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

Pacific Gas & Electric Company
ELC (Corp ID 39)
Status of Advice Letter 5595E
As of August 25, 2021

Subject: PG&E's Telemetering Proposals Pursuant to Decision 19-03-013, Ordering Paragraph 9.

Division Assigned: Energy

Date Filed: 07-26-2019

Date to Calendar: 07-31-2019

Authorizing Documents: D1903013

Disposition:	**Signed**
Effective Date:	**08-20-2021**

Resolution Required: Yes

Resolution Number: E-5038

Commission Meeting Date: None

CPUC Contact Information:

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AL Certificate Contact Information:

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

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
Effective Date of Filing
Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

Pacific Gas and Electric Company

Erik Jacobson
Director
Regulatory Relations

Pacific Gas and Electric Company
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July 26, 2019

Advice 5595-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **PG&E's Telemetering Proposals Pursuant to Decision 19-03-013, Ordering Paragraph 9**

Purpose

Pacific Gas and Electric (PG&E) submits this Tier 3 advice letter regarding proposals for Rule 21 Telemetry pursuant to Decision (D.) 19-03-013 Ordering and The Working Group One Report and following the June 26th California Public Utilities Commission's (CPUC) Telemetry Workshop[1].

Background

Order Instituting Rulemaking (R.) 17-07-007 was adopted July 13, 2017. It deals with refinements to Electric Rule 21 governing the interconnection of distributed energy resources for the three Investor Owned Utilities (IOUs).[2]

On October 2, 2017 the Scoping Memo of Assigned Commissioner and Administrative Law Judge (Scoping Memo) was issued. It set forth (i) the scope, (ii) the schedule and (iii) established a working group process for the proceeding.

[1] Pursuant to Ordering Paragraph 9 of D.19-03-013, the Energy Division held a workshop on June 26, 2019, during which PG&E, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) presented in detail the telemetry requirements for systems between 250 kilowatts (kW) and 9.9 megawatts (MW). The workshop was held from 10AM to 3PM in the Courtyard Room at the CPUC's 505 Van Ness Ave building in San Francisco.

[2] The IOUs are PG&E, SDG&E, and SCE (jointly, the Utilities)

In the scoping memo, Working Group One was defined, and identified with seven Issues:[3]

1) Screen Q modifications
2) Complex Metering clarification
3) Material modifications
4) Telemetry modifications
5) Retroactive Smart Meter Activations
6) Smart Inverter Aggregator Forms and Agreements (moved to Working Group 2)
7) ITCC treatment.

The IOUs and stakeholders presented each issue, debated proposed solutions, in a staggered schedule. Finally, on March 15, 2018, a Final Report for Working Group One was filed[4] that documented each issue and laid out various proposals from parties to each issue.

On June 19, 2018, the Administrative Law Judge facilitated a workshop at which time representatives of Working Group One presented the proposals and recommendations from the March Report. The purpose of the workshop was to provide additional clarity to enable the Commission to determine whether to approve the proposals recommended in the March Report.

On August 15, 2018, the Administrative Law Judge issued a ruling directing parties to respond to questions about the March Working Group One Report in order to complete the record. Various parties filed responses on September 5, 2018.

On April 5, 2019, D. 19-03-013, "Decision Adopting Proposals From March 15, 2018 Working Group One Report" was issued.

In it, Issue 4 on Telemetry was discussed among other issues. Issue 4 was described as:

> Issue 4: 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?

[3] In response to a January 25, 2018 motion filed by the California Solar Energy Industries Association, the Administrative Law Judge issued a ruling on February 14, 2018 that reassigned Issue 6 from the Smart Inverter Working Group to Working Group Two because the development of forms and agreements necessary for Issue 6 are better suited to be addressed by legal and regulatory representatives instead of engineers.

