PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

May 8, 2018

Advice Letter 5129-E

Erik Jacobson
Director, Regulatory Relations
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13C
P.O. Box 770000
San Francisco, CA 94177

SUBJECT: Modifications to PG&E's Electric Rule 21 Tariff and Interconnection Agreements and Forms to Incorporate Smart Inverter Phase 3 Modifications

Dear Mr. Jacobson:

Advice Letter 5129-E is effective as of April 26, 2018 per Resolution E-4898 per Ordering Paragraphs.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

Erik Jacobson
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

August 18, 2017

Advice 5129-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Modifications to PG&E's Electric Rule 21 Tariff and Interconnection Agreements and Forms to Incorporate Smart Inverter Phase 3 Modifications**

Purpose

In compliance the California Public Utilities Commission's (CPUC or Commission) Decisions (D.) 14-12-035[1] and 16-06-052[2] that addresses Phase 2 and 3 recommendation of the SIWG,[3] Pacific Gas and Electric Company (PG&E) respectfully submits this advice letter to update PG&E's Electric Rule 21 Tariff in order to facilitate smart inverter deployment.

The affected electric rate schedule tariff sheets are being submitted in final tariff form and are listed on the enclosed Attachment 1. A redlined version of changes to Electric Rule 21 is included as Attachment 2.

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[1] D.14-12-035 issued December 18, 2014: *INTERIM DECISION ADOPTING REVISIONS TO ELECTRIC TARIFF RULE 21 FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY TO REQUIRE "SMART" INVERTERS* on Page 8 required: "The effective mandatory date of the requirements [for 'smart" or "enhanced inverters] adopted today shall be the later of December 31, 2015, or 12 months after the date the Underwriters Laboratory approves the applicable standards."

[2] D.16-06-052, issued June 23, 2016: *ALTERNATE DECISION INSTITUTING COST CERTAINTY, GRANTING JOINT MOTIONS TO APPROVE PROPOSED REVISIONS TO ELECTRIC TARIFF RULE 21, AND PROVIDING SMART INVERTER DEVELOPMENT A PATHWAY FORWARD FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY*.

[3] SIWG, Smart Inverter Working Group

Background

The scope of Rulemaking (R.) 11-09-011[4] was established in part, to address Smart Inverter technology. In early 2013, the Smart Inverter Working Group (SIWG) was formed with the goal of including revisions to the Investor Owned Utilities' (IOUs) respective Electric Rule 21 (Rule 21) tariff.

In January 2014, the SIWG issued "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources" that came to be characterized as "Phase 1 Recommendations" of the group's efforts.

On July, 18, 2014, pursuant to the Assigned Commissioner's Ruling (ACR) and utilizing the SIWG's recommendations, the IOUs served a draft Advice Letter to facilitate the deployment of smart inverter capabilities.

On December 22, 2014, D.14-12-035 was issued, which required PG&E to file Advice Letter (AL) 4565-E[5], modifying Rule 21 and adding new Section Hh to Rule 21 addressing Smart Inverter functionality.

On September 8, 2016, the Underwriter's Lab (UL) approved the new smart inverter standard Supplement SA of UL-1741. In accordance with D.14-12-035, PG&E submitted AL 4914-E[6], which included reference to this standard, and which established September 8, 2017 (one year later), as the deadline for which Smart Inverters would be required for all new inverter based DER[7] interconnections.

In June of 2016, D.16-06-052 was approved and it concluded that, "the SIWG has completed its technical recommendations for Phase 2 communication protocols and Phase 3 additional advanced inverter functions after three years of collaboration and consensus-building. The utilities worked with stakeholders to revise Rule 21 to reflect the technical requirements of the SIWG's recommendations for Phase 2 communication protocols and Phase 3 additional advanced inverter functions." [8]

D.16-06-052 also ordered the IOUs to "…file proposed revisions to Tariff Rule 21 setting forth any agreed-upon technical requirements, testing and certification processes, and effective dates for Phase 2 communication protocols and Phase 3

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[4] R.11-09-011, *Order Instituting Rulemaking on the Commission's Own Motion to improve distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources*, filed September 22, 2011)

[5] AL 4565-E, *Revisions to Electric Tariff Rule 21 in Compliance with Decision 14-12-035*, filed January 20, 2015, and made effective the same date.

[6] AL 4914-E, *Modifications to Pacific Gas and Electric Company's Electric Rule 21 Tariff Pursuant to Decision 14-12-035 to Reflect the Approval Date of Inverter Based Technologies Requirements*, filed September 13, 2016.

[7] Distributed Energy Resources

[8] Find of Facts #20 and #21 in D. 16-06-052

additional advanced inverter functions in separate Tier 3 advice letters no later than six months from the effective date of this decision."[9]

In a parallel effort, SunSpec Alliance or another national organization is developing a national standard that will become the basis for testing and certifying Smart Inverter communication. Also, the current draft of IEEE 1547 standard covers the same advanced Smart Inverter functionality specified in the SIWG, and it is desired for Rule 21 to be aligned with both of these proposed national standards.

On December 20, 2016, the IOUs jointly filed AL 4983-E that provided a work plan and an outline of next steps for tariff development for Phase 3.[10] The work plan identified additional efforts to support the Phase 3 tariff development (inculding continuation of stakeholder discussions within the SIWG), and the proposal to submit a status update on the activities outlined in the work plan by March 30, 2017.[11]

In accordance with the work plan, the IOUs anticipated to each file the Tier 3 advice letter with proposed tariff revisions incorporating the Phase 3 functions in Rule 21 in June 2017. However, as the proposed June 2017 date was contingent on additional stakeholder discussions and related efforts, the IOUs therefore stated in the December 2016 advice letter that, "the filing date for the Tier 3 advice letters may be modified upon approval from the Commission's Energy Division, with support of SIWG members, if deemed appropriate to maintain with IEEE 1547 and still be within reason of attaining the goal of smart inverters reaching full functionality by 2020 as stated in the Commission's DER Action Plan."[12]

On June 20, 2017, the IOUs jointly requested to reschedule the submittal date for this advice letter to August 18, 2017. (See Attachment 3)

On June 27, 2017, Mr. Timothy Sullivan, Executive Director, CPUC granted the IOUs request for an extension. (See Attachment 4)

On June 30, 2017, AL 5107-E[13] supplemented the Rule 21 with Phase 1 technical requirements to fully implement UL 1741-Supplement SA and includes the September 8, 2017, Smart Inverter deadline. This Phase 1 advice letter sets the stage for the Rule 21 Phase 3 changes in this advice letter.

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[9] D.16-06-052, Ordering Paragraph 9.

[10] AL 4983-E (PG&E's AL number) *Information-Only Advice Letter Joint Investor-Owned Utilities Status Report and Supporting Action Plan for the Development of Advanced Inverter Functions for Smart Inverters (Phase 3),* effective January 19, 2017.

[11] SCE, on behalf of the IOUs, submitted a status update letter to the CPUC's Energy Division on March 30, 2017.

[12] *Ibid. at p. 7*

[13] AL 5107-E, *Modifications to PG&E's Electric Rule 21 Tariff and Interconnection Agreements and Forms to Incorporate Smart Inverter Phase 1 Modifications,* filed June 30, 2017, effective as of July 29, 2017.

The revisions proposed in this advice letter to Rule 21 are results of the SIWG Phase 3 discussions described above and PG&E submits this advice letter in a timely fashion.

Additional stakeholder discussions will be scheduled to assist stakeholders with review of the IOUs Advice Letters starting no later than two weeks after this Advice Letter submittal. PG&E appreciates SCE setting up this continued outreach and looks forward to participating. If additional enhancements to Rule 21 are identified in thes future discussions, mutually agreed upon changes will be made through the appropriate regulatory process.

Overview of Technical Changes

Table1 below summarizes the proposed function mandatory requirement dates for ease of review[14] including the propose function capability or requirement dates (for Functions Five and Six).

Table 1 – Summary of Rule 21 Smart Inverter Phase 3 Changes

Function	Description	Rule 21 Section	Requirement Date
One	Monitor Key DER Data	Hh.7	Later of March 1, 2018 or 9 months after the release of SunSpec Alliance Approved Test Procedure (or another industry-recognized protocol standard)
Two	DER Disconnect and Reconnect Command (Cease to Energize and Return to Service)	Hh.8	12 months after IEEE 1547.1 standard revision approval
Three	Limit Maximum Active Power Mode	Hh.8	12 months after IEEE 1547.1 standard revision approval
Four	Set Active Power Mode	Hh.2.n	Optional Upon Mutual Agreement between Utility and Applicant
Five	Frequency Watt Mode	Hh.2.l	12 months from Commission approval of the Phase 3 Advance Function Advice Letter
Six	Volt-Watt Mode	Hh.2.m	12 months from the Commission approval of the Phase 3 Advance Function Advice Letter Commission
Seven	Dynamic Reactive Support	Hh.2.o	Optional Upon Mutual Agreement between Utility and Applicant

[14] If the communication protocol is being satisfied at the aggregator level as discussed within section H.h.5, as aggregator applicable forms and agreements are not currently developed, this option is subject to Commission approval of applicable forms or agreements required to effectuate this option.

Eight	Scheduling Power Values and Modes	Hh.6	Later of March 1, 2018 or 9 months after the release of SunSpec Alliance Approved Test Procedure (or another industry-recognized protocol standard)

Tariff Revisions

Modification to Rule 21 (Bold text is added; strikethrough is removed)

1) In section Hh.2.i, changed the title from *Power Factor,* to ***Fixed*** *Power Factor.* (sheet 191)

2) In section Hh.2.j, made minor formatting changes.

3) In section Hh.2.l, changed the section title from *Recommended Frequency-Watt Settings* to *Frequency-Watt Requirements;* and made the following changes:

   This requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after 12 months from the date the Phase 3 Smart Inverter Advanced Function Advice Letter (AL 5129- E) was made effective by the Commission. Smart Inverters shall reduce their real power production as a function of system frequency, in accordance with the following: ~~The Smart Inverters, which have this optional function available, may enable this function with the following recommended settings. Smart Inverters with different frequency-watt capabilities may be enabled with Distribution Provider concurrence.~~

4) In section Hh.2.l, added a new bullet describing the graph:

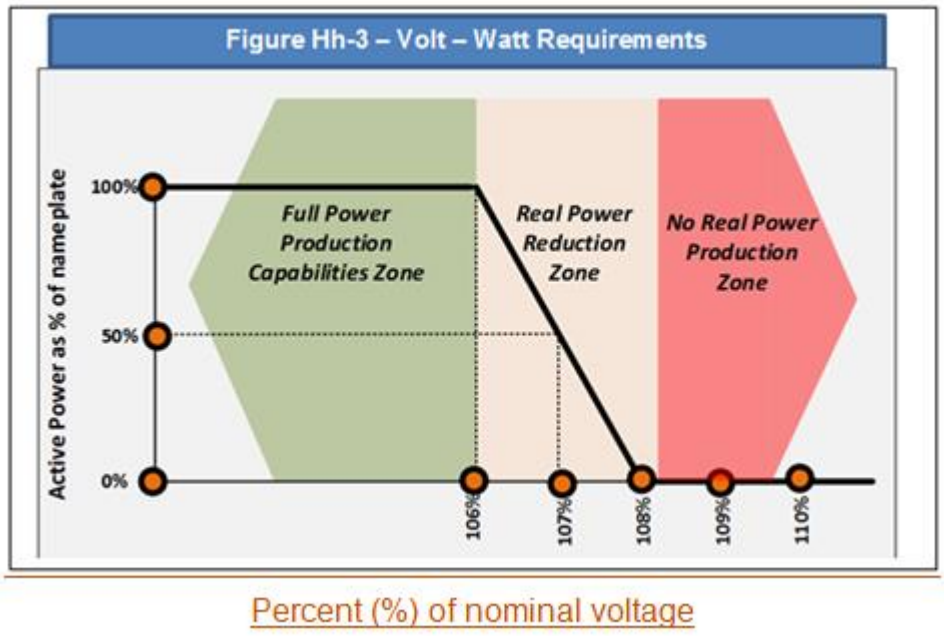
   - **Figure Hh-2 illustrated this requirement for three levels of output power. Figure Hh-2 is for illustration purposes only**

5) In section Hh.2. added new m., and new Figure Hh3 on Volt/Watt Requirements

   m. This requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after 12 months from the date the Phase 3 Smart Inverter Advanced Function Advice Letter (AL 5129-E) was made effective by the Commission. Smart Inverters shall reduce their real power production as a function of measured voltage at the inverter terminals or at the Generating Facility Point of Common Coupling (PCC) in accordance with the following:

- **When the measured voltage is greater than 106% of nominal voltage (for example: 127.2 volts on a 120 volts nominal), the Smart Inverter shall be reduced at a rate of 50% of real power nameplate rating per one percent of nominal voltage. Figure Hh-3 --Volt-Watt Requirements illustrates the required rate of reduction.**

- **When the measured voltage is greater than 108% of nominal voltage (Example: 129.6 volts on a 120 volts nominal), the active power output produced by the Smart Inverter shall be reduced to 0 watts.**



6) In section Hh.2, inserted new section n.

n. Set Active Power Level Mode Function

The utilization of this function is allowed and optional upon the mutual agreement of the Distribution Provider and the Applicant.

7) In section Hh.2, inserted new section o.

o. Dynamic Reactive Power Support Function

The utilization of this function is allowed and optional upon the mutual agreement of the Distribution Provider and the Applicant.

8) In section Hh.2. changed old section n. to p., and converted list into a table modifying some of the entries.

	Function	**State**
(i)	Anti-islanding	activated
(ii)	Low/High Voltage Ride-Through	activated
(iii)	Low/High Frequency Ride-Through	activated
(iv)	Dynamic Volt/VAR operations	activated
(v)	Ramp rates	activated
(vi)	Fixed power factor	deactivated
(vii)	Reconnect by “soft-start” methods	activated
(viii)	Frequency-Watt ~~(Optional)~~	**activated** ~~Implemented when available~~
(ix)	Volt/Watt	~~Deactivated~~ ~~A~~**activated** ~~Under mutual agreement with Distribution Provider instruction(s)~~
(x)	**Set Active Power Function Mode (Optional)**	**activated under mutual agreement**
(xi)	**Dynamic Reactive Power Support Mode (Optional)**	**activated under mutual agreement**

~~These default activation states may be modified by mutual agreement between Distribution Provider and Producer.~~

9) In section Hh.2., changed old section o. to q.

10) In section Hh.5., made first paragraph a., and made various edits including breaking out the three communication requirements

a. The communication **protocol** requirements included in this section **Hh.5** shall become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after the later of (a) March 1, 2018 or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry-recognized communication protocol certification test standard. Until such date, this subsection may be used in all or in part by inverter-based technologies by mutual agreement of the Distribution Provider and the Applicant. The communications requirements herein shall be between:

(i) the Distribution Provider and the individual Generating Facility**’s inverter control or energy management system;**

(ii) the Distribution Provider and **communication to** the Generating Facility **through an aggregator not co-located or part of the Generating Facility*** ~~energy management systems that manage the Generating Facility within a facility, plant and/or microgrid;~~; or

(iii) **other communication options as are mutually agreed to are by Applicant and the Distribution Provider.** ~~the Distribution Provider and aggregators, who manage and operate Generating Facilities at various locations.~~

*** Communication utilizing this aggregator option is not permitted at this time.**

11) In section Hh.5., changed section a. to b. and made the following changes

b~~a~~. Generating Facilities utilizing inverter-based technologies must adhere to all of the following communication protocol requirements **for communications between Distribution Provider and communication option selected in section Hh. 5. This Rule does not specify the communication between the selected communication option and Smart Inverter but performance will be enforced by in compliance with this Rule:**

(i) Shall be capable of communications;

(ii) Software shall be updateable via communications remotely;

(iii) The transport level protocol shall be TCP/IP; and,

(iv) The default application-level protocol shall be IEEE 2030.5 (i.e., Smart Energy Profile 2.0 (SEP 2)) as defined in the California IEEE 2030.5 Implementation Guide, but other application-level protocols may be used by mutual agreement of the parties including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850.

12) In section Hh.5., changed section b. to c.

13) Added new sections Hh.6., 7., and 8.

6. SCHEDULING CAPABILITY REQUIREMENTS

a. Generating Facilities which incorporate Smart Inverters shall incorporate scheduling capabilities with a minimum scheduling memory capability of at least 24 events. The capability for this requirement will be mandatory for Generating Facilities utilizing invert-based technologies for which an Interconnection Request is submitted on or after the later of (i) March 1, 2018, or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognize communication protocol certificate test standard. Each

event is composed of modifications to each, selected group of, or all of the following Smart Inverter function.

(i) Modifications to the voltage and reactive set-points of the Dynamic volt/var function.

(ii) Modification to the normal ramp-up rate and reconnect ramp-up rate set-points

(iii) Modifications to the reactive power set-points for the fixed power factor function

(iv) Modifications to the voltage and watt-reduction level set-points for the volt/watt function

b. The Generating Facility's scheduling capability requirement herein shall be met by one or more of the following options.

(i) Scheduling capability requirements may be stored at the Generating Facility Energy Management System (GFEMS). The GFEMS shall communicate the necessary commands to the Smart Inverters within 10 minutes from when GFEMS received the scheduling information:

(ii) Scheduling capability requirements may be stored at the Smart Inverter Control Unit (SMCU) within the Generating Facility. The SMCU shall communicate necessary commands to the Smart Inverters within 10 minutes from when SCMU received the scheduling information.

(iii) Scheduling capability requirements may be stored at an aggregator not co-located within the Generating Facility. The aggregator shall communicate the necessary commands to the Smart Inverters within 15 minutes of the aggregator receiving the scheduling information.

(iv) Other options may be utilized by mutual agreement between the Applicant and Distribution Provider.

c. The selected scheduling control system shall store the schedules and shall send operational commands to the Smart Inverters as required by the schedule received from the Distribution Provider. The Smart Inverter shall respond by changing its mode of operation as commanded with no unreasonable delay.

