customer-owned equipment
2. Customer or their contracted vendor is responsible for all firmware and security patching of customer-sited telemetry equipment
3. 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.
4. Remote Management Services for the Gateway provided by the customer's selected vendor is required and shall have the following specifications:
    a. Shall provide provisioning functions for software upgrades and/or firmware upgrades
    b. Shall provide software version control functions
    c. Shall provide status reports of software/firmware upgrade activities on a monthly / Quarterly / yearly basis
        i. Include software update Attempts/Successes/Failures
    d. Shall provide remote configuration changes using remote access capabilities as described below:
        i. Remote reboot (cold/warm start) of Gateway
        ii. Remote start/stop interface modules (e.g. local DER interfaces, IEEE 2030.5 registration profiles)
        iii. Remote application software upgrade (Manual)
        iv. Remote install security patches (Manual)
    e. Shall provide an encrypted interface for remote management

Cost of Installation:

- PG&E expects the utility related costs for installation to be less than $20,000.

These specifications may be refined further based on learnings and feedback near pilot completion to be ready for the subsequent production CSIP IEEE 2030.5 system.

It should be noted that this implementation plan is focused on addressing the near-term telemetry requirements for large DERs. However, PG&E sees this as the first step toward the larger context of leveraging IEEE 2030.5 beyond just telemetry towards enabling additional use cases in the future. As the industry continues to mature, PG&E expects updates to various aspects of the ecosystem from this initial starting point.

Protests

*****Due to the COVID-19 pandemic, PG&E is currently unable to receive protests or comments to this advice letter via U.S. mail or fax. Please submit protests or comments to this advice letter to EDTariffUnit@cpuc.ca.gov and PGETariffs@pge.com*****

Anyone wishing to protest this submittal may do so by letter sent via U.S. mail, facsimile or E-mail, no later than December 6, 2021, which is 21 days[13] after the date of this submittal. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

[13] The 20-day protest period concludes on a weekend, therefore, PG&E is moving this date to the following business day.

Sidney Bob Dietz II
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-3582
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, telephone number, postal address, and (where appropriate) 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).

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 and via U.S. mail to parties shown on the attached list and the parties on the service list for R.19-09-009. 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:
Appendix A – LogEvent Descriptions

cc: Service List R.19-09-009

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 U39E)

Utility type:
- [x] 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-A

Tier Designation: 1

Subject of AL: 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 [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Res 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 [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? [ ] Yes [x] 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 all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Name: Sidney Bob Dietz II, c/o Megan Lawson
Title: Director, Regulatory Relations
Utility Name: Pacific Gas and Electric Company
Address: 77 Beale Street, Mail Code B13U
City: San Francisco, CA 94177
State: California Zip: 94177
Telephone (xxx) xxx-xxxx: (415)973-2093
Facsimile (xxx) xxx-xxxx: (415)973-3582
Email: PGETariffs@pge.com

Name:
Title:
Utility Name:
Address:
City:
State: District of Columbia Zip:
Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

Clear Form

Appendix A

LogEvent Descriptions

Appendix A – 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	
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

*Low and high temperature alarms may be omitted if the enclosure temperature is monitored as a signal. Only enclosures that contain temperature-sensitive components and active heating or cooling require temperature alarms or signals.

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.
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
Cenergy Power
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 Energy Management Service
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
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
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