[4] Working Group One Final Report March 15, 2018 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M215/K187/215187299.PDF

In the Working Group One Report, the Utilities noted:

> "The IOUs believe that increased use of real-time telemetry is necessary for grid visibility. This grid visibility provides necessary information to grid operators who make decisions that support the safe and reliable operation of the electrical grid with the continued proliferation of DERs. The current 1MWac Rule 21 telemetry threshold was established when relatively few DERs were on the grid and the overall level of DER penetration was not significant in comparison to total load.
>
> Without the use of telemetry, the IOUs have no real-time visibility or operational awareness of projects connected to the utility' grid. With the increased levels of DER being connected to the distribution grid, this operational awareness is essential to maintain the safe operation of the distribution system while providing reliable service to all customers and DERs. In particular, telemetry addresses the concern of "load masking," which describes a situation in which the lack of generation output visibility prevents system operators and engineers from determining the real system load conditions which can inhibit the ability to plan and operate the distribution system. This load masking condition is caused equally by both exporting and non-exporting DER installations and from the point of view of the grid operator, the DER will reduce the localized electrical load served even if the DER does not export power into the grid...."

Many stakeholders have assumed that smart inverters will make telemetry cheap and easy once the new functionality is enabled. However:

- Smart inverters are not currently connected to the IOU's system to transmit the information in the secure, reliable and real-time manner that grid operators need,
- Smart inverters cannot provide telemetry on their own because additional equipment will be needed at most facilities to connect the smart inverter to the utility,
- A majority of customer sited solar installations have multiple inverters, thus the solar provider will have to aggregate the data prior to reporting, which cannot be done by the inverters themselves,
- Utility telemetry rules require DERs to report facility-level data rather than inverter-level data, and
- Phase 3 inverter function Hh.7 (Monitor and Telemetry Requirements) is only proposed as a *capability* and not an actual requirement.[5]

This advice letter is primarily concerned with Issue 4 Proposals 1 and 2 that came out of the 2018 Working Group. Proposal 1 would "require systems between 250 kW and 9.9 MW to provide telemetry only if all utility-sponsored telemetry costs are estimated to be

[5] 2018 Working Group One Report, Page 77 of 123.

less than $20,000" and so "would reduce the telemetry threshold from the current threshold of 1 MW. The customer would still be responsible for actual utility-related telemetry costs, which may exceed $20,000 (the IOUs propose reporting on telemetry costs to address overage concerns)."[6] Proposal 2 would "Maintain the threshold for requiring telemetry at 1 MW."[7]

Based the on Working Group One discussion and Final Report, D. 19-03-013 in Ordering Paragraph 9, requires:

> "Proposals 1 or 2 for Issue 4 will be implemented depending upon the outcomes of a workshop and subsequent advice letters.
>
> The Director of the Commission Energy Division is authorized to hold a workshop within 90 days of the issuance of this decision at which time Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall present in detail the telemetry requirements for systems between 250 kilowatts (kW) and 9.9 megawatts (MW).
>
> No later than 30 days following the workshop, the Utilities shall submit Tier 3 Advice Letters describing
>
> - the telemetry requirements,
> - including a cost-benefit analysis of the telemetry as a means of collecting data on the distribution system, and
> - 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.
>
> The ensuing resolution will implement Proposal 1, as modified below, if the telemetry is deemed necessary, which will then modify the telemetry requirement from 1 MW to between 250 kW and 9.9 MW on distribution voltage with a cost cap of $20,000 for estimated utility-related costs.
>
> The Utilities shall publish technical requirements for telemetry rather than requiring specific equipment.
>
> The ensuing resolution will implement Proposal 3, if the Advice Letter indicates the Utilities' telemetry approach is not cost-effective.
>
> The Utilities' published technical requirements shall be able to be met through alternative data sources, such as SCADA and smart inverter data, if those options are

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[6] Working Group One Final Report March 15, 2018, p. 71.

[7] (ibid), p. 71)

> shown to more cost-effectively produce the data necessary to provide system visibility and address load masking.
>
> The Utilities shall adopt certain technical requirements for telemetry only for systems larger than 1 MVA to avoid unnecessary costs."
>
> (Formatted to break out the specific requirements)

As required by D. 19-03-013, on June 26 a Telemetry Workshop was held at the CPUC where each utility provided details on its proposed telemetry requirements for systems between 250 kilowatts (kW) and 9.9 megawatts (MW).