Each scheduled mode of operation shall include and start-time and duration. The Smart Inverter should return to its default settings at the end of the duration time or shall enter a new operational mode as directed by the scheduling control system.

7. MONITORING AND TELEMETRY REQUIREMENTS

a. The capability for this requirement will be mandatory for Generating Facilities utilizing invert-based technologies for which an Interconnection Request is submitted on or after the later of (i) March 1, 2018, or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognize communication protocol certificate test standard. Smart Inverter shall have the capability to communicate its performance information including:

(i) Smart Inverter production or consumption of active power (Watts).

(ii) Smart Inverter consumption or production of reactive power (VARs)

(iii) Phase currents measure at the AC terminal of the Smart Inverter (Amps)

(iv) Phase voltage measured at the AC terminals of the Smart Inverter (Volts)

(v) Frequency measured at the AC terminals of the Smart Inverter (Hz)

b. When the Generating Facility includes energy-storage with Smart Inverters, the following monitoring and telemetry capability are required:

(i) The Smart Inverter shall be capable of communicating the available kWh for the energy-storage. Available kWh of the energy storage system is amount energy which can be used to support the energy needs of the electric system including the energy needs for the load within the generating facility or the Distribution System.

c. Operational State as In-Service or not In-service communication capability requirements. The Smart Inverter shall be capable of communicating when the Smart Inverter is capable of providing electric services as follows:

(i) In-Service state: An operational state which indicates that the Smart Inverter is connected to the electric system and operating as determined locally by the Generating Facility operator or by a scheduling control system as outlined in section Hh.6

(ii) Not In-Service state: An operating state which indicates that the Smart Inverter is not capable of connecting to the electric system

and not capable of providing any type of electrical support as required locally or as commanded by a scheduling control system as outlined in section Hh.

d. Monitoring and performance information should be communicated in aggregate at the Generating Facility as follows:

(i) When the Generating Facility includes only Smart Inverters, The production or consumption of active and reactive power shall be communicated as an aggregate of all Smart Inverters within the Generating Facility.

(ii) When a Generating Facility includes Smart Inverters and other technologies such as synchronous or induction generation systems, the Generating Facility should communicate the following:

a) The production or consumption of active and reactive power shall be communicated in aggregate of all Smart Inverters within the Generating Facility

b) The production or consumption of active and reactive power shall be communicated in aggregate of all the other technologies within the Generating Facility

(iii) When the Generating Facility with Smart Inverters includes one or multiple energy storage systems. The available kWh energy should be communicated as an aggregate of all the energy storage systems.

8. CONTROL THROUGH COMMUNICATION CAPABILITIES

a. The capability for this requirement will be mandatory for Generating Facilities utilizing invert-based technologies for which an Interconnection Request is submitted on or after the later of (i) March 1, 2018, or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognize communication protocol certificate test standard. Smart Inverters shall have the capabilities of accepting an operational controls through communications in accordance to the following:

(i) Cease to energize control command. When the Smart Inverter receives a cease-to-energize command through communication it must enter into a cease-to-energize state of operation or shall initiate the opening of the DER switch referenced in the ECP in order to galvanically isolate the DER system from the Distribution System

(ii) Return to service control command. When the Smart Inverter receives a return-to-service control command, the Smart Inverter may return to service operation as required by Generating Facility operator or as required by the scheduling control system as required by section H.6

(iii) Limit Active Power command. When the Smart Inverter receives a command to limit its production of real power, the Smart Inverter shall reduce its real power production to the specified percent of real power capacity of the Smart Inverter or to a specified real power value.

(iv) Suspension of Active Power restriction: When the Smart Inverter receives a command to suspend the command for active power reduction, the Smart Inverter may return to normal operation as required by Generating Facility operator or as required by the scheduling control system as required by section H.6

14) The utilization of this function is allowed and optional upon the mutual agreement of the Distribution Provider and the Applicant.

G. ENGINEERING REVIEW DETAILS (Cont'd.)

3. DETAILED STUDY SCREENS (Cont'd.)

a. Screen Q: Is the Interconnection Request electrically Independent of the Transmission System? (Cont'd.)

Distribution Provider will coordinate with the CAISO if necessary to conduct the Determination of Electrical Independence for the CAISO Controlled Grid as set forth in **the applicable CAISO Tariff in effect at the time the Electrical Independence Test (EIT) begins.** ~~**Section 4.2 of Appendix Y to the CAISO Tariff**~~. The results of the incremental power flow, aggregate power flow, and short-circuit current contribution tests set out in **the applicable CAISO Tariff in effect at the time the EIT begins** ~~**Section 4.2 of Appendix Y to the CAISO Tariff**~~ will determine whether the Interconnection Request is electrically independent from the CAISO Controlled Grid.

The filing would not increase any current rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than September 7, 2017, which is 20 days after the date of this filing. 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 filing 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 lists 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

Attachments

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

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING 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:	Contact Person: Kingsley Cheng
☑ ELC ☐ GAS	Phone #: (415) 973-5265
☐ PLC ☐ HEAT ☐ WATER	E-mail: k2c0@pge.com and PGETariffs@pge.com

EXPLANATION OF UTILITY TYPE

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

(Date Filed/ Received Stamp by CPUC)

Advice Letter (AL) #: **5129-E** **Tier: 3**

Subject of AL: **Modifications to PG&E's Electric Rule 21 Tariff and Interconnection Agreements and Forms to Incorporate Smart Inverter Phase 3 Modifications**

Keywords (choose from CPUC listing): Compliance, Rules, Metering

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other _____

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.14-12-035 and D.16-06-052

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: _____

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: No

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: _____

Resolution Required? ☑Yes ☐No

Requested effective date: **Upon Commission Approval** No. of tariff sheets: **66**

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: **Electric Rule 21**

Service affected and changes proposed: N/A

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

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division
EDTariffUnit
505 Van Ness Ave., 4th Flr.
San Francisco, CA 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company
Attn: Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177
E-mail: PGETariffs@pge.com

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
40930-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 158	40435-E
40931-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 181	40458-E
40932-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 191	40763-E
40933-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 192	40764-E
40934-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 194	40766-E
40935-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 195	40767-E
40936-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 196	40768-E
40937-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 197	
40938-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 198	40769-E
40939-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 199	40770-E
40940-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 200	40771-E
40941-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 201	
40942-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 202	40772-E
40943-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 203	

Cal P.U.C. Sheet No.	Title of Sheet	Cancelling Cal P.U.C. Sheet No.
40944-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 204	
40945-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 205	
40946-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 206	
40947-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 207	
40948-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 208	
40949-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 209	40773-E
40950-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 210	40774-E
40951-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 211	40775-E
40952-E	ELECTRIC RULE NO. 21 GENERATING FACILITY INTERCONNECTIONS Sheet 212	40776-E
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G. ENGINEERING REVIEW DETAILS (Cont'd.)

3. DETAILED STUDY SCREENS (Cont'd.)

a. Screen Q: Is the Interconnection Request electrically Independent of the Transmission System? (Cont'd.)

Distribution Provider will coordinate with the CAISO if necessary to conduct the Determination of Electrical Independence for the CAISO Controlled Grid as set forth in the applicable CAISO Tariff in effect at the time the Electrical Independence Test (EIT) begins. The results of the incremental power flow, aggregate power flow, and short-circuit current contribution tests set out in the applicable CAISO Tariff in effect at the time the EIT begins will determine whether the Interconnection Request is electrically independent from the CAISO Controlled Grid. (T) (T) (T) (T)

- If Yes (pass), continue to Screen R.
- If No (fail), proceed to Section F.3.d.

Note 1: NEM Generating Facilities with net export less than or equal to 500 kW that may flow across the Point of Common Coupling will not be studied in the Transmission Cluster Study Process, but may be studied under the Independent Study Process.

Significance: Generating Facilities that are electrically interdependent with the Transmission System must be studied with other interconnection requests that have Transmission System interdependencies. It is possible to pass this Screen Q (i.e., be found to have no electrical interdependencies with earlier-queued Distribution System and/or Transmission System interconnection requests as set out above), be studied under the Independent Study Process, and still trigger a Reliability Network Upgrade.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

a. Protective Functions Required (Cont'd.)

(ii) A voltage and frequency sensing and time-delay function to prevent the Smart Inverter from energizing a de-energized Distribution or Transmission System circuit and to prevent the Smart Inverter from reconnecting with Distribution Provider's Distribution or Transmission System unless Distribution Provider's Distribution System service voltage and frequency is within the ANSI C84.1-1995 Table 1 Range B voltage Range of 106 volts to 127 volts (on a 120 volt basis), inclusive, and a frequency range of 58.5 Hz to 60.5 Hz, inclusive, and are stable for at least 15 seconds; and

(iii) A function to prevent the Smart Inverter from contributing to the formation of an Unintended Island, and cease to energize Distribution Provider's Distribution System within two seconds of the formation of an Unintended Island.

The Smart Inverter shall cease to energize Distribution Provider's Distribution System for faults on Distribution Provider's Distribution System circuit to which it is connected (IEEE 1547-4.2.1). The Smart Inverter shall cease to energize Distribution Provider's Distribution circuit prior to re-closure by Distribution Provider's Distribution System equipment (IEEE 1547-4.2.2).

b. Momentary Paralleling Generating Facilities

With Distribution Provider's approval, the transfer switch or scheme used to transfer Producer's loads from Distribution Provider's Distribution or Transmission System to Producer's Generating Facility may be used in lieu of the Protective Functions required for Parallel Operation.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

g. Harmonics (Cont'd.)

Table Hh.3

Maximum harmonic current distortion in percent of current (I) [1,2]

Individual harmonic order, h (odd harmonics) [3]	h<11	11≤ h<17	17≤ h<23	23≤ h<35	35≤ h	Total demand distortion
Max Distortion (%)	4.0	2.0	1.5	0.6	0.3	5.0

[1] – IEEE1547-4.3.3

[2] – I = the greater of the maximum Host Load current average demand over 15 or 30 minutes without the GF, or the GF rated current capacity (transformed to the PCC when a transformer exists between the GF and the PCC).

[3] – Even harmonics are limited to 25% of the odd harmonic limits above.

h. Direct Current Injection

Smart Inverter should not inject direct current greater than 0.5% of rated output current into Distribution Provider's Distribution or Transmission System.

i. Fixed Power Factor (T)

Producer shall provide adequate reactive power compensation on site to maintain the Smart Inverter power factor near unity at rated output or a Distribution Provider specified power factor in accordance with the following requirements:

(i) Default Power Factor setting: Absorbing reactive power at 0.95 lagging power factor.

(ii) Aggregate generating facility is greater than 15 kW: 1.0 +/- 0.15 (0.85 Lagging to 0.85 Leading) down to 20% rated power based on available reactive power.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

i. Fixed Power Factor (Cont'd.) (T)

(iii) Aggregate generating facility is less than or equal to 15 kW: 1.0 +/- 0.10 (0.90 Lagging to 0.90 Leading) down to 20% rated power based on available reactive power.

j. Dynamic Volt/VAR Operations

The Smart Inverter shall be capable of operating dynamically within a power factor range of +/- 0.85 PF for larger (>15 kW) systems, down to 20% of rated active power, and +/- 0.9 PF for smaller systems (≤15 kW), down to 20% of rated active power, based on available reactive power. This dynamic Volt/VAR capability shall be able to be activated or deactivated in accordance with Distribution Provider requirements.

The Distribution Provider may permit or require the Smart Inverter systems to operate in larger power factor ranges, including in 4-quadrant operations for storage systems with the implementation of additional anti-islanding protection as determined by the Distribution Provider.

The Smart Inverter shall be capable of providing dynamic reactive power compensation (dynamic Volt/VAR operation) within the following constraints:

(i) The Smart Inverter shall be able to consume reactive power in response to an increase in line voltage, and produce reactive power in response to a decrease in line voltage. (T)

(ii) The reactive power provided shall be based on available reactive power, but the maximum reactive power provided to the system shall be as directed by the Distribution Provider. (T)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

k. Ramp Rate Requirements

The Smart Inverter is required to have the following ramp controls for at least the following four conditions. These functions can be established by multiple control functions or by one general ramp rate control function. Ramp rates are contingent upon sufficient energy available from the Smart Inverter.

- Normal ramp-up rate: For transitions between energy output levels over the normal course of operation. The default value is 100% of maximum current output per second with a range of adjustment between 1% to 100%, with specific settings as mutually agreed by the Distributor Provider and the Producer.

- Connect/Reconnect Ramp-up rate: Upon starting to inject power into the grid, following a period of inactivity or a disconnection, the inverter shall be able to control its rate of increase of power from 1 to 100% maximum current per second. The default value is 2% of maximum current output per second, with specific settings as mutually agreed upon by the Distribution Provider and the Producer.

l. Frequency-Watt Requirements (T)

This requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after 12 months from the date the Phase 3 Smart Inverter Advanced Function Advice Letter (AL 5129- E) was made effective by the Commission. Smart Inverters shall reduce their real power production as a function of system frequency, in accordance with the following: (N) I I I I I (N)

- When system frequency exceeds 60.1Hz, the active power output produced by the Smart Inverter shall be reduced by 50% of real power nameplate rating per hertz (5% of real power nameplate rating reduction per 0.1 hertz)

(Continued)

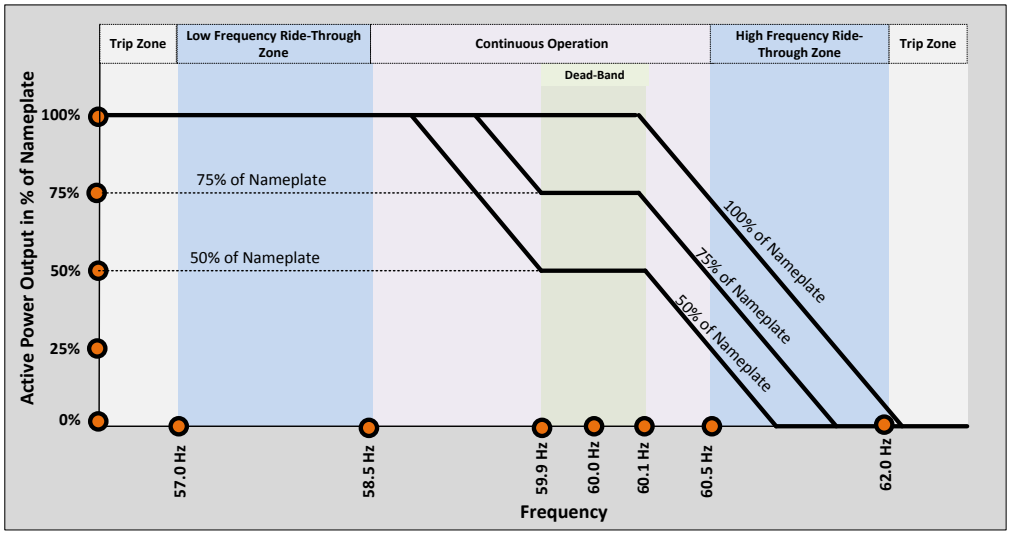
Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

l. Frequency-Watt Requirements (Cont'd.) (T)

- When system frequency moves under 59.9Hz, the active power output produced by the Smart Inverter shall be increased by 50% of real power nameplate rating per hertz (5% of real power nameplate rating increase per 0.1 hertz) when inverter is capable of increasing real power production.
- The default dead-band should be +/- 0.1 Hz from 60 hertz (59.9Hz to 60.1Hz). When the system frequency is in range of 59.9Hz and 60.1Hz, the Smart Inverter is not required to increase or decrease power as a function of system frequency.
- Open loop response time for Frequency –Watt shall be 5 seconds.
- Figure Hh-2 illustrated this requirement for three levels of output power. Figure Hh-2 is for illustration purposes only (N) (N)

Figure Hh-2: Active Power as a Function of System Frequency



(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

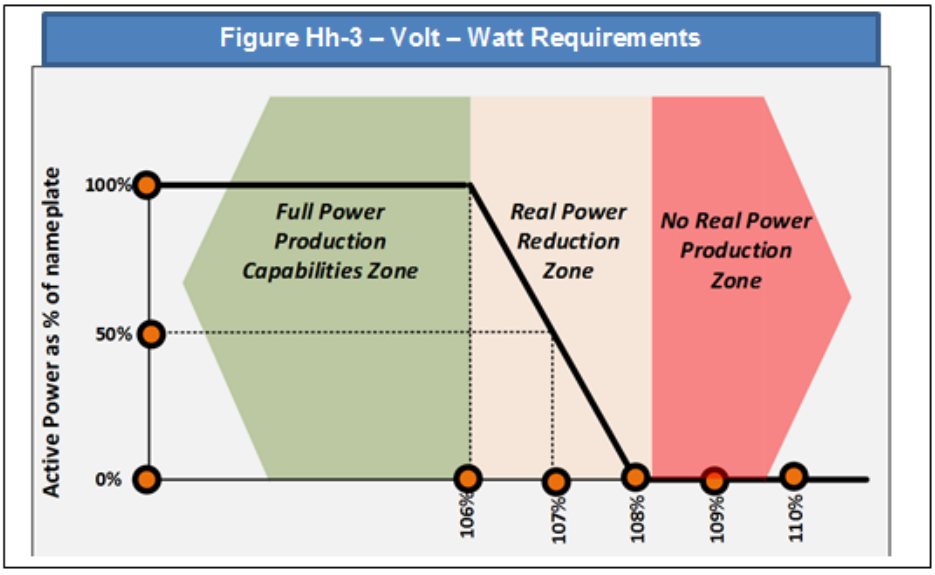
2. PREVENTION OF INTERFERENCE (Cont'd.)

m. This requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after 12 months from the date the Phase 3 Smart Inverter Advanced Function Advice Letter (AL 5129-E) was made effective by the Commission. Smart Inverters shall reduce their real power production as a function of measured voltage at the inverter terminals or at the Generating Facility Point of Common Coupling (PCC) in accordance with the following: (N)

- When the measured voltage is greater than 106% of nominal voltage (for example: 127.2 volts on a 120 volts nominal), the Smart Inverter shall be reduced at a rate of 50% of real power nameplate rating per one percent of nominal voltage. Figure Hh-3 -- Volt-Watt Requirements illustrates the required rate of reduction.