This Tier 3 advice letter is submitted timely to further elaborate on those details in compliance with this order to submit an advice letter 30 days following the June 26th CPUC Telemetry Working Group.

PG&E Telemetry Roadmap to Define Detailed Requirements

Based on PG&E's existing utility infrastructure for data processing, cybersecurity, and telecommunication, the only available option for PG&E to enable DER telemetry is through a SCADA device. However, the SCADA device option does not meet the low-cost telemetry target of below $20,000 one-time cost.

Therefore PG&E has been working with internal and external stakeholders to evaluate alternative options to reduce cost. Based on the evaluation, PG&E has decided to pursue deployment of a communication solution using the IEEE 2030.5[8] protocol, the approved default protocol for smart inverters in Rule 21 Section Hh. PG&E believes that the IEEE 2030.5 communication function 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. Moreover, it will align with California's planned adoption of IEEE 2030.5 as the default communication method for Rule 21 DERs, leverage investments by the industry in IEEE 2030.5 and smart inverters, and provide a foundation for more complex interactions between PG&E and DERs beyond telemetry.

To ensure that the solution is tested thoroughly, PG&E is currently proposing a pilot of a utility DER Headend platform. This platform will:

(i) prove out the target of lowering utility-related telemetry costs below $20,000, and

(ii) enable design around the future IEEE2030.5 DER communications standards that will provide PG&E a way to monitor and control smart inverter based DERs.

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[8] IEEE2030.5 is the Institute of Electrical and Electronics Engineers (IEEE) Standard for Smart Energy Profile Application Protocol. More info can be found at: https://standards.ieee.org/content/ieee-standards/en/standard/2030_5-2018.html

As shown in Figure 1 below, PG&E's proposed pilot to deploy low cost telemetry solutions to a limited number of sites using the DER Headend platform is expected to run through the end of year 2020. Based on the results from the pilot, PG&E will then transition towards an in-production system for widescale field deployment. Additionally, as part of the pilot PG&E will continue to engage with the DER industry and develop a set of detailed requirements for the on-premise telemetry devices that could be deployed and owned by the DER customers.

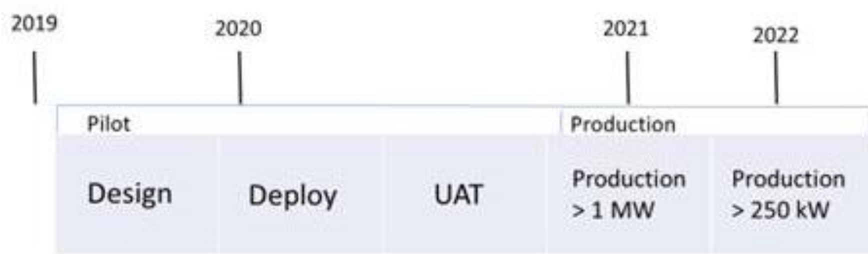

Figure 1 – PG&E DER Telemetry Deployment Timeline

Until PG&E's lower cost telemetry solution is deployed in production, the PG&E team will:

- Assess each 1MW and greater distribution-connected DER telemetry requirement on a project-by-project basis to determine if conditional Permission to Operate (PTO) could be offered to the interconnection customer. Some of the factors considered include whether PG&E can achieve grid visibility on subset of the monitoring parameters with other methods and/or can temporarily accept the operational risk of reduced telemetry at specific locations.
- Retain the threshold at 1MW and greater until the lower cost telemetry solution has been deployed.

Note that the Transmission-connected DERs will continue to require telemetry and no conditional PTO will be available for Transmission-connected DERs.

Preliminary Telemetering Requirements

PG&E has developed preliminary functional and technical requirements in collaboration with subject matter experts in PG&E's Distribution Operations, Transmission Operations, Cybersecurity, Electric Grid Interconnection (EGI), Information Technology (IT), and SCADA applications development teams. These requirements will be further refined and detailed through the proposed pilot of utility DER Headend platform.

I. Functional requirements for telemetry on distribution connected DERs:

	Near-Term Solution - Monitor Larger Distribution DERs
Voltage Class	Distribution Note: Transmission-connected DERs will continue to use existing telemetry solutions until new solution is approved for Transmission use
Monitoring and Control	Monitor Only
Measurement Point	Aggregate Generators (by fuel source) and/or PCC (Net) And/or: May depend on load at site relative to generation
Data Points	Distribution Interconnection Handbook (DIH) [9] Required Time-stamped Points: 3-phase and total MW 3-phase and total MVAR 3-phase Amps 3-phase Volts
Data Frequency	30 Sec
Data Identification	Unique identifiers by site and resource type

II. Preliminary technical requirements for customer sited equipment

	Near-Term Solution
Cost	Utility-related costs less than $20k per DER
Ownership	Customer-owned equipment for the site
Communications	Customer shall provide a communication medium that meets security, reliability, and bandwidth required by utility
Data Aggregation	Customer shall aggregate generation at site as described by R21 requirements
Data Identification	Data shall have unique identifiers in accordance with the utility convention

[9] https://www.pge.com/en_US/large-business/services/alternatives-to-pge/distribution-handbook.page

Data Points	Data points provided shall be as described in the DIH /TIH
Data Timestamps / Sampling Rate	Data shall be provided every 30 seconds with accurate timestamps
Hardware Maintenance	Customer is responsible for all customer-sited hardware maintenance
Software / Firmware Maintenance	Customer is responsible for all firmware, and security patching of customer-sited telemetry equipment
Maintenance Window	Cap of 30 days to repair or replace malfunctioning equipment. Security-related patching may be required in a shorter time-frame.

III. Preliminary cybersecurity requirements development framework

	Near-Term Solution (per NIST Cybersecurity Framework)
Network Protection	1. Network integrity is protected (e.g., network segregation, network segmentation) 2. Communications and control networks are protected 3. The network is monitored to detect potential cybersecurity events
Device Authentication	1. External information systems (telemetry equipment) are catalogued 2. Integrity checking mechanisms are used to verify software, firmware, and information integrity 3. Telemetry devices are authenticated (e.g., single-factor, multifactor, protocol authentication, device certificates, etc.) commensurate with the risk of the transaction (e.g., individuals' security and privacy risks and other organizational risks) 4. Communications and networks are protected
User Identity, Access Control, and Management	1. Identities and credentials are issued, managed, verified, revoked, and audited for authorized devices, users and processes 2. Remote access is managed 3. Access permissions and authorizations are managed, incorporating the principles of least privilege and separation of duties 4. Identities are proofed and bound to credentials and asserted in interactions

	5. Users, devices, and other assets are authenticated (e.g., single-factor, multifactor) commensurate with the risk of the transaction (e.g., individuals' security and privacy risks and other organizational risks) 6. Remote maintenance of organizational assets is approved, logged, and performed in a manner that prevents unauthorized access
Data Protection	1. Data-at-rest is protected 2. Data-in-transit is protected 3. Protections against data leaks are implemented
Device Configuration and Vulnerability Management	1. Asset vulnerabilities are identified and documented 2. Integrity checking mechanisms are used to verify hardware integrity 3. Configuration change control processes are in place 4. A vulnerability management plan is developed and implemented 5. Maintenance and repair of organizational assets are performed and logged, with approved and controlled tools 6. The principle of least functionality is incorporated by configuring systems to provide only essential capabilities 7. Event data are collected and correlated from multiple sources and sensors 8. Vulnerability scans are performed 9. Monitoring for unauthorized personnel, connections, devices, and software is performed
Physical Security	1. Physical access to assets is managed and protected 2. The physical environment is monitored to detect potential cybersecurity events

IV. Additional future-oriented platform requirements

The future-oriented platform requirements highlight the plan for PG&E to expand the DER Headend System capabilities beyond the initial telemetry functions.