- When the measured voltage is greater than 108% of nominal voltage (Example: 129.6 volts on a 120 volts nominal), the active power output produced by the Smart Inverter shall be reduced to 0 watts

Figure Hh-3 – Volt – Watt Requirements



(N)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

n. Set Active Power Level Mode Function (N)

The utilization of this function is allowed and optional upon the mutual agreement of the Distribution Provider and the Applicant.

o. Dynamic Reactive Power Support Function

The utilization of this function is allowed and optional upon the mutual agreement of the Distribution Provider and the Applicant. (N)

p. Default Activation States for Phase 1 Functions (L)/(T)

Unless otherwise provided by Distribution Provider, pursuant to Distribution Provider's Distribution Generation Interconnection Handbook, the default settings will be as follows: (L)

	Function	**State**
(i)	Anti-islanding	activated
(ii)	Low/High Voltage Ride-Through	activated
(iii)	Low/High Frequency Ride-Through	activated
(iv)	Dynamic Volt/VAR operations	activated
(v)	Ramp rates	activated
(vi)	Fixed power factor	deactivated
(vii)	Reconnect by "soft-start" methods	activated
(viii)	Frequency-Watt	activated
(ix)	Volt/Watt	activated
(x)	Set Active Power Function Mode (Optional)	activated under mutual agreement
(xi)	Dynamic Reactive Power Support Mode (Optional)	activated under mutual agreement

(L)/(T)
(N)
(N)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

q. Load Shedding or Transfer (L)/(T)
(L)

The voltage and frequency ride-through requirements of Hh.2.b.(ii) and Hh.2.f.(i) shall not apply if either: a) The real power across the Point of Common Coupling is continuously maintained at a value less than 10% of the aggregate rating of the Smart Inverters connected to the Generation Facility prior to any voltage disturbance, and the Generation Facility disconnects from the Distribution Provider's T&D system, along with Generation Facility load, such that the net change in real power flow from or to the Distribution Provider is less than 10% of the aggregate Smart Inverter capacity; or b) Generation Facility load real power demand equal to 90% to 120% of the pre-disturbance aggregate Smart Inverter real power output is shed within 0.1 seconds of Smart Inverter disconnection. I

3. TECHNOLOGY SPECIFIC REQUIREMENTS I

Grid-interactive inverters do not require separate synchronizing equipment. Non grid-interactive or "stand-alone" inverters shall not be used for Parallel Operation with Distribution Provider's Distribution or Transmission System. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

4. SUPPLEMENTAL SMART INVERTER REQUIREMENTS

a. Fault Detection

A Smart Inverter with an SCCR exceeding 0.1 or one that does not cease to energize Distribution Provider's Distribution or Transmission System within two seconds of the formation of an Unintended Island shall be equipped with Protective Functions designed to detect Distribution or Transmission System faults, both line-to-line and line-to-ground, and cease to energize Distribution Provider's Distribution or Transmission System within two seconds of the initiation of a fault.

b. Transfer Trip

For a Generating Facility that cannot detect Distribution or Transmission System faults (both line-to-line and line-to-ground) or the formation of an Unintended Island, and cease to energize Distribution Provider's Distribution or Transmission System within two seconds, Distribution Provider may require a Transfer Trip system or an equivalent Protective Function.

c. Reclose Blocking

Where the aggregate Generating Facility capacity exceeds 15% of the peak load on any automatic reclosing device, Distribution Provider may require additional Protective Functions, including, but not limited to reclose-blocking on some of the automatic reclosing devices. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

5. COMMUNICATION REQUIREMENTS

a. The communication protocol requirements included in this section Hh.5 shall become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after the later of (a) March 1, 2018 or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry-recognized communication protocol certification test standard. Until such date, this subsection may be used in all or in part by inverter-based technologies by mutual agreement of the Distribution Provider and the Applicant. The communications requirements herein shall be between: (L)/(T) (L)/(T) (L)

(i) the Distribution Provider and the individual Generating Facility's inverter control or energy management system; (L) (N)

(ii) the Distribution Provider and communication to the Generating Facility through an aggregator not co-located or part of the Generating Facility[A]; or (L)/(T)

(iii) other communication options as are mutually agreed to are by Applicant and the Distribution Provider. (L)/(T)

(L)

(N)

[A] Communication utilizing this aggregator option is not permitted at this time.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

5. COMMUNICATION REQUIREMENTS (Cont'd.)

b. Generating Facilities utilizing inverter-based technologies must adhere to all of the following communication protocol requirements for communications between Distribution Provider and communication option selected in section Hh. 5. This Rule does not specify the communication between the selected communication option and Smart Inverter but performance will be enforced by in compliance with this Rule: (L)/(T) (L)

(i) Shall be capable of communications;

(ii) Software shall be updateable via communications remotely;

(iii) The transport level protocol shall be TCP/IP; and,

(iv) The default application-level protocol shall be IEEE 2030.5 (i.e., Smart Energy Profile 2.0 (SEP 2)) as defined in the California IEEE 2030.5 Implementation Guide, but other application-level protocols may be used by mutual agreement of the parties including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.) (L)

5. COMMUNICATION REQUIREMENTS (Cont'd.) (L)

c. Additional communication protocol requirements shall also apply to Generating Facilities utilizing inverter-based technologies as provided in the following documents: (L)/(T) (L)

(i) Distribution Provider Generation Interconnection Handbook, which shall include:

a) Details and guidelines for the implementation of communications with Generating Facilities utilizing inverter-based technologies;

b) Cybersecurity and privacy requirements (these may additionally or alternatively be included in the application-level protocol implementation guide); and,

c) Generic device communications registration management requirements, including how to register individual Generating Facilities, Generating Facilities with energy management systems, and aggregators (these requirements additionally or alternatively may be included in the application-level protocol implementation guide).

(ii) Application-Level Protocol Implementation Guide, which shall provide:

a) Communication requirements and implementation guidelines to ensure consistent interoperability of the Generating Facilities with all California investor-owned utilities under the Commission's jurisdiction. (L)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

6. SCHEDULING CAPABILITY REQUIREMENTS (N)

a. Generating Facilities which incorporate Smart Inverters shall incorporate scheduling capabilities with a minimum scheduling memory capability of at least 24 events. The capability for this requirement will be mandatory for Generating Facilities utilizing invert-based technologies for which an Interconnection Request is submitted on or after the later of (i) March 1, 2018, or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognize communication protocol certificate test standard. Each event is composed of modifications to each, selected group of, or all of the following Smart Inverter function.

(i) Modifications to the voltage and reactive set-points of the Dynamic volt/var function.

(ii) Modification to the normal ramp-up rate and reconnect ramp-up rate set-points

(iii) Modifications to the reactive power set-points for the fixed power factor function

(iv) Modifications to the voltage and watt-reduction level set-points for the volt/watt function (N)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

6. SCHEDULING CAPABILITY REQUIREMENTS (Cont'd.) (N)

b. The Generating Facility's scheduling capability requirement herein shall be met by one or more of the following options.

(i) Scheduling capability requirements may be stored at the Generating Facility Energy Management System (GFEMS). The GFEMS shall communicate the necessary commands to the Smart Inverters within 10 minutes from when GFEMS received the scheduling information:

(ii) Scheduling capability requirements may be stored at the Smart Inverter Control Unit (SMCU) within the Generating Facility. The SMCU shall communicate necessary commands to the Smart Inverters within 10 minutes from when SCMU received the scheduling information.

(iii) Scheduling capability requirements may be stored at an aggregator not co-located within the Generating Facility. The aggregator shall communicate the necessary commands to the Smart Inverters within 15 minutes of the aggregator receiving the scheduling information.

(iv) Other options may be utilized by mutual agreement between the Applicant and Distribution Provider.

c. The selected scheduling control system shall store the schedules and shall send operational commands to the Smart Inverters as required by the schedule received from the Distribution Provider. The Smart Inverter shall respond by changing its mode of operation as commanded with no unreasonable delay.

Each scheduled mode of operation shall include and start-time and duration. The Smart Inverter should return to its default settings at the end of the duration time or shall enter a new operational mode as directed by the scheduling control system. (N)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

7. MONITORING AND TELEMETRY REQUIREMENTS (N)

a. The capability for this requirement will be mandatory for Generating Facilities utilizing invert-based technologies for which an Interconnection Request is submitted on or after the later of (i) March 1, 2018, or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognize communication protocol certificate test standard. Smart Inverter shall have the capability to communicate its performance information including:

(i) Smart Inverter production or consumption of active power (Watts).

(ii) Smart Inverter consumption or production of reactive power (VARs)

(iii) Phase currents measure at the AC terminal of the Smart Inverter (Amps)

(iv) Phase voltage measured at the AC terminals of the Smart Inverter (Volts)

(v) Frequency measured at the AC terminals of the Smart Inverter (Hz) (N)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

7. MONITORING AND TELEMETRY REQUIREMENTS (Cont'd.) (N)

b. When the Generating Facility includes energy-storage with Smart Inverters, the following monitoring and telemetry capability are required:

(i) The Smart Inverter shall be capable of communicating the available kWh for the energy-storage. Available kWh of the energy storage system is amount energy which can be used to support the energy needs of the electric system including the energy needs for the load within the generating facility or the Distribution System.

c. Operational State as In-Service or not In-service communication capability requirements. The Smart Inverter shall be capable of communicating when the Smart Inverter is capable of providing electric services as follows:

(i) In-Service state: An operational state which indicates that the Smart Inverter is connected to the electric system and operating as determined locally by the Generating Facility operator or by a scheduling control system as outlined in section Hh.6

(ii) Not In-Service state: An operating state which indicates that the Smart Inverter is not capable of connecting to the electric system and not capable of providing any type of electrical support as required locally or as commanded by a scheduling control system as outlined in section Hh. (N)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

7. MONITORING AND TELEMETRY REQUIREMENTS (Cont'd.) (N)

d. Monitoring and performance information should be communicated in aggregate at the Generating Facility as follows:

(i) When the Generating Facility includes only Smart Inverters, The production or consumption of active and reactive power shall be communicated as an aggregate of all Smart Inverters within the Generating Facility.

(ii) When a Generating Facility includes Smart Inverters and other technologies such as synchronous or induction generation systems, the Generating Facility should communicate the following:

a) The production or consumption of active and reactive power shall be communicated in aggregate of all Smart Inverters within the Generating Facility

b) The production or consumption of active and reactive power shall be communicated in aggregate of all the other technologies within the Generating Facility

(iii) When the Generating Facility with Smart Inverters includes one or multiple energy storage systems. The available kWh energy should be communicated as an aggregate of all the energy storage systems (N)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

8. CONTROL THROUGH COMMUNICATION CAPABILITIES (N)

a. The capability for this requirement will be mandatory for Generating Facilities utilizing invert-based technologies for which an Interconnection Request is submitted on or after the later of (i) March 1, 2018, or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognize communication protocol certificate test standard. Smart Inverters shall have the capabilities of accepting an operational controls through communications in accordance to the following:

(i) Cease to energize control command. When the Smart Inverter receives a cease-to-energize command through communication it must enter into a cease-to-energize state of operation or shall initiate the opening of the DER switch referenced in the ECP in order to galvanically isolate the DER system from the Distribution System

(ii) Return to service control command. When the Smart Inverter receives a return-to-service control command, the Smart Inverter may return to service operation as required by Generating Facility operator or as required by the scheduling control system as required by section H.6

(iii) Limit Active Power command. When the Smart Inverter receives a command to limit its production of real power, the Smart Inverter shall reduce its real power production to the specified percent of real power capacity of the Smart Inverter or to a specified real power value.

(iv) Suspension of Active Power restriction: When the Smart Inverter receives a command to suspend the command for active power reduction, the Smart Inverter may return to normal operation as required by Generating Facility operator or as required by the scheduling control system as required by section H.6 (N)

(Continued)

ELECTRIC RULE NO. 21 Sheet 209
GENERATING FACILITY INTERCONNECTIONS

I. THIRD-PARTY INSTALLATIONS, RESERVATION OF UNUSED FACILITIES, AND REFUND OF SALVAGE VALUE (L)

1. INTERCONNECTION FACILITIES AND DISTRIBUTION UPGRADES

Except as provided for in the Generator Interconnection Agreement of this Rule, Interconnection Facilities connected to Distribution Provider's side of the PCC and Distribution Upgrades shall be provided, installed, owned, and maintained by Distribution Provider at Producer's expense.

2. THIRD-PARTY INSTALLATIONS

Subject to the approval of Distribution Provider, a Producer may, at its option, employ a qualified contractor to provide and install Interconnection Facilities or Distribution Upgrades, to be owned and operated by Distribution Provider, on Distribution Provider's side of the PCC. Such Interconnection Facilities and Distribution Upgrades shall be installed in accordance with Distribution Provider's design and specifications. Upon final inspection and acceptance by Distribution Provider, Producer shall transfer ownership of such Producer installed Interconnection Facilities or Distribution Upgrades to Distribution Provider and such facilities shall thereafter be owned and maintained by Distribution Provider at Producer's expense. Producer shall pay Distribution Provider's reasonable cost of design, administration, and monitoring of the installation for such facilities to ensure compliance with Distribution Provider's requirements. Producer shall also be responsible for all costs, including any income tax liability, associated with the transfer of Producer installed Interconnection Facilities and Distribution Upgrades to Distribution Provider. (L)

(Continued)

ELECTRIC RULE NO. 21 Sheet 210
GENERATING FACILITY INTERCONNECTIONS

I. THIRD-PARTY INSTALLATIONS, RESERVATION OF UNUSED FACILITIES, AND REFUND OF SALVAGE VALUE (Cont'd.) (L)

3. RESERVATION OF UNUSED FACILITIES

When a Producer wishes to reserve Distribution Provider-owned Interconnection Facilities or Distribution Upgrades installed and operated as Added Facilities for Producer at Producer's expense, but idled by a change in the operation of Producer's Generating Facility or otherwise, Producer may elect to abandon or reserve such facilities consistent with the terms of its agreement with Distribution Provider. If Producer elects to reserve idle Interconnection Facilities or Distribution Upgrades, Distribution Provider shall be entitled to continue to charge Producer for the costs related to the ongoing operation and maintenance of the Added Facilities.

4. REFUND OF SALVAGE VALUE

When a Producer elects to abandon the Special Facilities or Added Facilities for which it has either advanced the installed costs or constructed and transferred to Distribution Provider, Producer shall, at a minimum, receive from Distribution Provider a credit for the net salvage value of the Added Facilities.

J. METERING, MONITORING AND TELEMETERING

1. GENERAL REQUIREMENTS

All Generating Facilities shall be metered in accordance with this Section J and shall meet all applicable standards of Distribution Provider contained in Distribution Provider's applicable tariffs and published Distribution Provider manuals dealing with Metering specifications.

2. METERING BY NON-DISTRIBUTION PROVIDER PARTIES

The ownership, installation, operation, reading, and testing of revenue Metering Equipment for Generating Facilities shall be by Distribution Provider except to the extent that the Commission authorizes any or all these services be performed by others. (L)

(Continued)

ELECTRIC RULE NO. 21 Sheet 211
GENERATING FACILITY INTERCONNECTIONS

J. METERING, MONITORING AND TELEMETERING (Cont'd.) (L)

3. NET GENERATION OUTPUT METERING

Generating Facility customers may be required to install Net Generation Output Metering for evaluation, monitoring, and verification purposes and to determine applicable standby and non-bypassable charges as defined in Distribution Provider's tariffs, to satisfy applicable California Independent System Operator (CAISO) reliability requirements, and for Distribution System planning and operations.

However, Generating Facility customers do not need to install Net Generation Output Metering where less intrusive and/or more cost effective options, for Producer/Customer, are available for providing generator data to Distribution Provider. These Generating Facilities may opt to have Distribution Provider estimate load data in accordance with Distribution Provider's applicable tariffs to determine or meet applicable standby and non-bypassable and other applicable charges and tariff requirements. However, if a Generating Facility customer objects to Distribution Provider's estimate of the Generator(s) output, the customer may elect to install the Net Generation Output Metering, or have Distribution Provider install Net Generation Output Metering at the customer's expense.

(a) All metering options available to the customer must conform to the requirements set forth in Distribution Provider's Rule 22. If Distribution Provider does not receive meter data in accordance with Rule 22, Distribution Provider shall have the right to install Distribution Provider-owned Net Generation Output Metering at the customer's expense. The relevant factors in determining the need for Net Generation Output Metering are as listed below:

i) Data requirements in proportion to need for information;

ii) Producer's election to install equipment that adequately addresses Distribution Provider's operational requirements; (L)

(Continued)

ELECTRIC RULE NO. 21 Sheet 212
GENERATING FACILITY INTERCONNECTIONS

J. METERING, MONITORING AND TELEMETERING (Cont'd.) (L)

3. NET GENERATION OUTPUT METERING (Cont'd.)

iii) Accuracy and type of required Metering consistent with purposes of collecting data;

iv) Cost of Metering relative to the need for and accuracy of the data;

v) The Generating Facility's size relative to the cost of the Metering/monitoring;

vi) Other means of obtaining the data (e.g. Generating Facility logs, proxy data, etc.);

vii) Requirements under any Generator Interconnection Agreement with Producer.

The requirements in this Section may not apply to Metering of Generating Facilities operating under Distribution Provider's Net Energy Metering tariffs. Nothing in this Section J.3 supersedes Section D.4, Compliance with Laws, Rules and Tariff Schedules.

Distribution Provider will report to the Commission or designated authority, on a quarterly basis, the rationale for requiring Net Generation Output Metering equipment in each instance along with the size and location of the facility.

4. POINT OF COMMON COUPLING (PCC) METERING

For purposes of assessing Distribution Provider's charges for retail service, Producer's PCC Metering shall be reviewed by Distribution Provider, and if required, replaced to ensure that it will appropriately measure electric power according to the provisions of the Customer's electric service Tariff. Where required, the Customer's existing meter may be replaced with a bi-directional meter so that power deliveries to and from Producer's site can be separately recorded. Alternately, (L)

(Continued)

ELECTRIC RULE NO. 21 Sheet 213
GENERATING FACILITY INTERCONNECTIONS

J. METERING, MONITORING AND TELEMETERING (Cont'd.) (L)

4. POINT OF COMMON COUPLING (PCC) METERING (Cont'd.)

Producer may, at its sole option and cost, require Distribution Provider to install multi-metering equipment to separately record power deliveries to Distribution Provider's Distribution System and retail purchases from Distribution Provider. Where necessary, such PCC Metering shall be designed to prevent reverse registration.

Generating Facilities participating in Net Energy Metering shall have metering provided pursuant to the terms of the applicable Net Energy Metering tariff schedule.

5. TELEMETERING

If the nameplate rating of the Generating Facility is 1 MW or greater, Telemetering equipment at the Net Generation Output Metering location may be required at Producer's expense. If the Generating Facility is Interconnected to a portion of Distribution Provider's Distribution System operating at a voltage below 10 kV, then Telemetering equipment may be required on Generating Facilities 250 kW or greater. Distribution Provider shall only require Telemetering to the extent that less intrusive and/or more cost effective options for providing the necessary data in real time are not available. Distribution Provider will report to the Commission or designated authority, on a quarterly basis, the rationale for requiring Telemetering equipment in each instance along with the size and location of the facility.

6. LOCATION

Where Distribution Provider-owned Metering is located on Producer's premises, Producer shall provide, at no expense to Distribution Provider, a suitable location for all such Metering Equipment. (L)

(Continued)

J. METERING, MONITORING AND TELEMETERING (Cont'd.) (L)

7. COSTS OF METERING

Producer will bear all costs of the Metering required by this Rule, including the incremental costs of operating and maintaining the Metering Equipment.

8. MULTIPLE TARIFF METERING

The requirements of Section J.3 may not apply where a Generating Facility includes multiple generators eligible for service under more than one Net Energy Metering (NEM) tariff schedule (e.g. NEM-1, NEM-2, NEMBIO, NEMFC), or where a Generating Facility consists of one or more NEM-eligible generators in combination with one or more non-NEM eligible generators without Non-Export relays ("Reverse Power Protection"). To ensure proper tariff administration, metering will be required at the PCC and at each of the NEM eligible generator groups eligible for service under the same NEM tariff schedule. For combinations of multiple NEM eligible generators under different tariffs, billing administration and metering requirements will be as specified in the appropriate NEM tariff schedule.

Where a Generating Facility consists of one or more NEM eligible generator groups in combination with one or more non-NEM generators, metering of the non-NEM generators is not required, except as specified in Section J.3. (L)

(Continued)

K. DISPUTE RESOLUTION PROCESS (L)

In addition to the informal procedures for timeline-related disputes set out in Section F.1.d, the following procedures will apply for disputes arising from this Rule:

1. SCOPE

The Commission shall have initial jurisdiction to interpret, add, delete or modify any provision of this Rule or of any agreements entered into between Distribution Provider and Applicant or Producer to implement this tariff ("Implementing Agreements") and to resolve disputes regarding Distribution Provider's performance of its obligations under Commission-jurisdictional tariffs, the applicable agreements, and requirements related to the interconnection of Applicant's or Producer's Generating Facility or Interconnection Facilities pursuant to this Rule.

2. PROCEDURES

Any dispute arising between Distribution Provider and Producer (individually referred to in Section K as "Party" and collectively "the Parties") regarding Distribution Provider's or Producer's performance of its obligations under its tariffs, the Implementing Agreements, and requirements related to the interconnection of Producer's Facilities pursuant to this Rule shall be resolved according to the following procedures:

a. The dispute shall be documented in a written notice ("notice") by the aggrieved Party to the other Party containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the aggrieved Party that it is invoking the procedures under this Section. The notice shall be sent to the Party's email address and physical address set forth in the Generator Interconnection Agreement or Interconnection Request, if there is no Generator Interconnection Agreement. A copy of the notice shall also be sent to the Energy Division, Office of the Director, at the Commission. The receiving Party shall acknowledge the notice within five (5) Calendar Days of its receipt. (L)

(Continued)

K. DISPUTE RESOLUTION PROCESS (Cont'd.) (L)

2. PROCEDURES (Cont'd.)

a Upon the aggrieved Party notifying the other Party of the dispute, each Party must designate a representative with the authority to make decisions for its respective Party to review the dispute within seven (7) Calendar Days. In addition, upon receipt of the notice, Distribution Provider shall provide the aggrieved Party with all relevant regulatory and/or technical details and analysis regarding any Distribution Provider interconnection requirements under dispute within twenty-one (21) Calendar Days.

Within forty-five (45) Calendar Days of the date of the notice, the Parties' authorized representatives will be required to meet and confer to try to resolve the dispute. Parties are expected to operate in good faith and use best efforts to resolve the dispute.

b. If a resolution is not reached in forty-five (45) Calendar Days from the date of the notice, either 1) a Party may request to continue negotiations for an additional forty-five (45) Calendar Days or 2) the Parties may by mutual agreement make a written request for mediation to the ADR Coordinator in the Commission's ALJ Division. The request may be submitted by electronic mail to adr_program@cpuc.ca.gov. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

c. At any time, either Party may file a formal complaint before the Commission pursuant to California PUC section 1702 and Article 4 of the Commission's Rules of Practice and Procedure.

Nothing in this section shall be construed to limit the rights of any Party to exercise rights and remedies under Commission law. (L)

(Continued)

K. DISPUTE RESOLUTION PROCESS (Cont'd.) (L)

3. PERFORMANCE DURING DISPUTE

Pending resolution of any dispute under this Section, the Parties shall proceed diligently with the performance of their respective obligations under this Rule and the Implementing Agreements, unless the Implementing Agreements have been terminated. Disputes as to the Interconnection Request and implementation of this Section shall be subject to resolution pursuant to the procedures set forth in this Section.

L. CERTIFICATION AND TESTING CRITERIA

1. INTRODUCTION

This Section describes the test procedures and requirements for equipment used for the Interconnection of Generating Facilities to Distribution Provider's Distribution or Transmission System. Included are Type Testing, Production Testing, Commissioning Testing, and Periodic Testing. The procedures listed rely heavily on those described in appropriate Underwriters Laboratory (UL), Institute of Electrical and Electronic Engineers (IEEE), and International Electrotechnical Commission (IEC) documents—most notably UL 1741 and IEEE 929 as well as the testing described in *May 1999 New York State Public Service Commission's Interconnection Requirements.* As noted in Section B, this Rule has been revised to be consistent with ANSI/IEEE 1547-2003 Standard for Interconnecting Distribution Resources with Electric Power Systems. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

1. INTRODUCTION (Cont'd.)

The tests described here, together with the technical requirements in Section H of this Rule, are intended to provide assurance that the Generating Facility's equipment will not adversely affect Distribution Provider's Distribution or Transmission System and that a Generating Facility will cease providing power to Distribution Provider's Distribution or Transmission System under abnormal conditions. The tests were developed assuming a low level of Generating Facility penetration or number of connections to Distribution Provider's Distribution or Transmission System. At high levels of Generating Facility penetration, additional requirements and corresponding test procedures may need to be defined.

Section L also provides criteria for "Certifying" Generators or inverters. Once a Generator or inverter has been Certified per this Rule, it may be considered suitable for Interconnection with Distribution Provider's Distribution or Transmission System. Subject to the exceptions described in Section L, Distribution Provider will not repeat the design review or require retesting of such Certified Equipment. It should be noted that the Certification process is intended to facilitate Generating Facilities Interconnections. Certification is not a prerequisite to interconnect a Generating Facility for Section H but it is a prerequisite for inverters installed after September 8, 2017, pursuant to Section Hh of this Rule. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

2. CERTIFIED AND NON-CERTIFIED INTERCONNECTION EQUIPMENT

a. Certified Equipment

Equipment tested and approved (i.e. "Listed") by an accredited NRTL as having met both the Type Testing and Production Testing requirements described in this document is considered to be Certified Equipment for purposes of Interconnection with Distribution Provider's Distribution or Transmission System. Certification may apply to either a pre-packaged system or an assembly of components that address the necessary functions. Type Testing may be done in the manufacturer's factory or test laboratory, or in the field. At the discretion of the testing laboratory, field-certification may apply only to the particular installation tested. In such cases, some or all of the tests may need to be repeated at other installations.

When equipment is Certified by a NRTL, the NRTL shall provide to the manufacturer, at a minimum, a Certificate with the following information for each device:

Administrative:

(1) The effective date of Certification or applicable serial number (range or first in series), and/or other proof that certification is current;

(2) Equipment model number(s) of the Certified equipment;

(3) The software version utilized in the equipment, if applicable;

(4) Test procedures specified (including date or revision number); and

(5) Laboratory accreditation (by whom and to what standard). (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

2. CERTIFIED AND NON-CERTIFIED INTERCONNECTION EQUIPMENT (Cont'd.)

a. Certified Equipment (Cont'd.)

Technical (as appropriate):

(1) Device ratings (kW, kV, Volts, amps, etc.);

(2) Maximum available fault current in amps;

(3) In-rush Current in amps;

(4) Trip points, if factory set (trip value and timing);

(5) Trip point and timing ranges for adjustable settings;

(6) Nominal power factor or range if adjustable;

(7) If the equipment is Certified as Non-Exporting and the method used (reverse power or underpower); and

(8) If the equipment is Certified as Non-Islanding

It is the responsibility of the equipment manufacturer to ensure that Certification information is made publicly available by the manufacturer, the testing laboratory, or by a third party.

b. Non-Certified Equipment

For non-Certified equipment, some or all of the tests described in this Rule may be required by Distribution Provider for each Generating and/or Interconnection Facility. The manufacturer or a laboratory acceptable to Distribution Provider may perform these tests. Test results for non-Certified equipment must be submitted to Distribution Provider for the Supplemental Review. Approval by Distribution Provider for equipment used in a particular Generating and/or Interconnection Facility does not guarantee Distribution Provider's approval for use in other Generating and/or Interconnection Facilities. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING

a. Type Tests and Criteria for Interconnection Equipment Certification

Type testing provides a basis for determining that equipment meets the specifications for being designated as Certified equipment under this Rule. The requirements described in this Section cover only issues related to Interconnection and are not intended to address device safety or other issues.

Table L.1 defines the test criteria by Generator or inverter technology. While UL 1741(1) and UL 1741 – Supplement SA were written specifically for inverters, the requirements are readily adaptable to synchronous Generators, induction Generators, as well as single/multi-function controllers and protection relays. Until a universal test standard is developed, Distribution Provider or NRTL shall adopt the procedures referenced in Table L.1 as appropriate and necessary for a Generating Facility and/or Interconnection Facilities or associated equipment performance and its control and Protection Functions. These tests shall be performed in the sequence shown in Table L.2. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

a. Type Tests and Criteria for Interconnection Equipment Certification (Cont'd.)

Table L.1, Type Test and Requirements for Interconnection Equipment Certification

Type Test	Reference 1	Inverter (6)	Smart Inverter (7)	Synchronous Generators	Induction Generators
Utility Interaction	UL 1741 – 39, 40	X	X	X	X
Utility Compatibility (Required testing to 1547 & 1547.1)	UL 1741 - 46	X	X	X	X
DC Isolation	IEEE 1547.1(8) -5.6	X	X	-	-
Dielectric Voltage Withstand	IEEE 1547.1(8) -5.5.3	X	X	X	X
Harmonic Distortion	IEEE 1547.1(8) -5.11	X	X	X	X
DC Injection	IEEE 1547.1(8) -5.6	X	X	-	-
Distribution Provider Voltage Variation	IEEE 1547.1(8) -5.2	X	-	X	X
Distribution Provider Frequency Variation	IEEE 1547.1(8) -5.3	X	-	X	X
Abnormal Tests	UL 1741 – 47				
Loss of Control Circuit	UL 1741 – 47.8	X	X	X	X
Short Circuit	UL 1741 - 47.3	X	X	X	X
Load Transfer	UL 1741 - 47.7	X	X	X	X
Surge Withstand Capability	L.3.e	X	X	X	X
Anti-Islanding (non-Smart Inverters)	L.3.b	(2)	-	(2)	(2)
Non-Export	L.3.c	(3)	(3)	(3)	(3)
In-rush Current	L.3.d	-	-	-	(4)
Synchronization	L.3.f	(5)	(5)	X	(5)
Anti-islanding (Smart Inverters)	UL 1741 SA - SA8	-	X	-	-
Low and High Voltage Ride-through (L/H VRT)	UL 1741 SA – SA9	-	X	-	-
Low and High Frequency Ride-through (L/H FRT)	UL 1741 SA - SA10	-	X	-	-
Normal and Soft-Start Ramp Rate (RR)	UL 1741 SA - SA11	-	X	-	-
Specified Power Factor	UL 1741 SA - SA12	-	X	-	-
Volt/Var Mode (Q(V))	UL 1741 SA - SA13	-	X	-	-
Frequency-Watt(FW) - optional	UL 1741 SA - SA14	-	X	-	-
Volt-Watt (VW) - optional	UL 1741 SA - SA15	-	X	-	-
Markings and Instructions	UL 1741 SA6, SA16	-	X	-	-

Table Notes:

(1) References are to section numbers in either UL 1741 and/or UL 1741-Supplement SA (Inverters, Converters and Charge Controllers for Use in Independent Power Systems) or this Rule. References in UL 1741 to "photovoltaics" or "inverter" may have to be adapted to the other technologies by the testing laboratory to appropriately apply in the tests to other technologies.
(2) Required only if Non-Islanding designation.
(3) Required only if Non-Export designation is desired.
(4) Required for Generators that use Distribution Provider power to motor to speed.
(5) Required for all self-excited induction Generators as well as Inverters that operate as voltage sources when connected to Distribution Provider's Distribution or Transmission System.
(6) Inverters compliant with Section H.
(7) Inverters compliant with Section Hh.
(8) IEEE 1547.1 refers to 2005 revision.

"X" = Required "-" = Not Required (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

a. Type Tests and Criteria for Interconnection Equipment Certification (Cont'd.)

Table L.2 Type Tests Sequence for Interconnection Equipment Certification

Test No.	Type Test
1	Distribution Provider Voltage and Frequency Variation
2	Synchronization
3	Surge Withstand Capability
4	Distribution Provider Voltage and Frequency Variation, including ride through
5	Synchronization
6	Other Required and Optional Tests

Tests 1, 2, and 3 must be done first and in the order shown. Tests 4 and on follow in order convenient to the test agency.

b. Anti-Islanding Test

Devices that pass the Anti-Islanding test procedure described in UL 1741 Section 46.3 will be considered Non-Islanding for the purposes of these Interconnection requirements. The test is required only for devices for which a Certified Non-Islanding designation is desired.

c. Non-Export Test

Equipment that passes the Non-Export test procedure described in Section L.7.a will be considered Non-Exporting for the purposes of these Interconnection requirements. This test is required only for devices for which a Certified Non-Export designation is desired. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

d. In-rush Current Test

Generation equipment that utilizes Distribution Provider power to motor up to speed will be tested using the procedure defined in Section L.7.b to determine the maximum current drawn during this startup process. The resulting In-rush Current is used to estimate the Starting Voltage Drop.

e. Surge Withstand Capability Test

The interconnection equipment shall be tested for the surge withstand requirement in Section H.1.c in all normal operating modes in accordance with IEEE Std C62.45-2002 for equipment rates less than 1000 V to confirm that the surge withstand capability is met by using the selected test level(s) from IEEE Std C62.41.2-2002. Interconnection equipment rated greater than 1000 V shall be tested in accordance with manufacturer or system integrator designated applicable standards. For interconnection equipment signal and control circuits, use IEEE Std C37.90.1-2002. These tests shall confirm the equipment did not fail, did not misoperate, and did not provide misinformation (IEEE 1547-5.1.3.2).

The location/exposure category for which the equipment has been tested shall be clearly marked on the equipment label or in the equipment documentation. External surge protection may be used to protect the equipment in harsher location/exposure categories. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

f. Synchronization Test

This test is applied to synchronous Generators, self-excited induction generators, and inverters capable of operating as voltage-source while connected to Distribution Provider's Distribution or Transmission System. The test is also applied to the resynchronization Function (transition from stand-alone to parallel operation) on equipment that provides such functionality. This test may not need to be performed on both the synchronization and re-synchronization functions if the manufacturers can verify to the satisfaction of the testing organization that monitoring and controls hardware and software are common to both functions. This test is not necessary for induction generators or current-source inverters. Instead, the ln-rush Current test Section L.3.d shall be applied to those generators.

This test shall demonstrate that at the moment of the paralleling-device closure, all three synchronization parameters in Table L.3 are within the stated limits. This test shall also demonstrate that if any of the parameters are outside of the limits stated in the table, the paralleling-device shall not close (IEEE 1547-5.1.2A). The test will start with only one of the three parameters: (1) voltage difference between Generating Facility and Distribution Provider's Distribution or Transmission System; (2) frequency difference; or (3) phase angle outside of the synchronization specification. Verify that the Generating Facility is brought within specification prior to synchronization. Repeat the test five times for each of the three parameters. For manual synchronization with synch check or manual control with auto synchronization, the test must verify that paralleling does not occur until the parameters are brought within specifications. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

3. TYPE TESTING (Cont'd.)

f. Synchronization Test (Cont'd.)

Table L.3
***Synchronization Parameter Limits* [1]**

Aggregate Rating of Generator Units (kVA)	Frequency Difference (Δf, Hz)	Voltage Difference (ΔV, %)	Phase Angle Difference (ΔΦ,°)
0-500	0.3	10	20
> 500-1,500	0.2	5	15
> 1,500-10,000	0.1	3	10

[1] – IEEE 1547-5.1.1B

g. Paralleling Device Withstand Test

The di-electric voltage withstand test specified in Section L.1 shall be performed on the paralleling device to ensure compliance with those requirements specified in Section H.1.c (IEEE 1547-5.1.3.3).

4. PRODUCTION TESTING

At a minimum, each interconnection system shall be subjected to Distribution Provider Voltage and Frequency Variation Test procedure described in UL1741 under Manufacturing and Production Tests, Section 68 and the Synchronization test specified in Section L.3.f. Interconnection systems with adjustable set points shall be tested at a single set of set points as specified by the manufacturer. This test may be performed in the factory or as part of a Commissioning Test (Section L.5). (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING

a. Commissioning Testing

Commissioning Testing, where required, will be performed on-site to verify protective settings and functionality. Upon initial Parallel Operation of a Generating Facility, or any time interface hardware or software is changed that may affect the functions listed below, a Commissioning Test must be performed. An individual qualified in testing protective equipment (professional engineer, factory–certified technician, or licensed electrician with experience in testing protective equipment) must perform Commissioning Testing in accordance with the manufacturer's recommended test procedure to verify the settings and requirements per this Rule.

Distribution Provider may require written Commissioning test procedure be submitted to Distribution Provider at least 10 working days prior to the performance of the Commissioning Test. Distribution Provider has the right to witness Commissioning Test. Distribution Provider may also require written certification by the installer describing which tests were performed and their results. Protective Functions to be tested during commissioning, particularly with respect to non-Certified equipment, may consist of the following:

(1) Over and under voltage

(2) Over and under frequency

(3) Anti-Islanding function (if applicable)

(4) Non-Exporting function (if applicable)

(5) Inability to energize dead line (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING (Cont'd.)

a. Commissioning Testing (Cont'd.)

(6) Time delay on restart after Distribution Provider source is stable

(7) Distribution Provider system fault detection (if used)

(8) Synchronizing controls (if applicable)

(9) Other Interconnection Protective Functions that may be required as part of the Generator Interconnection Agreement

Commissioning Test shall include visual inspections of the interconnection equipment and protective settings to confirm compliance with the interconnection requirements.

b. Review, Study, and Additional Commissioning Test Verification Costs

A Producer shall be responsible for the reasonably incurred costs of the reviews, studies and additional Commissioning Test verifications conducted pursuant to Section E of this Rule. If the initial Commissioning Test verification is not successful through no fault of Distribution Provider, Distribution Provider may impose upon Producer a cost based charge for subsequent Commissioning Test verifications. All Costs for additional Commissioning Test verifications shall be paid by Producer within thirty days of receipt of Distribution Provider's invoice. The invoice provided by Distribution Provider shall consist of the hourly rate multiplied by the hours incurred by Distribution Provider and will separately specify the amount of time spent on-site from that spent in roundtrip travel to the Commissioning Test site. Additional cost, if any, will be specified on the invoice. If the initial Commissioning Test verification is not successful through the fault of Distribution Provider, that visit will not be considered the initial Commissioning Test verification. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING (Cont'd.)

c. Other Checks and Tests

Other checks and tests that may need to be performed include:

(1) Verifying final Protective Function settings

(2) Trip test (L.5.g)

(3) In-service tests (L.5.h)

d. Certified Equipment

Generating Facilities qualifying for interconnection through the Fast Track process incorporate Certified Equipment that have, at a minimum, passed the Type Tests and Production Tests described in this Rule and are judged to have little or no potential impact on Distribution Provider's Distribution or Transmission System. For such Generating Facilities, it is necessary to perform only the following tests:

(1) Protective Function settings that have been changed after Production Testing will require field verification. Tests shall be performed using injected secondary frequencies, voltages and currents, applied waveforms, at a test connection using a Generator to simulate abnormal Distribution Provider voltage or frequency, or varying the set points to show that the device trips at the measured (actual) Distribution Provider voltage or frequency.

(2) The Non-Islanding function shall be checked by operating a load break disconnect switch to verify the Interconnection equipment ceases to energize Distribution Provider's Distribution or Transmission System and does not re-energize it for the required time delay after the switch is closed. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING (Cont'd.)

d. Certified Equipment (Cont'd.)

(3) The Non-Exporting function shall be checked using secondary injection techniques. This function may also be tested by adjusting the Generating Facility output and local loads to verify that the applicable Non-Exporting criteria (i.e., reverse power or underpower) are met.

The Supplemental Review or an Interconnection Study may impose additional components or additional testing.

e. Non-Certified Equipment

Non-certified Equipment shall be subjected to the appropriate tests described in Type Testing (Section L.3) as well as those described in Certified Equipment Commissioning Tests (Section L.5.d). With Distribution Provider's approval, these tests may be performed in the factory, in the field as part of commissioning, or a combination of both. Distribution Provider, at its discretion, may also approve a reduced set of tests for a particular Generating Facility or, for example, if it determines it has sufficient experience with the equipment.

f. Verification of Settings

At the completion of Commission testing, Producer shall confirm all devices are set to Distribution Provider-approved settings. Verification shall be documented in the Commissioning Test Certification. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

5. COMMISSIONING TESTING (Cont'd.)

g. Trip Tests

Interconnection Protective Functions and devices (e.g. reverse power relays) that have not previously been tested as part of the Interconnection Facilities with their associated interrupting devices (e.g. contactor or circuit breaker) shall be trip tested during commissioning. The trip test shall be adequate to prove that the associated interrupting devices open when the protective devices operate. Interlocking circuits between Protective Function devices or between interrupting devices shall be similarly tested unless they are part of a system that has been tested and approved during manufacturing.

h. In-service Tests

Interconnection Protective Functions and devices that have not previously been tested as part of the Interconnection Facilities with their associated instrument transformers or that are wired in the field shall be given an in-service test during commissioning. This test will verify proper wiring, polarity, CT/PT ratios, and proper operation of the measuring circuits. The in-service test shall be made with the power system energized and carrying a known level of current. A measurement shall be made of the magnitude and phase angle of each Alternating Current (AC) voltage and current connected to the protective device and the results compared to expected values. For protective devices with built-in Metering Functions that report current and voltage magnitudes and phase angles, or magnitudes of current, voltage, and real and reactive power, the metered values may be used for in-service testing. Otherwise, portable ammeters, voltmeters, and phase-angle meters shall be used. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

6. PERIODIC TESTING

Periodic Testing of Interconnection-related Protective Functions shall be performed as specified by the manufacturer, or at least every four years. All Periodic Tests prescribed by the manufacturer shall be performed. Producer shall maintain Periodic Test reports or a log for inspection by Distribution Provider. Periodic Testing conforming to Distribution Provider test intervals for the particular Line Section may be specified by Distribution Provider under special circumstances, such as high fire hazard areas. Batteries used to activate any Protective Function shall be checked and logged once per month for proper voltage. Once every four years, the battery must be either replaced or a discharge test performed.

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS

This Section describes the additional Type Tests necessary to qualify a device as Certified under this Rule. These Type Tests are not contained in Underwriters Laboratories UL 1741 Standard *Inverters, Converters and Controllers for Use in Independent Power Systems,* or other referenced standards.

a. Non-Exporting Test Procedures

The Non-Exporting test is intended to verify the operation of relays, controllers and inverters designed to limit the export of power and certify the equipment as meeting the requirements of Screen I, Options 1 and 2, of the review process. Tests are provided for discrete relay packages and for controllers and inverters with the intended Functions integrated. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

i) Discrete Reverse Power Relay Test

This version of the Non-Exporting test procedure is intended for discrete reverse power and underpower relay packages provided to meet the requirements of Options 1 and 2 of Screen I. It should be understood that in the reverse power application, the relay will provide a trip output with power flowing in the export (toward Distribution Provider's Distribution or Transmission System) direction.

Step 1: Power Flow Test at Minimum, Midpoint and Maximum Pickup Level Settings

Determine the corresponding secondary pickup current for the desired export power flow of 0.5 secondary watts (the minimum pickup setting, assumes 5 amp and 120V CT/PT secondary). Apply nominal voltage with minimum current setting at zero (0) degrees phase angle in the trip direction. Increase the current to pickup level. Observe the relay's (LCD or computer display) indication of power values. Note the indicated power level at which the relay trips. The power indication should be within 2% of the expected power. For relays with adjustable settings, repeat this test at the midpoint, and maximum settings. Repeat at phase angles of 90, 180 and 270 degrees and verify that the relay does not operate (measured watts will be zero or negative). (L)

(Continued)

ELECTRIC RULE NO. 21 Sheet 234
GENERATING FACILITY INTERCONNECTIONS

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

i) Discrete Reverse Power Relay Test (Cont'd.)

Step 2: Leading Power Factor Test

Apply rated voltage with a minimum pickup current setting (calculated value for system application) and apply a leading power factor load current in the non-trip direction (current lagging voltage by 135 degrees). Increase the current to relay rated current and verify that the relay does not operate. For relays with adjustable settings, this test should be repeated at the minimum, midpoint, and maximum settings.

Step 3: Minimum Power Factor Test

At nominal voltage and with the minimum pickup (or ranges) determined in Step 1, adjust the current phase angle to 84 or 276 degrees. Increase the current level to pickup (about 10 times higher than at 0 degrees) and verify that the relay operates. Repeat for phase angles of 90, 180 and 270 degrees and verify that the relay does not operate.

Step 4: Negative Sequence Voltage Test

Using the pickup settings determined in Step 1, apply rated relay voltage and current at 180 degrees from tripping direction, to simulate normal load conditions (for three-phase relays, use Ia at 180, Ib at 60 and Ic at 300 degrees). Remove phase-1 voltage and observe that the relay does not operate. Repeat for phases-2 and 3. (L)

(Continued)

ELECTRIC RULE NO. 21 Sheet 235
GENERATING FACILITY INTERCONNECTIONS

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

i) Discrete Reverse Power Relay Test (Cont'd.)

Step 5: Load Current Test

Using the pickup settings determined in Step 1, apply rated voltage and current at 180 degrees from the tripping direction, to simulate normal load conditions (use Ia at 180, Ib at 300 and Ic at 60 degrees). Observe that the relay does not operate.

Step 6: Unbalanced Fault Test

Using the pickup settings determined in Step 1, apply rated voltage and 2 times rated current, to simulate an unbalanced fault in the non-trip direction (use Va at 0 degrees, Vb and Vc at 180 degrees, Ia at 180 degrees, Ib at 0 degrees, and Ic at 180 degrees). Observe that the relay, especially single phase, does operate properly.

Step 7: Time Delay Settings Test

Apply Step 1 settings and set time delay to minimum setting. Adjust the current source to the appropriate level to determine operating time, and compare against calculated values. Verify that the timer stops when the relay trips. Repeat at midpoint and maximum delay settings. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

i) Discrete Reverse Power Relay Test (Cont'd.)

Step 8: Dielectric Test

Perform the test described in IEC 414 using 2 kV RMS for 1 minute.

Step 9: Surge Withstand Test

Perform the surge withstand test described in IEEE C37.90.1.1989 or the surge withstand capability test described in L.3.e.

ii) Discrete Underpower Relay Test

This version of the Non-Exporting test procedure is intended for discrete underpower relay packages and meets the requirements of Option 2 of Screen I. A trip output will be provided when import power (toward Producer's load) drops below the specified level.

Note: For an underpower relay, pickup is defined as the highest power level at which the relay indicates that the power is less than the set level. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

ii) Discrete Underpower Relay Test (Cont'd.)

Step 1: Power Flow Test at Minimum, Midpoint and Maximum Pickup Level Settings

Determine the corresponding secondary pickup current for the desired power flow pickup level of 5% of peak load minimum pickup setting. Apply rated voltage and current at 0 (zero) degrees phase angle in the direction of normal load current.

Decrease the current to pickup level. Observe the relay's (LCD or computer display) indication of power values. Note the indicated power level at which the relay trips. The power indication should be within 2% of the expected power. For relays with adjustable settings, repeat the test at the midpoint, and maximum settings. Repeat at phase angles of 90, 180 and 270 degrees and verify that the relay operates (measured watts will be zero or negative).

Step 2: Leading Power Factor Test

Using the pickup current setting determined in Step 1, apply rated voltage and rated leading power factor load current in the normal load direction (current leading voltage by 45 degrees). Decrease the current to 145% of the pickup level determined in Step 1 and verify that the relay does not operate. For relays with adjustable settings, repeat the test at the minimum, midpoint, and maximum settings. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

ii) Discrete Underpower Relay Test (Cont'd.)

Step 3: Minimum Power Factor Test

At nominal voltage and with the minimum pickup (or ranges) determined in Step 1, adjust the current phase angle to 84 or 276 degrees. Decrease the current level to pickup (about 10% of the value at 0 degrees) and verify that the relay operates. Repeat for phase angles 90, 180 and 270 degrees and verify that the relay operates for any current less than rated current.

Step 4: Negative Sequence Voltage Test

Using the pickup settings determined in Step 1, apply rated relay voltage and 25% of rated current in the normal load direction, to simulate light load conditions. Remove phase 1 voltage and observe that the relay does not operate. Repeat for Phases-2 and 3.

Step 5: Unbalanced Fault Test

Using the pickup settings determined in Step 1, apply rated voltage and two times rated current, to simulate an unbalanced fault in the normal load direction (use Va at 0 degrees, Vb and Vc at 180 degrees, Ia at 0 degrees, Ib at 180 degrees, and Ic at 0 degrees). Observe that the relay (especially single-phase types) operates properly. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

ii) Discrete Underpower Relay Test (Cont'd.)

Step 6: Time Delay Settings Test

Apply Step 1 settings and set time delay to minimum setting. Adjust the current source to the appropriate level to determine operating time, and compare against calculated values. Verify that the timer stops when the relay trips. Repeat at midpoint and maximum delay settings.

Step 7: Dielectric Test

Perform the test described in IEC 414 using 2 kV RMS for 1 minute.

Step 8: Surge Withstand Test

Perform the surge withstand test described in IEEE C37.90.1.1989 or the surge withstand test described in Section L.3.e. (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

a. Non-Exporting Test Procedures (Cont'd.)

iii) Tests for Inverters and Controllers with Integrated Functions

Inverters and controllers designed to provide reverse or underpower functions shall be tested to certify the intended operation of this function. Two methods are acceptable:

Method 1: If the inverter or controller utilizes external current/voltage measurement to determine the reverse or underpower condition, then the inverter or controller shall be functionally tested by application of appropriate secondary currents and potentials as described in the Discrete Reverse Power Relay Test, Section L.7.a.i of this Rule.

Method 2: If external secondary current or voltage signals are not used, then unit-specific tests must be conducted to verify that power cannot be exported across the PCC for a period exceeding two seconds. These may be factory tests, if the measurement and control points are integral to the unit, or they may be performed in the field.

iv) Tests for Inadvertent Export Inverters

Test requirements for certified inverters with integrated functions for Inadvertent Export shall verify the performance requirements specified in Section Mm of this Rule.

b. In-rush Current Test Procedures

This test will determine the maximum In-rush Current drawn by the Generator.

i) Locked-Rotor Method

Use the test procedure defined in NEMA MG-1 (manufacturer's data is acceptable if available). (L)

(Continued)

L. CERTIFICATION AND TESTING CRITERIA (Cont'd.) (L)

7. TYPE TESTING PROCEDURES NOT DEFINED IN OTHER STANDARDS (Cont'd.)

b. In-rush Current Test Procedures (Cont'd.)

ii) Start-up Method

Install and setup the Generating Facility equipment as specified by the manufacturer. Using a calibrated oscilloscope or data acquisition equipment with appropriate speed and accuracy, measure the current draw at the Point of Interconnection as the Generating Facility starts up and parallels with Distribution Provider's Distribution or Transmission System. Startup shall follow the normal, manufacturer-specified procedure. Sufficient time and current resolution and accuracy shall be used to capture the maximum current draw within 5%. In-rush Current is defined as the maximum current draw from Distribution Provider during the startup process, using a 10-cycle moving average. During the test, Distribution Provider source, real or simulated, must be capable of maintaining voltage within +/- 5% of rated at the connection to the unit under test. Repeat this test five times. Report the highest 10-cycle current as the In-rush Current. A graphical representation of the time-current characteristic along with the certified In-rush Current must be included in the test report and made available to Distribution Provider. (L)

(Continued)

M. INADVERTENT EXPORT (L)

Under certain operating conditions, an Applicant may choose to completely offset their facility load by installing generation systems which are optimally sized to meet their peak demand with load following functionality on the Generator controls to ensure conditional export of electrical power from the Generating Facility to Distribution Provider's Distribution or Transmission System. In situations where the loading changes rapidly and/or the Generator cannot ramp down quickly enough, the Generating Facility may need to export small amounts of power for limited duration. The event of exporting uncompensated power for a short time is referred to as Inadvertent Export.

The following are the minimum requirements for Inadvertent Export systems. Other factors relevant to the interconnection study process (e.g. 15% screen results, short circuit current ratio, etc.) may necessitate additional technical requirements (e.g. reclose block, transfer trip, ground bank, etc.) that are not explicitly noted here. Inadvertent Export may not be available for interconnections to Networked Secondary Systems.

1. For Inadvertent Export interconnection requests, additional Protective Functions and equipment to detect Distribution or Transmission System faults (per Distribution Provider's standard practices) may be required over and above the basic Protective Functions and equipment associated with the four options in the Export Screen. Protective Functions may include, but are not limited to, directional overcurrent/voltage-restraint overcurrent Protective Functions for line-to-line fault detection and overcurrent/overvoltage Protective Functions for line-to-ground detection. The addition of a ground bank or ground detector may also be necessary. (L)

(Continued)

M. INADVERTENT EXPORT (Cont'd.) (L)

2. The effect on equipment ratings can be mitigated by limiting the amount of inadvertent export allowed. To a large degree, Voltage Regulation may be similarly handled. The amount of Inadvertent Export is dependent on specific Distribution Provider requirements and should be limited to the lesser of the following values:

   a. 50% of the Generating Facility Capacity, or

   b. 10% of the continuous conductor rating in watts at 0.9 power factor for the lowest rated feeder conductor upstream of the GF (i.e. 200kW @ 12kV), or

   c. 110% of the largest load block in the facility, or

   d. 500kW or some other maximum level indicated by Distribution Provider

3. In addition to the limits above, the following are required:

   a. A reverse power Protective Function will be provided to trip the connected Generator(s) within two seconds if the proposed amount of Inadvertent Export is exceeded.

   b. The frequency of Inadvertent Export occurrences should be less than two occurrences per 24-hour period.

   c. A separate reverse power or underpower Protective Function will be required (in addition to the reverse power Protective Function described in 3a. above) to trip the connected Generator(s) if the duration of reverse power or underpower (i.e. ANY export) exceeds 60 seconds. (L)

(Continued)

Mm. INADVERTENT EXPORT FOR INTERCONNECTION REQUESTS UTILIZING UL-1741 CERTIFIED OR SA LISTED GRID SUPPORT (NON-ISLANDING) INVERTERS (Cont'd.) (L)

3) Applicability of Engineering Review Screens.

Inadvertent Export systems that meet the requirements described herein are processed under Initial Review Screens A through J as described in Section H. If these systems fail Screen J, they then bypass Screens K and L and are processed under Screens M and M1 as described below.

Screen M: Is the aggregate Generating Facility capacity on the Line Section less than 15% of Line Section peak load for all line sections bound by automatic sectionalizing devices?

- If Yes (pass), Initial Review is complete.
- If No (fail), continue to Screen M1.

Screen M1: Is the aggregate of all distributed energy resources (DER) causing reverse power flow (1) at a line section with a voltage regulator device(s) or (2) at a protection device, including the circuit breaker / field recloser?*,**

- If No (pass), existing DER does not cause reverse power flow at (1) or (2) and Initial Review is complete.
- If Yes (fail), existing DER causes reverse power flow at (1) or (2); fail Initial Review and Supplemental Review is required.

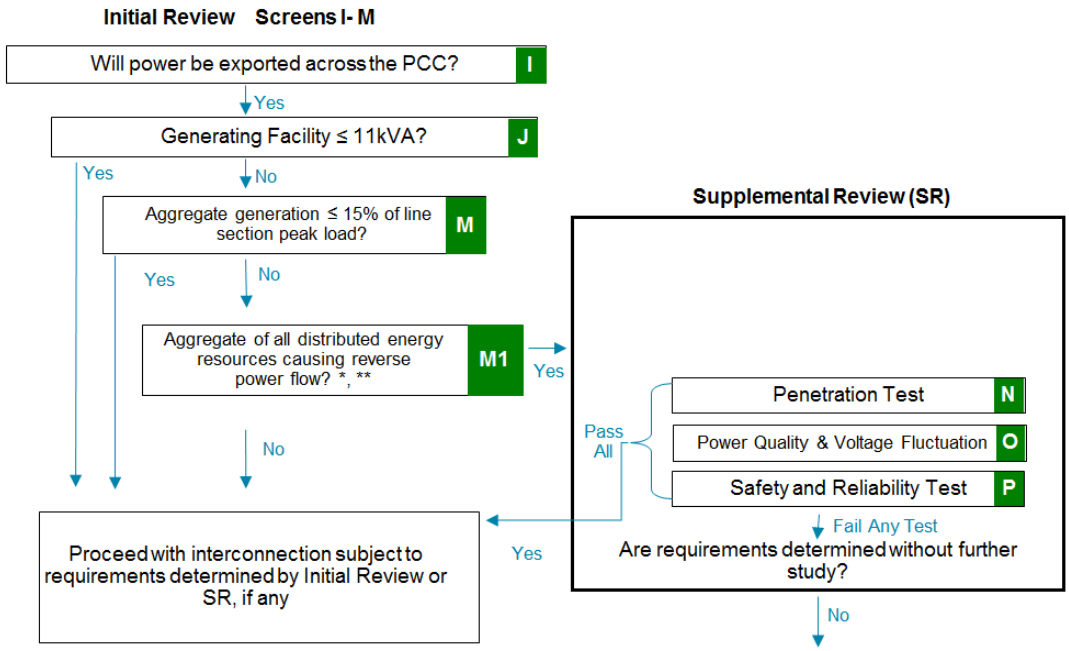
* For the purposes of applying Screen M1 herein, Distribution Provider shall utilize a zero coincidence factor when considering the impact of other Inadvertent Export systems that meet the requirements of Section Mm (i.e., projects that qualify for Option 6 under Section G.1.i) such that those Inadvertent Export systems do not impact Screen M1's aggregate analysis determination for the individual Inadvertent Export project being evaluated.

** The presence of existing non-certified DER on the line section may require additional review to ensure safe and reliable grid operation. (L)

(Continued)

Mm. INADVERTENT EXPORT FOR INTERCONNECTION REQUESTS UTILIZING UL-1741 CERTIFIED OR SA LISTED GRID SUPPORT (NON-ISLANDING) INVERTERS (Cont'd.) (L)

3) Applicability of Engineering Review Screens. (Cont'd.)



* For the purposes of applying Screen M1 herein, Distribution Provider shall utilize a zero coincidence factor when considering the impact of other Inadvertent Export systems that meet with the requirements of Section Mm (i.e., projects that qualify for Option 6 under Section G.1.i) such that those Inadvertent Export systems do not impact Screen M1's aggregate analysis determination for the individual analysis determination for the individual Inadvertent Export project being evaluated.

** The presence of existing non-certified DER on the line section may require additional review to ensure safe and reliable grid operation. (L)

(Continued)

N. EXPEDITED INTERCONNECTION PROCESS FOR NON-EXPORT ENERGY STORAGE GENERATING FACILITIES (L)

Applicants with Interconnection Requests for Non-Export Energy Storage Generating Facilities who meet the requirements outlined below are eligible for expedited interconnection in accordance with the Fast Track Process technical review requirements of Section F.2.[1]

1. Eligibility Requirements.

   Applicants seeking to interconnect a Generating Facility under the provisions of this Section N must meet the following eligibility requirements.

   a. Applicant must electronically submit a completed Interconnection Request, including completing all application fields and submitting all supporting documentation necessary to facilitate the expedited review as required by Distribution Provider. Such documentation may include, but is not limited to, single line diagrams with specific details, manufacturer data sheets for proposed equipment, description of control systems, validation of the right to do business in the state, etc. Distribution Provider shall clearly communicate these requirements as part of the application process. Applicant shall select this process option in the Interconnection Request.

   b. Applicant's Generating Facility must meet the requirements outlined in Section N.2 below.

   c. Applicant's Interconnection Request must be eligible for and select the Fast Track Process.

   d. Applicant's Interconnection Request must pass Fast Track Initial Review and not require any Interconnection Facilities, Distribution Upgrades or Network Upgrades to remain eligible under this Section. As such, Interconnection Requests that select the Cost Envelope Option are not eligible.

   e. Applicants selecting this section shall use the corresponding interconnection agreement type provided for eligible Generating Facilities.

[1] In accordance with Advice 4941-E-A, the provisions provided for in Section N are being implemented under a pilot approach with a July 1, 2017 through June 30, 2018 reporting period. As such, the provisions may be continued, modified and/or withdrawn as determined by the Commission (L)

(Continued)

N. EXPEDITED INTERCONNECTION PROCESS FOR NON-EXPORT ENERGY STORAGE GENERATING FACILITIES (Cont'd.) (L)

2. Generating Facility Eligibility Criteria.

An Applicant's Generating Facility must meet and adhere to the following criteria.

a. The Generating Facility must be comprised solely of the following specific categories of generation technology: Non-Exporting battery storage.

b. The Generating Facility must have an aggregate maximum inverter nameplate rating of no greater than 500 kW. There is no limitation on an energy storage device's kWh capacity rating.

c. The Generating Facility must be located behind an existing single retail meter and Point of Common Coupling with a single, clearly marked and accessible disconnect. No other Generators, other than isolated back-up Generators, may be at the same Point of Interconnection or Point of Common Coupling.

d. The Generating Facility must utilize Option 3 or Option 4 to meet the non-export protection requirements of Screen I in Section G.1.i.

e. The Generating Facility must have a single or coordinated control system for all charging functions if utilizing multiple inverters. The control system must also ensure that there is no increase in the Interconnection Customer's existing peak load demand.

f. The Generating Facility must utilize only inverter-based, UL 1741 and UL 1741 SA-listed equipment. Additionally, all installed equipment must meet Distribution Provider's current electric service requirements with no violations or variances. (L)

(Continued)

ELECTRIC RULE NO. 21 Sheet 248
GENERATING FACILITY INTERCONNECTIONS

(L)

Appendix A Forms Associated with Rule 21 Generating Facility Interconnections			
Form Number	Title	Associated Tariffs	Use Guidance
Pre-Application Request			
79-1181	Rule 21 Pre-Application Report Request	Rule 21	For Generator Developer to request basic info about local distribution circuit
Study Agreement			
79-1162	Rule 21 Detailed Study Agreement	Rule 21	Independent Study and Distribution Group Study Process Study Agreement
NEM and Non-Export Interconnection Forms			
79-978	Interconnection Agreement for Net Energy Metering of Solar or Wind Electric Generating Facilities of 1,000 kW or Less, Other Than Facilities of 30 kW or Less	NEM, Rule 21	Solar and/or Wind > 30 kW and ≤ 1 MW expanded NEM used with Form 79-1174-02
79-978-02	Interconnection Agreement for Net Energy Metering (NEM2) of Solar or Wind Electric Generating Facilities of 1,000 Kilowatts or Less, Other than Facilities of 30 Kilowatts or Less	NEM2, Rule 21	Solar and/or Wind > 30 kW and ≤ 1 MW expanded NEM2 used with Form 79-1174-02
79-997	Interconnection Agreement for Net Energy Metering of Biogas Digester Generating Facilities	NEM, Rule 21	NEMBIO (Closed to new applicants), NEMBIOA Interconnection Agreement used with Form 79-1174
79-1010	Interconnection Agreement for Net Energy Metering of Fuel Cell Generating Facilities	NEM, Rule 21	NEMFC Interconnection Agreement used with Form 79-1174
79-1069	Generating facility Interconnection Agreement (Multiple Tariff)	NEM, Rule 21	NEMMT Interconnection Agreement used with Form 79-1174
79-1069-02	Generating Facility Interconnection Agreement (Multiple Tariff NEM2MT)	NEM2, Rule 21	NEM2MT Interconnection Agreement used with Form 79-1174-02
79-1109 ***	Virtual Net Energy Metering Application and Interconnection Agreement For The Building Owner of Multifamily Affordable Housing With A Solar Generating Facility of 1 Megawatt or Less	NEM, Rule 21	NEMV Interconnection Agreement used with Form 79-974

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Appendix A (Cont'd.) Forms Associated with Rule 21 Generating Facility Interconnections			
Form Number	Title	Associated Tariffs	Use Guidance
NEM and Non-Export Interconnection Forms (Cont'd.)			
79-1109-02***	NEM2VMSH Virtual Net Energy Metering Application and Interconnection Agreement for the Building Owner of Multifamily Affordable Housing with a Solar Generating Facility of 1 Megawatt or Less	NEM2VMSH, Rule 21	NEM2VMSH Interconnection Agreement used with Form 79-1174-02
79-1151A	Net Energy Metering Interconnection for Solar And/or Wind Electric Generating Facilities Of 30 Kilowatts Or Less Agreement and Customer Authorization	NEM, Rule 21	NEMS Interconnection Agreement be used with 79-1151B Application
79-1151A-02	Agreement And Customer Authorization - Net Energy Metering (NEM2) Internconnection For Solar And/Or Wind Electric Generating Facilities Of 30 Kilowatts Or Less	NEM2, Rule 21	NEM2S Application to be used with 79-1151A Interconnection Agreement
79-1151B	Net Energy Metering Interconnection For Solar And/or Wind Electric Generating Facilities Of 30 Kilowatts Or Less Application	NEM, Rule 21	NEMS Application to be used with 79-1151A Interconnection Agreement
79-1151B-02	Application - Net Energy Metering (NEM2) Interconnection For Solar And/Or Wind Electric Generating Facilities Of 30 Kilowatts Or Less	NEM2, Rule 21	NEM2S Application to be used with 79-1151A-02 Interconnection Agreement
79-1124 ***	Eligible Low Income Development Virtual Net Energy Metering Application and Interconnection Agreement for Multifamily Affordable Housing with Solar Generation Totaling 1 Megawatt or Less	NEMVMASH, Rule 21	NEMVMASH Interconnection Agreement
79-1124-02***	Eligible Low Income Development Virtual Net Energy Metering (NEM2VMSH) Application and Interconnection Agreement for Multifamily Affordable Housing with Solar Generation Totaling 1 Megawatt or Less	NEM2VMSH, Rule 21	NEM2VMSH Interconnection Agreement
79-1131 ***	NEMV Application and Interconnection Agreement for a Solar (PV) or Wind Generating Facility of 1 MW or Less *Serving Multiple Tenants Served at a Single Property Delivery Point*	NEM, Rule 21	NEMV Interconnection Agreement
79-1131-02***	NEM2V Application and Interconnection Agreement for a Solar (PV) or Wind Generating Facility of 1 MW or Less *Serving Multiple Tenants Served at a Single Property Delivery Point*	NEM2V, Rule 21	NEM2V Interconnection Agreement

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Appendix A (Cont'd.) Forms Associated with Rule 21 Generating Facility Interconnections			
Form Number	Title	Associated Tariffs	Use Guidance
NEM and Non-Export Interconnection Forms (Cont'd.)			
79-1137	Interconnection Agreement for Net Energy Metering for a Renewable Electrical Generation Facility of 1,000 kW or Less, Except Solar or Wind (SB 489)	NEM, Rule 21	NEMV, NEMEXP, NEMEXPM Interconnection Agreement typically used with Forms 79-974 and 79-1142 Applications
79-1137-02	Interconnection Agreement for Net Energy Metering (NEM2/NEM2V) for a Renewable Electricity Generation Facility of 1,000 Kilowatts or Less, Except Solar or Wind	NEM2, NEM2V, Rule 21	NEM2V, NEM2EXP, NEM2EXPM Interconnection Agreement typically used with Forms 79-1174-02
79-1142 ***	NEMV Interconnection Application for a Renewable Electrical Generation Facility of 1 Megawatt or Less	NEM, Rule 21	Used with Form 79-1137 (L)
79-973	Generating Facility Interconnection Agreement For Non-Export Generating Facilities (Rule 21 Interconnection Agreement)	Rule 21	Interconnection Agreement used for RESBCT and non-NEM generation with Application 79-974 and 79-1112
79-992	Customer Generation Agreement (Third party Generator on Premises, Non-Exporting)	Rule 21	Used with Forms 79-1174
79-1070	Export Addendum to Generating Facility Interconnection Agreement for Non-Export Generating Facilities (Form 79-973) Sized 2 Megawatts or Less	Rule 21	Export addendum used with Form 79-973
79-1136	PG&E Interconnection Agreement For an Existing Small Generating Facility Interconnecting to the Distribution System under Rule 21	Rule 21	Used for existing QFs with Form 79-974 (L)
79-1192	Interconnection Agreement for Non-Export Storage Generating Facilities 500KW or Less	Rule 21	Used for expedited interconnection of non-export energy storage, pursuant to Rule 21 Section N, PG&E AL 4941-E & E-A and D.16-06-052, & Attachment C, Section II.1
Other NEM and Non-Export Forms			
79-1125	NEM / NEMV / NEMVMASH Inspection Report	NEM, Rule 21	

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ELECTRIC RULE NO. 21 Sheet 251
GENERATING FACILITY INTERCONNECTIONS

Appendix A (Cont'd.) Forms Associated with Rule 21 Generating Facility Interconnections			
Form Number	Title	Associated Tariffs	Use Guidance
Other NEM and Non-Export Forms (Cont'd.)			
79-1130	Request to Opt-out of / Opt-in to Compensation for Surplus Electricity	NEM	AB 920- Opt not to receive compensation for net annual excess energy
79-1153 ****	NEM Load Aggregation Appendix	NEM, Rule 21	Use as an Appendix with Form 79-1151A, 79-978, 79-1137 or 79-1069
79-1153-02****	NEM2A Load Aggregation Appendix	NEM2, Rule 21	Use as an Appendix with Form 79-1151A-02, 79-978-02, 79-1137-02 or 79-1069-02
79-1155	Schedules NEM, NEMV, NEMVMASH, Net Surplus Electricity (NSE) Renewable Energy Credits Compensation	NEM, Rule 21	
79-1155-02	Schedules NEM2, NEM2V, NEM2VMSH, Net Surplus Electricity (NSE) Renewable Energy Credits Compensation	NEM2 NEM2V NEM2VMSH, Rule 21	
79-1174	Rule 21 Generator Interconnection Application	NEM (NEMEXP, NEMMT and NEMA), NEMFC, NEMV, NEMVMASH, RES-BCT, Rule 21	Rule 21 customer interconnection application form for expanded net-energy metered (all NEM > 30 kw and all non-Solar/Wind NEM), NEMFC, NEMV, NEMVMASH, RES-BCT, and non-export and limited export Rule 21 generation. (Standard NEM for solar and/or wind ≤ 30 kw will continue to use the 79-1151B application.)
79-1174-02	Rule 21 Generator Interconnection Application	NEM2 (NEM2EXP, NEM2MT and NEM2A), NEMFC, NEM2V, NEM2VMSH, RES-BCT, Rule 21	Rule 21 customer interconnection application form for expanded net-energy metered (all NEM2 > 30 kw and all non-Solar/Wind NEM), NEMFC, NEM2V, NEM2VMSH, RES-BCT, and non-export and limited export Rule 21 generation. (Standard NEM for solar and/or wind ≤ 30 kw will continue to use the 79-1151B application.)

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ELECTRIC RULE NO. 21 Sheet 252
GENERATING FACILITY INTERCONNECTIONS

Export for Sale Interconnection Forms			
79-1144	Rule 21 Generator Interconnection Agreement for Exporting Generating Facilities Interconnecting Under the Fast Track Process	Rule 21	To be used with the GIA For Exporting GFs Interconnecting Under The Detailed Study Process
79-1144-02	Rule 21 Generator Interconnection Agreement for New Energy Metering (NEM-2) Generating Facilities Greater than 1,000 Kilowatts Interconnecting Under the Fast Track Process	NEM2, Rule 21	To be used with the GIA For NEM-2s > 1MW Interconnecting Under The Fast Track Process
79-1145	Rule 21 Exporting Generator Interconnection Request	Rule 21	Preferred online application: http://www.pge.com/mybusiness/ customerservice/nonpgeutility/ generateownpower/egi/
79-1161	Rule 21 Generator Interconnection Agreement (GIA) For Exporting Generating Facilities Interconnecting Under The Detailed Study Process	Rule 21	Interconnection Agreement to be used for Interconnecting Under The Independent Study, Distribution Group Study, or Transmission Cluster Study Process
79-1161-02	Rule 21 Generator Interconnection Agreement (GIA) for Net Energy Metering (NEM2) Generating Facilities Greater than 1,000 Kilowatts Interconnecting Under the Independent Study, Distribution Study, or Transmission Cluster Process	NEM2	Interconnection Agreement to be used for NEM-2s>1MW Interconnecting Under The Independent Study, Distribution Group Study, or Transmission Cluster Study Process
Other Agreements			
79-280	Agreement for Installation of Allocation of Special Facilities for Parallel Operation of Non-Utility-Owned Generation and/or Electrical Standby Service (Electric Rules 2 and 21)	Rule 21	Special Facilities Agreement to be used with Form 79-702
79-702	Appendix A: Detail of Special Facilities Charges to be used in concert with form 79-280	Rule 21	Used with Form 79-280

(L)

*** The application section of these forms is replaced by 79-1174.
**** For NEMA expanded customers, use the online 79-1174 form.

(L)

(Continued)

APPENDIX B (L)

Unit Cost Guide

Distribution Provider shall publish a Unit Cost Guide for facilities generally required to interconnect generation in Distribution Provider's Distribution System. The Unit Cost Guide shall not be binding for actual facility costs and is provided only for additional cost transparency, developer reference, and Distribution Provider's reference when preparing the cost estimate provided in any applicable studies. The Unit Cost Guide shall not replace the estimated cost provided by Distribution Provider in an Interconnection Study or an initial or supplemental review under the Fast Track Process.

The Unit Cost Guide shall include the anticipated cost of procuring and installing Interconnection Facilities and Distribution Upgrades generally utilized by the Applicant. An annual adjustment shall be performed within the Unit Cost Guide for five (5) years to account for the anticipated timing of procurement to accommodate a potential range of Commercial Operation Dates.

The Unit Cost Guide shall be updated annually in accordance with the process set forth in D.16-06-052. (L)

(Continued)

ELECTRIC TABLE OF CONTENTS Sheet 1

TABLE OF CONTENTS

(Continued)

ELECTRIC TABLE OF CONTENTS Sheet 20

(Continued)

ELECTRIC TABLE OF CONTENTS Sheet 20

(Continued)

Advice 5129-E
August 18, 2017

Attachment 2

G. ENGINEERING REVIEW DETAILS (Cont'd.)

3. DETAILED STUDY SCREENS (Cont'd.)

a. Screen Q: Is the Interconnection Request electrically Independent of the Transmission System? (Cont'd.)

Distribution Provider will coordinate with the CAISO if necessary to conduct the Determination of Electrical Independence for the CAISO Controlled Grid as set forth in the applicable CAISO Tariff in effect at the time the Electrical Independence Test (EIT) begins.~~Section 4.2 of Appendix Y to the CAISO Tariff.~~ The results of the incremental power flow, aggregate power flow, and short-circuit current contribution tests set out in the applicable CAISO Tariff in effect at the time the EIT begins ~~Section 4.2 of Appendix Y to the CAISO Tariff~~ will determine whether the Interconnection Request is electrically independent from the CAISO Controlled Grid.

- If Yes (pass), continue to Screen R.
- If No (fail), proceed to Section F.3.d.

Note 1: NEM Generating Facilities with net export less than or equal to 500 kW that may flow across the Point of Common Coupling will not be studied in the Transmission Cluster Study Process, but may be studied under the Independent Study Process.

Significance: Generating Facilities that are electrically interdependent with the Transmission System must be studied with other interconnection requests that have Transmission System interdependencies. It is possible to pass this Screen Q (i.e., be found to have no electrical interdependencies with earlier-queued Distribution System and/or Transmission System interconnection requests as set out above), be studied under the Independent Study Process, and still trigger a Reliability Network Upgrade.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

1. GENERAL INTERCONNECTION AND PROTECTIVE FUNCTION REQUIREMENTS (Cont'd.)

a. Protective Functions Required (Cont'd.)

(ii) A voltage and frequency sensing and time-delay function to prevent the Smart Inverter from energizing a de-energized Distribution or Transmission System circuit and to prevent the Smart Inverter from reconnecting with Distribution Provider's Distribution or Transmission System unless Distribution Provider's Distribution System service voltage and frequency is within the ANSI C84.1-1995 Table 1 Range B voltage Range of 106 volts to 127 volts (on a 120 volt basis), inclusive, and a frequency range of 58.5 ~~59.3~~ Hz to 60.5 Hz, inclusive, and are stable for at least 15 seconds; and

(iii) A function to prevent the Smart Inverter from contributing to the formation of an Unintended Island, and cease to energize Distribution Provider's Distribution System within two seconds of the formation of an Unintended Island.

The Smart Inverter shall cease to energize Distribution Provider's Distribution System for faults on Distribution Provider's Distribution System circuit to which it is connected (IEEE 1547-4.2.1). The Smart Inverter shall cease to energize Distribution Provider's Distribution circuit prior to re-closure by Distribution Provider's Distribution System equipment (IEEE 1547-4.2.2).

b. Momentary Paralleling Generating Facilities

With Distribution Provider's approval, the transfer switch or scheme used to transfer Producer's loads from Distribution Provider's Distribution or Transmission System to Producer's Generating Facility may be used in lieu of the Protective Functions required for Parallel Operation.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

g. Harmonics (Cont'd.)

Table Hh.3

Maximum harmonic current distortion in percent of current (I) [1,2]

Individual harmonic order, h (odd harmonics) [3]	h<11	11≤ h<17	17≤ h<23	23≤ h<35	35≤ h	Total demand distortion
Max Distortion (%)	4.0	2.0	1.5	0.6	0.3	5.0

[1] – IEEE1547-4.3.3

[2] – I = the greater of the maximum Host Load current average demand over 15 or 30 minutes without the GF, or the GF rated current capacity (transformed to the PCC when a transformer exists between the GF and the PCC).

[3] – Even harmonics are limited to 25% of the odd harmonic limits above.

h. Direct Current Injection

Smart Inverter should not inject direct current greater than 0.5% of rated output current into Distribution Provider's Distribution or Transmission System.

i. Fixed Power Factor

Producer shall provide adequate reactive power compensation on site to maintain the Smart Inverter power factor near unity at rated output or a Distribution Provider specified power factor in accordance with the following requirements:

(i) Default Power Factor setting: Absorbing reactive power at 0.95 lagging power factor.

(ii) Aggregate generating facility is greater than 15 kW: 1.0 +/- 0.15 (0.85 Lagging to 0.85 Leading) down to 20% rated power based on available reactive power.

(Continued)

ELECTRIC RULE NO. 21 Sheet 192
GENERATING FACILITY INTERCONNECTIONS

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

i. Fixed Power Factor (Cont'd.)

(iii) Aggregate generating facility is less than or equal to 15 kW: 1.0 +/- 0.10 (0.90 Lagging to 0.90 Leading) down to 20% rated power based on available reactive power.

j. Dynamic Volt/VAR Operations

The Smart Inverter shall be capable of operating dynamically within a power factor range of +/- 0.85 PF for larger (>15 kW) systems, down to 20% of rated active power, and +/- 0.9 PF for smaller systems (≤15 kW), down to 20% of rated active power, based on available reactive power. This dynamic Volt/VAR capability shall be able to be activated or deactivated in accordance with Distribution Provider requirements.

The Distribution Provider may permit or require the Smart Inverter systems to operate in larger power factor ranges, including in 4-quadrant operations for storage systems with the implementation of additional anti-islanding protection as determined by the Distribution Provider.

The Smart Inverter shall be capable of providing dynamic reactive power compensation (dynamic Volt/VAR operation) within the following constraints:

(i) The Smart Inverter shall be able to consume reactive power in response to an increase in line voltage, and produce reactive power in response to a decrease in line voltage.

(ii) The reactive power provided shall be based on available reactive power, but the maximum reactive power provided to the system shall be as directed by the Distribution Provider.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

k. Ramp Rate Requirements

The Smart Inverter is required to have the following ramp controls for at least the following four conditions. These functions can be established by multiple control functions or by one general ramp rate control function. Ramp rates are contingent upon sufficient energy available from the Smart Inverter.

- Normal ramp-up rate: For transitions between energy output levels over the normal course of operation. The default value is 100% of maximum current output per second with a range of adjustment between 1% to 100%, with specific settings as mutually agreed by the Distributor Provider and the Producer.

- Connect/Reconnect Ramp-up rate: Upon starting to inject power into the grid, following a period of inactivity or a disconnection, the inverter shall be able to control its rate of increase of power from 1 to 100% maximum current per second. The default value is 2% of maximum current output per second, with specific settings as mutually agreed upon by the Distribution Provider and the Producer.

l. ~~Recommended~~ Frequency-Watt Requirements~~Settings~~

This requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after 12 months from the date the Phase 3 Smart Inverter Advanced Function Advice Letter (AL 5129- E) was made effective by the Commission. Smart Inverters shall reduce their real power production as a function of system frequency, in accordance with the following: ~~The Smart Inverters, which have this optional function available, mayenable this function with the following recommended settings. SmartInverters with different frequency-watt capabilities may be enabledwith Distribution Provider concurrence.~~

- When system frequency exceeds 60.1Hz, the active power output produced by the Smart Inverter shall be reduced by 50% of real power nameplate rating per hertz (5% of real power nameplate rating reduction per 0.1 hertz)

(Continued)

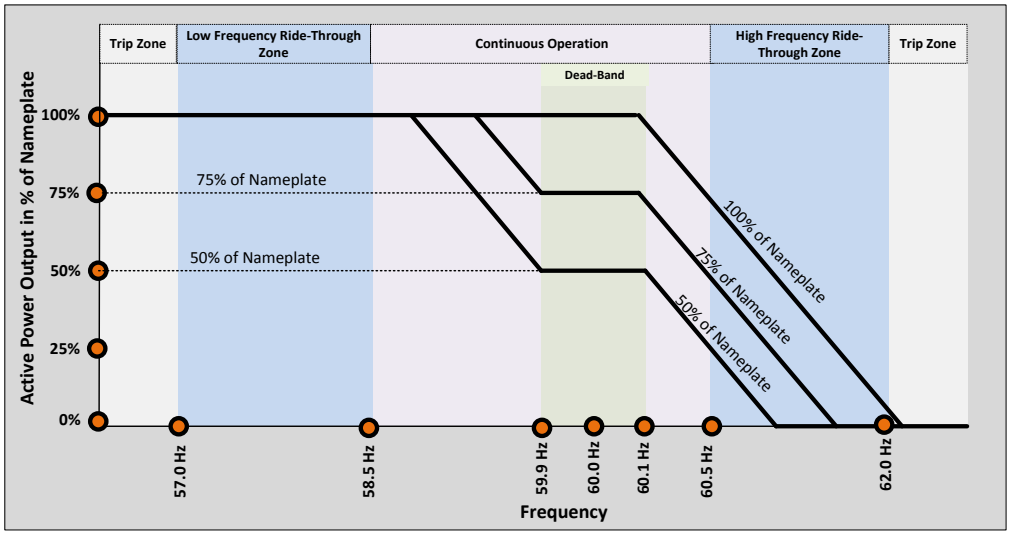
Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

l. ~~Recommended~~ Frequency-Watt Requirements~~Settings~~ (Cont'd.)

- When system frequency moves under 59.9Hz, the active power output produced by the Smart Inverter shall be increased by 50% of real power nameplate rating per hertz (5% of real power nameplate rating increase per 0.1 hertz) when inverter is capable of increasing real power production.
- The default dead-band should be +/- 0.1 Hz from 60 hertz (59.9Hz to 60.1Hz). When the system frequency is in range of 59.9Hz and 60.1Hz, the Smart Inverter is not required to increase or decrease power as a function of system frequency.
- Open loop response time for Frequency –Watt shall be 5 seconds.
- Figure Hh-2 illustrated this requirement for three levels of output power. Figure Hh-2 is for illustration purposes only

Figure Hh-2: Active Power as a Function of System Frequency



(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

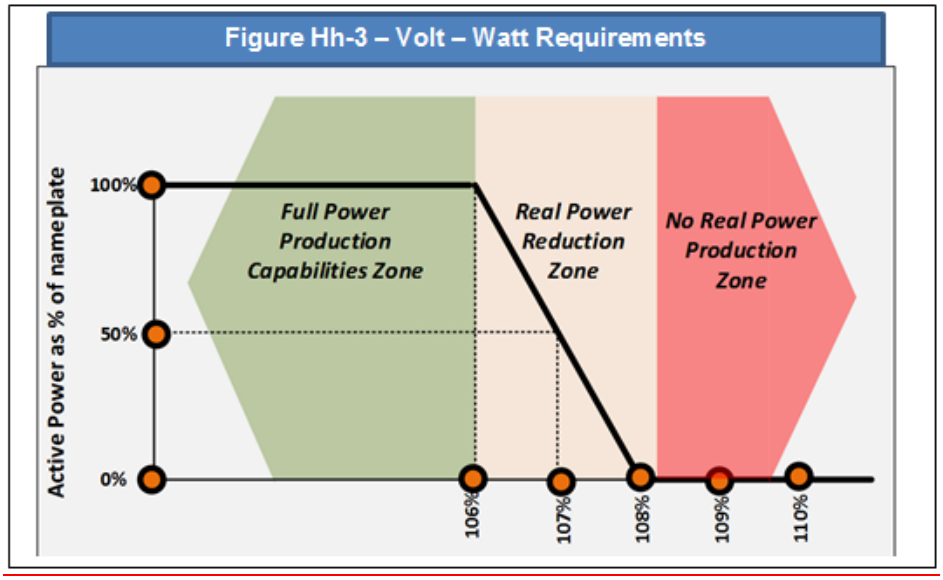
2. PREVENTION OF INTERFERENCE (Cont'd.)

m. This requirement will become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after 12 months from the date the Phase 3 Smart Inverter Advanced Function Advice Letter (AL 5129-E) was made effective by the Commission. Smart Inverters shall reduce their real power production as a function of measured voltage at the inverter terminals or at the Generating Facility Point of Common Coupling (PCC) in accordance with the following:

- When the measured voltage is greater than 106% of nominal voltage (for example: 127.2 volts on a 120 volts nominal), the Smart Inverter shall be reduced at a rate of 50% of real power nameplate rating per one percent of nominal voltage. Figure Hh-3 -- Volt-Watt Requirements illustrates the required rate of reduction.

- When the measured voltage is greater than 108% of nominal voltage (Example: 129.6 volts on a 120 volts nominal), the active power output produced by the Smart Inverter shall be reduced to 0 watts

Figure Hh-3 – Volt – Watt Requirements



(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

n. Set Active Power Level Mode Function

The utilization of this function is allowed and optional upon the mutual agreement of the Distribution Provider and the Applicant.

o. Dynamic Reactive Power Support Function

The utilization of this function is allowed and optional upon the mutual agreement of the Distribution Provider and the Applicant.

p~~n~~. Default Activation States for Phase 1 Functions

Unless otherwise provided by Distribution Provider, pursuant to Distribution Provider's Distribution Generation Interconnection Handbook, the default settings will be as follows:

	Function	**State**
(i)	Anti-islanding	activated
(ii)	Low/High Voltage Ride-Through	activated
(iii)	Low/High Frequency Ride-Through	activated
(iv)	Dynamic Volt/VAR operations	activated
(v)	Ramp rates	activated
(vi)	Fixed power factor	deactivated
(vii)	Reconnect by "soft-start" methods	activated
(viii)	Frequency-Watt ~~(Optional)~~	activated ~~Implemented when available~~
(ix)	Volt/Watt ~~(Optional)~~	activated ~~Deactivated. Activated under mutual agreement with Distribution Provider instruction(s).~~
(x)	Set Active Power Function Mode (Optional)	activated under mutual agreement

(Continued)

(xi)	Dynamic Reactive Power Support Mode (Optional)	activated under mutual agreement

~~These default activation states may be modified by mutual agreement between Distribution Provider and Producer.~~

(Continued)

ELECTRIC RULE NO. 21 Sheet 198
GENERATING FACILITY INTERCONNECTIONS

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

2. PREVENTION OF INTERFERENCE (Cont'd.)

gθ. Load Shedding or Transfer

The voltage and frequency ride-through requirements of Hh.2.b.(ii) and Hh.2.f.(i) shall not apply if either: a) The real power across the Point of Common Coupling is continuously maintained at a value less than 10% of the aggregate rating of the Smart Inverters connected to the Generation Facility prior to any voltage disturbance, and the Generation Facility disconnects from the Distribution Provider's T&D system, along with Generation Facility load, such that the net change in real power flow from or to the Distribution Provider is less than 10% of the aggregate Smart Inverter capacity; or b) Generation Facility load real power demand equal to 90% to 120% of the pre-disturbance aggregate Smart Inverter real power output is shed within 0.1 seconds of Smart Inverter disconnection.

3. TECHNOLOGY SPECIFIC REQUIREMENTS

Grid-interactive inverters do not require separate synchronizing equipment. Non grid-interactive or "stand-alone" inverters shall not be used for Parallel Operation with Distribution Provider's Distribution or Transmission System.

(Continued)

ELECTRIC RULE NO. 21 Sheet 200
GENERATING FACILITY INTERCONNECTIONS

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

5. COMMUNICATION REQUIREMENTS

a. The communication protocol requirements included in this section Hh.5 shall become mandatory for Generating Facilities utilizing inverter-based technologies for which an Interconnection Request is submitted on or after the later of (a) March 1, 2018 or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry-recognized communication protocol certification test standard. Until such date, this subsection may be used in all or in part by inverter-based technologies by mutual agreement of the Distribution Provider and the Applicant. The communications requirements herein shall be between:

(i) the Distribution Provider and the individual Generating Facility's inverter control or energy management system;

(ii) the Distribution Provider and communication to the Generating Facility through an aggregator not co-located or part of the Generating Facility[A]; ~~energy management systems that manage the Generating Facility within a facility, plant and/or microgrid;~~ or

(iii) other communication options as are mutually agreed to are by Applicant and the Distribution Provider. ~~the Distribution Provider and aggregators, who manage and operate Generating Facilities at various locations.~~

[A] Communication utilizing this aggregator option is not permitted at this time.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

5. COMMUNICATION REQUIREMENTS (Cont'd.)

ba. Generating Facilities utilizing inverter-based technologies must adhere to all of the following communication protocol requirements for communications between Distribution Provider and communication option selected in section Hh. 5. This Rule does not specify the communication between the selected communication option and Smart Inverter but performance will be enforced by in compliance with this Rule:

(i) Shall be capable of communications;

(ii) Software shall be updateable via communications remotely;

(iii) The transport level protocol shall be TCP/IP; and,

(iv) The default application-level protocol shall be IEEE 2030.5 (i.e., Smart Energy Profile 2.0 (SEP 2)) as defined in the California IEEE 2030.5 Implementation Guide, but other application-level protocols may be used by mutual agreement of the parties including IEEE 1815/DNP3 for SCADA real-time monitoring and control and IEC 61850.

(Continued)

ELECTRIC RULE NO. 21 Sheet 202
GENERATING FACILITY INTERCONNECTIONS

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

5. COMMUNICATION REQUIREMENTS (Cont'd.)

c~~b~~. Additional communication protocol requirements shall also apply to Generating Facilities utilizing inverter-based technologies as provided in the following documents:

(i) Distribution Provider Generation Interconnection Handbook, which shall include:

a) Details and guidelines for the implementation of communications with Generating Facilities utilizing inverter-based technologies;

b) Cybersecurity and privacy requirements (these may additionally or alternatively be included in the application-level protocol implementation guide); and,

c) Generic device communications registration management requirements, including how to register individual Generating Facilities, Generating Facilities with energy management systems, and aggregators (these requirements additionally or alternatively may be included in the application-level protocol implementation guide).

(ii) Application-Level Protocol Implementation Guide, which shall provide:

a) Communication requirements and implementation guidelines to ensure consistent interoperability of the Generating Facilities with all California investor-owned utilities under the Commission's jurisdiction.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

6. SCHEDULING CAPABILITY REQUIREMENTS

a. Generating Facilities which incorporate Smart Inverters shall incorporate scheduling capabilities with a minimum scheduling memory capability of at least 24 events. The capability for this requirement will be mandatory for Generating Facilities utilizing invert-based technologies for which an Interconnection Request is submitted on or after the later of (i) March 1, 2018, or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognize communication protocol certificate test standard. Each event is composed of modifications to each, selected group of, or all of the following Smart Inverter function.

(i) Modifications to the voltage and reactive set-points of the Dynamic volt/var function.

(ii) Modification to the normal ramp-up rate and reconnect ramp-up rate set-points

(iii) Modifications to the reactive power set-points for the fixed power factor function

(iv) Modifications to the voltage and watt-reduction level set-points for the volt/watt function

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

6. SCHEDULING CAPABILITY REQUIREMENTS (Cont'd.)

b. The Generating Facility's scheduling capability requirement herein shall be met by one or more of the following options.

(i) Scheduling capability requirements may be stored at the Generating Facility Energy Management System (GFEMS). The GFEMS shall communicate the necessary commands to the Smart Inverters within 10 minutes from when GFEMS received the scheduling information:

(ii) Scheduling capability requirements may be stored at the Smart Inverter Control Unit (SMCU) within the Generating Facility. The SMCU shall communicate necessary commands to the Smart Inverters within 10 minutes from when SCMU received the scheduling information.

(iii) Scheduling capability requirements may be stored at an aggregator not co-located within the Generating Facility. The aggregator shall communicate the necessary commands to the Smart Inverters within 15 minutes of the aggregator receiving the scheduling information.

(iv) Other options may be utilized by mutual agreement between the Applicant and Distribution Provider.

c. The selected scheduling control system shall store the schedules and shall send operational commands to the Smart Inverters as required by the schedule received from the Distribution Provider. The Smart Inverter shall respond by changing its mode of operation as commanded with no unreasonable delay.

Each scheduled mode of operation shall include and start-time and duration. The Smart Inverter should return to its default settings at the end of the duration time or shall enter a new operational mode as directed by the scheduling control system.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

7. MONITORING AND TELEMETRY REQUIREMENTS

a. The capability for this requirement will be mandatory for Generating Facilities utilizing invert-based technologies for which an Interconnection Request is submitted on or after the later of (i) March 1, 2018, or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognize communication protocol certificate test standard. Smart Inverter shall have the capability to communicate its performance information including:

(i) Smart Inverter production or consumption of active power (Watts).

(ii) Smart Inverter consumption or production of reactive power (VARs)

(iii) Phase currents measure at the AC terminal of the Smart Inverter (Amps)

(iv) Phase voltage measured at the AC terminals of the Smart Inverter (Volts)

(v) Frequency measured at the AC terminals of the Smart Inverter (Hz)

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

7. MONITORING AND TELEMETRY REQUIREMENTS (Cont'd.)

b. When the Generating Facility includes energy-storage with Smart Inverters, the following monitoring and telemetry capability are required:

(i) The Smart Inverter shall be capable of communicating the available kWh for the energy-storage. Available kWh of the energy storage system is amount energy which can be used to support the energy needs of the electric system including the energy needs for the load within the generating facility or the Distribution System.

c. Operational State as In-Service or not In-service communication capability requirements. The Smart Inverter shall be capable of communicating when the Smart Inverter is capable of providing electric services as follows:

(i) In-Service state: An operational state which indicates that the Smart Inverter is connected to the electric system and operating as determined locally by the Generating Facility operator or by a scheduling control system as outlined in section Hh.6

(ii) Not In-Service state: An operating state which indicates that the Smart Inverter is not capable of connecting to the electric system and not capable of providing any type of electrical support as required locally or as commanded by a scheduling control system as outlined in section Hh.

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

7. MONITORING AND TELEMETRY REQUIREMENTS (Cont'd.)

d. Monitoring and performance information should be communicated in aggregate at the Generating Facility as follows:

(i) When the Generating Facility includes only Smart Inverters, The production or consumption of active and reactive power shall be communicated as an aggregate of all Smart Inverters within the Generating Facility.

(ii) When a Generating Facility includes Smart Inverters and other technologies such as synchronous or induction generation systems, the Generating Facility should communicate the following:

a) The production or consumption of active and reactive power shall be communicated in aggregate of all Smart Inverters within the Generating Facility

b) The production or consumption of active and reactive power shall be communicated in aggregate of all the other technologies within the Generating Facility

(iii) When the Generating Facility with Smart Inverters includes one or multiple energy storage systems. The available kWh energy should be communicated as an aggregate of all the energy storage systems

(Continued)

Hh. SMART INVERTER GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS (Cont'd.)

8. CONTROL THROUGH COMMUNICATION CAPABILITIES

a. The capability for this requirement will be mandatory for Generating Facilities utilizing invert-based technologies for which an Interconnection Request is submitted on or after the later of (i) March 1, 2018, or (b) nine months after the release of the SunSpec Alliance communication protocol certification test standard or the release of another industry recognize communication protocol certificate test standard. Smart Inverters shall have the capabilities of accepting an operational controls through communications in accordance to the following:

(i) Cease to energize control command. When the Smart Inverter receives a cease-to-energize command through communication it must enter into a cease-to-energize state of operation or shall initiate the opening of the DER switch referenced in the ECP in order to galvanically isolate the DER system from the Distribution System

(ii) Return to service control command. When the Smart Inverter receives a return-to-service control command, the Smart Inverter may return to service operation as required by Generating Facility operator or as required by the scheduling control system as required by section H.6

(iii) Limit Active Power command. When the Smart Inverter receives a command to limit its production of real power, the Smart Inverter shall reduce its real power production to the specified percent of real power capacity of the Smart Inverter or to a specified real power value.

(iv) Suspension of Active Power restriction: When the Smart Inverter receives a command to suspend the command for active power reduction, the Smart Inverter may return to normal operation as required by Generating Facility operator or as required by the scheduling control system as required by section H.6

(Continued)

Advice 5129-E
August 18, 2017

Attachment 3

Clay Faber - Director
CA & Federal Regulatory
8330 Century Park Court, CP32F
San Diego, CA 92123-1548

cfaber@semprautilities.com

June 20, 2017

Mr. Timothy Sullivan, Executive Director
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102-3298

RE: Joint Investor-Owned Utility Request for Extension to File a Tier 3 Advice Letter Implementing Tariff Changes for Advanced Inverter Functions for Smart Inverters pursuant to CPUC Decision No. 16-06-052

Dear Mr. Sullivan:

Pursuant to California Public Utilities Commission (Commission) Rule 16.6, San Diego Gas & Electric Company (SDG&E), on behalf of SDG&E, Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E) (the Utilities) requests an extension to file respective Tier 3 advice letters implementing revised tariffs for advanced inverter functions for smart inverters pursuant to Ordering Paragraph 9 of Decision (D.) 16-06-052.

As explained below, the Utilities filed a joint information-only advice letter on December 20, 2016 which anticipated that the Tier 3 advice letter filings directed by Ordering Paragraph 9 was contingent on additional efforts, and therefore, the December 2016 advice letter highlighted that the filing date for the future Tier 3 advice letters may be modified by the Commission, with support of the Smart Inverter Working Group (SIWG) members, if deemed appropriate.

Granting this extension will allow the Utilities to work with stakeholders within the SIWG to develop the necessary tariff updates. The Utilities believe that customers will not be harmed or otherwise adversely impacted by the approval of this extension request.

Original Directive

As noted below, Ordering Paragraph 9 of D.16-06-052 required the Utilities to file proposed revisions to their Tariff Rule 21 in order to implement “agreed upon” technical requirements for certain Phase 2 communication protocols and Phase 3 advanced inverter functions. The filings were due within six months of the effective date of the decision, or December 20, 2016.

> 9. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall file proposed revisions to Tariff Rule 21 setting forth any **agreed-upon technical requirements**, testing and certification processes, and effective dates for Phase 2 communication protocols and Phase 3 additional advanced inverter functions in separate Tier 3 advice letters no later than six months from the effective date of this decision. [Ordering Paragraph 9, D.16-06-052, emphasis added]

December 2016 Advice Letters

Because issues remained outstanding for Phase 2 and Phase 3 functions, the Commission hosted a public SIWG workshop on adoption of Phase 2 and 3 recommendations pursuant to D.16-06-052. One of the key objectives of the workshop was to provide guidance to the Utilities on the Phase 2 and 3 filings. During the workshop, it was determined that there was sufficient consensus to support tariff revisions associated with the Phase 2 communication protocols. It was also recognized that additional work remained for Phase 3 functions.

Because the Phase 3 functions were not developed at a level to support a tariff filing, the Commission requested that the Utilities file a "work plan" by advice letter setting forth how the Phase 3 tariff revisions would proceed. Accordingly, the Utilities filed a joint information-only advice letter on December 20, 2016 providing the work plan and outlining the next steps for tariff development.[1]

The filed work plan identified additional efforts to support the Phase 3 tariff development with proposed June 2017 advice letter filings to incorporate the Phase 3 functions. The filed work plan also anticipated that the proposed date was contingent on additional efforts, and therefore, the December 2016 advice letter highlighted that "the filing date for the Tier 3 advice letters may be modified upon approval from the Commission's Energy Division, with support of SIWG members, if deemed appropriate to maintain with IEEE 1547 and still be within reason of attaining the goal of smart inverters reaching full functionality by 2020 as stated in the Commission's DER Action Plan."

Extension Request

Recent discussions held within the Smart Inverter Working Group have identified the benefit of additional stakeholder dialogue continuing past June 2017 to assist with the Phase 3 tariff development. The Utilities discussed such an extension with stakeholders in meetings held on June 1 and June 8, and proposed a revised filing date in August 2017 to incorporate the results of these continued discussions. No party objected to the proposed extension. Therefore, the Utilities request a revised advice letter filing date for the Phase 3 functions to August 18, 2017.

Sincerely,

CLAY FABER
Director – Regulatory Affairs

cc: Dan Skopec, Vice President
Edward Randolph, Director of Energy Division
Gabriel Petlin, Energy Division
Jeffrey Kwan, Energy Division
Mary Claire Evans, Energy Division
Karen Clopton, Chief Administrative Law Judge
John Sowers, Senior Vice President
Parties to Service List: R.11-09-011

[1] See SDG&E Advice Letter 3022-E, SCE Advice Letter 3533-E and PG&E Advice Letter 4983-E

Advice 5129-E
August 18, 2017

Attachment 4

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

June 27, 2017

Clay Faber
cfaber@semprautilities.com
Director, CA & Federal Regulatory
San Diego Gas & Electric Company
8330 Century Park Court, CP32F
San Diego, CA 92123-1548

VIA E-MAIL

File No.: R.11-09-011

RE: Joint Investor-Owned Utility Request for Extension to File a Tier 3 Advice Letter Implementing Tariff Changes for Advanced Inverter Functions for Smart Inverters pursuant to CPUC Decision No. 16-06-052

Dear Mr. Faber:

I am in receipt of your letter dated June 20, 2017, in which San Diego Gas & Electric Company (SDG&E), on behalf of SDG&E, Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E) (the Utilities), request approval of an extension of time to file respective Tier 3 advice letters implementing revised tariffs for advanced inverter functions for smart inverters pursuant to Ordering Paragraph 9 of Decision (D.) 16-06-052.

In your letter, you note that the Utilities' advice letter is currently due to be filed on June 30, 2017, pursuant to the work plan jointly submitted through advice letter on December 20, 2016, which was itself pursuant to D.16-06-052. The filed work plan anticipated that the proposed date was contingent on additional efforts, and that the filing date for the Tier 3 advice letters may be modified upon approval from the Commission's Energy Division, with support of SIWG [Smart Inverter Working Group] members, if deemed appropriate to maintain with IEEE 1547 and still be within reason of attaining the goal of smart inverters reaching full functionality by 2020 as stated in the Commission's DER Action Plan.

In your letter, you state that recent discussion within the Smart Inverter Working Group has identified the benefit of additional stakeholder dialogue past June 2017 to assist with the Phase 3 tariff development. In addition, you note that the Utilities discussed the extension with stakeholders in meetings held on June 1 and June 8, the Utilities proposed a revised filing date of August 2017 to incorporate the results of continued discussions, and no party objected to the proposed extension.

For the reasons described in your letter, the Utilities' request for an extension of time is granted. Pursuant to Rule 16.6 of the Rules of Practice and Procedure, the Utilities must promptly inform all parties to this proceeding of this extension. For simplicity's sake, in this instance, the Energy Division will distribute this electronically to the R.11-09-011 service list.

Sincerely,

Timothy Sullivan
Executive Director

cc:

Karen Clopton, Chief Administrative Law Judge	karen.clopton@cpuc.ca.gov
Edward Randolph, Director, Energy Division	edward.randolph@cpuc.ca.gov
Regina DeAngelis, Administrative Law Judge	regina.deangelis@cpuc.ca.gov
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John Sowers, Senior Vice President	jsowers@semprautilities.com
Parties to Service List: R.11-09-011	

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

AT&T
Albion Power Company
Alcantar & Kahl LLP
Anderson & Poole
Atlas ReFuel

BART
Barkovich & Yap, Inc.
Braun Blaising McLaughlin & Smith, P.C.
Braun Blaising McLaughlin, P.C.

CENERGY POWER
CPUC
CalCom Solar
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
California State Association of Counties
Calpine
Casner, Steve
Center for Biological Diversity
City of Palo Alto
City of San Jose
Clean Power
Clean Power Research
Coast Economic Consulting
Commercial Energy
Cool Earth Solar, Inc.
County of Tehama - Department of Public Works
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Defense Energy Support Center
Dept of General Services
Division of Ratepayer Advocates

Don Pickett & Associates, Inc.
Douglass & Liddell
Downey & Brand
Ellison Schneider & Harris LLP
Evaluation + Strategy for Social Innovation

G. A. Krause & Assoc.
GenOn Energy Inc.
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Charge Networks
Green Power Institute
Hanna & Morton
ICF
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
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
McKenna Long & Aldridge LLP
McKenzie & Associates
Modesto Irrigation District

Morgan Stanley
NLine Energy, Inc.
NRG Solar
Nexant, Inc.

ORA
Office of Ratepayer Advocates
Office of Ratepayer Advocates, Electricity Planning and Policy B

OnGrid Solar
Pacific Gas and Electric Company
Praxair
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions

SCE
SDG&E and SoCalGas
SPURR
San Francisco Water Power and Sewer
Seattle City Light
Sempra Energy (Socal Gas)
Sempra Utilities
SoCalGas
Southern California Edison Company
Southern California Gas Company (SoCalGas)
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
TerraVerde Renewable Partners, LLC
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
Yelp Energy