	Longer-Term Solution to monitor and control DERs
Protocol	IEEE 2030.5: Expected to be mandated in the near future
Variable Polling Rates	Ability to adjust the polling rate, depending on the particular application
Expanded Monitoring	Monitoring shall expand beyond basic telemetry measurements to include registration and settings information such as Volt/Watt curve and MW dispatch schedule
Control	Platform shall provide control capabilities as needed such as: real-time output, scheduled output, real-time constraints, scheduled constraints, disconnect/reconnect, settings configuration, over-the-air updates etc.
Vendor Agnostic	Provide path for customer-sited equipment to be vendor agnostic
Custom Extensions	Provide capabilities to use custom extensions beyond CSIP IEEE 2030.5 implementation as new use cases arise to inform future standards

Cost Benefit Analysis of Telemetry on Distribution System

In this section, we first describe the risk reduction benefits provided by telemetering larger DERs. Then we highlight the cost comparison of the options that were evaluated to identify the most cost-effective telemetry solution.

The risk mitigation benefit achieved by implementing telemetry on larger DERs has been described in detail in the Working Group One Final Report[10], “With the increased levels of DER being connected to the distribution grid, this operational awareness is essential

[10] Working Group One Final Report: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/Infrastructure/RDI/itcn/R1707007WorkingGroupOneFinalReport.pdf

to maintain the safe operation of the distribution system while providing reliable service to all customers and DERs. In particular, telemetry addresses the concern of “load masking,” which describes a situation in which the lack of generation output visibility prevents system operators and engineers from determining the real system load conditions which can inhibit the ability to plan and operate the distribution system...which can lead to delays in restoration of service, inability to reconfigure the system as needed to meet the load needs or potentially reconfigure the system is a manner which could create system issues such as overload and over-voltages.”

In summary, having situational awareness of masked load allows grid operators to make faster and more reliable decisions. Additionally, it helps avoid potentially unsafe conditions that could be created due to overloading and overvoltage on the grid.

To ensure that we achieve telemetry in the most cost-effective manner, PG&E evaluated the costs of implementation for several different telemetry options. The table below shows a cost effectiveness of PG&E’s proposed IEEE 2030.5 telemetry solution compared to other options.

Telemetry Solution Options	Operational Capabilities	Customer		Future Oriented	Readiness
		Cost	Responsibility		
SCADA Recloser (Existing Solution)	**Provides Net Load Only** (No Masked Generation Information) Provides Added Utility Disconnect and Protection Capabilities	**High**: ~$160k Utility Owned Solution	**None**	**Cannot Enable Future-Oriented** smart inverter monitor and control requirements	**Existing**
SCADA Mini-Remote Terminal Unit **(Existing Solution)**	**Meets Operational Requirements**	**High**: ~$70k Utility Comms Customer Metering	**Aggregate** Input Devices for Mini-RTU **Maintain** Customer Input Devices	**Enables Most Future-Oriented** Requirements **Lacks Aggregator Support** **Cybersecurity Constraints** Limit Future Use	**Existing**
AMI Metering	**Provides Net Load Only** (No Masked Generation Information) **Slow Data Sampling Rates** **Slow Data Retrieval Rates**	**Cost**: NA because it does not meet the operational requirements.	**None**	**Cannot Enable Future-Oriented** Requirements	**Development Needed** to Operationalize Existing Data **but Still Cannot Enable Future** Requirements

<table>
<tr><th rowspan="2">Telemetry Solution Options</th><th rowspan="2">Operational Capabilities</th><th colspan="2">Customer</th><th rowspan="2">Future Oriented</th><th rowspan="2">Readiness</th></tr>
<tr><th>Cost</th><th>Responsibility</th></tr>
<tr><td>Proposed 2030.5 Solution (Includes Smart Inverters)</td><td>Meets Operational Requirements</td><td>Low: Targeted <$20k Customer Owned</td><td>Aggregate Input Devices
Maintain Devices
• Comms
• Hardware
• Firmware
• Software
• Security</td><td>Enables Future Oriented Requirements
IEEE 2030.5 Expected to be mandated for smart inverter interconnection in California</td><td>Development Needed to Enable Platform</td></tr>
</table>

Assessment of Capabilities of Existing Telemetry Solutions

In this section we provide information on the existing telemetry data from SCADA, AMI, and smart inverter, and why the existing telemetry data does not meet utility requirements.

As described in the table above, PG&E distribution operations currently has two ways to gain situational awareness on the grid:

1. SCADA monitoring points are available at majority of the circuit breakers located at the substations to provide situational awareness at the feeder-head level. However, there are generally low penetrations of SCADA devices along the feeder except for some specific feeders. Additionally, traditional SCADA devices only provide net loading which does not help with the masked load issues presented by DERs. Therefore, the data that SCADA devices can provide does not meet the DER telemetry requirements in addition to not being cost effective.

2. Advanced Metering Infrastructure (AMI) data provides net loading data at customer meters. However, the AMI network was designed to provide data for customer for the purpose of billing, which required low sampling rate and low retrieval rates. Currently AMI data is sampled at 15 min intervals and has a 48-hour delay before it is available for operators to view. While investments could be made to improve the sampling rate, retrieval rates, and operations integration of AMI for telemetry, this would still not provide the basic function of determining masked load, or would it help meet upcoming IEEE 2030.5 requirements or provide a foundation to do more advanced DER interactions.

With regards to the smart inverter, we have evaluated the use of smart inverter data as a telemetry solution. Currently, smart inverters can acquire telemetry data at the device level but the capability to communicate the data to utility does not exist yet. PG&E's proposed solution leverages smart inverter's Phase II communication function to send this data to utility DER Headend platform so that it can be used by distribution grid operators.

Protests

Anyone wishing to protest this advice letter may do so by letter sent via U.S. mail, facsimile or E-mail, no later than August 15, 2019, which is 20 days 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:

Erik Jacobson
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

PG&E requests that this Tier 3 advice submittal become effective upon Commission approval.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service lists for R.11-09-011 and 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 filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Erik Jacobson
Director, Regulatory Relations

cc: Service Lists R.11-09-011 and R.17-07-007

California Public Utilities Commission

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:
☑ ELC ☐ GAS ☐ WATER
☐ PLC ☐ HEAT

Contact Person: Yvonne Yang
Phone #: (415)973-2094
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: Yvonne.Yang@pge.com

EXPLANATION OF UTILITY TYPE

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

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 5595-E

Tier Designation: 3

Subject of AL: PG&E's Telemetering Proposals Pursuant to Decision 19-03-013, Ordering Paragraph 9

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 #:
D.19-03-013

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: N/A

Resolution required? ☑ Yes ☐ No

Requested effective date:

No. of tariff sheets: N/A

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: Erik Jacobson, c/o Megan Lawson
Title: Director, Regulatory Relations
Utility Name: Pacific Gas and Electric Company
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City: San Francisco, CA 94177
State: California Zip: 94177
Telephone (xxx) xxx-xxxx: (415)973-2093
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Name:
Title:
Utility Name:
Address:
City:
State: District of Columbia Zip:
Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email:

Clear Form

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

AT&T
Albion Power Company
Alcantar & Kahl LLP

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
P.C. CalCom Solar
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
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Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
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City of Palo Alto

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

Dept of General Services
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Engineers and Scientists of California
Evaluation + Strategy for Social Innovation
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Charge Networks
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Hanna & Morton
ICF
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc. Linde
Los Angeles County Integrated Waste Management Task Force
Los Angeles Dept of Water & Power
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
Morgan Stanley
NLine Energy, Inc.
NRG Solar

Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy
Praxair

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions

SCE
SDG&E and SoCalGas

SPURR
San Francisco Water Power and Sewer
Seattle City Light
Sempra Utilities
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
Troutman Sanders LLP
Utility Cost Management
Utility Power Solutions
Utility Specialists

Verizon
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy