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Working Group One Final Report

March 15, 2018

California Public Utilities Commission
Interconnection Rulemaking (R.17-07-007)

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Background

Procedural Background

On July 13, 2017, the California Public Utilities Commission (CPUC or Commission) issued an Order Instituting Rulemaking to consider a variety of refinements to the interconnection of distributed energy resources under Electric Rule 21. On October 2, 2017, the Commission issued a scoping ruling for R.17-07-007 directing the utilities to convene eight working groups to develop proposals to address the issues of that working group.[1]

The scoping ruling tasked the first working group, "Working Group One", with developing a final report for recommending proposals to address seven "urgent and/or quickly resolved issues" no later than February 15, 2018. A subsequent email ruling extended the report deadline to March 15, 2018 and removed the sixth issue from the scope of the working group.[2]

The Commission intends to issue a proposed decision on the Working Group One report in fall 2018, following completion of Working Group Two in the same proceeding.

Working Group Scope

Working Group One developed proposals addressing Issues 1-5 and 7 in the scoping ruling:

1) Should the Commission modify Fast Track Screen Q to minimize the number of distributed energy resource projects subjected to transmission cluster studies and, if so, how?
2) Should the Commission clarify the definition of "complex metering solutions" for storage facilities and, if so, how?
3) How should the Commission clarify the definition of a "material modification" to a project and what should be the procedures for processing these modifications?
4) As the penetration levels of distributed energy resources increase, what changes to telemetry requirements should the Commission adopt to ensure adequate visibility while minimizing cost?
5) Should the Commission require activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017 and, if so, how?
7) Is there inconsistent application of the requirement to pay the Income Tax Component of Contribution charges across the Utilities? If yes, how should the Commission address this inconsistency?

Per the scoping ruling, the Smart Inverter Working Group (SIWG) developed the proposal for Issue 5 and shared with Working Group One for incorporation in the final report.

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[1] R.17-07-007 Scoping Ruling, October 2, 2017. (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M196/K476/196476255.PDF)

[2] Email Ruling Revising Schedule and Reassigning Issue Six, February 14, 2018. (http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=211794527)

Working Group Process

Issues 1-4 and 7

Working Group One met 18 times between October 13, 2017 and March 2, 2018 to develop proposals to address Issues 1-4 and 7. Two thirds of the meetings were via teleconference and lasted 2.5 hours; one third were in-person at the Commission's San Francisco offices and lasted 3.5 hours. Energy Division staff facilitated working group meetings with assistance from utility and non-utility stakeholders.

The working group generally spent three meetings per issue, with a draft proposal developed after the second meeting for group review during the third.[3] Proposals were drafted by the utilities and the stakeholder lead assigned to the issue, with input from Energy Division staff. The non-utility stakeholder lead assignments were:

- Issue 1: CALSSA
- Issue 2: CESA
- Issue 3: CESA
- Issue 4: CALSSA
- Issue 5: Enphase Energy and CALSSA
- Issue 7: Clean Coalition

To meet the March 15 report deadline, proposal development often had to be completed offline while the working group moved to the next issue. To ensure incorporation of stakeholder feedback, working group participants were given multiple opportunities to submit written comments on all issue proposal drafts prior to the report's submission to the Commission, both during the issue's allotted discussion time and during compilation of the final report. However, edits received as part of the final Working Group review in some cases were never discussed amongst the working group and may need to be further addressed within written comments.

Issue 5

The Smart Inverter Working Group met eight times between December 7, 2017 and February 15, 2018 to develop proposals to address Issue 5. Meetings were conducted via WebEx and lasted between 1 hour and 1.5 hours. Energy Division staff facilitated the SIWG meetings. Proposals were drafted by the utilities and stakeholder leads with input from Energy Division staff.

Consensus and Non-Consensus Proposals

Working group members made significant efforts to reach consensus on each issue and were often successful. For issues where consensus was not reached, either because parties had fundamentally differing viewpoints or because the working group did not have sufficient time to work through

[3] The most significant exception to this was Issue 3, on which the working group spent seven meetings. The working group requested and received a one-month extension to complete a proposal addressing an additional use case under Issue 3.

differences, the working group attempted to document the various viewpoints to provide the Commission with sufficient information to make an informed decision.

Each proposal's consensus "status" is indicated immediately following the proposal. A proposal marked "consensus" received general support from all working group members who participated in meetings when that proposal was discussed. A proposal marked "non-consensus" received both support and opposition from members who participated in meetings when that proposal was discussed. Non-consensus proposals also include a list of supporters and opponents to provide information about the extent to which the proposal was supported and opposed.

Working Group Participants

The "working group" references all active parties participating in Working Group One meetings, which include the IOUs, government representatives, DER developers, nonprofits, and independent advocates and consultants. A working group participant list may be found in the appendix. The final report is the product of written and oral contributions from participants representing the following organizations:

- ABB
- Borrego Solar
- Bosch
- CalCom
- California Solar and Storage Association (CALSSA)
- California Energy Storage Alliance (CESA)
- California Independent System Operator (CAISO)
- Chico Electric
- Clean Coalition
- Enphase Energy
- Green Power Institute (GPI)
- Interstate Renewable Energy Council (IREC)
- JKB Energy
- Office of Ratepayer Advocates (ORA)
- OutBack Power Technologies
- Pacific Gas & Electric (PG&E)
- Southern California Edison (SCE)
- San Diego Gas and Electric (SDG&E)
- Tesla
- The Utility Reform Network (TURN)
- Sunrun
- Sunworks

Issue 1: Transmission Cluster Studies

Issue 1: Should the Commission modify Fast Track Screen Q to minimize the number of distributed energy resource projects subjected to transmission cluster studies and, if so, how?

Proposal Summary

The following four proposals were developed by various stakeholders as part of the working group process to address Issue 1. The proposals are independent alternatives, meaning any combination may be selected. Proposals 1-A, 2, and 3 have consensus support; Proposals 1-B and 4 are non-consensus.

To minimize the number of distributed energy resource (DER) projects subjected to transmission cluster studies, the Commission should:

- **Proposal 1:** Expand the existing Screen Q exemption for NEM facilities with net export less than or equal to 500 kW by:
  - **A.** Increasing the exemption size threshold to 1 MVA nameplate capacity
    - **Consensus on the core proposal**
  - **B.** Extending the exemption from NEM projects to all projects
    - **Non-Consensus**. Supported by IREC, Clean Coalition, Green Power Institute, CALSSA, Sunworks and Outback. Opposed by TURN, PG&E, SCE, and SDG&E.
- **Proposal 2**: Create a soft link within Screen Q to the CAISO Tariff
  - **Consensus**
- **Proposal 3**: Direct the utilities to identify engineering review guidelines related to the evaluation of Screen Q
  - **Consensus**
- **Proposal 4**: Create a venue to discuss a “Cost Cap” for qualifying DERs that fail Screen Q to proceed despite transmission interdependence
  - **Non-Consensus**. Supported by Green Power Institute and Clean Coalition. Opposed by TURN, ORA, PG&E, SCE, and SDG&E.

This section presents a summary of the proposals only. The “Working Group Proposals” section further describes the proposals and the positions for and against each.

Background

Screen Q: Electrical Independence Test for Transmission System

For all interconnection applicants applying under Rule 21's Detailed Study Track, as well as applicants that have failed Rule 21's Fast Track, the specific study path for which the applicant is eligible is determined in part by the application of Screen Q.[4]

Screen Q is an engineering test that evaluates whether a project is electrically independent of the transmission system. The utility determines, based on knowledge of interdependencies with earlier-queued interconnection requests under any tariff, whether the project is of sufficient size and located at a point of interconnection such that it is reasonably anticipated to require or contribute to the need for upgrades to the transmission system ("Network Upgrades").

Projects that are found to *not* have interdependencies as described above will pass Screen Q and continue to be studied under Rule 21.[5] Projects that are found to *have* interdependencies as described above will fail Screen Q, be withdrawn from Rule 21, and have the option of applying for interconnection under the Transmission Cluster Study Process of the FERC-jurisdictional Wholesale Distribution (Access) Tariff.[6]

The Transmission Cluster Study Process is administered by the host utility in conjunction with the CAISO and, if any, Affected Systems, and is designed to allocate costs for transmission system upgrades that are studied under FERC tariffs and procedures. Projects are grouped by geographical and system areas to be studied together (as a cluster): upgrades are identified for the clustered group and the cost of the upgrades are then allocated to projects in that clustered group. A request for interconnection under the cluster study can only be submitted during a Cluster Application Window in March. Projects that become part of the Transmission Cluster Study Process cannot move forward until the Phase I and Phase II studies are completed approximately 2 years later. Based upon the level of generating facilities proposed for interconnection, projects may need to wait an additional 1-2 years to complete the construction process and associated approvals to operate in parallel with the grid.

500 kW Exemption Threshold

Screen Q in Rule 21 currently contains an exemption for NEM projects with net exports 500 kW or under to proceed as part of the Rule 21 Independent Study Process, which has substantially shorter study timelines:

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[4] Screen Q is described in Section G.3.a of Rule 21. See Appendix A for the full text of Section G.3.a.

[5] Note that it is possible to pass Screen Q (i.e., be found to have no electrical interdependencies with earlier-queued projects), be studied under the Independent Study Process of Rule 21, and still trigger a transmission system upgrade.

[6] The Transmission Cluster Study Process is described in Section F.3.d of Rule 21. See Appendix A for the full text of 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. (Rule 21, Section G.3.a)

The 500 kW threshold was chosen by settlement parties during the last major update to Rule 21 in 2012. The basis for choosing 500 kW as the threshold, and for limiting the exemption to NEM, was not discussed in detail as part of the related settlement documents. However, the working group members who participated in prior settlement discussions highlighted that NEM projects were deemed less likely to contribute to the need for upgrades as these projects mainly serve their host electrical load, and that 500 kW was seen as a high enough threshold that the majority of customer-sited projects would not be subject to the screen review.

Initial Stakeholder Concerns

Solar parties are concerned that the 500 kW exemption still leads to the inclusion of systems that are likely to have negligible impact on the transmission system. For example, a 1 MW DER project can fail screen Q because 50 kW of generation is modeled to back feed onto a transmission level device rated for 100 MW. This additional 50 kW represents a +0.05% impact on the transmission system device. It is unlikely that a project of that size will ultimately be assessed cost responsibility for transmission system upgrades, and DER developers therefore believe that such projects should not be subject to the untenable timelines of the Transmission Cluster Study Process.

Solar parties are concerned that Rule 21 projects will increasingly be caught in the Transmission Cluster Study Process even though their contribution to Network Upgrades may not be significant. They believe there is an urgent need to address the issue before it becomes an unnecessary roadblock for a large portion of projects.

Working Group Consensus on Whether to Modify Screen Q

Non-utility working group members agree that the multi-year timelines of the Transmission Cluster Study Process are injurious to Rule 21 projects and that modifications to Screen Q are needed to ensure that projects which are highly unlikely to be assigned cost responsibility for upgrades are exempted from the process.

The utilities highlighted the limited use of Screen Q within their respective territories. PG&E has encountered nine project failures of Screen Q, with SCE encountering one failure and SDG&E zero failures. Furthermore, PG&E represented that the 9 projects would not have failed Screen Q if the updated CAISO Appendix DD which clarified what level of review for potential reliability and deliverability system upgrades in a Screen Q evaluation, had been incorporated within Rule 21 (for further discussion of the CAISO appendix, see below). Notwithstanding, the utilities support further clarifications as to the Screen Q application and discussion of whether the existing 500 kW exemption allowing study under the Independent Study Process could be supported at a greater level.

Working Group Proposals

The following four proposals were developed by various stakeholders as part of the working group process to address Issue 1. The proposals are independent alternatives, meaning any combination may be selected. Proposals 1-A, 2, and 3 have consensus support; Proposals 1-B and 4 are non-consensus.

The first proposal addresses expanding the 500 kW exemption and consists of two component proposals: 1-A and 1-B.

Proposal 1-A: The Commission should modify Rule 21 to change the Screen Q exemption size threshold from 500 kW net export to 1 MVA nameplate capacity

Status

Consensus on the core proposal. IREC, CESA, and Tesla support raising the threshold to 1 MVA, but objects to measuring system size by nameplate capacity instead of net export. TURN and ORA's support is contingent on Phase 2 of this proceeding evaluating whether there are any ratepayer cost impacts as a result of this change, and addressing any impacts that are found.

Discussion

The working group proposes that the Screen Q exemption be increased from 500 kW to 1 MW, that system size be measured for purposes of the exemption threshold using megavolt-amperes (MVA) instead of MW, and that the threshold level be measured against the nameplate capacity of the proposed system.

The Utilities are agreeable to changing the exemption size to 1 MVA for NEM eligible projects based upon their expectation that projects of that size would commonly not be found to contribute to the need for Network Upgrades as they service their electrical host load.[7] The working group notes that the change from 500 kW to 1 MW aligns with other 1 MW thresholds for NEM cost allocation. Project developers, customers, and Utilities are generally accustomed to having different rules for projects smaller and larger than 1 MW.

The working group also proposes that system size be measured for purposes of the exemption threshold using megavolt-amperes (MVA) instead of MW. The change from MW to MVA reflects inverters and transformers increasingly being rated in MVA rather than in MW.

In addition, some members of the working group recommend that the threshold level be measured against the nameplate capacity of the proposed system rather than the system's anticipated net export. Measuring net export involves comparing expected production with the customer's historic hourly

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[7] As part of this proposal, the Utilities believe the cost responsibility framework for NEM-1 and NEM-2 less than or equal to 1 MW must be the same regardless of what study process a project is studied under (e.g., Transmission Cluster Study Process or the Independent Study Process). The Utilities note that they have identified conflicting language between Rule 21, Section E.4 and Table E-2 regarding the cost responsibility framework for Network Upgrades for NEM 1 and NEM 2 systems ≤1 MW, which should be reviewed and made consistent in the next Rule 21 update.

electricity consumption, and this can lead to disputes and uncertainty. Although net export is the more relevant metric for measuring the impact on the system caused by the proposed generator, using the nameplate capacity as the trigger for study exemption would make the rule much easier to administer for both utilities and project developers of exporting projects. It would result in a lower effective threshold than one based on net export, except when reviewing a non- or limited-export project, but exporting project developers consider this change to be worthwhile in order to increase predictability and reduce procedural burden. As explained further below, the Interstate Renewable Energy Council (IREC) has a different proposal on how to measure the size threshold to take into account limited-export and non-exporting projects.

To implement these recommendations, the supporting parties propose the following edits to Section G.3.a of Rule 21:[8]

> *NEM Generating Facilities with nameplate capacity ~~net export~~ less than or equal to 1 MVA ~~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.*[9]

IREC Proposal to Keep Net Export Measure

IREC, Tesla, GPI, and CESA oppose using nameplate capacity for all projects and propose that projects which limit net export to 1 MVA or less be eligible for the exemption. It is fine to use the nameplate rating for traditional exporting projects, but for limited-export or non-exporting projects this is not appropriate as it does not properly reflect their impacts. While there is effort required to calculate net export, that effort is inconsequential compared to the time that would be required to complete the cluster study process for these projects. Thus, IREC recommends allowing projects with nameplate capacity below 1 MVA to avoid having to go through the net export calculation, but allowing projects with nameplate capacity above 1 MVA but net export below 1 MVA to still benefit. IREC recommends the following edits to Section G.3.a. of Rule 21:

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

TURN, PG&E, SCE, and SDG&E oppose IREC's proposal. The benefit of avoiding the calculation of net export is eliminated and the proposal of calculating net export of up to 1 MVA for systems with nameplate 1 MVA or above is effectively modifying the exemption to 2 MVA or greater nameplate. If this proposal is adopted, it practically then allows for projects that may be interdependent to the transmission system and may reasonably contribute to the need for Network Upgrades to avoid the transmission cluster study process. This could contribute to capacity concerns in addition to reliability

[8] All specific tariff language changes in this proposal are included for illustrative purposes only. Final tariff revisions will be proposed via advice letter upon the Commission's approval of the proposal in 2018.
[9] Specific language is from PG&E's Rule 21. Edits to Rule 21 for other IOUs may differ.

concerns. In addition, the continued use of net export creates additional processing steps and corresponding process time as compared to the use of the nameplate capacity.

Note from Tesla: Tesla observers that although predicting the amount of net export a system would produce may be challenging, given the variability and unpredictability of underlying load, the use of software or firmware controls that expressly limit exports such that they never meet the 1 MVA threshold would address this concern, by simply forcing the system to operate within this limit. This should be an option that developers can avail themselves of and would seem to address the utility concerns regarding the challenges of assessing whether or not a system would export 1 MVA or more.

> *IOU Response*: the use of potential software or firmware controls as discussed by Tesla was never discussed as part of this proposal and would have to first be certified to provide for this usage which does not exist today as discussed within other issues within the Working Group.

The Utility Reform Network Support is Contingent on Possible Consideration of Fees in Phase 2

The Utility Reform Network's support for expansion of the exemption is contingent on an agreement by parties that should this change be thought to result in the potential for costs otherwise paid by a DER developer to instead be paid by ratepayers, a solution to remove this potential for ratepayer subsidization will be discussed in Phase 2 of this proceeding.

Other working group members wish to state clearly for the record that this proposal does not produce a direct cost shift from developers to ratepayers. If a project is exempted from a Transmission Cluster Study and thus avoids costs that would otherwise be their responsibility to pay, those costs are shifted to other developers in the cluster, not to ratepayers.

With this understanding, the working group does not object to TURN's request to consider in Phase 2 whether fees are appropriate if such a cost shift does exist. Phase 2 will not consider further changes to Screen Q, but it is recognized that Phase 2 could evaluate whether it is appropriate to establish new fees. There is no agreement that such fees are appropriate; just agreement to discuss in Phase 2 whether fees are needed or appropriate.

Proposal 1-B: The Commission should modify Rule 21 to expand the Screen Q exemption from NEM-only to all projects

Status

Non-Consensus. Supported by IREC, Clean Coalition, Green Power Institute, CALSSA, Sunworks and Outback. Opposed by TURN, PG&E, SCE, and SDG&E.

Discussion

This change could be accomplished by deleting "NEM" from the tariff language cited in Proposal 1-A:

> *~~NEM~~ Generating Facilities with nameplate capacity ~~net export~~ less than or equal to 1 MVA ~~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.* (Rule 21, Section G.3.a)

Reasoning of Proposal Supporters

Supporters of this proposal see no reason why a NEM system and a non-NEM system of identical nameplate capacity should be treated differently. The concept behind the proposal is that projects will still be studied in Rule 21's Independent Study Process (as described more below) and any costs will be properly allocated; thus there is no need for a distinction between NEM projects and non-NEM projects on a cost-allocation basis. Just as with NEM systems, they believe it is unnecessary to perform Screen Q on smaller non-NEM systems if it is highly unlikely that the systems would meaningfully contribute to the need for Reliability Network Upgrades. Project developers would benefit from increased certainty of interconnection costs and reduced study timelines. This treatment would also better focus the rules on the electrical impacts of projects rather than making further distinctions based upon procurement programs that may evolve in the future. This change is also in line with the broader policy goal of keeping Rule 21 focused on reviewing the electrical impacts of projects rather than creating distinctions based on different procurement programs, although the tariff does currently today recognize distinctions for some customer programs, such as Net Energy Metering.

Reasoning of Proposal Opponents

PG&E, SCE, SDG&E and TURN oppose extending an exemption (of any size) that is applied to generators that quality for the NEM Tariff to generators that do not qualify for the NEM Tariff, for the following reasons:

- **Undermining of Rule 21 Cost Allocation Principals and Participation in System Reliability Solutions due to Screen Exemption:** The IOUs support revising the NEM exemption size to 1 MVA based upon their expectation that projects of that size which are meant to service exisiting electrical load would commonly not be found to contribute to the need for Network Upgrades. However, the IOUs do not support expansion to non-NEM projects because they are concerned such projects are more likely to contribute to the need for Network Upgrades and/or reliability system upgrades. Thus, the allowance of this exemption for all Rule 21 projects creates the potential of costs that should have been attributed to projects but were not because they were exempt from Screen Q. In addition, projects who should be part of a system reliability solution would also not be subject to the solution as they would be exempted from study under this proposal.
- **Discussion Focused On Proposals 1-A to 1-B:** The majority of Working Group discussion on this topic was centered on increasing the existing NEM extension to a higher level. This issue was not discussed at great length and involves far reaching implications including interaction with WD(A)T study process and CAISO Tariff procedures. The IOUs do not believe there has been sufficient analysis to extend the existing exemption to non-NEM projects.

Response of Proposal Supporters:

Supporters believe the proposal is clearly within the defined scope of this issue. They do not believe the fact that the exemption previously applied only to NEM systems to be a valid reason in itself that it should not apply to non-NEM systems.

It is not clear why extending the cap to non-NEM projects creates any different "equity" issues than extending that same cap to NEM projects would. The crux of Proposal 1-A is that provided systems stay within the 1 MVA threshold, any cost impacts and attendant cost shifts associated with projects exempted from Screen Q would be *de minimis.*

It makes sense to extend the Screen Q exemption to larger projects from an efficiency standpoint if the likelihood of them contributing to the need for Network Upgrades is small. There have been no electrically-related differences identified between NEM and non-NEM projects and thus the common sense reasons that apply to NEM should also be applied to all other projects below 1 MVA.

In addition, all parties were invited to participate in this proceeding and have and will have an opportunity to participate going forward. The fact that some types of project developers have not been in the room is not a valid reason to limit the Screen Q exemption to only NEM projects because the theoretical impacts on these hypothetical developers are the same as the impact would be from NEM projects.

TURN opposes this proposal due to potential cost shifts to the ratepayers.

Proposal 2: The Commission should modify Screen Q to create a soft link to the CAISO Tariff

Status
Consensus

Discussion
Section G.3.a. of Rule 21 refers to the CAISO Tariff for procedures regarding performance of the determination of electrical independence under Screen Q:

> *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 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 Section 4.2 of Appendix Y to the CAISO Tariff will determine whether the Interconnection Request is electrically independent from the CAISO Controlled Grid.* (Emphasis added.)

In 2012, the CAISO moved its rules for the Generator Interconnection and Deliverability Allocation Procedures from Appendix Y to Appendix DD of the CAISO Tariff. Due to the rarity of projects failing Screen Q, utilities and stakeholders have only recently identified the outdated reference to Appendix Y in Rule 21. The tariff should be updated to cite the CAISO Tariff in effect without naming the specific appendix in case it changes again.

There are two different types of Network Upgrades identified in Rule 21 and the CAISO Tariff: "Reliability Network Upgrades" and "Deliverability Network Upgrades".[10] The change from Appendix Y to Appendix DD means the determination of electrical independence will be performed against Reliability Network Upgrades only versus Reliability and Deliverability Network Upgrades. The Joint IOUs believe that this proposal will reduce the likelihood of projects failing Screen Q. As discussed during working group discussions, the nine PG&E projects that failed Screen Q in 2016 were due to electrical interdependence with Deliverability Network Upgrades, and those failures would not have occurred if studied only against Reliability Network Upgrades.

PG&E's advice letter implementing the Phase 3 recommendations from the Smart Inverter Working Group contains updates to the Rule 21 language for Screen Q to reference the applicable CAISO tariff in effect.[11] The other IOUs are reviewing procedural filings to make similar updates. PG&E's advice letter is currently suspended pending Commission review.

The working group supports this change. For PG&E, the change may happen via approval of the smart inverter advice letter. For SCE and SDG&E, the same change could be made as part of this proposal.

Below is the applicable excerpt from PG&E's advice letter:

> *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.*

Applicable language from Appendix DD of the CAISO Tariff is located in Appendix B of this proposal.

Proposal 3: The Joint Utilities should identify engineering review guidelines related to the evaluation of Screen Q

Status

Consensus

[10] Rule 21 defines Reliability Network Upgrades as "The transmission facilities at or beyond the point where Distribution Provider's Distribution System interconnects to the CAISO Controlled Grid, necessary to interconnect one or more Generating Facility(ies) safely and reliably to the CAISO Controlled Grid, as defined in the CAISO Tariff." Rule 21 defines Delivery Network Upgrades as "The transmission facilities at or beyond the point where Distribution Provider's Distribution System interconnects to the CAISO Controlled Grid, other than Reliability Network Upgrades, as defined in the CAISO Tariff." Projects applying under Rule 21 are assumed to be seeking "energy only" status and thus are not subject to responsibility for Deliverability Network Upgrades.
Projects that are seeking "deliverability" must apply for a deliverability assessment under the Wholesale Distribution Access Tariffs.

[11] PG&E Advice 5129-E.

Discussion

To assess a project's electrical interdependence with the transmission system, the utility performs tests for determining electrical independence[12] collectively called the "Electrical Independence Test" (EIT) as defined in Rule 21.[13] For projects that fail the EIT, the utility has discretion under the current rules to perform additional engineering review (subject to CAISO concurrence) to determine whether the interconnection request's contribution is indeed expected to require or contribute to the need for Reliability Network Upgrades. If assessed to be electrically independent (project passes the EIT) or reasonably anticipated not to require or significantly contribute to Reliability Network Upgrades, the project passes Screen Q and proceeds pursuant to Rule 21 system study protocols.

Several working group members requested additional utility explanations to educate and alleviate confusion regarding when and how the utilities perform additional review following failure of the EIT. To provide stakeholders with greater transparency, the Joint Utilities list below the following guidelines that a utility engineer would look to if the EIT test results warrant additional review:

1. List all generation projects in the current queue that are adjacent to proposed project.
2. If current base-case is not complete, use last approved cluster base-case.
3. If a cluster is ongoing, with RNUs not yet finalized, compare pre-project base-case and post project base-case loading when necessary to determine if there is/are any potential network upgrade(s) required.
4. If a cluster is ongoing, with RNUs finalized, compare pre-project base-case and post project base-case with RNUs considered and determine if the subject interconnection request triggers a change in scope for that RNU.
5. Consult with the CAISO as necessary.

Due to the numerous possible interconnection requests, the timing of the interconnection requests, transmission area constraints, and the different base-cases that have to be developed at different points in time and for different needs, it is difficult to have specific language to define the guideline more granularly than the five steps above. At any given time, there are projects within the Independent Study Process, Cluster Study, or reliability processes as well as projects within construction phases that may change system size, configurations, and status – all of which impact the base-cases that were developed and utilized for active interconnection studies.

In response to stakeholder comments, PG&E, SCE, and SDG&E propose to perform the additional engineering review when a project fails the EIT and further review is warranted, and to make the guidelines above available on their interconnection websites to provide greater transparency for developers. The working group also proposes the following minor modifications to Section G.3.a of Rule 21 to provide clarity on the role of the additional engineering review following EIT results:

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[12] These tests are defined in Section 4.2 of Appendix DD of the CAISO Tariff.

[13] Rule 21, Section C, defines Electrical Independence Test as "The tests set forth in Section G.3 used to determine eligibility for the Independent Study Process."

Distribution Provider, in consultation with the CAISO, will determine, based on knowledge of the interdependencies with earlier-queued interconnection requests under any tariff, whether the Interconnection Request to the Distribution System is of sufficient MW size and located at a point of interconnection such that it is reasonably anticipated to require or contribute to the need for Reliability Network Upgrades. In making this determination, the Distribution Provider will make a 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 begins.

If Distribution Provider determines that no interdependencies exist ~~as described above~~ or that interdependencies do exist but the proposed Generating Facility is not reasonably anticipated to require or contribute to the need for Reliability Network Upgrades, then the Interconnection Request will be deemed to have passed Distribution Provider's Determination of Electrical Independence for the CAISO Controlled Grid.

If Distribution Provider determines that interdependencies exist ~~as described above~~ and that they are reasonably anticipated to require or contribute to the need for Reliability Network Upgrades, then Applicant may be studied under the Transmission Cluster Study Process as set forth in Section F.3.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 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 Section 4.2 of Appendix Y to the CAISO Tariff will determine whether the Interconnection Request is electrically independent from the CAISO Controlled Grid.~~

Proposal 4: The Commission should create another venue to discuss a "Cost Cap" for qualifying DERs that fail Screen Q to proceed despite transmission interdependence

Status

Non-Consensus. Supported by Green Power Institute and Clean Coalition. Opposed by TURN, ORA, PG&E, SCE, and SDG&E.

Discussion

Green Power Institute proposes the following. A project would proceed with the interconnection approval process under Rule 21 without participating in a transmission cluster study if willing to pay a "Cost Cap" fee that is the calculated share of the applicant's costs for RNU from the applicable cluster. The Cost Cap shall establish the maximum Cluster Study upgrade charge liability applicable to the project. Final charges will be reconciled upon completion of the Cluster Study. If review by the IOU indicates that applicant's project could operate safely without completion of the RNU upgrades, it will be allowed to interconnect to the grid and commence operations under the normal Rule 21 non-cluster timelines (i.e., projects will interconnect long before the cluster study is completed in most cases).

The Cost Cap fee for each applicant shall be calculated based on either:

a. A proportionate share of the IOU's applicable transmission-level RNU upgrades, based on historical average costs;
b. Costs the IOU reasonably believes will be incurred by the applicant, based on project specific cost estimates, comparable to the Rule 21 Cost Envelope review process.

Green Power Institute proposes that DER projects less than or equal to 5 MVA (NEM and non-NEM) that fail Screen Q be given this additional option. Green Power Institute recommends 5 MVA because that is the limit for lower-cost interconnection studies under the Rule 21 Independent Study Process.

Reasoning of Proposal Supporters:

This is not a change in Screen Q, only in how costs may be assigned if a project seeks to proceed under the Cost Cap Fee Option and avoid the Transmission Cluster Study Process. It only applies if the DER fails Screen Q. Per existing tariff, the Distribution Provider may assess if the Generating Facility being tested is one (1) percent or less than the transmission facility's capacity as a basis for allowing the Generating Facility to pass Screen Q.

Historically, DER RNU costs and impacts have been *de minimis,* which allows the IOUs and Energy Division to have some confidence that many and perhaps most DER projects will continue to have *de minimis* transmission grid impacts even when they are found to be electrically interdependent.

It appears (based on data obtained to date) that there may be no instances of DER failing Screen Q based on RNU only. IOUs cannot predict whether projects will fail in the future, however, and the aggregate impact of future DER may have a significant impact (>1%).

Green Power Institute believes this proposal is additional rather than alternative. It is complementary to other proposals herein and is not in conflict with them.

Reasoning of Proposal Opponents:

PG&E, SCE, and SDG&E oppose inclusion of this aspect of the proposal as they believe it is both outside the scope of this Issue, and it is not practical, even if adopted, for the IOUs to comply due to the lack of data. Most importantly, however, the IOUs point to the CAISO Tariff in how Transmission Network Upgrades are determined and costs allocated for most DER interconnections.

- **Out of scope:** As stated within the Commission's Scoping Ruling, Issue 1 for this Working Group was specific to considering/implementing ways that enable DER projects to be excluded from the Transmission Study Cluster Study Process. A proposal to consider ways to estimate costs and/or implement a type of cost-containment process for projects that are studied as part of a Transmission Cluster Study are clearly beyond the scope of this issue.
    - *GPI response*: the Cost Cap proposal is well within scope because this proceeding was opened " …. in order to consider a variety of refinements to the interconnection of distributed energy resources under Electric Tariff Rule 21" and it is an overly restrictive reading of the scoping memo to suggest that proactive solutions to Screen Q issues are outside of scope. In terms of time delays versus costs, the Cost Cap proposal resolves both of these issues by dramatically reducing time delays – by allowing projects to move

forward once they are deemed eligible for the Cost Cap – as well as providing a cost cap for costs.

- **Lack of data to comply:** As was discussed during the working group discussions, the impetus of this issue being scoped with the Rulemaking was the failure of nine (9) projects to Screen Q in PG&E's service territory. One (1) additional project has similarly failed Screen Q in SCE's service territory and none (0) have failed in SDG&E's service territory. In addition, because there have been so few (and in some cases zero) examples from which the utility would be able to extract data and involves facilities goverened under the CAISO tariff, the Utilities have no rational basis from which, as is required per this proposal, to reasonably estimate costs that would be incurred as a result of the Transmission Cluster Study.
    - *GPI response*: GPI feels that any DER interconnection costs data from the last decade is relevant data for crafting reasonable cost caps and it is not the case that only projects that have been screened out by Screen Q, to date, are relevant. The IOUs have offered no rationale as to why the much larger set of DER interconnection data can't be used to craft reasonable cost caps.
- **Inadequate Level of Discussion:** The majority of working group discussion on this topic was centered on increasing the existing NEM exemption to a higher level as proposed in Proposals 1-A and 1-B. This issue was not discussed at any great length and involves far reaching implications including interaction with a FERC jurisdictional WD(A)T study process along with cost allocation rules pursuant to CAISO Tariff. It is not appropriate to extend the existing exemption to projects never included as part of the original exemption to which the majority of discussion was centered upon resulting in Proposal 1-A. In addition, the previous Rule 21 rulemaking included a multi-year discussion on cost related proposals, the results of which are adopted in Commission Decision 16-06-052. PG&E, SCE, and SDG&E request that any discussions on cost cap type issues in Rule 21 should be allocated sufficient time to be fully vetted, and the schedule allotted for the issues scoping within Working Group One does not allow such a discussion.
    - *GPI response:* The previous Rule 21 was extremely delayed, as all parties will attest, so it is not the case that we will want to emulate that five-year timeframe for resolving the present set of issues. That said, GPI agrees that the timeframe for Working Group One has been shorter than optimal, given the number of issues to be resolved, and GPI suggests that another one-day workshop, with post-workshop written comments, be convened to further discuss proposed solutions for Issue 1 before a proposed decision is issued.

ORA opposes because creating a cap would negatively affect ratepayers by requiring them to cover the remaining upgrade cost.

TURN opposes this proposal because costs that exceed the Cost Cap would be borne by ratepayers, and there is no study to show that potential benefits to the ratepayers, if any at all, would exceed the potential costs to the ratepayers.

Issue 1 Appendices

Appendix A: Relevant Sections of Rule 21

Rule 21, Section G.3.a (Screen Q):

G. ENGINEERING REVIEW DETAILS

3. DETAILED STUDY SCREENS

a. Screen Q: Is the Interconnection Request Electrically Independent of the Transmission System?

Distribution Provider, in consultation with the CAISO, will determine, based on knowledge of the interdependencies with earlier-queued interconnection requests under any tariff, whether the Interconnection Request to the Distribution System is of sufficient MW size and located at a point of interconnection such that it is reasonably anticipated to require or contribute to the need for Network Upgrades. If Distribution Provider determines that no interdependencies exist then the Interconnection Request will be deemed to have passed Distribution Provider's Determination of Electrical Independence for the CAISO Controlled Grid. If Distribution Provider determines that interdependencies exist as described above, then Applicant may be studied under the Transmission Cluster Study Process as set forth in Section F.3.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 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 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 next 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.

Rule 21, Section F.3.d (Transmission Cluster Study Process):

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS

3. DETAILED STUDY INTERCONNECTION REVIEW PROCESS

d. Transmission Cluster Study Process

If Applicant's Interconnection Request fails Screen Q or elects to be studied under the Transmission Cluster Study Process, Applicant shall have the option of applying for Interconnection under the Transmission Cluster Study Process of the Wholesale Distribution Tariff in accordance with its provisions. If Applicant fails Screen Q, Applicant's Interconnection Request shall be deemed withdrawn under this Rule regardless of whether Applicant applies for Interconnection under the WDT.

An Applicant that chooses to apply under the Transmission Cluster Study Process of the WDT must file a valid Interconnection Request and post the applicable study deposit as set out in Distribution Provider's WDT. If Applicant chooses to apply under the WDT, then Applicant's Interconnection Request will be subject to the terms of Distribution Provider's WDT applicable to the Transmission Cluster Study Process, including those provisions establishing cost responsibility. Upon completion of the Transmission Cluster Study Process under the WDT, Applicants that are eligible for a State-jurisdictional Interconnection can, in accordance with the WDT, either execute the applicable Commission-approved Rule 21 Generator Interconnection Agreement for Exporting Generating Facilities or the WDT Generator Interconnection Agreement. Such Commission-approved Generator Interconnection Agreement for Exporting Generating Facilities will include the cost responsibility established in the Transmission Cluster Study.

If and when an Applicant submits a new interconnection request under the WDT, Applicant is under the jurisdiction of FERC. On the date the applicable Commission-approved Rule 21 Generator Interconnection Agreement for Exporting Generating Facilities is executed by Applicant, or Producer where those are different entities, and Distribution Provider, jurisdiction over the Interconnection reverts back to the Commission.

Appendix B: CAISO Tariff, Appendix DD, Section 4.2

4.2 Determination of Electrical Independence

An Interconnection Request will qualify for the Independent Study Process without having to demonstrate electrical independence pursuant to this Section 4.2 if, at the time the Interconnection Request is submitted, there are no other active Interconnection Requests in the same study area in the current Queue Cluster or in the Independent Study Process.

Otherwise, an ach Interconnection Request submitted under the Independent Study Process must pass all of the tests for determining electrical independence set forth in this Section 4.2 in order to qualify for the Independent Study Process. These tests will utilize study results for active Interconnection Requests in the same study area, including Phase I Interconnection study results for Generating Facilities in the current Queue Cluster and any system impact study (or combined system impact and facilities study) results for earlier queued Generating Facilities being studied in the Independent Study Process.

4.2.1 Flow Impact Test/Behind-the-Meter Capacity Expansion Criteria

An Interconnection Request shall have satisfied the requirements of this Section if it satisfies, alternatively, either the set of requirements set forth in Section 4.2.1.1 or the set of requirements set forth in Section 4.2.1.2.

4.2.1.1 Requirement Set Number One: General Independent Study Requests

The CAISO, in coordination with the applicable Participating TO(s), will perform the flow impact test for an Interconnection Request requesting to be processed under the Independent Study Process as follows:

(i) Identify the transmission facility closest, in terms of electrical distance, to the proposed Point of Interconnection of the Generating Facility being tested that will be electrically impacted, either as a result of Reliability Network Upgrades identified or reasonably expected to be needed in order to alleviate power flow concerns caused by Generating Facilities currently being studied in a Queue Cluster, or as a result of Reliability Network Upgrades identified or reasonably expected to be needed to alleviate power flow concerns caused by earlier queued Generating Facilities currently being studied through the Independent Study Process. If the current Queue Cluster studies or earlier queued Independent Study Process studies have not yet determined which transmission facilities electrically impacted by the Generating Facility being tested require Reliability Network Upgrades to alleviate power flow concerns, and the CAISO cannot reasonably anticipate whether such transmission facilities will require such Reliability Network Upgrades from other data, then the CAISO will wait to conduct the independence analysis under this section until sufficient information exists in order to make this determination. If the flow impact on a Reliability Network Upgrade identified pursuant to these criteria cannot be tested due to the nature of the Upgrade, then the flow impact test will be performed on the limiting element(s) causing the need for the Reliability Network Upgrade.

(ii) The incremental power flow on the transmission facility identified in Section 4.2.1.1(i) that is caused by the Generating Facility being tested will be divided by the lesser of the Generating Facility's size or the transmission facility capacity. If the result is five percent (5%) or less, the Generating Facility shall pass the flow impact test. If the Generating Facility being tested is tested against the nearest transmission facility and that transmission facility has been impacted by a cluster that required an upgrade as a result of a contingency, then that contingency will be used when applying the flow impact test.

(iii) If the Generating Facility being tested under the flow impact test is reasonably expected to impact transmission facilities that were identified, per Section 4.2.1.1(i), when testing one or more earlier queued Generating Facilities currently being studied through the Independent Study Process, then an additional aggregate power flow test shall be performed on these earlier identified transmission facilities. The aggregate power flow test shall require that the aggregated power flow of the Generating Facility being tested, plus the flow of all earlier queued Generating Facilities currently being studied under the Independent Study Process that were tested against the transmission facilities described in the previous sentence, must be five (5) percent or less of those transmission facilities' capacity.

However, even if the aggregate power flow on any transmission facility tested pursuant to this section (iii) is greater than five (5) percent of the transmission facility's capacity but the incremental power flow as a result of the Generating Facility being tested is one (1) percent or less than of the transmission facility's capacity, the Generating Facility shall pass the test.

If the Generating Facility being tested is tested against the nearest transmission facility and that transmission facility has been impacted by a cluster that required an upgrade as a result of a contingency, then that contingency will be used when applying the flow impact test.

The Generating Facility being tested must pass both this aggregate test as well as the individual flow test described in Section 4.2.1.1(ii), in no particular order.

4.2.1.2 Requirement Set Number Two: for Requests for Independent Study of Behind-the-Meter Capacity Expansion of Generating Facilities

This Section 4.2.1.2 applies to an Interconnection Request relating to a behind-the-meter capacity expansion of a Generating Facility. Such an Interconnection Request submitted under the Independent Study Process will satisfy the requirements of Section 4.2.1 if it satisfies all of the following technical and business criteria:

(i) Technical criteria.

1) The total nameplate capacity of the existing Generating Facility plus the incremental increase in capacity does not exceed in the aggregate one hundred twenty-five (125) percent of its previously studied capacity and the incremental increase in capacity does not exceed, in the aggregate, including any prior behind-the-meter capacity expansions implemented pursuant to this Section 4.2.1.2, one hundred (100) MW.

2) The behind-the-meter capacity expansion shall not take place until after the original Generating Facility has achieved Commercial Operation and all Reliability Network Upgrades for the original Generating Facility have been placed in service. An Interconnection Request for behind-the-meter capacity expansion may be submitted prior to the Commercial Operation Date of the original Generating Facility.

3) The Interconnection Customer must install an automatic generator tripping scheme sufficient to ensure that the total output of the Generating Facility, including the behind-the-meter capacity expansion, does not at any time exceed the capacity studied in the Generating Facility's original Interconnection Request. The CAISO will have the authority to trip the generating equipment subject to the automatic generator tripping scheme or take any other actions necessary to limit the output of the Generating Facility so that the total output of the Generating Facility does not exceed the originally studied capacity.

(ii) Business criteria.

1) The Deliverability Status (Full Capacity, Partial Capacity or Energy-Only) of the original Generating Facility will remain the same after the behind-the-meter capacity expansion. The capacity expansion will have Energy-Only Deliverability

Status, and the original Generating Facility and the behind-the-meter capacity expansion will be metered separately from one another and be assigned separate Resource IDs, except as set forth in (2) below.

2) If the original Generating Facility has Full Capacity Deliverability Status and the behind-the-meter capacity expansion will use the same technology as the original Generating Facility, the Interconnection Customer may elect to have the original Generating Facility and the behind-the-meter capacity expansion metered together, in which case both the original Generating Facility and the behind-the-meter capacity expansion will have Partial Capacity Deliverability Status and a separate Resource ID will not be established for the behind-the-meter capacity expansion.

3) A request for behind-the-meter expansion shall not operate as a basis under the CAISO Tariff to increase the Net Qualifying Capacity of the Generating Facility beyond the rating which pre-existed the Interconnection Request.

4) The GIA will be amended to reflect the revised operational features of the Generating Facility's behind-the-meter capacity expansion.

5) An active Interconnection Customer may at any time request that the CAISO convert the Interconnection Request for behind-the-meter capacity expansion to an Independent Study Process Interconnection Request to evaluate an incremental increase in electrical output (MW generating capacity) for the existing Generating Facility. The Interconnection Customer must accompany such a conversion request with an appropriate Interconnection Study Deposit and agree to comply with other sections of Section 4 applicable to an Independent Study Process Interconnection Request.

4.2.2 Short Circuit Test

The Generating Facility shall pass the short circuit test if (i) the combined short circuit contribution from all the active Interconnection Requests in the Independent Study Process in the same study area is less than five (5) percent of the available capacity of the circuit breaker upgrade identified in Section 4.2.1.1 and; (ii) total fault duty on each circuit breaker upgrade identified for the current Queue Cluster and active Independent Study Process Interconnection Requests in the same study area is less than eighty (80) percent of the nameplate capacity of the respective circuit breaker upgrade.

4.2.3 Transient Stability Test

The Generating Facility shall pass the transient stability test if the Generating Facility has requested interconnection in a study area where transient stability issues are not identified for active Interconnection Requests in the current Queue Cluster or Independent Study Process.

4.2.4 Reactive Support Test

The Generating Facility shall pass the reactive support test if the Generating Facility has requested interconnection in a study area where reactive support needs are not identified as requiring Reliability Network Upgrades for active Interconnection Requests in the current Queue Cluster or Independent Study Process.

Issue 2: Complex Metering

Issue 2: Should the Commission clarify the definition of "complex metering solutions" for storage facilities and, if so, how?

Proposal Summary

The following three proposals were developed by various stakeholders as part of the working group process to address Issue 2. The proposals are independent alternatives, meaning any combination may be selected. All proposals are consensus.

The Commission should clarify the definition of complex metering solutions by directing the utilities to:

- **Proposal 1:** Develop illustrative metering configurations and cost tables to provide more transparency in the application of complex metering solutions
    - **Consensus**
- **Proposal 2:** Post information on their websites clarifying requirements for non-export relays and controls for solar plus storage systems to maintain Commission-required Net Energy Metering (NEM) Tariff integrity requirements
    - **Consensus**
- **Proposal 3:** Support development of DC metering standards by participating in the EMerge Alliance initiative or equivlaent as utility resources allow
    - **Consensus**

This section presents a summary of the proposals only. The "Working Group Proposals" section further describes the proposals and the positions for and against.

Background

Metering Requirements to Protect NEM Integrity

The Commission developed new rules for NEM-paired storage in 2013-2014, following publication by the California Energy Commission of the seventh edition of the Renewables Portfolio Standard Eligibility Guidebook, which altered the definition of energy storage that may be considered an addition or enhancement to a renewable energy system. The resulting decision, D.14-05-033 (Decision), required customers to use the metering requirements of the NEM-Multiple Tariff provisions to ensure that energy exported for NEM credits only comes from renewable generating facilities (GFs).[14] Specifically,

[14] The Commission continues to actively consider issues regarding NEM-paired storage and NEM integrity in R.14-07-002. Recent developments include for instance issuance of D.17-12-005 to facilitate virtual net energy metering (VNEM) paired with a storage system. The Energy Division facilitated a public workshop earlier this year that included discussion of how to implement a non-import configuration for VNEM as provided in the decision. Tariff updates to the IOUs' VNEM tariffs are due later this month. Additional topics regarding NEM-paired storage,

for "large" NEM-paired storage facilities (solar facilities paired with storage greater than 10 kW and all other non-solar NEM paired storage facilities regardless of size), D.14-05-033 ordered that:

> *Large NEM paired storage GFs will be required to: 1) install a non-export relay on the storage device(s); 2) install an interval meter for the NEM-eligible generation, meter the load, and meter total energy flows at the point of common coupling; or 3) install interval meter directly to the NEM-eligible generator(s).* (Page 21)

As part of the discussion on this topic prior to the Commission drafting and adopting the Decision, solar and storage parties raised concerns that the cost of metering would be prohibitive and that utilities would too often err on the side of excessive requirements and associated charges for metering. SolarCity proposed a cost cap of $500 for metering. The Decision established a cap of $600, but also said the utilities can go beyond the cap if they determine that "complex metering solutions" are needed. The decision stated:

> *We also find that SolarCity's proposal to impose a cost cap is reasonable. We shall require the utilities to use their best efforts to install standard metering equipment whenever possible while interconnecting large GFs and will impose a $600 limit for fees associated with this metering requirement. However, the metering cost cap shall not apply to large GFs requiring more complex metering solutions to capture the required data for validating eligible NEM credits.* (Page 21)

Per the Decision, the IOUs filed proposed NEM Tariff revisions, that were approved by the Commission, that define standard and complex metering for NEM-paired storage as follows (from the SDG&E NEM Tariff):

> *SDG&E will install standard metering equipment whenever possible. Standard metering equipment for this purpose is comprised of two or more self-contained, single-phase, meters. The fee for installation of standard metering equipment is capped at $600.00.*
>
> *The $600.00 cap does not apply to metering for NEM Paired Storage requiring complex metering. Complex metering includes any configuration other than the standard equipment described above. The amount billed to a customer for complex metering varies and is based on actual costs incurred by SDG&E. A description of the costs associated with complex metering equipment will be included with the customer's invoice.*[15]

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including DC coupled systems, were submitted to the Commission for consideration in the Petition for Modification submitted by CALSSA (then CalSEIA) on September 1, 2017.

[15] Similarly, SCE and PG&E define complex metering in the context of NEM-paired storage in its NEM tariffs as (1) more than two self-contained meters in addition to the SCE revenue meter(s); or (2) any non-self-contained meters (i.e., those that include Circuit Transformers/Power Transformers) not including the SCE revenue meter(s). The $600 metering cost cap does not apply to Complex Metering.

Stakeholder Desire for Additional Guidance Regarding When Complex Metering is Necessary

Solar and storage companies voiced that the lack of a clear definition of when complex metering is required is problematic because it makes understanding meter configurations and costs more challenging. Stakeholders desire greater transparency regarding how the need for complex metering is determined and applied. Although not providing specific examples, CALSSA spoke to instances represented to them where project developers considered metering costs to be excessive and instances in which facilities that appeared to be similar in size and configuration had different metering solutions. However, after the IOUs explained their rationale for different metering configurations, CALSSA agreed that transparency is the best next step in the hope that better understanding and predictability could alleviate the tension.

Initial Stakeholder Concerns Regarding Complex Metering for DC-Coupled Systems

DC-coupled systems, in which the solar and storage have separate inputs into a single inverter, cannot be configured with the same type of metering solutions used for AC-coupled systems, in which the solar and storage each have separate inverters. Because the Decision declined to adopt alternate metering for DC-coupled systems, stakeholders are uncertain whether DC-coupled storage systems greater than 10 kW have a viable path to interconnect in compliance with NEM Tariff provisions protecting NEM integrity. Stakeholders sought clarification regarding whether metering involving two meters and a tailored billing treatment could serve as a viable path for DC-coupled systems larger than 10 kW to interconnect under NEM. If the answer is no, stakeholders seek to identify the metering and/or configuration schemes that would offer a viable path for DC-coupled systems to interconnect under NEM, regardless of whether the requirement is standard or complex metering.

Working Group Consensus on Whether to Clarify the Definition of Complex Metering

Non-IOU working group members propose that the Commission should require the IOUs to provide additional clarification on the definition of complex metering and when complex metering is required. They believe that providing more upfront transparency regarding how utilities determine the need for complex metering would reduce uncertainty in costs and the timing associated with the interconnection process and further Commission goals of streamlining interconnections.

For DC-coupled systems specifically, CESA initially sought clarity regarding whether a standard metering solution such as a dual meter/billing solution could in fact protect NEM integrity. However, the working group determined that such a solution is not viable for storage capable of grid charging due to the potential for time-of-use rate arbitrage.[16] The working group thus agrees that, for DC-coupled systems, there is no need for the Commission to clarify the definition of standard and complex metering, as such solutions may not be applicable to DC-coupled systems capable of grid charging. However, non-IOU stakeholders agree that the Commission should direct the utilities to provide additional stakeholder transparency about existing options for DC-coupled systems to interconnect as recommended in Proposal 2.

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[16] Appendix A provides more detail on why metering solutions are not available to DC-coupled systems.

The IOUs support providing additional transparency on project factors that trigger the need for complex metering. Appendix B was presented during the working group meetings and the IOUs believe that this type of information provides additional transparency and is proposed to be made available via the IOUs respective public interconnection websites.

Working Group Proposals

The following three proposals were developed by various stakeholders as part of the working group process to address Issue 2. The proposals are independent alternatives, meaning any combination may be selected. All proposals are consensus.

Proposal 1: Utilities will develop illustrative metering configurations and cost tables to provide more transparency in the application of complex metering solutions to be posted on each utility's respective website

Status

Consensus

Discussion

In response to stakeholder concerns regarding transparency in the application of the complex metering arrangements, each IOU agrees to develop illustrative materials as follows:

1. An illustrative cost table based upon existing metering arrangements utilized by the IOU. A metering cost table is proposed to be provided for illustrative purposes only, and will not be binding towards the actual metering costs. The metering cost table will include the anticipated cost[17] of procuring, installing, and maintaining the required metering arrangements and may vary among the IOUs. For each meter type listed, the table will provide the voltage, arrangement (single-phase or three-phase), amperage limitation, and whether the meter is a smart meter or non-smart meter. By way of example, PG&E provided the metering cost table below as part of the initial IOU proposal and discussed it during the Working Group One meeting held on November 9, 2017. Each IOU will develop an illustrative metering cost table as directed in the Commission's decision adopting the working group proposals.[18]

Table 1 – Example of metering details to help inform market and set expectations

[17] Costs incurred by the interconnection customer, e.g., the meter enclosure, are not represented.

[18] Per R.17-07-007 Scoping of Assigned Commissioner and Administrative Law Judge at p. 14, the Proposed Decision regarding Working Group One and Two Proposals is scheduled to be issued in the Fall of 2018.

Smart Meter or Non-Smart Meter	Meter Description	Average Cost (including material and labor)
Smart Meter	Single phase, self-contained meter (600 V)	$405
Smart Meter	Transformer-rated meter (600 V):	$1,410
Smart Meter	Primary Transformer-rated meter (5 kV)	$7,240
Smart Meter	Primary Transformer-rated meter (15 kV)	$9,415
Smart Meter	Primary Transformer-rated meter (25 kV)	$15,000
Non-Smart Meter	Single phase, self-contained meter (600 V)	$1,060
Non-Smart Meter	Transformer-rated meter (600 V):	$2,160
Non-Smart Meter	Primary Transformer-rated meter (5 kV)	$8,000
Non-Smart Meter	Primary Transformer-rated meter (15 kV)	$10,170
Non-Smart Meter	Primary Transformer-rated meter (25 kV)	$15,700
Non-Smart Meter	Transmission Transformer-rated Meter (60-230 kV)	$69,000

2. Examples of common configurations that typically require standard or complex metering. By way of example, SCE provided configurations in Appendix B as part of the initial IOU proposal and discussed them during the Working Group One meeting held on November 9, 2017. The final example configurations for each IOU will be developed upon the Commission's adoption of the Working Group One Proposals.

This information will be posted to each utility's interconnection website and will be updated as needed.

Proposal 2: Utilities will post information on their websites clarifying requirements for non-export relays and controls for solar plus storage systems to protect NEM integrity

Status

Consensus

Discussion

D.14-05-033 requires large NEM paired systems to follow one of three paths to ensure that energy exported for NEM credits only comes from renewable generation:

> *Large NEM paired storage GFs will be required to: 1) install a non-export relay on the storage device(s); 2) install an interval meter for the NEM-eligible generation, meter the load, and meter total energy flows at the point of common coupling; or 3) install interval meter directly to the NEM-eligible generator(s).* (Page 21)

Many customers installing NEM paired storage have installed AC-coupled systems and used the third option. For DC-coupled solar plus storage projects, working group stakeholders agreed that the second and third paths, which involve using meters to maintain NEM eligibility, are not viable paths to interconnect under NEM due to 1) the unavailability of revenue-grade DC metering provisions, and 2) the potential for time-of-use rate arbitrage when applying AC metering to estimate renewable energy credits in use cases where storage is capable of grid charge. Appendix A provides more detail on why metering solutions are not available to DC-coupled systems.

The working group agreed that installation of a non-export *relay* on the DC-coupled storage device(s) does ensure that energy exported across the Point of Common Coupling (PCC) from a NEM-paired system originates from the renewable generator, and thus offers a viable path for DC-coupled NEM paired storage systems larger than 10 kW to interconnect under NEM.[19]

At the November 9, 2017 working group meeting, the IOUs clarified that the definition of "non-export relay" for this purpose does not need to be limited to an external device that is a stand-alone relay. The relay function for this purpose can be achieved with a non-export *control* for purposes of interconnecting a DC-coupled solar and storage system under the NEM Tariff if the control is configured in a way that would comply with the NEM Tariff and maintain NEM integrity.

Certification standards for such controls are under development. When such standards are approved and equipment is certified to those standards, the IOUs will allow them to be used in DC-coupled systems for NEM compliance. The IOUs are also working with stakeholders to develop interim standards that can be used until national standards are finalized. In addition, the IOUs stated that non-certified control schemes can be reviewed, approved if compliant with IOU requirements, and validated via commissioning if deemed necessary in accordance with existing Rule 21 allowances, but that certification is a much more efficient path for interconnection.[20]

CALSSA's Petition for Modification and the Use Case Allowing Storage to Discharge to Meet Onsite Load at Times of Grid Export

This renders moot part of a petition for modification filed by CALSSA in September 2017 to allow the interconnection of DC-coupled solar plus storage systems under the NEM tariff.[21] The petition proposed to require utilities to allow two use cases. The first, and likely more widely desired, is a configuration in which the storage device can only be charged from solar. This remains an active proposal before the Commission and was not addressed by the working group.[22] The second is a configuration in which the storage device can charge from the grid but can only discharge to meet onsite load.

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[19] The non-export relay (or non-export control) would be installed to monitor the load side of the main meter. Upon sensing export to the grid from the NEM-paired storage system, the relay would prevent the battery from discharging, therefore ensuring generation exported across the PCC is from the NEM eligible generators. The customer can proceed with designing their system under the non-export relay option per existing written NEM Tariff rules (e.g. Special Condition 10 in PG&E's NEM 2 Tariff).

[20] In accordance with Rule 21 Section L.7.a, control schemes can be reviewed for compliance prior to certification. As noted in the Response of Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas and Electric Company to the Petition of the California Solar Energy Industries Association for Modification of Decision D. 14-05-033 (pg. 3), certification of control schemes is a key aspect of ensuring safety and reliability of the grid as it provides the utility assurance that a control scheme will perform as proposed.

[21] "Petition of the California Solar Energy Industries Association for Modification of Decision D. 14-05-033 to Allow DC-Coupled Solar Plus Storage Systems," filed in R.14-07-002 on September 1, 2017.

[22] Stakeholders are actively seeking consensus on this use case in relation to the petition and other activity in R.14-07-002.

That second use case is similar to the non-export control that the utilities in this working group have clarified is acceptable. Although the CALSSA petition envisioned that the storage device could not discharge at all at times when solar is discharging to the grid, discussion in the working group included a use case in which a storage device can discharge to meet onsite load at times of grid export as long as the system design makes it impossible for more power to flow to the grid than is generated by a NEM eligible generator. Specifically, a controller would be utilized such that it measures the power at the load side of the PCC and provides an inhibit output signal to the battery's control system when power exported to the Distribution System is greater than the power generated by the NEM eligible generator. The battery control system would use the inhibit output signal to prevent export of more power than is being generated by the NEM eligible generator.

The IOUs support further exploration of the proposed control scheme but have not seen technical details. The IOUs are interested in determining if the control scheme can accurately perform this comparison and control the energy storage system while maintaining NEM integrity.

Non-IOU working group members note that while traditional relays represent a compliant path to interconnect under NEM rules, they are generally considered both very expensive and impractical to implement.[23] The working group anticipates customers with DC-coupled systems will use a non-export control scheme rather than a relay if they choose to maintain NEM integrity by limiting export of the storage device.

To raise developer awareness of acceptable non-export options for large AC- and DC-coupled NEM-paired storage projects, the working group recommends the IOUs post the following information on their websites:

- Additional technical guidance for acceptable non-export relay and control configurations, as shown in Appendix C
- Citations to relevant provisions in the NEM and Rule 21 tariffs

Proposal 3: Utilities will support development of DC metering standards by participating in the EMerge Alliance initiative or equivalent as utility resources allow

Status

Consensus

Discussion

In order for a DC-coupled system to technically and cost-wise replicate a standard metering arrangement utilized by an AC-coupled system, a DC meter may be required to directly measure the output of the NEM-eligible generator on the DC side. However, there are currently no standards for revenue-grade DC meters as there are for AC meters. As the number and variety of behind-the-meter

[23] A physical relay can require manual reset and prevent supply to local loads under certain conditions, which makes it an impractical option to implement.

DC applications grow, the development of a DC metering standard may become increasingly important to support technology-agnostic interconnection rules.

Duke Energy and EMerge Alliance are currently working on developing a DC metering standard, and the working group requests involvement from the California IOUs to support the standard development. It was expressed by some working group members that California utility involvement is needed to ensure the standard is serviceable and ultimately accepted by the California utilities.

In response to stakeholder requests regarding IOU participation in standard development efforts, the IOUs agree to participate in the EMerge Alliance effort or equivalent effort led by a nationally recognized testing laboratory as resources allow. For purposes of initial outreach, each of the IOU Regulatory Case Managers for the Rule 21 proceeding will act as the first point of contact.

Additional support for development of DC metering standards, beyond the EMerge Alliance initiative, will require further analysis by the IOUs of the incremental costs to integrate DC meters into utility operations. This includes upgrades to billing systems, which are currently AC-based. The working group agreed that any additional analysis by the IOUs of these incremental costs would not occur prior to at least a draft of a DC metering standard being issued for stakeholder review, and the working group agrees asking the Commission to direct any further analysis is outside the current scope of this Rulemaking.

Issue 2 Appendices

Appendix A: Explanation of inability to meter DC-coupled solar and storage systems (CESA)

This appendix describes the technical rationale supporting the working group's determination that a metering solution may not be sufficient to maintain NEM integrity.

AC-coupling and DC-coupling are the two different methods of combining a solar and energy storage system. An AC-coupled system has an inverter for the storage and a separate inverter for the solar. It is therefore possible to directly meter the AC output of the solar as seen in Figure 1 on the left. DC-coupled systems combine the solar and storage on the DC side of the single inverter. This means any meter on the AC side records both solar and storage as seen in Figure 1 on the right.

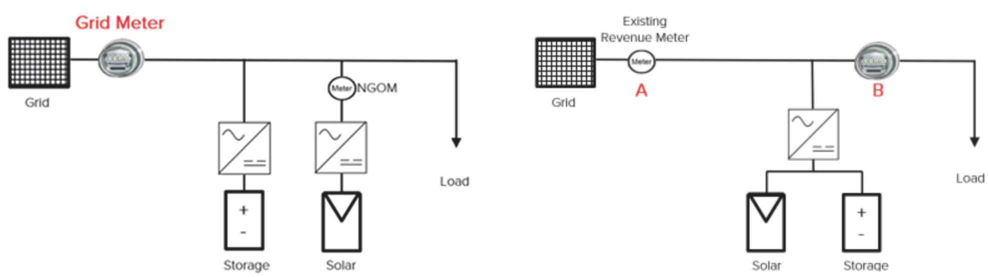


Figure 1 – AC-coupled systems left with a NGOM directly metering the AC output of the solar and DC-coupled system right, where no AC point exists to directly monitor the solar

CESA proposed a metering arrangement as seen in Figure 2 below. This arrangement would calculate the solar generation effectively by recording all charging of the energy storage (meter A – meter B) allowing this to be deduced from all exports. Whilst this arrangement allows all energy flows to be accurately captured, it is not possible to use this arrangement with time of use rates. With time of use rates, it is not possible to determine when the storage is discharged and when the solar is generating, only that the total amounts are accurate. There is currently no other proposed way to monitor DC-coupled systems with two or more self-contained AC meters. As such DC-coupled systems cannot participate under the existing definition unless additional measures are taken such as blocking export.

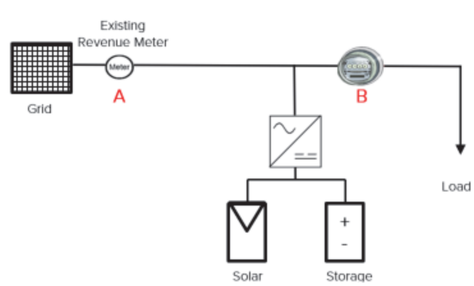


Figure 2 – Proposed metering arrangement for DC-coupled solar plus storage systems

To further illustrate the inability to utilize the current definition, the time at which the energy storage is charged is known by subtracting Meter B from Meter A as seen in Figure 3.

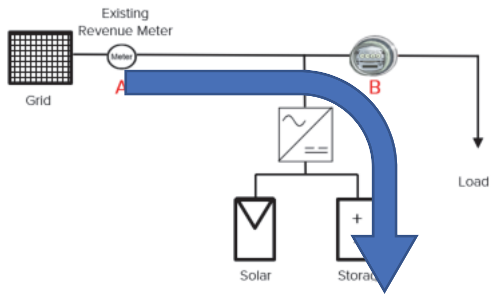


Figure 3 – Proposed metering arrangement for DC-couple solar plus storage systems

Energy that is discharged cannot be determined to be solar or storage grid power which is the challenge that cannot be reconciled under the existing definition. It is known how much grid power has been stored so this amount can be subtracted to get the total solar generation but there is no way to know at what time interval the solar was generating or the stored grid power is exported. This can be seen in Figure 4 and led to concerns regarding energy arbitrage by charging storage during low TOU rates and discharging storage during high TOU rates. This is the exact behavior desired to help the grid, however under the TOU rate, the IOUs stated that this arbitrage is not acceptable.[24]

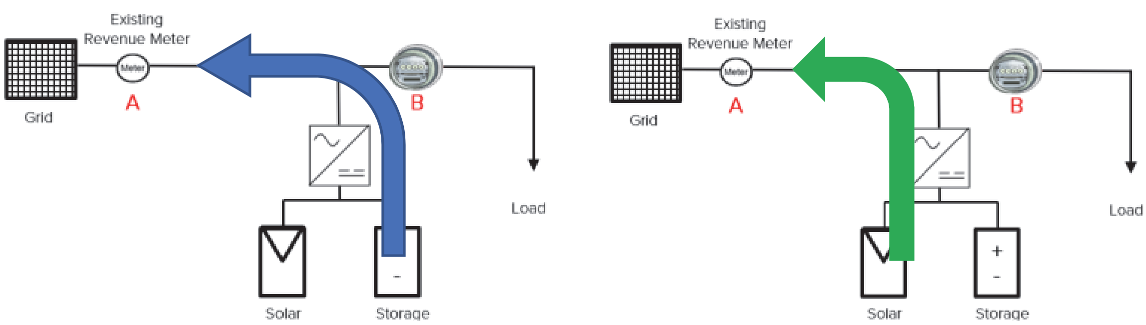


Figure 4 – Proposed metering arrangement for DC-couple solar plus storage systems

It is possible to know the time of charging as shown and if all charging is attributed the highest TOU tier rate it would protect against any arbitrage benefit. This becomes a complicated situation which may have unintended consequences (such as no disincentive to charge during peak) and is not recommended.

This situation does highlight the need for appropriate price signals for customers to respond to when operating energy storage beyond NEM. This also highlights the limitation of existing rules to address interconnection of DC-coupled systems.

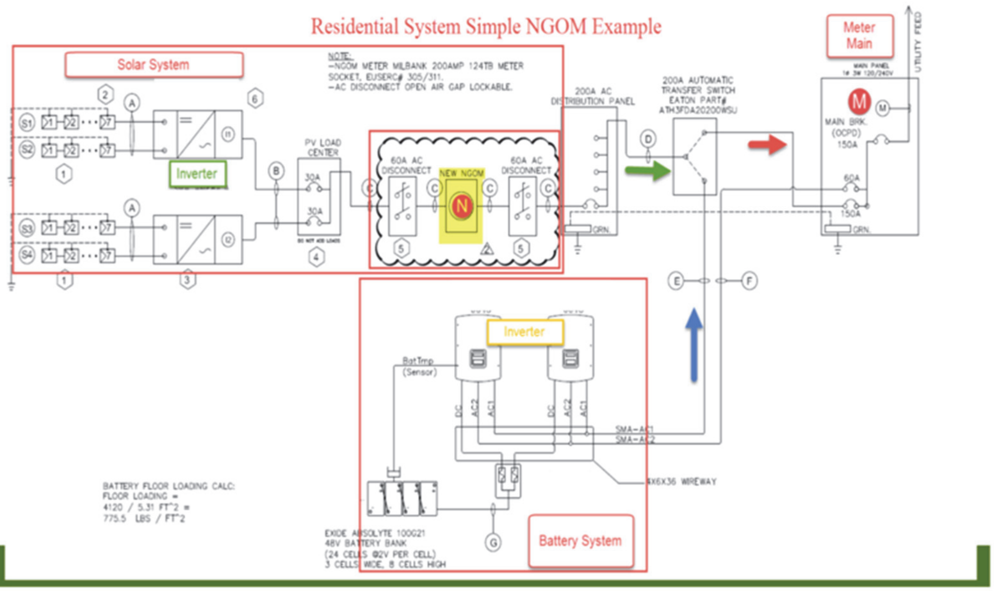
[24] Outback notes that separately, the Commission may wish to give guidance as to whether or not arbitrage is acceptable; as noted above, this metering solution accurately captures all energy inputs and outputs, the question appears to be whether PV power needs to be exported at the exact moment that it is generated.

Energy arbitrage operation of energy storage can greatly assist the grid, by customers responding to price signals. Current NEM TOU rates may not be appropriate, but longer term a framework to drive customer charging and discharging for the benefit of this grid needs to be put in place.

Appendix B: SCE Complex Metering Solutions - NGOM Meter Examples (Illustrative Purposes Only)

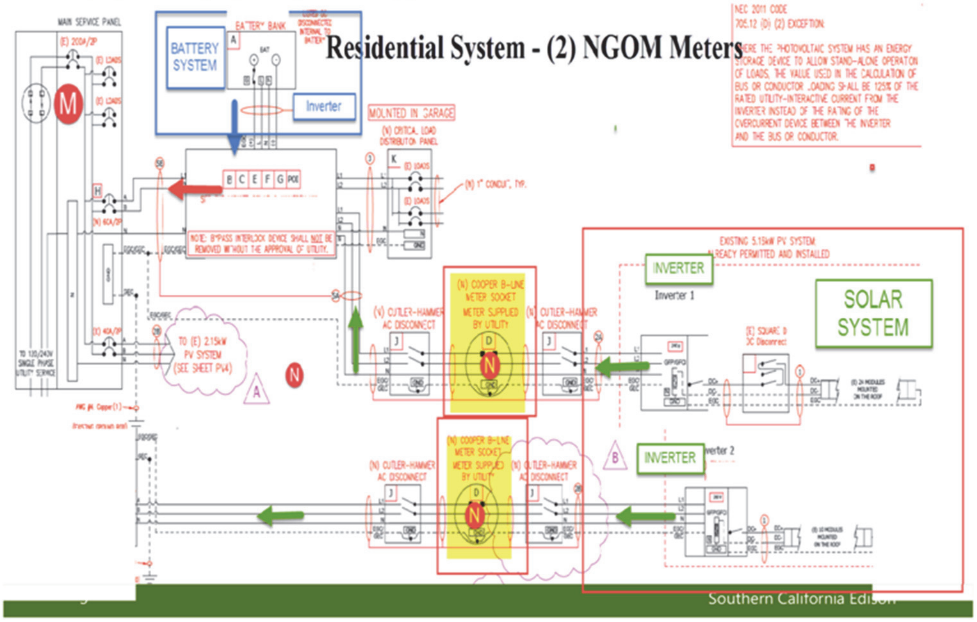
Simple Meter Solution - Residential
Self Contained Meter with Less than 200A

- The example below illustrates a “Simple Meter” solution for a residential NEM paired storage project. The maximum amperage for a self contained meter is 200A. This self contained NGOM covers most residential applications.



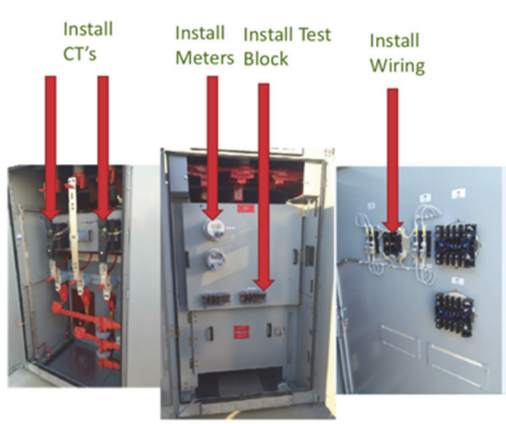
Simple Meter Solution – Residential Example

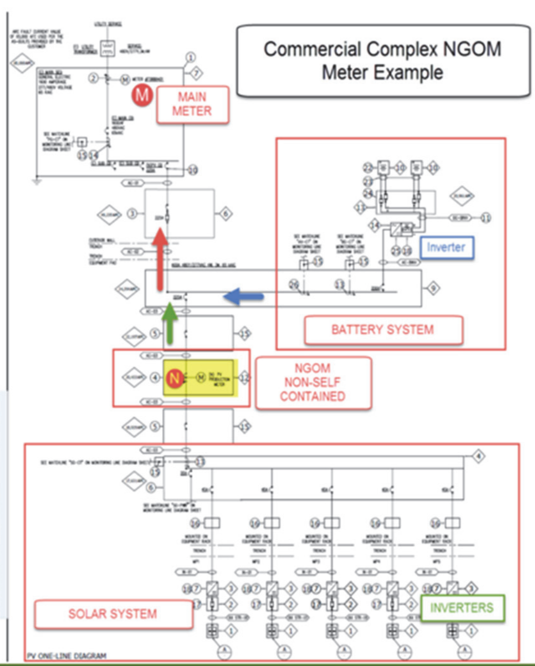
- The example below illustrates a "Simple Meter" solution for a residential NEM paired storage project. This project required two (2) NGOM meters due to customers design.



Complex Meter Solution- Non Self Contained NGOM

- The following example shows a complex meter solution for a NEM paired storage. The picture below shows the wiring requirements and the installation of current transformers inside the switchboard bussing.





4 Southern California Edison

Appendix C: Illustrative Language Clarifying Technical Requirements for Non-Export Relays and Controllers

The following is illustrative language clarifying technical requirements for non-export relays and controllers. In Proposal 2, the working group recommends the IOUs post this language, or language similar to this, to their interconnection webpages to raise developer awareness of acceptable non-export options for large AC- and DC-coupled NEM-paired storage projects.

This language is adapted from PG&E's interconnection handbook. SCE and SDG&E will need to modify the language to align it with the organization of their technical guidance documents.

Rule 21 Non-Export Relay and Controller

Non-Export Relays to date have been utilized by Interconnection Customers for non-exporting generating facility projects that select Option 1 under Screen I. As a result, technical requirements for relays are based on protection considerations and designed for non-export facilities. Rule 21's Screen I Option 1 language from PG&E's Rule 21 is shown below which is consistent across IOUs. Similar language is contained within SCE's and SDG&E's Rule 21.

> Option 1 ("Reverse Power Protection"): To ensure power is never exported across the PCC, a reverse power Protective Function may be provided. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay. For multiple tariff interconnections refer to Section J.8.

NEM facilities that are adding a non-NEM eligible generator component, can do so under special condition 4 under the NEM tariff. For those facilities, the response to Screen I in Rule 21 would be Yes and the project continue on to Screen J. Options 1-4 for non-export and option 5 and 6 for inadvertent export do not apply to NEM as NEM projects are allowed to regularly export across the Point of Common Coupling.

> i. Screen I: Will power be exported across the PCC?
>
> - If Yes, Continue to Screen J. This includes Options 5 and 6 below.
> - If No, then to ensure that the Generating Facility does not export across the PCC, the Generating Facility must incorporate one of the first four options shown below. Following that selection, Initial Review is complete.

Under special condition 4 and special condition 10 (NEM paired storage) under the NEM tariff, an interconnection customer can elect 1 of 3 options to ensure the non-NEM eligible generator component is not receiving NEM treatment. Non-Export relay is an option currently and thus the Interconnection Customer can elect to install a non-export relay which is not required for interconnection but for the purposes of satisfying NEM program eligibility requirements. Excerpt from PG&E's NEM2 Rate Schedule is shown below. Similar language is contained within SCE's and SDG&E's NEM Tariff.

g. Multiple Tariff Facility Configurations and Metering.

2) For all eligible combinations of NEM-Eligible Constituent Groups and non-NEM eligible Constituent Groups, the Customer-Generator must select one of the following options:

a) **The Non Export Relay Option:** A Customer-Generator must install a Non-Export relay on their non-NEM Constituent Generator Groups and install metering as follows: 1) If there is only one type of NEM-eligible Constituent Generator Group then metering at the PCC is all that is required and the terms of the appropriate NEM2 tariff for that group will apply; 2) If there are two or more types of NEM2-Eligible Constituent Generator Groups, then Metering at the PCC and NGOM metering of each NEM2-Eligible Constituent Generator Group is required. The requirements of Special Condition 4.f and 4.g apply.

SPECIAL CONDITIONS: (Cont'd.)

10. NEM Paired Storage (Cont'd.)

d. Storage Size Dependent Requirements

Requirements differ depending on the size of the NEM Paired Storage and whether it is paired with a solar generator or not. The storage device size is determined by the inverter alternating current nameplate rating.

e. Requirements for Large NEM Paired Storage (i.e., All NEM Paired Storage Devices except Solar NEM paired with Storage Sized 10 KW and Smaller)

For NEM-paired storage systems with storage devices larger than 10 kW, the NEM Paired Storage shall have a maximum output power no larger than 150% of the NEM-eligible generator's maximum output capacity.

Large NEM Paired Storage systems are required to either:

1) install a non-export relay on the storage device(s);

2) install an interval meter for the NEM-eligible generation, meter the load, and meter total energy flows at the point of common coupling; or

3) install an interval meter directly to the NEM-eligible generator(s).

When a relay is being utilized for either interconnection or for NEM program eligibility, relay schemes must be reviewed and approved, including during commissioning testing, if deemed necessary. A typical relay scheme measures power at the Point of Common Coupling (PCC) and provides a trip output if certain conditions are met to separate the generating facility. Typically, trip outputs have been connected to a circuit breaker to separate the generating facility from the electrical system to mitigate the reverse or under power condition.

Commissioning requirements are described in Rule 21 Section L.7.a. Excerpt from PG&E's Rule 21 is shown below. Similar language is contained within SCE's and SDG&E's Rule 21.

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.

If a non-export relay is elected for NEM MT program eligibility, there are a few methods from which customers can elect. All relay schemes however must be reviewed and approved including during commissioning if deemed necessary. In response to Issue 2 per R.17-07-007, additional information on the non-export relay option is provided for Battery Storage plus PV systems.

There are two categories of "*non-export relay*" options covered below:

1. Under Consideration Control Options – use cases that were discussed in this working group through inverter controls to address NEM integrity
2. Existing Control or Relay requirements – use cases that utilities have considered acceptable to date and continue to accept

Control Options for Battery Storage plus PV systems

- Control Scheme in-lieu of a physical non-export relay
  In-lieu of a physical non-export relay, implement a control scheme that meets 1 of 2 uses cases:
  1) Prevent power from the energy storage system discharging across the point of common coupling to the distribution grid.
  2) Prevent the energy storage system charging from the distribution grid.

These options are outlined in CalSEIA's PFM[1] which describe <u>some</u> suitable options for achieving these desired, no grid charging and prevention of export functions. However, other methods and mechanisms to achieve these use cases will be accepted if they are effective at achieving one of the two above use cases. The IOUs support further exploration and certification of these schemes and look forward to participating in next steps related to the PFM.

<u>Existing requirements for Battery Storage plus PV systems</u>:

- <u>Inhibit Output of Battery Controller</u>
  A non-export relay device or controller is installed at the PCC and measures the power at the PCC and provides an inhibit output signal to the battery's control system when power is exporting to the Distribution System. The battery control system must use the inhibit output signal to prevent the system from discharging from the battery storage system. The IOUs support this scheme as long as it passes the Pre-Parallel Inspection.

  An excerpt from PG&E's Rule 21 Section L.7.a.iii Non-Exporting Test Procedures is shown below that covers additional details on this method. Similar language is contained within SCE's and SDG&E's Rule 21.

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

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.

- <u>Non-Export Relay - Separate Inverters for Battery Storage & PV System</u>[25]
  A Non-export relay device is installed at the PCC[26]. It measures the power at the load side of the PCC and provides a trip output signal to the battery storage A/C system breaker when power is exporting to the distribution system. The battery's A/C system breaker must use the trip output signal to trip the battery, preventing discharge of the battery storage system

- <u>Non-Export Relay - Same Inverter for Battery Storage & PV System</u>

[25] Stakeholders note that tripping breakers is very problematic for most storage systems. Breakers generally do not include the ability to reset, and physically disconnecting the batteries may cause operating problems. This reinforces the need for control options to manage operation.

[26] Tesla would like to see the language changed so that rather than saying "at the PCC, it would instead say "at the load side of the PCC."

A Non-export relay device is installed at the PCC[27]. It measures the power at the load side of the PCC and provides a trip output signal to the battery DC system breaker when power is exporting to the distribution system. The battery's DC system breaker must use this trip output signal to prevent the battery storage system from discharging.

The following sections are PG&E's technical requirements for relays and are provided for illustrative purposes only. SCE and SDG&E requirements are similar.

A list of PG&E approved relays is provided on pages 27 and 28 of Section G2 of PG&E's Transmission Interconnection Handbook, available on line at:
<http://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/g2final.pdf>
<https://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/app_r.pdf>

Pre-parallel Inspection Requirements – PG&E

Please note upon notification of the generator(s) readiness for the pre-parallel inspection, it can take up to 30 days for the pre-parallel inspection due to available resources. The following items must be completed prior to the scheduling of the inspection:

- All required agreements executed.
- There must be an accessible, visible and lockable disconnect switch. (This must be shown on the single line drawing. Include manufacturer name and model number.)
- A copy of the final signed building permit from the local authority having jurisdiction over the installation of the co-generation system is provided.
- If required, all electric work by PG&E is completed.
- If required, gas service/meter (PG&E owned) installation is completed.

Once the inspection is scheduled, our Station Test Department requires the following information be provided a minimum of 15 days prior to the inspection:

- Single line and three-line relay drawings approved. (An electronic version is preferred.)
- The G5-1 Form completed and returned electronically. (Will be provided)
- Basic Info Requirement Form completed and returned electronically. (Will be provided)
- Field "bench test" of relays approved. (An electronic version is preferred.)
- Battery Discharge Test Report and Commissioning Test Checklist. (Form will be provided)

[27] Tesla would like to see the language changed so that rather than saying "at the PCC, it would instead say "at the load side of the PCC."

Issue 3: Material Modifications

> ***Issue 3: How should the Commission clarify the definition of a "material modification" to a project and what should be the procedures for processing these modifications?***

The working group identified a need to clarify the definition of material modification for two types of modifications:

I. Modifications to *interconnection applications* (e.g. decreasing system size to avoid upgrades)
II. Modifications to *existing facilities with Permission to Operate* (e.g. maintenance, retrofit)

They are distinct enough that the working group addresses them separately: the proposal first addresses making modifications to pending interconnection applications (pp. 43-48), and then addresses making modifications to existing facilities (pp. 48-63).

Proposal Summary

To clarify the definition of material modifications to *interconnection applications*, the working group recommends the Commission modify Rule 21 to allow the following modifications under Fast Track (there is **consensus on the core proposal**):

- **Like-for-like**[28] **equipment replacements** that meet the following criteria:
    - The equipment replacement does not increase facility size[29]
    - Any decrease in size does not exceed 20%
    - No upgrades or mitigations are identified

[28] Definition of "Like for Like": For inverters, like for like means certified, same nameplate or smaller, same fault current or smaller. For solar panels, like for like means certified, same CEC-AC rating of the system or smaller. For batteries, like for like means same or less kWh & kW rating (see the following footnote), and same operating profile. For transformers, like for like means same connection type, same or smaller impedance and capacity.

[29] Definition of "Size": For the purposes of this proposal, system size is defined as the limiting factor that determines the maximum generating facility capacity. For solar systems, the limiting factor is the lesser of inverter nameplate capacity (kW) or maximum solar output (CEC-AC rating) for PG&E and SDG&E or inverter nameplate capacity (kW) for SCE. For energy storage systems, both the inverter nameplate capacity (kW) and the capacity of the storage device (kWh) are considered in the definition of size (see below). For all other generation types, the limiting factor is the gross nameplate rating of the generator.

The IOUs require kWh in addition to kW for energy storage systems. KW is critical as stakeholders note for maximum capacity to determine if the electric system can handle the energy storage system from a reliability perspective. KWh is important from a capacity and modeling perspective. This is not important for other resources such as solar which is modeled to perform when the sun is out. Energy storage systems need to be modeled based on intended operation mode and duration against load data.

- **Size reductions** that meet the following criteria:
    - The size reduction does not exceed 20%
    - The customer pays for any upgrades or mitigations identified
- **Size reductions to avoid upgrades** that meet the following criteria:
    - The size reduction does not exceed 20%
    - The customer pays a $300 fee for the utility to conduct a re-study to validate that no other DERs shall be impacted due to this modification request.
    - The re-study finds that no other DERs shall be impacted

To recommend procedures for processing modifications to *existing facilities with Permission to Operate*, the working group identified seven modification use cases and defined four options for processing modifications based on the modification's potential impact on the distribution system. The working group discussion then turned to determining which use cases should be processed under which process options. Little consensus was found between utilities and stakeholders on this question, and even the utilities' proposals differed. Party positions on how to process modifications also varied greatly depending on the attributes of the individual use case. Thus, this report presents the proposals of the working group by use case, and recommends the Commission determine how to proceed on each use case individually.

The table below summarizes stakeholder proposals by use case. Green indicates consensus and pale red highlights use cases where consensus has not been reached.

Table: Stakeholder Positions on How to Process Modifications to Existing Facilities, by Use Case

Process Options:
• Process Option 1: No notification is required
• Process Option 2: Notification is required but the customer can proceed with building the system and turning on the system without waiting for utility approval
• Process Option 3: Abridged/Streamlined interconnection request is required and the customer must wait for utility approval to turn on the system (engineering review required)
• Process Option 4: Normal interconnection request

Use Case	Use Case Description	Proposed Process Option: PG&E	SCE	SDG&E	Non-IOU Stakeholders
1	Replacing equipment with exact same equipment type (i.e. same make and model) or performing upgrades to inverter firmware that do not affect grid interactions (e.g. fixes to software bugs, improving MPPT algorithm to increase energy yield)	1	1	3	1

2	Replacing equipment "like-for-like", where system output does not exceed what is listed in the original interconnection agreement and operating mode[30] is not adjusted	3	2	3	1/2
3	Replacing equipment that may increase the nameplate capacity of the system, but which employ firmware controls that limit the real power output to the inverter listed size in the original interconnection agreement	4	4	4	2
4	Adding storage capacity (kWh) to an existing storage facility without changing inverter (e.g. increasing a 1-hour system to a 2-hour system)	3	3	3	1/2
5	Adding or replacing equipment such that system capacity increases and no firmware or other controls are employed to limit the real power output to the inverter listed size in the original interconnection agreement	4	4	4	4
6	Adding storage to an existing generating facility that does not have storage[31]	4	4	4	4
7	Changing inverter operating characteristics (e.g. some smart inverter settings[32], operating mode, export limits)	4	4	4	4

This section presents a summary of the proposals only. The "Working Group Proposals" section further describes the proposals and the positions for and against.

Type I: Modifications to Interconnection Applications

Background

Customers must sometimes make modifications to pending interconnection applications to accommodate changing business conditions and product availability. Rule 21 allows for some modifications to be made without requiring an applicant to withdraw and reapply so long as those modifications are not "material" per the following definition:

[30] As used here, "operating mode" refers to the operational profile of the system relevant to the assessment of the system's impacts on the distribution system for purposes of interconnection review/study. Operational modes are "No Grid Charging", "Peak Shaving" or "Unrestricted Charging" as outlined on p.6 of PG&E's "Guide to Energy Storage Charging Issues for Rule 21 Generator Interconnection," (https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/GuidetoEnergyStorageChargingIssues.pdf).

[31] Note that creating a notification-only process for adding non-exporting storage will be discussed in Working Group Two. This is Issue 11 in the October 2017 scoping memo.

[32] The working group did not discuss in detail the use case for updating inverters to be compliant with Phase 2 and 3 smart inverter requirements. The utilities note that updating inverters to be compliant with these requirements will require some back and forth between the customer and utility to set up communications between the inverter and the utility's system. The utilities are committed to making this process as efficient as possible.

> ***Material Modification****: Those modifications that have a material impact on cost or timing of any Interconnection Request with a later queue priority date or a change in Point of Interconnection. A Material Modification does not include a change in ownership of a Generating Facility.* (Section C)

For projects applying under Rule 21's Detailed Study process, Rule 21 specifies several types of modifications that will be considered non-material.[33] However, for projects applying under Rule 21's Fast Track process (the vast majority of DER interconnections), Rule 21 does not specify modifications that will be considered non-material. This is in part because Fast Track was designed to *expedite* review of projects not expected to create a significant impact to the electrical grid, and requiring utilities to process ad hoc modifications could result in reduced processing speeds for all Fast Track projects.

Initial Stakeholder Concerns

Rule 21 currently addresses Fast Track modifications as follows:[34]

> *No changes may be made to the planned Point of Interconnection or Generating Facility size included in the Interconnection Request during the Fast Track Process, unless such changes are agreed to by Distribution Provider. Where agreement has not been reached, Applicants choosing to change the Point of Interconnection or Generating Facility size must reapply and submit a new Interconnection Request.* (Section F.2.a)

Per the provision "unless such changes are agreed to by Distribution Provider," the IOUs are allowed to consider modification requests within the Fast Track process for revisions to a planned Point of Interconnection or Generating Facility size under reasonable discretion.[35] Stakeholders raised concerns that the current language (a) is unnecessarily restrictive and (b) leads to inconsistent utility treatment of modification requests within Fast Track. From the stakeholders' perspective, maintaining their place in the interconnection queue and not requiring the submission of a new interconnection request is important for time and cost certainty. Where modifications have no adverse consequences, stakeholders believe they should be permitted without resulting in loss of queue position.

Stakeholders also raised legitimate concerns that some circumstances are outside of their control, therefore necessitating the need to make modification requests. Stakeholders provided the following examples:

- **Equipment Availability**: The equipment that was designed for a project may not be available when it comes time to installing the system, necessitating a swap of equipment. A project developer will commonly seek to use replacement equipment that maintains the original design, but matching the exact rated output may not be possible.

[33] See Appendix B for Rule 21 language addressing modification types and the timing of these requests within section F.3.c (Independent Study Process (ISP)) and F.3.d (Distribution Group Study Process (DGSP)).
[34] See Appendix B for all relevant Rule 21 language addressing Fast Track modifications.
[35] Discussion of modifications takes place in accordance with Rule 21, Section F.2.b (Optional Initial Review Results Meeting). See Appendix B for tariff language.

- **Unforeseen Upgrades**: A project that is similar in size and nature to many other projects submitted to the IOU but in a location with more constraints than others, resulting in a transformer upgrade or secondary line upgrade. The cost of the mitigations makes the project uneconomic, triggering the customer to seek to downsize the system to avoid upgrades.

As the frequency of the need for minor changes that are outside of the customers' control has become clearer, a refined definition of material modification is needed in the Fast Track process.

Stakeholders also raised concerns regarding whether modification requests have been treated consistently across the IOUs. The current treatment of modifications made within the Rule 21 Fast Track process was discussed within correspondence sent from Heather Sanders, Special Advisor at the CPUC, attached in Appendix C.

Initial Concerns with Allowing Modifications

The IOUs are supportive of evaluating modifications within the Fast Track Process but highlight that the original design of the process did not consider modifications, illustrated by the following:

- **Timelines:** Timelines exist for when modification requests can be made in the ISP and DGSP and timelines to review them. Those timelines and tariff language do not exist in the Fast Track Process.
- **Financial Security During Study Process:** Financial Security is provided within the ISP and DGSP as projects progress, to ensure that although modifications are made, that they are serious projects. This is important because modification of project sizes can impact other projects and financial securities help minimize such impacts. These provisions do not exist in the Fast Track Review Process.
- **Costs:** Fast Track Process costs are covered by fees collected. These fees were set based on historic costs of processing and engineering time to complete the Initial Review and Supplemental Review. These costs do not include costs of re-performing reviews based on modified interconnection requests.[36] In contrast, ISP and DGSP are structured with deposits and actual costs to be billed once the interconnection process is completed.

In addition to the structure of the process, it is important to emphasize that modification requests are reviewed for potential impacts to other projects in the queue. A DER project utilizes capacity on the transmission or distribution system, and if the DER adjusts its capacity, that can impact the available capacity or lack thereof for another project. This becomes problematic when the IOU has completed studies or reviews for a DER project but, because of a modification made by another project, the results must be modified to reflect that change. This causes a material impact to another interconnection party and must not be allowed to ensure fair and equitable treatment to all customers. In addition, IOUs process significant volumes of small NEM projects, and have streamlined their internal processes to be

[36] Non-utility stakeholders note that utilities are expected to propose to update the NEM fee amounts based on real costs to process applications and perform studies, so these costs are expected to be covered in the application fee. In response, utilities state that these functions were not accounted for within the existing IOU NEM fees.

able to complete these interconnections in a much shorter time than what is common for larger projects. In determining whether to allow modifications within Fast Track, the Commission should consider any adverse impact to processing times for small NEM interconnection requests.

With these principles in mind, the IOUs agree that not all modification requests are equal and that some modification requests should be considered in cases where a system re-study is not required or there is no material impact to another party.

Working Group Proposals Addressing Modifications to Interconnection Applications

Proposal 1: Modify Rule 21 to Allow Certain Modifications under Fast Track

Status
Consensus on the core proposal

Discussion
The working group recommends the Commission modify Rule 21 to allow the following modifications to Fast Track interconnection applications:

- **Like-for-like**[37] **equipment replacements** that meet the following criteria:
  - The equipment replacement does not increase facility size[38]
  - Any decrease in size does not exceed 20%
  - No upgrades or mitigations are identified
- **Size reductions** that meet the following criteria:
  - The size reduction does not exceed 20%
  - The customer pays for any upgrades or mitigations identified

[37] Definition of "Like for Like": For inverters, like for like means certified, same nameplate or smaller, same fault current or smaller. For solar panels, like for like means certified, same CEC-AC rating of the system or smaller. For batteries, like for like means same or less kWh & kW rating (see the following footnote), and same operating profile. For transformers, like for like means same connection type, same or smaller impedance and capacity.

[38] Definition of "Size": For the purposes of this proposal, system size is defined as the limiting factor that determines the maximum generating facility capacity. For solar systems, the limiting factor is the lesser of inverter nameplate capacity (kW) or maximum solar output (CEC-AC rating) for PG&E and SDG&E or inverter nameplate capacity (kW) for SCE. For energy storage systems, both the inverter nameplate capacity (kW) and the capacity of the storage device (kWh) are considered in the definition of size (see below). For all other generation types, the limiting factor is the gross nameplate rating of the generator.

The IOUs require kWh in addition to kW for energy storage systems. KW is critical as stakeholders note for maximum capacity to determine if the electric system can handle the energy storage system from a reliability perspective. KWh is important from a capacity and modeling perspective. This is not important for other resources such as solar which is modeled to perform when the sun is out. Energy storage systems need to be modeled based on intended operation mode and duration against load data.

- **Size reductions to avoid upgrades** that meet the following criteria:
    - The size reduction does not exceed 20%
    - The customer pays a $300 fee for the utility to conduct a re-study to validate that no other DERs shall be impacted due to this modification request.
    - The re-study finds that no other DERs shall be impacted

The working group also recommends the Commission implement the following as it relates to these modification types:

- **Number of modifications**: Customers may make only one modification request per interconnection request, . A modification request can incorporate more than one modification type.
    - Non-utility stakeholders recommend allowing further changes at the discretion of the Distribution Provider, with the expectation that this will happen only rarely. If a utility can plainly see that it would take more effort from them to review a new application than to approve a small change, the rules should not prevent them from moving forward.
    - The IOUs are concerned that if there's discretion, (1) customers may come to expect utilities to grant additional modification requests, which could slow down Fast Track for all projects, and (2) customers may become concerned that utilities use their discretion inconsistently. Futhermore, as discussed within Working Group discussions, nothing would preclude an interconnecting customer from bundling all of their allowed changes into one modification request which would be allowed under this proposal and not undermine the existing expedited NEM process.
- **Fee for modification**: No additional fees will be required for processing modifications, with the exception of modifications that qualify as "Size Reductions to Avoid Upgrades." This type of modification requires a $300 fee to conduct a re-study to validate that no other DERs shall be impacted due to the modification request.
- **Modification processing and re-study time**: All modification types will require 10 business days for processing time. Modification types requiring engineering re-study will require an additional 20 business days for engineering re-study time. This timeline was mirrored on existing timelines for modification requests under the Cost Envelope option. See Appendix D for tariff language.
    - CALSSA proposes that, when no upgrades or mitigation is needed or when the customer pays for upgrades, processing time should be limited to 5 business days and study time is not necessary.
        - IOU Response: Note CALSSA's alternative proposal was not discussed at the Working Group. Rule 21 has many timelines and having different processing times based on various conditions becomes very challenging to manage from both the IOU and stakeholder perspective. Timelines for modification requests exist in Rule 21 today and the IOUs strongly recommend mirroring those timelines. The timelines do not mean that all modification requests will take the

full 10 business days but that they will be processed within 10 business days and could be done quicker.

- **Cost Responsibility**: If a project downsizes and the revised size belongs to a different cost responsibility regime than the original, the cost responsibility regime of the interconnection request remains that of the original interconnection request. For example, reducing from a NEM2 1.05 MW to NEM2 0.95 MW would maintain the cost responsibility requirements of NEM2 greater than 1 MW.
- **Other Modifications:** Additional changes outside of the modification types identified here shall not be accepted within Fast Track. The customer will be required to withdraw and reapply to make such modifications, which include:
    - Size reductions greater than 20%
    - Size increases
    - Point of Interconnection changes (minor changes such as location of meter can be managed in the design/construction phase of the project; changes to Point of Interconnection within the same land parcel may sometimes be acceptable)
    - Adding storage
    - Changes in connection types (e.g. delta, wye)

The Detailed Study section of Rule 21 already contains some definitions of allowable modifications. The only recommendation from the Working Group on that section is to add language clarifying that like-for-like equipment swaps are allowable. The IOUs support utilizing the same definition of like-for-like for all study processes.

If the Commission adopts this proposal, Rule 21 tariff language will need to be updated. Tariff language shall be drafted and proposed as directed in the Commission decision on the proposal.

Type II: Modifications to Existing Facilities (e.g. Maintenance, Retrofit)

Background

The interconnection application process implements the requirements for safely and reliably operating generating facilities in parallel with the electrical grid. This process requires capturing the specific details of the generating facility in the interconnection agreement, including the operating mode[39], make, model, rated capacity of the generators, and in some cases the serial numbers of the generators. With respect to this process, the working group also discussed that the rules for managing retrofits to existing interconnected resources warrants further discussion. A retrofit is a modification to an interconnected generating facility that has received permission to operate in parallel with the electric grid. Retrofits require a new interconnection request where the interconnection agreement is amended or modified in

[39] Operational modes are “No Grid Charging”, “Peak Shaving” or “Unrestricted Charging” as outlined on p.6 of PG&E’s “Guide to Energy Storage Charging Issues for Rule 21 Generator Interconnection,” https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/GuidetoEnergyStorageChargingIssues.pdf

writing, and signed by both Parties.[40] The Rule 21 interconnection process currently allows for retrofits as can be seen in the definition of Interconnection Request in Rule 21:

> ***Interconnection Request:*** *An Applicant's request to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of an existing Generating Facility that is interconnected with Distribution Provider's Distribution or Transmission System.* (Section C)

Stakeholders expressed during Working Group discussions that there currently is a lack of clarity regarding requirements for retrofits and represented that the risk exists that potentially retrofits are being made in the field without submission of a new interconnection request due to this lack of clarity. The IOUs warned that this poses potential safety risks and is potentially inconsistent with Commission approved forms and agreements. The IOUs emphasized the requirement for submission of an interconnection request when retrofits to existing interconnected generators are proposed.

Stakeholders represented during Working Group discussions that not all retrofits, such as replacing inverters and panels as a part of maintenance, create additional or new safety and reliability concerns. Ultimately, stakeholders don't want the burden of time and monetary obligations associated with filing new interconnection requests which do not provide benefit, and the utilities recognize that the process for updating information must be streamlined to not create large volumes of additional work associated with high volumes of maintenance driven interconnection requests. Stakeholders suggest that this would not be in the interests of the market, utilities or ratepayers. Replacing equipment is part of regular maintenance and components available today may differ slightly from the originals. It is important that a common-sense approach is taken to balance the potentially significant burden and cost with the benefit gained.

The IOUs appreciate the points raised by stakeholders and agree that the process could benefit from additional clarity. At the same time, the utilities assert that it is important to recognize that current processes and automation have evolved over the years to allow for expedited processing of interconnection applications. As the IOUs shared with stakeholders our common goal of streamlining process that allow for timely compliance, the following guidelines informed proposal discussions:

- Ensure IOUs maintain the requirements established for the safety and reliability of electric system
- Need for maintaining current and accurate records of equipment connected to the electric system
- Streamline paperwork and make the process efficient and easy to understand
- Consistency of treatment amongst the IOUs (especially concerning maintenance)

The IOUs also emphasized the following points to the working group to provide awareness of existing obligations and considerations:

[40] See Appendix A

- **Safety and Reliability**: Changes proposed may impact the safe operation and reliability of the generating facility and the electric grid, the safety of customer using the generating facility, utility facilities, the safety of other customers upstream along the distribution system, and the safety of utility personnel. This concern is heightened when changes occur which were not studied under the interconnection process.
    - *Local jurisdiction*: Local jurisdictions may require a new electrical permit and approval for proposed changes to ensure the operation of the system does not pose safety risks.
    - *National Electric Codes (NEC)*: Proposed changes must comply with NEC regulations.
- **Accurate Records**: Accurate records are critical for:
    - *Utility Operations*: In order to operate the distribution system, the utility must be aware of generating facilities that are operating in parallel with its system and must also be made aware of changes to such facilities
    - *Programmatic Requirements*: Specific equipment information for major components is required for projects seeking eligibility under Net Energy Metering ("NEM") programs and supporting tariffs and generators changes need to be confirmed against Commission approved NEM program requirements.
    - *Integrated Capacity Analysis ("ICA") / Renewable Auction Mechanism ("RAM") Map*: Information is posted externally with how much distributed generation is interconnected and what capacity may be available for future generation requests. Information from customers is required when changes are proposed in the field, to ensure ICA/RAM maps are also updated with the most current information.
    - *Regulatory Requirements and accurate Records Relationship*: The IOUs regularly report to the Commission and other agencies as to the amount of distributed generation interconnected with the electric grid among other items. It is important that the IOUs maintain accurate records to ensure information provided reflects actual installations.

Working Group Findings

The working group identified seven use cases when customers may seek to make modifications to existing facilities:

- **Use Case 1**: Replacing equipment with exact same equipment type (i.e. same make and model) or performing upgrades to inverter firmware that do not affect grid interactions (e.g. fixes to software bugs, improving MPPT algorithm to increase energy yield)
- **Use Case 2**: Replacing equipment "like-for-like", where system output does not exceed what is listed in the original interconnection agreement and operating mode[41] is not adjusted

[41] As used here, "operating mode" refers to the operational profile of the system relevant to the assessment of the system's impacts on the distribution system for purposes of interconnection review/study. Operational modes are "No Grid Charging", "Peak Shaving" or "Unrestricted Charging" as outlined on p.6 of PG&E's "Guide to Energy Storage Charging Issues for Rule 21 Generator Interconnection," (https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/GuidetoEnergyStorageChargingIssues.pdf).

- **Use Case 3**: Replacing equipment that may increase the nameplate capacity of the system, but which employ firmware controls that limit the real power output to the inverter listed size in the original interconnection agreement
- **Use Case 4**: Adding storage capacity (kWh) to an existing storage facility without changing inverter (e.g. increasing a 1-hour system to a 2-hour system)
- **Use Case 5**: Adding or replacing equipment such that system capacity increases and no firmware or other controls are employed to limit the real power output to the inverter listed size in the original interconnection agreement
- **Use Case 6**: Adding storage to an existing generating facility that does not have storage[42]
- **Use Case 7**: Changing inverter operating characteristics (e.g. some smart inverter settings[43], operating mode, export limits)

The working group also defined four options for processing modifications to existing facilities based on the modification's potential impact on the distribution system:

- **Process Option 1:** No notification is required; this process type means:
    - No requirement to amend to an existing interconnection agreement
    - No engineering review is required
    - No program check required, such as what modifications are allowed under NEM
    - No need to update records
- **Process Option 2:** Notification is required but the customer can proceed with building the system and turning on the system without waiting for utility approval; this process type means:
    - Customer may be required to complete a form listing the changes and/or sign an amended interconnection agreement. Exact process is to be determined and any resulting changes to pro forma forms and agreements and will be subject to Commission approval.
    - No engineering review required
    - Administrative confirmation to ensure equipment rating or inverter settings match the output level in the original interconnection agreement
    - Program check may be required, such as what modifications are allowed under NEM
    - Need to update records
    - When permit is required by AHJ, utility must receive electric release in notification
    - Implementation may require modifications to utility interconnection application IT systems, which could take two or more years and require funding approval. See "Discussion on Feasibility of Process Options 2 and 3" below for more details.

[42] Note that creating a notification-only process for adding non-exporting storage will be discussed in Working Group Two. This is Issue 11 in the October 2017 scoping memo.

[43] The working group did not discuss in detail the use case for updating inverters to be compliant with Phase 2 and 3 smart inverter requirements. The utilities note that updating inverters to be compliant with these requirements will require some back and forth between the customer and utility to set up communications between the inverter and the utility's system. The utilities are committed to making this process as efficient as possible.

- **Process Option 3:** Abridged/Streamlined interconnection request is required and the customer must wait for Utility approval to turn on the system (engineering review **not** required); this process type means:
    - New "abridged" interconnection request must be submitted
    - Requirement to amend an existing interconnection agreement
    - No engineering review is expected
    - Program check may be required, such as what modifications are allowed under NEM
    - Need to update records
    - When permit is required by AHJ, utility must receive electric release before approving project
    - Implementation may require modifications to utility interconnection application IT systems. See "Discussion on Feasibility of Process Options 2 and 3" below for more details.
- **Process Option 4:** Interconnection request is required and the customer must wait for Utility approval to turn on the system (engineering review required); this process type means:
    - New interconnection request must be submitted
    - Requirement to amend an existing interconnection agreement
    - Engineering review will be required
    - Program check may be required, such as what modifications are allowed under NEM
    - When permit is required by AHJ, utility must receive electric release before approving project
    - Need to update records

Discussion on Feasibility of Process Options 2 and 3

Utility Stakeholder Discussion:

At this time, the IOUs do not have processes in place for a notification only or an abridged interconnection request. The IOUs are today receiving interconnection requests for new generating facilities and modifications through the existing interconnection portals and related processes. The portals have greatly automated the process for both the interconnection customer/developer and the IOUs. In some cases, the portals have backend connections to billing systems, mapping systems, etc. to avoid manual processes and streamline the process in order to support the growing demand for interconnections.

The IOU interconnection portals would likely need to be modified to support Process Options 2 and 3. Otherwise, the manual processes of checking forms with billing systems, uploading documents to various systems, and updating records would be re-introduced which would slow down the interconnection process. Similar to prior enhancements to the interconnection portal, enhancements take significant investment and time to operationalize. PG&E and SDG&E do not consider adding an automated notice only capability to be a high priority given the current volume of like for like modification requests is small at this point and it is unclear when the IOUs would be receiving a much higher volume of these like for like requests. The IOUs also have to consider that the existing tools facilitate a streamlined interconnection and are capable of processing thousands of interconnection requests a month.

To implement Process Options 2 and/or 3, the IOUs would likely need to make modifications to interconnection tools. The IOUs would request funding approval to facilitate the development of this new process. The proposal implementation would involve:

- Forms/Agreement update: New modification request form will likely be proposed after Commission decision. Modifications to existing agreements would likely also be proposed after Commission decision reflecting limited changes that are allowed without mutual agreement as long as interconnection customers meet certain requirements and does not hold the Utility liable for violations or safety incidents that the modification triggers. New language would also be expected to added to Interconnection Agreements to reflect the customers' requirement to follow local jurisdiction requirements, NEC codes and other related requirements.
- Interconnection/Tools update: As noted above, new processes would likely need to be designed along with associated tools to implement. The new process should also have automation to determine eligibility for the various processes and for validation of existing program requirements such as NEM-1 grandfathering.

The IOUs do recognize that systems reach end of useful life and will eventually fail driving the need to replace systems. Some of the processes proposed here are logical and would be beneficial for both the interconnection customer and the IOUs. However the IOUs consider the implementation costs high relative to the added benefit. The IOUs also recognize the impact of waiting for approval and thus work towards continuing to improve the existing process and strive for quick turn around on interconnections. Introducing additional complexity with this proposed process may be counter to stakeholder goals.

Non-Utility Stakeholder Discussion:

For Process Option 2, utilities will need to add functionality to their existing application portals for customers and their representatives to update records of their solar and/or storage installations by submitting a notification form that is separate from a full application. We recognize this will take some information technology work, but adding this function to the existing automated system will be much more efficient than hiring people to manually process applications. It will also allow a more efficient application process that is not "clogged up" with maintenance notifications, many of which can be electronically matched against existing records. The updated system will also need to be able to create an addendum to the interconnection agreement that can be delivered to the customer.

PG&E and SDG&E claim that creating efficient functionality is not worth the effort because the volume of requests is low. However, most solar companies do not understand that the current rules require them to submit a new application when replacing a failed inverter. An eduction campaign is necessary, and it will come as inverter replacement activity greatly increases. In the coming years, more than 100,000 solar systems per year will need inverter replacements. For the safe and reliable operation of the grid, we need to make sure a reasonable process is in place that achieves a high compliance rate by local contractors that are focused on serving their customers.

The cost of the technology will be borne by solar customers. The interconnection application fee created for the NEM successor tariff is based on actual utility costs to process and study applications. The NEM-2 decision envisioned utilities proposing to update the fee level periodically. Thus, the information technology work can be paid for through existing balancing accounts rather than needing a specific appropriation in a future rate case.

IOU Response: The last paragraph was submitted as part of the final comments on the working group report and the use of a balancing account in this instance has not been reviewed. Also, in the NEM-2 decision, the Commission spelled out exactly what should be included in the calculation of customer interconnection application fees. Neither information technology work nor retrofit interconnections were included in the list of items to be tracked and averaged. In fact, any retrofit interconnections would have been included as independent interconnections and averaged along with primary interconnections. And there is no balancing account established for tracking such costs.

The working group discussion then turned to determining which use cases should be processed under which process options. Little consensus was found between utilities and stakeholders on this question, and because the conversation has been conceptual so far and how the proposals would be implemented depends on the level of automation each utility currently has, even the utilities' proposals differed. Party positions on how to process modifications also varied greatly depending on the attributes of the individual use case. Thus, this report presents the proposals of the working group by use case and does not attempt to present holistic proposals. The Commission will need to determine how to proceed on each use case individually.

Working Group Proposals Addressing Modifications to Existing Facilities, by Use Case

The table below shows utility and non-utility stakeholder positions on each use case at a glance. Green indicates consensus and pale red highlights use cases where consensus has not been reached. A detailed discussion on each use case follows the table.

Table: Stakeholder Positions on How to Process Modifications to Existing Facilities, by Use Case

Process Options: • *Process Option 1: No notification is required* • *Process Option 2: Notification is required but the customer can proceed with building the system and turning on the system without waiting for utility approval* • *Process Option 3: Abridged/Streamlined interconnection request is required and the customer must wait for utility approval to turn on the system (engineering review required)* • *Process Option 4: Normal interconnection request*		
Use	**Use Case Description**	**Proposed Process Option**

Case		PG&E	SCE	SDG&E	Non-IOU Stakeholders
1	Replacing equipment with exact same equipment type (i.e. same make and model) or performing upgrades to inverter firmware that do not affect grid interactions (e.g. fixes to software bugs, improving MPPT algorithm to increase energy yield)	1	1	3	1
2	Replacing equipment "like-for-like", where system output does not exceed what is listed in the original interconnection agreement and operating mode[44] is not adjusted	3	2	3	1/2
3	Replacing equipment that may increase the nameplate capacity of the system, but which employ firmware controls that limit the real power output to the inverter listed size in the original interconnection agreement	4	4	4	2
4	Adding storage capacity (kWh) to an existing storage facility without changing inverter (e.g. increasing a 1-hour system to a 2-hour system)	3	3	3	1/2
5	Adding or replacing equipment such that system capacity increases and no firmware or other controls are employed to limit the real power output to the inverter listed size in the original interconnection agreement	4	4	4	4
6	Adding storage to an existing generating facility that does not have storage[45]	4	4	4	4
7	Changing inverter operating characteristics (e.g. some smart inverter settings[46], operating mode, export limits)	4	4	4	4

[44] As used here, "operating mode" refers to the operational profile of the system relevant to the assessment of the system's impacts on the distribution system for purposes of interconnection review/study. Operational modes are "No Grid Charging", "Peak Shaving" or "Unrestricted Charging" as outlined on p.6 of PG&E's "Guide to Energy Storage Charging Issues for Rule 21 Generator Interconnection," (https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/GuidetoEnergyStorageChargingIssues.pdf).

[45] Note that creating a notification-only process for adding non-exporting storage will be discussed in Working Group Two. This is Issue 11 in the October 2017 scoping memo.

[46] The working group did not discuss in detail the use case for updating inverters to be compliant with Phase 2 and 3 smart inverter requirements. The utilities note that updating inverters to be compliant with these requirements will require some back and forth between the customer and utility to set up communications between the inverter and the utility's system. The utilities are committed to making this process as efficient as possible.

Use Case 1: Replacing equipment with exact same equipment type (i.e. same make and model) or performing upgrades to inverter firmware that do not affect grid interactions (e.g. fixes to software bugs, improving MPPT algorithm to increase energy yield)

Status

Non-Consensus

Proposals

- Non-utility stakeholders (including TURN), PG&E and SCE propose **Process Option 1** (no notification required)
- SDG&E proposes **Process Option 3** (abridged interconnection request without engineering review)

Discussion

Discussion in Support of Process Option 1:

Customers have authorization in their existing interconnection agreements to operate a certain model number of inverter. If their inverter fails and they replace it with another one of the same make and model, they have already received permission to operate it. That type of maintenance work can be done without communicating with the utility. This applies to all equipment including solar panels and battery modules.

CESA notes that the intent of specifying “performing upgrades to inverter firmware that do not affect grid interactions” within this use case is to differentiate firmware changes that impact the grid versus updates that do not affect the grid. Firmware changes that effect operating setpoints and grid interaction should require a new interconnection application as outlined in Use Case 7. However, as part of regular maintenance a vendor may need to update firmware to correct minor software bugs (much the same way smartphones require periodic updates).[47] This shouldn’t require a new application.

ORA supports limiting administrative burdens. Notifications or new interconnection applications should only be required to the extent they are needed for safety or reliability concerns.

Discussion in Support of Process Option 3:

SDG&E believes that replacing inverter equipment requires a building permit depending on the local jurisdiction and should be managed through an abridged interconnection request.

Please note that Commission adoption of Process Option 3 may require modifications to utility interconnection application IT systems. See “Discussion on Feasibility of Process Options 2 and 3” above for more details.

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[47] Outback adds that similarly, smart inverter updates or setting changes made to bring an inverter into alignment with the current R21 requirements should fall under Process Option 1 or 2 – if service personnel are on site performing maintenance and they are able to update to the most recent settings, they should be encouraged to proceed.

Use Case 2: Replacing equipment "like-for-like", where system output does not exceed what is listed in the original interconnection agreement and operating mode[48] is not adjusted

Status

Non-Consensus

Proposals

- Non-utility stakeholders (including TURN) and SCE propose **Process Option 2** (notification only)
    - SCE provides conceptual support to Process Option 2 and intends to supplement its support with additional details within written comments due in April as final stakeholder proposal was presented within one week of final Working Group comments being submitted to the Commission.
- PG&E and SDG&E propose **Process Option 3** (abridged interconnection request without engineering review)
- Non-utility stakeholders propose that system size should be assumed not to increase for systems smaller than 10 kW that replace inverters

Discussion

Discussion in Support of Process Option 2:

Review of the notification is an administrative review. The system has not increased its output, so no engineering review would be expected. The customer should be allowed to operate their system while the administrative review is underway. Although in most cases utilities should be able to process the review quickly, experience shows that this is not always the case. Customers should not be made to turn their systems off for weeks when they are fixing failed equipment and operating under the existing interconnection agreement. If the review finds that the information in the notification is not accurate and inverter settings need to be adjusted, this can be fixed quickly by customers. The notification form can include information making clear that customers must cease to operate their systems if utilities determine that the capacity of the interconnection agreement has been exceeded.

It is Sunworks' position that it would impose an unfair burden on customers and developers to be forced to wait for utility approval before moving forward with necessary system maintenance. Process Option 3 should be reserved for cases when the lowest limiting factor per the interconnection agreement cannot be matched using any available equipment. If the system output can be matched to the interconnection agreement, maintenance should be allowed to proceed, with notification if necessary, then a revised interconnection agreement issued at the time the IOU is able to administratively process the update.

[48] As used here, "operating mode" refers to the operational profile of the system relevant to the assessment of the system's impacts on the distribution system for purposes of interconnection review/study. Operational modes are "No Grid Charging", "Peak Shaving" or "Unrestricted Charging" as outlined on p.6 of PG&E's "Guide to Energy Storage Charging Issues for Rule 21 Generator Interconnection," (https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/GuidetoEnergyStorageChargingIssues.pdf).

Discussion in Support of Process Option 3:

PG&E and SDG&E believe this type of use case can be processed quickly but does require review before the applicant can operate the system. The IOUs review the information provided to verify the following:

- Customer provided consent for a third party to act on their behalf
- The records match customer records including billing information and existing DER information
- The new proposed system is certified and the size matches what is in the original interconnection agreement

Without verification, PG&E and SDG&E would not be able to provide a pre-approval where customers are authorized to make modifications without IOU review. SCE provides conceptual support to Process Option 2 for Use Case 2 and intends to supplement its support within comments due in April 2018 on the Working Group One Final Report along with any additional comments regarding reviews for Use Cases 3 and 4.

Please note that Commission adoption of Process Option 3 may require modifications to utility interconnection application IT systems. See "Discussion on Feasibility of Process Options 2 and 3" above for more details.

Discussion in Support of Accepting Inverter Replacements for Small Systems:

This will be the highest volume maintenance issue and the one with the least impact. If applications and manual intervention are required for this type of maintenance it has the potential to clog up an interconnection review process that is already extremely challenging for the utilities to manage without this additional workload.

Standard design principles for small solar systems have an even match between solar output and inverter capacity. PV Watts, the industry standard solar output estimating tool maintained by the National Renewable Energy Laboratory, includes default inputs of 2% production loss from wiring, 2% from mismatched components, 1.5% from light-induced degradation in the first few months of operation, 1% from the panels not operating at the engineered potential, and 0.5% for connections. Simply put, when you assemble a system it will produce at a level slightly lower than the maximum rated capacity of the panels themselves. To make up for these system losses, plus the inevitable grime and pollen that further reduce output, it is standard design practice to size a solar array at 110% of inverter capacity, which is also a default setting of PV Watts.

In addition, panel output degrades over time. The standard assumption is 0.5% per year, although some manufacturer spec sheets document degradation rates as low as 0.3%. This results in a capacity reduction after ten years of 3-5%. Therefore, even when the rated inverter capacity is slightly lower than the rated PV capacity, the system output is not limited by the inverter size. Although utility records may show an average DC-AC ratio of 1.1, systems are well balanced between effective solar capacity and inverter capacity.

This is especially true for microinverters, which have become very common for small solar systems. A system with microinverters has a small inverter connected to each solar panel. These inverters are obviously designed to match the typical size of solar panels. As solar panel efficiency has gradually increased, microinverter capacity has increased to keep pace.

Because of these factors, if a customer with a typical small solar system replaces a failed inverter with a larger one, it will not increase system capacity. Allowing maintenance on these systems with a notification to utilities will avoid creating a major bottleneck in the interconnection review process.

This proposal is not intended to cover replacement of equipment other than inverters. If solar panels are changed for higher capacity panels, we would expect utilities to consider that an increase in system size.

Discussion in Opposition to Accepting Inverter Replacements for Small Systems:

The IOUs agree that systems under 10 kW represent the highest volume which is why the IOUs want to ensure the right policy is in place to maintain accurate records and safety and reliability of the system especially for projects to which in aggregate represent a significant potential impact to the utility grid. This proposal is to replace inverters but not panels for systems under 10 kW. If the inverter was the "limiting factor" this would be an increase in system size for all three IOUs. If the inverter was not the "limiting factor", this would be an increase in system size only for SCE. In either case, engineering review is required to validate that the proposed inverter is indeed not an increase in system capacity.

Use Case 3: Replacing equipment that may increase the nameplate capacity of the system, but which employ firmware controls that limit the real power output to the inverter listed size in the original interconnection agreement

Status

Non-Consensus

Proposals

- Non-utility stakeholders (including TURN) propose **Process Option 2** (notification only)
- PG&E, SCE, and SDG&E propose **Process Option 4** (normal interconnection request)
- Utilities propose to add a limitation that firmware controls can only be used if the system capacity otherwise would not be increased more than 10%, aligning with NEM 1 grandfathering rules where a system can be replaced with a system that is greater of 1 kW or 10% of generating facility capacity specified in the original permission to operate.

Discussion in Support of Process Option 2:

If a customer replaces an inverter with a nameplate capacity of 100 kW with an inverter rated at 120 kW but uses certified inverter functionality to limit the output to 100 kW, the inverter should be treated as a 100 kW inverter. That is the purpose of standards and certification. Once certified, the equipment is understood to operate according to the standards and settings.

This inverter capability is Function 3 (Limit Maximum Active Power Mode) in the Phase 3 recommendations of the Smart Inverter Working Group. The technical parameters were developed by consensus with the utilities and other stakeholders, and are included in the IOU advice letters implementing those recommendations.[49] The function will be included in the forthcoming update to Standard 1547 of the Institute of Electrical and Electronics Engineers (IEEE 1547). When complete, a Nationally Recognized Testing Laboratory will be able to test and certify equipment to that standard.

This is a very important and pragmatic option for developers to maintain equipment, meet their existing interconnection agreement and manage the fact inverters on the market are growing in nameplate capacity, and has been adopted by Australian/New Zealand interconnection codes.[50]

Given that the utilities are relying on the IEEE 1547 standard and the NRTL certification to verify that standard, the utilities note that any changes to the firmware that may result in changes to its operating parameters—such as how the firmware limits the real power output of the storage device or by how much—would necessitate re-certification by NRTL.

Please note that Commission adoption of Process Option 2 may require modifications to utility interconnection application IT systems, which could take two or more years and require funding approval. See "Discussion on Feasibility of Process Options 2 and 3" above for more details.

Discussion in Support of Process Option 4:

The IOUs agree that utilization of smart inverter functions would help drive further DER adoption. IOUs believe that this use case can be processed quickly but requires engineering review to ensure settings are properly configured and a new interconnection agreement be executed to establish contractually the usage of the smart inverter functionality. In particular with a firmware solution allows a DER to have greater capacity than studied by the utility within the interconnection process it is critical that the IOU review and confirm the firmware settings which are intended to keep the DER within reviewed limits.

Discussion in Support of Proposal to Cap the Use of Inverter Controls

The IOUs propose that software controls be utilized for systems that is 110% of the original generating facility capacity as identified in its original permission to operate letter. The IOUs note that systems that increase in capacity may not be compliant with local jurisdiction electrical codes and other national electric codes. The 110% also aligns with NEM grandfather language (Excerpt from PG&E NEM2 Tariff):

> *After the NEM Cap as defined above is reached, modifications or repairs made to the Renewable Electric Generation Facilities of NEM Transition Eligible Customers, NEMV Transition Eligible Customers or NEMVMASH Transition Eligible Customers, shall remain eligible as long as the modifications or repairs do not increase the Renewable Electrical Generation Facility's generating capacity by more than the greater of:*

[49] See CPUC Resolution E-4898. The Commission has not approved the resolution as of the publication of this working group report, but no party protested any details of Function 3.

[50] AS/NZS 4777.1:2016 Australian/New Zealand Standard Grid connection of energy systems via inverters Part 1: Installation requirements

(i) 10 percent of the Renewable Electrical Generation Facility's generating capacity specified in the original PTO establishing the NEM Transition Period; or

(ii) 1 kilowatt, so long as it otherwise continues to remain eligible for NEM, NEMV, or NEMVMASH. NEM Transition Eligible Customers, NEMV Transition Eligible Customers or NEMVMASH Transition Eligible Customers making modifications that increase the Renewable Electrical Generation Facility's size by more than the above amounts may either choose to (i) meter the additions separately under the successor tariff or (ii) elect for the whole system to take service under the successor tariff.

Use Case 4: Adding storage capacity (kWh) to an existing storage facility without changing inverter (e.g. increasing a 1-hour system to a 2-hour system)

Status

Non-Consensus

Proposals

- Tesla and CALSSA propose **Process Option 1** (no notification)
- Other non-utility stakeholders (including TURN) propose **Process Option 2** (notification only). Tesla and CALSSA support Process Option 2 in lieu of Process Option 3.
- PG&E, SCE and SDG&E propose **Process Option 3** (abridged interconnection request without expected engineering review)

Discussion

Discussion in Support of Process Option 1:

Energy storage has two types of capacity – the maximum charge/discharge rate and the amount of stored energy. The charge and discharge rate, in kW, is akin to the generating capacity of a solar system or the demand of an appliance. It is the rate of power output or input, and the distribution system has to be big enough to handle the generation or load. The storage capacity, in kWh, determines the duration of time for which the system can charge or discharge. It does not have the same grid impacts. If the distribution system is built to handle 100 kW for one hour, it is capable of handling 100 kW for two hours.

Battery cells degrade over time, and that degradation rate tends to be inconsistent between cells. If 10% of cells are not performing well after seven years, a maintenance technician may replace those cells and add an extra 10% of new cells to compensate for other cells that will degrade in the near future. Continual replacement of a small number of cells to maintain storage capacity very near to a fixed target is impractical. Customers should be allowed to add storage capacity to their systems that does not impact the charge/discharge capacity without waiting for utility approval.

Tesla and CALSSA further believe that customers should be allowed to add storage capacity to their systems that does not impact the charge/discharge capacity without notifying the utility at all (Process

Option 1). The energy capacity of a storage system does not seem relevant to the system impacts evaluated under the interconnection process.

Note from Energy Division Staff: Tesla and CALSSA changed their support from Process Option 2 to Process Option 1 shortly before the report was filed, thus supporters of Process Option 3 did not have an opportunity to prepare a response opposing Process Option 1 specifically. Supporters of Process Option 3 did prepare a response to the original discussion supporting Process Option 2 (see "Discussion in Support of Process Option 3", below), which is almost identical to the discussion now supporting Process Option 1.

Discussion in Support of Process Option 2:

For the reasons stated above, adding kWh storage capacity does not change the impact of the system on the grid. Customers should be allowed to add storage capacity to their systems that does not impact the charge/discharge capacity without waiting for utility approval, but should be required to notify the utility when they do so.

Please note that Commission adoption of Process Option 2 may require modifications to utility interconnection application IT systems, which could take two or more years and require funding approval. See "Discussion on Feasibility of Process Options 2 and 3" above for more details.

Discussion in Support of Process Option 3:

Similar to Use Case 3, the IOUs believe this type of use case can be processed quickly and may not require full engineering re-review given that the kW of the energy storage system is not being changed. However, for planning purposes, kWh is utilized to model the contribution of storage and for what duration. The IOUs will review the request for completeness before issuing a new permission to operate.

Please note that Commission adoption of Process Option 3 may require modifications to utility interconnection application IT systems, which could take two or more years and require funding approval. See "Discussion on Feasibility of Process Options 2 and 3" above for more details.

Use Cases 5-7: System expansions

Status

Consensus

Proposals

- Working group proposes **Process Option 4** (normal interconnection request)

Discussion

The working group noted that some use cases that fit under Process Option 4 are those that increase capacity or materially change generating facility characteristics and that those use cases should continue to be handled by submitting a new interconnection request. In fact, these types of requests should not fall into the retrofit or maintenance definition in that they are not modifying existing equipment covered in the existing interconnection agreement but rather fundamentally adding generating equipment capacity or altering the existing generating facilities characteristics than those.

Issue 3 Appendices

Appendix A: Interconnection Agreement Excerpts

PG&E Form 79-1131-02, excerpted below. The customer identifies if the Agreement is covering a new interconnection (check box 1) or an update to an existing interconnection (check box 2)

C. Description of Service (This Agreement is being filed for, check all that apply):

❑ A New NEM2V Renewable Electric Generation Facility interconnection (at an existing service).

❑ **For Physical/Electrical Changes to an interconnected NEM2V Renewable Electric Generation Facility with previous approval by PG&E (adding PV panels, changing inverters, or changing load and/or operations).**

❑ A New NEM2V interconnection in conjunction with a new service. An **Application for Service** must be completed. Additional fees may be required if a service or line extension is required (in accordance with PG&E Electric Rules 15 and 16). Please contact PG&E at 1-800-PGE-5000 (or 1-800-743-5000).

❑ A Reallocation of Eligible Energy Generation Credits under NEM2V for an Existing Renewable Electric Generation Facility (see Appendix A). For a reallocation, Owner only needs to fill out Part I, sign Part IV, and complete Appendix A with the reallocation for the NEM2V accounts.

Special Condition 6 of Schedule NEM2V requires that any Customer with an existing generating facility and meter who enters into a new NEM2V agreement shall complete and submit a copy of Form 79-1125 *NEM / NEMV / NEMVMASH Inspection Report* to PG&E, unless the electrical generating facility and meter have been installed and/or inspected within the previous three years.

Others PG&E Agreements such as Form 79-1069 and 1069-02, include general language that covers amendments and modifications

14. AMENDMENT AND MODIFICATION

This Agreement can only be amended or modified in writing, signed by both Parties.

Appendix B: Sections of Rule 21 Addressing Modifications

<u>Section C. Definitions</u>

PG&E and SDG&E Definition:
Material Modification: Those modifications that have a material impact on cost or timing of any Interconnection Request with a later queue priority date or a change in Point of Interconnection. A Material Modification does not include a change in ownership of a Generating Facility.

SCE Definition:
Material Modification: Those modifications that have a material impact on cost or timing of any Interconnection Request with the same or a later queue priority date or a change in Point of Interconnection. A Material Modification does not include a change in ownership of a Generating Facility.

<u>Section D.5. Design Reviews and Inspections</u>

Distribution Provider may require a Producer to make modifications as necessary to comply with the requirements of this Rule.

<u>Section F. Review Process for Interconnection Requests</u>

Fast Track Process

F.2.a Initial Review
No changes may be made to the planned Point of Interconnection or Generating Facility size included in the Interconnection Request during the Fast Track Process, unless such changes are agreed to by Distribution Provider. Where agreement has not been reached, Applicants choosing to change the Point of Interconnection or Generating Facility size must reapply and submit a new Interconnection Request.

F.2.b Optional Initial Review Meeting
If modifications that obviate the need for Supplemental Review are identified, and Applicant and Distribution Provider agree to such modifications, Distribution Provider shall provide Applicant with a Generator Interconnection Agreement within fifteen (15) Business Days of the Initial Review results meeting if no Interconnection Facilities or Distribution Upgrades are required. If Interconnection Facilities or Distribution Upgrades are required, Distribution Provider shall provide Applicant with a non-binding cost estimate of any Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Initial Review results meeting.

F.2.d Optional Supplemental Review Meeting
If modifications that obviate the need for Detailed Study are identified and Applicant and Distribution Provider agree to such modifications, Distribution Provider shall provide Applicant with a Generator Interconnection Agreement within fifteen (15) Business Days of the Supplemental Review results meeting if no Interconnection Facilities or Distribution Upgrades are required. If Interconnection Facilities or Distribution Upgrades are required, Distribution Provider shall provide Applicant with a non-binding cost estimate of any Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Supplemental Review results meeting.

Independent Study Process

F.3.b.v Independent Study Process
At any time during the course of the Interconnection Studies, Applicant, Distribution Provider, or the CAISO, as applicable, may identify changes to the planned Interconnection that may improve the costs and benefits (including reliability) of the Interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to Distribution Provider, the CAISO, as applicable, and Applicant, such acceptance not to be unreasonably withheld, Distribution Provider shall modify the Point of Interconnection and/or configuration in accordance with such changes without altering the Interconnection Request's eligibility for participating in Interconnection Studies.

Modifications permitted under this Section F.3.b.v shall include specifically:

(a) a decrease in the electrical output (MW) of the proposed Generating Facility;
(b) modifying the technical parameters associated with the Generating Facility technology or the Generating Facility step-up transformer impedance characteristics; and
(c) modifying the interconnection configuration.

For any modifications other than those permitted above, Distribution Provider, in coordination with CAISO, if applicable, will evaluate whether the proposed modification to the Interconnection Request constitutes a Material Modification.

Distribution Provider will inform Applicant in writing whether the modifications would constitute a Material Modification within ten (10) Business Days of receipt of the proposed request for modification. Any change to the Point of Interconnection, except for that specified by Distribution Provider in an Interconnection Study or otherwise allowed under this Section F.3.d.v, shall constitute a Material Modification.

If the proposed modification is determined to be a Material Modification, Applicant may either withdraw the proposed modification or proceed with a new Interconnection Request for such modification. Applicant shall make such determination within ten (10) Business Days after being provided the Material Modification determination results.

Proposed modifications determined not to be Material Modifications may still necessitate the need to re-evaluate the System Impact Study to determine modifications to the Interconnection Facilities and Distribution Upgrades. Distribution Provider will provide Applicant an estimate of time to complete the re-evaluation and the associated incremental cost required to complete the re-evaluation. Applicant may either accept the additional time and cost to complete the re-evaluation, withdraw the proposed modification request, or proceed with a new Interconnection Request for such modification. Applicant shall make such determination within ten (10) Business Days after being provided the Material Modification results.

Distribution Group Study Process

F.3.c.vii Distribution Group Study Process – *similar language to the Independent Study Process*

Appendix C: Email to Interconnection Discussion Forum regarding Utility Evaluation of Downsizing Requests during Rule 21 Fast Track

From: Sanders, Heather [mailto:Heather.Sanders@cpuc.ca.gov]
Sent: Monday, November 27, 2017 1:32 PM
To: Evans, Mary Claire E.; Sanders, Heather
Subject: IDF Update: Downsizing During Rule 21 Fast Track Review Process

Stakeholders,

One of our interconnection discussion forum objectives is to communicate understanding of how Rule 21 is being implemented in the case where there could be different interpretations of the Rule.

The following seeks to clarify how each IOU will treat reductions in size to solar systems after initial submission. Note that all the scenarios relate to the customer being in the initial review fast track process.

- Both PG&E and SDG&E will not require application withdrawal and resubmittal when the system size is reduced and either no mitigations (upgrades) were required, or the customer accepts them.
- SDG&E will not require application withdrawal and resubmission in the case the system size has reduced and mitigations were required and the customer doesn't accept them, while PG&E currently does but is open to discuss the treatment on a case by case basis.
- SCE evaluates the request applying a Material Modification standard.
- All three IOUs require application withdrawal and resubmission if the size has increased.

See below for the scenarios and individual utility responses. Please respond with any clarifying questions.

Thanks,
Heather

Heather Sanders
Special Advisor, Energy Division
(916) 327–6786 | cell (916) 224–4479

From: Plummer, Matthew [mailto:M3Pu@pge.com]
Sent: Thursday, November 16, 2017 3:55 PM
To: Sanders, Heather <Heather.Sanders@cpuc.ca.gov>
Cc: Evans, Mary Claire E. <MaryClaire.Evans@cpuc.ca.gov>; Charipar, Kristin <KDCI@pge.com>; Diana Genasci (diana.s.genasci@sce.com) <diana.s.genasci@sce.com>; Kathryn Enright <Kathryn.Enright@sce.com>; joe mccawley <JMcCawley@semprautilities.com>
Subject: Update: Downsizing During Rule 21 Fast Track Review Process

Heather,

You contacted each utility to ask that they explain how they interpret and apply relevant Rule 21 tariff provisions to address four scenarios. We understand these four scenarios to be as follows:

Scenario Overviews:

- Scenario 1: Customer is currently being reviewed under the Fast Track Initial Review process. During this process, no mitigation was identified. The customer then requests to decrease the inverter nameplate of their proposed generating facility.

- Scenario 2: Customer is currently being reviewed under the Fast Track process. During this process, a mitigation(s) was identified. The customer then requests to decrease the inverter nameplate. The customer accepts the mitigation.

- Scenario 3: Customer is currently being reviewed under the Fast Track process. During this process, a mitigation(s) that was identified. The customer then requests to decrease the inverter nameplate. The customer does not accept the mitigation.

- Scenario 4: Customer is currently being reviewed under the Fast Track process. During this process, no mitigation was identified. The customer then requests to increase the inverter nameplate of their proposed generating facility. The change may or may not trigger mitigation.

Utilities Responses
For each scenario, a utility evaluates requests to change inverter nameplate pursuant to Rule 21, including Sections F.2.a, F.2.b and/or F.2.d.

- PG&E: For Scenarios 1 and 2, PG&E will not require withdrawal and a new application. For Scenario 3, PG&E will require withdrawal and a new application, but is open to more discussion. For Scenario 4, PG&E will require a new application as the change may trigger mitigation.
- SCE: For customer requests to decrease nameplate (Scenarios 1, 2 & 3), SCE evaluates the request applying a Material Modification standard to determine whether a new application is required.
- SDG&E: For Scenarios 1, 2, and 3, SDG&E will not require withdrawal and a new application. For Scenario 4, SDG&E requires a new application as the change may trigger mitigation.

Best,
Matthew Plummer
Regulatory Relations
Pacific Gas and Electric Company

77 Beale Street, Rm 2338
San Francisco, CA 94105

Appendix D: Rule 21 Tariff Language on Modifications under Cost Envelope Option

F. REVIEW PROCESS FOR INTERCONNECTION REQUESTS (Cont'd.)

7. COST ENVELOPE OPTION (Cont'd.)

f. Modifications

Under the Fast Track Process, modifications are not permitted to the Generating Facility, related equipment, Point of Interconnection or other interconnection parameters that would require a re-evaluation of the Initial Review or Supplemental Review. However, notwithstanding these restrictions, an Applicant may identify and suggest minor changes to the Interconnection Facilities (e.g., minor adjustments to physical location of switchgear or other equipment, adjustments to routing of conductor from the Point of Common Coupling to the Point of Interconnection, etc.) upon or near completion of Applicant's final design of its Interconnection Facilities. If an Applicant identifies such changes, Applicant shall notify Distribution Provider of the requested changes and if, in the reasonable judgement of Distribution Provider, a re-evaluation of the costs under the Cost Envelope Option is required, Distribution Provider will provide Applicant within ten (10) Business Days of receipt of Applicant's notice an estimate of the time required to re-evaluate the costs under the Cost Envelope Option and the estimated cost of such re-evaluation. Applicant may either (i) accept the additional time and cost to complete the re-evaluation, (ii) withdraw the proposed changes, or (iii) proceed with a new Interconnection Request for such changes. Applicant shall provide Distribution Provider written notice of its election within ten (10) Business Days following Applicant's receipt of Distribution Provider's estimated additional time and cost required for the re-evaluation. If Applicant elects to proceed with the re-evaluation of the costs under the Cost Envelope Option, Distribution Provider shall complete the reevaluation within twenty (20) Business Days from receipt of all required technical data related to the proposed changes and payment of the estimated cost of the reevaluation. Should Applicant fail to so notify Distribution Provider within such ten (10) Business Day period, Applicant's request to make the proposed changes shall be deemed withdrawn.

Issue 4: Telemetry

> ***Issue 4: As the penetration levels of distributed energy resources increase, what changes to telemetry requirements should the Commission adopt to ensure adequate visibility while minimizing cost?***

Proposal Summary

The following five proposals were developed by various stakeholders as part of the working group process to address Issue 4. Proposals 1 and 2 are mutually exclusive alternatives, meaning none or one may be selected. Proposals 3, 4, and 5 are independent alternatives, meaning none, one, or more than one may be selected. None have consensus support.

To ensure adequate visibility while minimizing cost, the Commission should adopt the following changes to telemetry requirements:

- **Proposal 1:** Allow utilities to require systems between 250 kW and 9.9 MW to provide telemetry only if all utility-related telemetry costs are estimated to be less than $20,000. This would reduce the telemetry threshold from the current threshold of 1 MW. The customer would still be responsible for actual utility-related telemetry costs, which may exceed $20,000 (the IOUs propose reporting on telemetry costs to address overage concerns).
    - **Non-Consensus**. Supported by TURN, PG&E, SCE, and SDG&E. Opposed by CALSSA and its member companies.
- **Proposal 2:** Maintain the threshold for requiring telemetry at 1 MW
    - **Non-Consensus**. Supported by CALSSA and its member companies, and Clean Coalition. Opposed by TURN, PG&E, SCE, and SDG&E.
- **Proposal 3:** Require the IOUs to adopt certain technical requirements for telemetry for systems larger than 1 MW to avoid unnecessary costs
    - **Non-Consensus**. Supported by CALSSA and its member companies, and Clean Coalition. Opposed by TURN, PG&E, SCE, and SDG&E.
- **Proposal 4:** Apply the telemetry threshold to the maximum facility export in the interconnection agreement if this value is different from the total nameplate rating of all generation on the site
    - **Non-Consensus**. Supported by CALSSA and its member companies. Opposed by TURN, PG&E, SCE, and SDG&E.
- **Proposal 5:** Customer ownership of behind-the-meter telemetry equipment should be allowed where practicable to avoid federal tax for Income Tax Component of Contribution and Cost of Ownership charges
    - **Non-Consensus**. Supported by CALSSA and its member companies, and Clean Coalition. SCE and SDG&E's support is contingent on interconnection agreement modifications. Opposed by PG&E.

This section presents a summary of the proposals only. The "Working Group Proposals" section further describes the proposals and the positions for and against.

If the Commission believes it is premature to rule on this issue for whatever reason, then the IOUs request that the Commission not rule on this Issue and instead continue discussions as part of Issue 27 in Working Group Four. However, the IOUs believe this proposal is ripe for review and directly in response to Commission programs supporting expansion of DERs.[51]

Background

What is Telemetry?

Telemetry is the real-time transmittal of information from a resource on the distribution system to the utilities. It provides distribution system operators with operational awareness of projects connected to the grid to inform decisions about switching and other grid operations. Telemetry data includes the real power a generator system is producing, the reactive power the system is producing or absorbing, how much a battery is charging or discharging, and voltage conditions. As highlighted in Table 1 below, "real time" data for purposes of grid operations is measured in seconds.

Telemetry has several general components[52]:

- Metering equipment[53]
- A communication path from metering equipment to telemetering equipment
- Telemetering equipment
- A communication path from telemetering equipment to the utilities

The utilities represent that a telemetry system commonly comprises the following:

- A data acquisition system installed on the generating facility that measures and, if desired, records operational data, e.g. metering equipment
  - The Utilities require data from the generating facility. In the event that there are multiple generating facilities, the Interconnection Customer is required to aggregate the information, e.g. leverage an energy management system to gather operational data from various DERs in a generating facility
- A secure communication channel between the generating facility and the utility (e.g., copper wire, fiber optic cable, a wireless signal)
  - Firewalls and other cybersecurity measures are required for telemetry.

[51] In the interim, to address stakeholder concerns regarding PG&E's current telemetry solution and associated costs, PG&E will continue to develop a cheaper telemetry solution and update its Distribution Interconnection Handbook by 1st Q 2019 for projects that may require telemetry.
[52] The four components listed here have not been reviewed by all IOUs.
[53] This includes potential transformers (PTs) to measure voltage and current transformers (CTs) to measure current.

- Applicable "housing", i.e., cabinets installed within which to place the telemetry system's equipment (equipment must be appropriately programed)
    - The customer is responsible, at their directly incurred costs, to install the applicable "housing" materials. The IOU charges, via Rule 2, the customer for costs associated with the IOU purchasing, installing, owning, and maintaining the telemetry system's equipment, and programing of that equipment that is placed within the "housing".
    - SCE and SDG&E proposals include the option for the customer to direcly procure, own and install the telemetry system's equipment as interconnection facilities which then do not trigger IOUs cost of ownership and taxes. The IOUs have developed and are continuing to develop options to address stakeholder concerns.

Current Rule 21 Telemetry Requirements

Rule 21 currently allows utilities to require DERs larger than 1 MWac to provide telemetry at the DER owner's expense. Rule 21 directs utilities to "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," and requires utilities to "report to the Commission on a quarterly basis the rationale for requiring telemetry in each instance."[54]

CAISO notes that the telemetry requirements being discussed in this report refer only to Rule 21. Resources participating in the CAISO markets will need to adhere to CAISO requirements. For example, the CAISO requires **all** resources providing ancillary services, regardless of the MW amount, to have real-time telemetry.[55]

The Need for Telemetry

The IOUs believe that increased use of real-time telemetry is necessary for grid visibility. This grid visibility provides necessary information to grid operators who make decisions that support the safe and reliable operation of the electrical grid with the continued proliferation of DERs. The current 1MWac Rule 21 telemetry threshold was established when relatively few DERs were on the grid and the overall level of DER penetration was not significant in comparison to total load.

Without the use of telemetry, the IOUs have no real-time visibility or operational awareness of projects connected to the utility's grid. With the increased levels of DER being connected to the distribution grid, this operational awareness is essential to maintain the safe operation of the distribution system while providing reliable service to all customers and DERs. In particular, telemetry addresses the concern of "load masking," which describes a situation in which the lack of generation output visibility prevents system operators and engineers from determining the real system load conditions which can inhibit the ability to plan and operate the distribution system. This load masking condition is caused equally by both exporting and non-exporting DER installations and from the point of view of the grid operator, the

[54] Rule 21, Section J.5 (Telemetering). This section also allows the IOUs to require telemetry for smaller systems if they are on a circuit with voltage below 10 kV, but this is a small portion of the distribution system.

[55] California Independent System Operator, Business Practice Manual for Direct Telemetry, Section 2: Overview of Telemetry to the CAISO, available at: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Direct%20Telemetry

DER will reduce the localized electrical load served even if the DER does not export power into the grid. Figure 1 is an example of how DERs connected to the distribution circuits hide (load mask) the real load on the distribution circuits and its impact to what grid operators actually see on the system. As depicted in Figure 1, the real load on the distribution feeder is 4.5 MW. However, because of the generation connected to the feeder is serving local customer load, the distribution operator only sees that 2.65MW of load. Without this telemetry data, the operator would have difficulty making operational decisions during normal operation (switching) or abnormal operation (restoration of power) which can lead to delays in restoration of service, inability to reconfigure the system as needed to meet the load needs or potentially reconfigure the system is a manner which could create system issues such as overload and over-voltages.

Figure 1: Load Masking

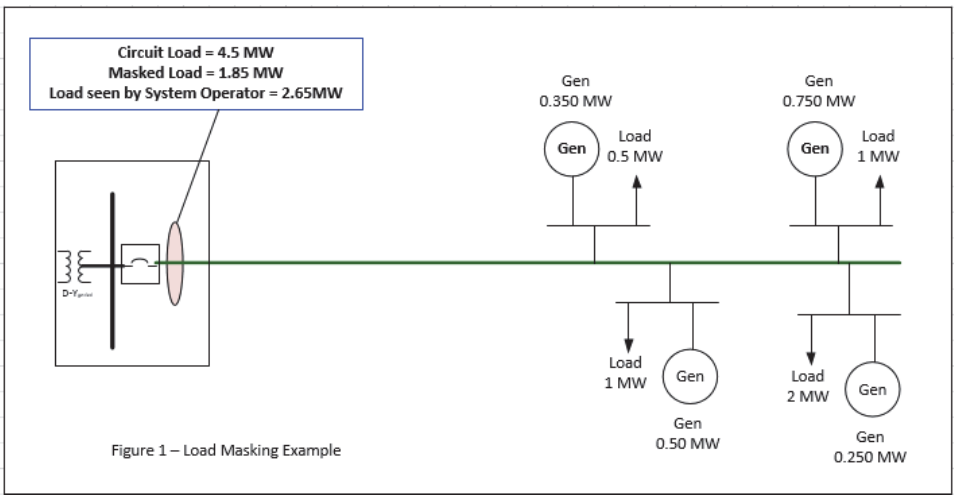

Table 1: Operational Need for Real Time Data

Operational Data Need	Intended Utility Personnel	Data Need	Data Frequency Need/Scan Rate	Need for Data Frequency	Reliability Concern and Related Need
Moving Electrical Load Between Electrical Circuits (Operating Switching)	Grid Operators	1547 Standard (active, reactive power, voltage, frequency)	Within Seconds	Operators need to know full electrical load served immediately served prior to switching (switching is transferring the electrical load on one circuit to another circuit) to make appropriate circuit transfer decisions maintaining safety and reliability	Allowance of DER projects to remain on line during circuit switching and to ensure that the electrical load can be served and ensuring that electrical configuration does not contribute to an electrical overload or over-voltages after the switching is performed
System	Grid	1547	Within	In the event of an outage	Inability to reconfigure

Diagnostics for Grid Outages (Planned/Unplanned)	Operators	Standard (active, reactive power, voltage, frequency)	seconds	(planned or unplanned), operators need to identify what electrical load and generation was immediately served prior to the event occurring in order to reconfigure the distribution grid to meet load requirements	the system as needed can create or prolong system issues such as overloads or over voltages if load or generation was different than expected
Circuit Automatic Reclosing/Restoration	Grid Operators	1547 Standard (active, reactive power, voltage, frequency)	Within seconds	When an electrical feeder experiences a system disturbance and DERs as designed trips offline, when restoration occurs and DERs do not re-energize immediately as designed, operators must be able to aware of the intermittent masked load	Inability to configure the system as needed can create system issues such as overload or over voltages
Customer Maintenance and Related Load	Grid Operators	1547 Standard (active, reactive power, voltage, frequency)	Within seconds	When an electrical feeder experiences a system disturbance, the need for restoration requires operators to identify what electrical load was served	Customers can request disconnect / reconnect to perform system maintenance and would have the ability to perform this work. Real time visibility would enable operators to manage these requests and mitigate potential overloads

Another illustrative example is a condition that occurs when the feeder circuit breaker recloses automatically to restore electrical load. When this occurs, inverters on the circuit are required to have a short time delay to return so that it does return until the feeder's voltage and frequency are stabilized. During this short time, the unmasked load will appear potentially overloading the feeder and creating a subsequent outage. Real time visibility via telemetry can help the IOU plan for these situations, facilitate the identification of the masked load situation, with the result that electrical service can be restored to customers more expeditiously.

Current Telemetry Costs

Both the IOUs and stakeholders acknowledge that telemetry costs in some cases have been cost prohibitive, especially for PG&E customers. Recognizing this issue, the IOUs have continued to look for more cost-effective solutions. Stakeholders represent that based on current projects, telemetry costs have ranged from $10,000-$250,000. Based upon IOU review, costs have generally ranged from $20,000-$190,000.[56]

As outlined above and in the table below, the IOU's charges to a customer for a telemetry system can include charges for metering equipment (meters, circuit transformers (CT) and potential transformers (PT)), communications/telemetry equipment (Remote Terminal Unit (RTU) and a modem), and charges for labor, taxes, and maintenance. These costs are collectively referred to as "utility-related telemetry costs" for the purposes of this report. The customer may also be required to independently purchase additional equipment and communication channels that meet technical specifications set by the utility. These costs will be referred to as "customer-related telemetry costs".

Current utility-related telemetry costs are summarized below:

- SCE's current utility-related telemetry costs are between $10,000 - $20,000.
- PG&E's current utility-related telemetry costs for most systems larger than 1 MW are approximately $160,000. PG&E requires circuit breakers called reclosers that can be controlled remotely. The main purpose of this device in the telemetry context is telemetry, but the device was designed to provide grid protection when the utility has reason to believe there is risk of inappropriate power flow. Within the telemetry context, the circuit interruption functionality is not needed. PG&E has used this approach because it is a reliable device that has communications. PG&E is exploring a pilot approach similar to SCE, but it is in progress.
- SDG&E's current utility-related telemetry costs (including for applicable metering) are $19,000-$46,000.[57] As part of this proposal, SDG&E has developed options that will enable customers to install the required equipment with charges from the IOU being under the stakeholder-desired $20,000 (outlined in Appendix A).

SCE and SDG&E note that their proposals for the customer to opt to own the metering and communication equipment associated with the telemetry system will result in the IOU's expected charges to the customer being less than $20,000 vs. greater than $20,000 if owned by the IOU. These charges are based upon current prices incurred by the IOU, and should the customer's incurred costs to procure and install this equiplment, plus the IOU's charges for labor (associated with programming the RTU equipment et al) be greater than $20,000, the IOU will continue to require a telemetry system be installed. Should the customer not opt for the lower costs associated with customer purchasing, installing, owning and maintaining the telemetry system's equipment, the IOUs continues to require a telemetry system be installed and will bill the customer (per Rule 2) charges corresponding to the IOU's purchasing and installing the necessary equipment.

[56] Based on several real-world project quotes, as well as the PG&E Unit Cost Guide, current solutions cost approximately $180,000. This is based on 2018 '1.048' cost escalation factor of the 2016 base price of $80,000; as well as the 2018 One-Time COO calculation and ITCC @ a rate of 24%. The most recent PG&E base quote for SCADA Sunworks received was $85,000. Total cost = $182,165.20.
[57] In all cases, SDG&E customers will incur costs to purchase and install metering section equipment.

Phase 3-Compliant Smart Inverters Do Not Fulfill Telemetry Requirements

As part of its Phase 3 recommendations, the Smart Inverter Working Group included a requirement that generating facilities be capable of reporting operational data. The Commission is currently considering advice letters implementing these requirements, and smart inverters may be required to be capable of reporting operational data as early as Q4 2018.

Many stakeholders have assumed that smart inverters will make telemetry cheap and easy once the new function is enabled. Tesla in particular notes that there appears to be a disconnect between this telemetry proposal and the smart inverter Phase 3 requirements. Specifically, Phase 3 contemplated requirements for individual inverters including a requirement for the inverters to report VARs and Watts at the system level which they believe could be leveraged to provide much of the data the utilities seek through telemetry. From Tesla's perspective this information could be leveraged to offer a lower cost solution.

However, utilities assert smart inverters cannot provide telemetry on their own because additional equipment will be needed at most facilities to connect the smart inverter to the utility. Utility telemetry rules require DERs to report facility-level data rather than inverter-level data. A majority of customer-sited solar installations have multiple inverters, thus the solar provider will have to aggregate the data prior to reporting, which cannot be done by the inverters themselves. This aggregation must also be performed in a way that gathers all the data reliably.

Also, Phase 3 inverter function Hh.7 (Monitor and Telemetry Requirements) is only at this time proposed as a *capability* as compared to an actual requirement. It would be premature to assume that the function will be required in the short to medium term. And even if a smart inverter is installed at a developer's site, it will still need a connection to the IOU's system to transmit the information in the secure, reliable and real-time manner that grid operators need to make grid decisions as discussed in the table above. Therefore, inverter capabilities alone do not address the urgent need to review telemetry standards in support of grid operation decisions.

Working Group Proposals

The following five proposals were developed by various stakeholders as part of the working group process to address Issue 4. Proposals 1 and 2 are mutually exclusive alternatives, meaning none or one may be selected. Proposals 3, 4, and 5 are independent alternatives, meaning none, one, or more than one may be selected. None have consensus support.

To ensure adequate visibility while minimizing cost, the Commission should adopt the following changes to telemetry requirements:

Proposal 1: Require systems between 250 kW and 9.9 MW to provide telemetry only if all utility-sponsored telemetry costs are estimated to be less than $20,000

Summary

Currently, Rule 21 allows the utilities to require generating facilities sized 1 MW and higher to install telemetry at the producer's expense, without incorporation of a cost "trigger". PG&E, SCE, and SDG&E

propose to lower the size threshold for requiring telemetry to 250 kW for distribution connections and to require telemetry only if all utility-related telemetry costs are estimated to be less than $20,000. The cost trigger would apply to all projects connecting to distribution voltage between 250 kW and 9.9 MW. The project would still be responsible for actual utility-related telemetry costs,[58] which may exceed $20,000.

To support stakeholder concerns regarding costs, the IOUs have developed and continue to develop solutions and options such that the utility-related telemetry costs would fall below $20,000.

Status

Non-Consensus. Supported by TURN, PG&E, SCE, and SDG&E. Opposed by CALSSA and its member companies.

Discussion

PG&E, SCE, and SDGE propose the following:

1. Modify telemetry requirement from 1 MW and above to between 250 kW and 9.9 MW on distribution voltage,[59] but only if all utility required telemetry system and related utility charges costs are estimated to be less than $20,000.
    a. As outlined above in the Current Telemetry section, and in the table below, the IOU's charges to a customer for a telemetry system can include charges for metering equipment (meters, circuit transformers (CT) and potential transformers (PT)), communications/telemetry equipment (Remote Terminal Unit (RTU) and a modem), and charges for labor, taxes, and maintenance. These costs, collectively referred to as "utility-related telemetry costs" for the purposes of this proposal, are proposed to be included in the $20,000 estimate.
    b. Keeping utility related telemetry costs below $20,000 is proposed to be applied for projects less than 9.9 MW connected to the distribution system. Allowing projects less than 9.9 MW to qualify for this represents an improvement of the existing Rule 21 1 MW and above telemetry requirement as such requirement is not currently triggered by an IOU estimated charge of $20,000 or lower.
2. IOUs will develop technical specifications in support of the telemetry solution within ninety calendar days after the final Commission decision on Working Group One.
3. SCE and SDG&E will develop Interconnection Agreement revisions to reflect an option for when the Interconnection Customer's provision for customer or third party ownership is utilized as part of the telemetry system solution. The Interconnection Agreement revisions will include a provision allowing thirty days for a customer to repair or replace malfunctioning equipment as notified by the IOU. If the malfunctioning equipment is not repaired within this thirty day period, the IOUs reserve the right to make such repairs, charge the Interconnection Customer for related costs, and reserve the right to disconnect the DER.

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[58] This is consistent with cost responsibility treatment of other interconnection facilities.

[59] Distribution is under 60kV for PG&E and SDG&E and under 50kV for SCE.

a. PG&E does not support this option at this time. PG&E would like to understand stakeholder maintenance plans that cover these repairs and the level of standards they would comply with.

The table below is provided to illustrate expected utility and non-utility related telemetry costs. Telemetry solutions remain under development and thus the table is illustrative only.

Table: Anticipated Telemetry Costs (Illustrative Only)

	Anticipated Utility-Related Costs ***(Subject to Proposed $20,000 Estimate)***	**Anticipated Customer-Related Costs** ***(NOT Subject to Proposed $20,000 Estimate)***
SCE	No equipment costs – unless the applicant requests SCE to install the equipment. Labor cost for programming RTU to SCE's systems.	RTU with specification to be provided by SCE (anticipated interconnection customer ranging from $1.5-$2K), data combiner box or existing EMS if available, internal communication wiring between combiner data combiner box or EMS to RTU. Verizon LTE service
SDG&E	None – unless the applicant requests SDG&E to install the equipment. Labor cost for programming RTU to SDG&E's systems.	**SDG&E purchases, installs, owns, and maintains:** • Metering equipment: meter(s), CT(s)/PT(s); and • Communication/telemetry equipment: RTU and modem Total SDG&E charges billed to customer (via Rule 2) are estimated to be greater than $20,000 if this option is selected. Customer supplies metering cabinet per SDG&E standards: Costs directly incurred by customer subject to their material and labor vendors. --- **Customer purchases, installs, owns, maintains**: • Metering equipment: meter(s), CT(s)/PT(s) (or equivalent equipment); and • Communicaton/telemetry equipment: RTU and modem Total SDG&E charges billed to customer (via Rule 2) are estimated to be less than $20,000. o SDG&E will charge the customer $150 per hour, as allowed in Rule 21, to provide support that is deemed necessary to maintain a customer owned RTU or modem

		after the initial set-up. The customer's costs to purchase, install, own, and maintain the telemetry system equipment are directly incurred by the customer and are subject to their material and labor vendors. Customer supplies metering cabinet per SDG&E standards: Costs directly incurred by customer subject to their material and labor vendors. Customer must supply proper electric signal to RTU. See Appendix A: SDG&E Telemetry Options for more details
PG&E	Huffman Box[60] (~$20,000) (includes cell modem/power converter, modem, and Eaton RTU), Labor, ITCC, and Cost of Ownership	Verizon LTE service, EMS or combiner box to connect to Huffman Box

Supporting Discussion

Real-time telemetry is a critical component that allows the utility to allow for grid operators to make safe and reliable system decisions in cases involving movement of electrical served load, restoration of electricity in response to system outages, as well as system diagnostics supporting planned electrical outages to allowing for maintenance to the IOU systems, along with customer required equipment replacements and related system needs.[61]

Without the use of telemetry, the IOUs have limited system visibility or situational awareness to make grid operation decisions for DERs under 1 MWac. Fundamentally, the current telemetry requirement has not kept up with DER growth driven by programs such as NEM. The IOUs are proposing for telemetry on projects which are large enough to influence grid operator decisions to maintain a safe and reliable grid. Table 1 above highlights cases where grid operators need real time data (data provided in seconds) to make decisions to operate electrical facilities. Utilizing SCE's territory as an example, the vast majority of Rule 21 projects are interconnected within SCE's territory without telemetry and, thus, SCE's grid

[60] PG&E is exploring additional telemetry solution options one of which includes smart meters. Should those technologies prove more effective and can be implemented at a lower cost, PG&E will update its Interconnection Handbook to reflect the updated telemetry solution.

[61] While the CAISO does not yet support a particular kW threshold for telemetry requirements, real-time telemetry, especially for distribution-side resources like behind-the-meter PV, is important to assist in forecasting and reliable real-time operation of both the distribution and bulk electric grid. Given the dearth of available data today and growing penetration of distributed energy resources, the CAISO supports more granular real-time telemetry requirements under Rule 21.

operators don't see the full electrical load served by circuits on the system (see Figure 1 – Load Masking Example) which impacts operator decisions ranging from:

- Transferring electric load between facilities (switching)
- Restoration of power for abnormal conditions (DERs don't automatically re-energize when systems are restored compared to load which resumes quickly potentially overloading the system)
- System diagnostics supporting planned and unplanned outages
- Allowing customers to service their own facilities

Although the vast majority of Rule 21 projects are of a small project size, the aggregate amount of generation is not trivial. The IOUs also recognize that as California continues to lead in renewable generation, that the growth of small DERs will continue and therefore the antiquated telemetry requirement should be adjusted to reflect the type of generation connecting to distribution. In addition, as presented during working group discussions, looking at SCE's service territory, lowering of the telemetry threshold to 250 kW is expected to potentially impact approximately *four* percent of Rule 21 projects but would provide an additional *sixteen* percent grid operator distribution capacity visibility. SCE historical data shows that only approximately 250 additional projects annually would be subject to telemetry if the telemetry requirement was reduced to 250 kW.

The IOU proposal in response to stakeholder comments also incorporates improved telemetry solutions. Currently, telemetry may be required for projects 1MW and above with no reference to cost. The IOU proposed solution refines the current Rule 21 telemetry requirement to not require telemetry less than 9.9 MW unless the IOU's related telemetry costs are estimated at less than $20,000 for distribution level connections. PG&E and SDG&E have made progress in developing telemetry options that are expected to meet the total related utility proposed cost target of $20,000 or less. SCE also had developed cost effective solutions that are also expected to meet the $20,000 cost threshold. Telemetry costs have been a major decision point in whether the lowering of the telemetry threshold was appropriate at this time.

Finally, the use of telemetry is already common today throughout transmission level interconnections and although DER telemetry from all projects would be viewed as optimal, the IOUs believe they have continued to balance the need for system visibility vs. appropriate project size and related cost pressures in development of the IOU proposal.

TURN supports the IOUs' proposal but recommends a compromise by increasing the threshold from 250 kWac to 500 kWac.

Opposing Discussion

Distributed energy resource providers do not dispute that utilities would benefit from better data on the output of customer-sited solar systems, but expensive real-time telemetry is not worth the cost. In Hawaii, where the need is more acute due to the much higher penetration of solar, utilities have built modeling capabilities to use satellite irradiance data. Knowing how intense the sunlight is in real time with high geographic granularity and knowing the location, size and orientation of solar systems, they have information on the real-time output of solar. This data covers all systems, not only large systems.

In the development of this proposal, the utilities have not provided the technical specifications for telemetry. Normally, when there is a need for a market participant to perform a service, stakeholders develop a standard and the competitive market creates products that can deliver the service according to the standard. In this case, utilities want to require a service and dictate the exact equipment to be used. They are offering to define technical specifications 90 days after a decision establishing the requirement. That is backwards.

The solar market for medium sized commercial customers has been slowed greatly by rate uncertainty and the switch to TOU rate structure with evening peak periods. There is hope that solar plus storage will become a common solution, but storage is still prohibitively expensive for most customers. Adding anything to the cost of a 250 kW solar system is significant.

Note from Energy Division Staff: The opposing discussion to Proposal 1 was added in writing to the report one day prior to filing, thus the supporters of Proposal 1 did not have time to review or prepare a response. They may choose to respond in their written comments submitted in April.

Proposal 2: Maintain the threshold for requiring telemetry at 1 MW

Summary
Maintain the threshold for requiring telemetry at 1 MW.

Status
Non-Consensus. Supported by CALSSA and its member companies, and Clean Coalition. Opposed by TURN, PG&E, SCE, and SDG&E.

Discussion

Supporting Discussion:
Non-utility stakeholders believe the IOUs have not shown shown that the incremental value of real-time data over 15-minute data or modeled data is worth the cost for systems smaller than 1 MW. Non-utility stakeholders remain very concerned about the implications on project economics of reducing the telemetry threshold, especially when the technical requirements are still not settled. Any consideration of reducing the threshold for the telemetry requirement will have to clearly consider the costs and benefits of doing so and the implications on project economics.

Opposing Discussion:
Please see the discussion under Proposal 1 and The Need for Telemetry section regarding the need for real-time data.

With respect to costs, as discussed above, telemetry is not being proposed for all projects but only for projects 250 kW and above which, for SCE, represents only an additional 250 projects annually out of approximately 48,000 projects. This ratio is similar for PG&E as well.

Proposal 3: Require the IOUs to adopt certain technical requirements for telemetry for systems larger than 1 MW to avoid unnecessary costs

Summary

The Commission should adopt the following technical requirements for telemetry for systems larger than 1 MW. This is intended to achieve the same purpose as a $20,000 cap but is structured as technical specifications rather than a monetary cap.

- Facilities can report measurements in 15-minute increments using customer-owned, non-revenue-grade metering and a data aggregation device comparable to the serial device server that SCE has historically required.
- Customers can choose to connect the reporting device to the utility Energy Management System via cellular modem or dedicated internet connection.
- Measurements do not have to be made from revenue grade equipment since the telemetry data is used for operational and planning purposes only. Thus, producers are not required to measure total generation output data from a costlier utility-owned Net Generation Output Meter.

Status

Non-Consensus. Supported by CALSSA and its member companies, and Clean Coalition. Opposed by TURN, PG&E, SCE, and SDG&E.

Discussion

Supporting Discussion:

Non-IOU stakeholders believe the most important element of Issue 4 is to require both PG&E and SDG&E to match SCE's current technical requirements and practices. This has allowed a system larger than 1 MWac to provide telemetry for approximately $13,000, as a truly all-in cost for the customer. Systems of this size have existing metering for system monitoring purposes. . Customers should not be required to install duplicative metering for telemetry. Combining the data from multiple metering devices at the site and transmitting it securely to the utility is not difficult. A telemetry unit that aggregates data and operates as a modem can be purchased for less than $1000.[62] The utility has some set-up costs, and the customer has to maintain a dedicated cellular line. Anything more than this is excessive.

Opposing Discussion:

Fundametally, real time is in seconds not minutes as discussed in Table 1 and does not satisfy the need the IOUs require telemetry for. "Near" real time or 15 minute increments is not quick enough to allow for a utility operator to make grid decisions impacting the safety and reliability of the grid. As illustrated in the figure in the Background section on load masking, without telemetry the utility does not see the entire electrical load served on a circuit.

[62] See (https://store.perle.com/iolansds1ta4d2) for the Serial Device Server SCE currently requires.

Current Rule 21 telemetry requirements are based on project system size (nameplate capacity rating) and not based upon the type of telemetry solution. Although stakeholder's point to SCE's current technical requirements and practices, SCE's solution is under refinement and all three IOUs have agreed to provide specific technical specifications upon the Commission decision, a illustrative table with what would be expected to be provided by the IOU vs. Interconnection Customer and have provided an assurance that unless the estimated utility cost is under $20,000 there is no telemetry requirement up to 9.9MW. This underscores that no prescriptive telemetry solutions should be established. It is critical that the IOUs have enough flexibility in order to reach the telemetry cost goals that allow for cheaper DER project solutions. In addition, SCE, PG&E, and SDG&E may not share Operations Distribution Networks (ODN) and SCADA systems that support the same telemetry solutions along with communication protocols (DNP3 or Secure DNP3). Thus, the communication options and hardware necessary to communicate with infrastructure and software for each IOU operations may not be the same. However, as consistent with today's practices, even with these slight variations, all three IOUs share the same telemetry needs today along with obligations to meet cybersecurity and operations related functions and have provided great detail discussed above to set stakeholder expectations.

Proposal 4: Apply the telemetry threshold to the maximum facility export in the interconnection agreement if this value is different from the total nameplate rating of all generation on the site

Summary

Apply the telemetry threshold to the maximum facility export in the interconnection agreement if this value is different from the total nameplate rating of all generation on the site.

Status

Non-Consensus. Supported by CALSSA and its member companies. Opposed by TURN, PG&E, SCE, and SDG&E.

Discussion

Supporting Discussion:

Utilities have clarified that the threshold for telemetry is based on the sum of nameplate capacities of all inverters (summing solar and storage inverters). In cases where a maximum facility export is included in the interconnection agreement, utilities have not been using that lower number for this purpose. For example, in cases where a non-export or reverse power relay limits facility export below the total nameplate, the total nameplate is still used as the threshold for requiring telemetry.

If a customer has a 700 kW solar system and a 400 kW storage system, current utility practice considers this an 1100 kW system even if the storage is configured in a way that will never export to the grid or if there are operating requirements or controls that limit export to a small amount. If a system export capacity is stipulated in the interconnection agreement that is different from the sum of the nameplate capacities, that value should be used for determining whether the telemetry threshold is exceeded.

Similarly, if a system is configured or controlled in such a manner that the total output at any time will always be below 1 MW, that should allow a system to be deemed as falling below the 1 MW threshold above which the utilities may require telemetry. In the example above, such a control scheme could be established such that the battery discharge would be limited by the difference between the solar systems ouput at any time and 1 MW. Under this regime, if the solar system were producing below 600 kW, the storage system would be allowed to discharge to its maximum rated capacity. Above this amount, the storage system's discharge would be capped below this amount.

Opposing Discussion:

Please refer to the discussion of load masking in the Background section that explains how although load masking could be estimated based on Generating Facility nameplate, the actual output of these generating facilities can vary greatly and is not sufficient to determine real time operational decisions, including system contingencies.

The size of a generating facility for purposes of determining whether telemetry is required is based upon the aggregate generating facility nameplate rating, with energy storage DERs counted as a generator at its full inverter nameplate rating. This is consistent with how telemetry requirements are currently decided under Rule 21. As discussed within the Background section, the most common concern that the IOUs have (as echoed by the California Independent System Operator[63]) is the issue of load masking. Both non-exporting and exporting resources are capable of masking load. The amount of generation in relation to load determines how great the load masking issue is, and when it becomes critical. While load masking could be estimated based on Generating Facility nameplate, the actual output of these generating facilities can vary greatly and is not sufficient to determine real time operational decisions, including system contingencies. For example, if an electrical service feeder circuit with high levels of DER experiences a permanent electrical fault, the IOUs need to restore power to grid in order to restore power to our customer. This is typically done via manual and/or automated system reconfiguration. However, if there are high levels of DER on that line section, and no telemetry information is available, the reconfiguration may be delayed or not completed until operation of DER is confirmed. This is due to the fact that reconfiguration with high levels of DER could cause significant overvoltage or thermal issues under the new configuration, which can lead to issues with safety and reliability. Thus, when telemetry data is not available, that hinders the ability of the grid operator to operate the system in the most effective manner.

Proposal 5: Customer ownership of behind-the-meter telemetry equipment should be allowed where practicable to avoid federal tax for Income Tax Component of Contribution and Cost of Ownership charges.

Summary

Customer ownership of behind-the-meter telemetry equipment should be allowed where practicable to avoid federal tax for Income Tax Component of Contribution (ITCC) and Cost of Ownership (COO) charges.

[63] See Footnote 61 for CAISO comments regarding real-time telemetry.

Status

Non-Consensus. Supported by CALSSA and its member companies, and Clean Coalition. SCE and SDG&E's support is contingent on interconnection agreement modifications. Opposed by PG&E.

Discussion

Supporting Discussion:

DER developers understand that maintenance of equipment and required uptime metrics will be specified in the interconnection agreement, but cost of ownership charges and ITCC are so high that customers should be permitted to maintain systems on their own. Non-utility stakeholders support the IOU proposal to allow utilities to require that problems be fixed within 30 days.

Opposing Discussion:

Please also see Proposal 1 where SCE and SDG&E will develop Interconnection Agreement revisions to reflect an option for when the Interconnection Customer's is providion for third party ownership is utilized as part of telemetry system solution. The Interconnection Agreement revisions will allow thirty days to repair or replace malfunctioning equipment as notified by the IOU utility. If the malfunctioning equipment is not repaired within the thirty day period, the SCE and SDG&E reserve the right to make such repairs, charge the Interconnection Customer for related costs, and reserve the right to disconnect the DER. If the developer does not service their owned equipment supporting telemetry in a timely fashion, the IOUs reserve the right to repair at developer cost as discussed within the IOU proposal

PG&E does not support this option at this time. PG&E would like to understand stakeholder maintenance plans that cover these repairs and the level of standards it would comply with. Cost of ownership and ITCC are charges tied to the IOU procuring, installing, and maintaining equipment necessary to meet telemetry requirements. Stakeholders should be required to provide proposals on how equipment will be maintained not just through warranty periods but beyond in order for an alternate proposal of customer ownership be considered.

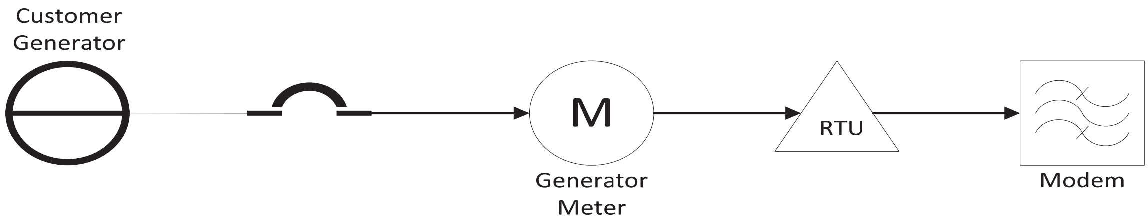
Sunworks does not specifically oppose the idea of IOU ownership, so long as the all in $20,000 cost cap does not exclude anything that would impose an unreasonable additional cost to the customer. It would be preferable for the IOUs to hold the responsibility of upkeep and maintenance, not only for customer convenience, but also for the reliability of the equipment to the grid.

Issue 4 Appendices

Appendix A: SDG&E Telemetering Options

This appendix outlines eight different ownership options that SDG&E is offer DER customers to choose from as a means to allow the DER customers to minimize their costs associated with a telemetry system. Selection of four of the options (1, 2, 5, 6) will result in SDG&E charging the customer greater than $20,000 for a telemetry system, and four of the options (3, 4, 7, 8) will result in SDG&E charging the customer less than $20,000 for a telemetry system. To the extent SDG&E did not have sufficient time to fully describe these options, SDG&E will provide an expanded description if the Commission directs the Working Group to continue discussing this Issue or as directed in a Commission's Decision.

Figure: Metering and Telemetering configuration for Options 1 – 4



Option #1 – Renewable or Non-renewable Generator

- SDG&E purchases, installs, owns, and maintains: meter, CT/PT's, RTU, RTU cabinet, and Modem
- SDG&E Rule 2 Bill to customer: Greater than $20k
    - Customer supplies metering cabinet per SDG&E standards

Option #2 – Renewable or Non-renewable Generator

- SDG&E purchases, installs, owns, and maintains: meters and CT/PT's. SDG&E also programs and installs RTU and modem
- Customer purchases, owns, and maintains: RTU, RTU cabinet, and modem specified by SDG&E. (SDG&E will charge customer $150 per hour per Rule 21 to provide support necessary to maintain customer owned RTU or modem.)
- SDG&E Rule 2 Bill to customer: Greater than $20k
    - Customer supplies metering cabinet per SDG&E standards

Option #3 – Renewable or Non-renewable Generator

- SDG&E purchases, installs, owns, and maintains: RTU, RTU cabinet, and Modem
- Customer purchases, installs, owns, maintains meter[64], CT/PT's (or equivalent equipment) to provide generator output data signal[65] to SDG&E.
- SDG&E Rule 2 Bill to customer: Less than $20k

Option #4 – Renewable or Non-renewable Generator

- SDG&E installs and programs RTU and modem.
- Customer purchases, installs, owns, and maintains meter[64], CT/PT's (or equivalent equipment) to provide generator output data signal[65] to SDG&E. Customer also purchases

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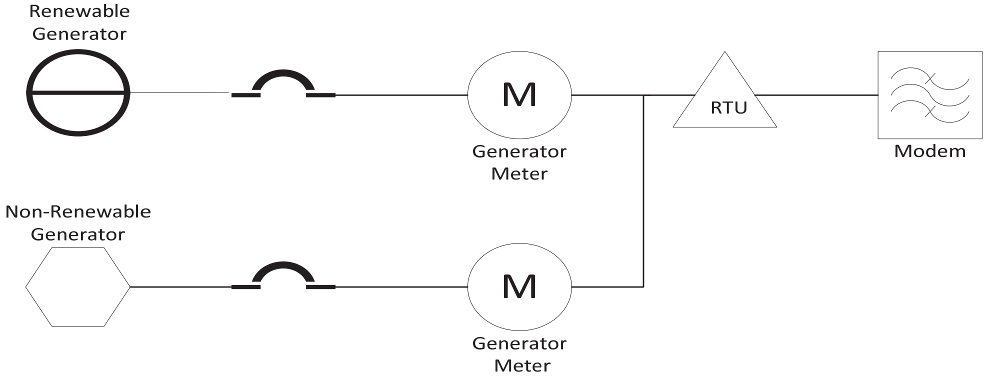
[64] For multiple tariff projects and non-renewable generators, customer can use revenue grade meter, or non-revenue grade meter with estimation methodology for calculating stand-by and departing load charges.

[65] Customer must supply proper electric signal to RTU.

RTU, RTU cabinet, and modem specified by SDG&E. (SDG&E will charge customer $150 per hour per Rule 21 to provide support necessary to maintain customer owned RTU or modem.)
- SDG&E Rule 2 Bill to customer: Less than $20k

Figure: Metering and Telemetering configuration for Options 5 – 8



Option #5 – Combined technology generation
- SDG&E purchases, installs, owns, maintains: (2) meters, (2) CT/PT's, RTU, RTU cabinet, and Modem
- SDG&E Rule 2 Bill to customer: Greater than $20k
  - Customer supplies metering cabinet per SDG&E standards

Option #6 – Combined technology generation
- SDG&E purchases, installs, owns, and maintains: (2) meters, (2) CT/PT's, and SDG&E programs and installs RTU and modem
- Customer purchases, owns, and maintains: RTU, RTU cabinet, and modem specified by SDG&E. (SDG&E will charge customer $150 per hour per Rule 21 to provide support necessary to maintain customer owned RTU or modem.)
- SDG&E Rule 2 Bill to customer: Greater than $20k
  - Customer supplies metering cabinet per SDG&E standards

Option #7 – Combined technology generation
- SDG&E purchases, installs, owns, and maintains: RTU, RTU cabinet, and modem
- Customer purchases, installs, owns, maintains (2) meters[64], (2) CT/PT's (or equivalent equipment) to provide generator output data signal[65] to SDG&E. Customer also purchases RTU, RTU cabinet, and modem specified by SDG&E. (SDG&E will charge customer $150 per hour per Rule 21 to provide support necessary to maintain customer owned RTU or modem.)
- SDG&E Rule 2 Bill to customer: Less than $20k

Option #8 – Combined technology generation

- SDG&E installs and programs RTU and modem.
- Customer purchases, installs, owns, and maintains (2) meters[64], (2) CT/PT's (or equivalent equipment) to provide generator output data signal[65] to SDG&E. Customer also purchases RTU, RTU cabinet, and modem specified by SDG&E. (SDG&E will charge customer $150 per hour per Rule 21 to provide support necessary to maintain customer owned RTU or modem.)
- SDG&E Rule 2 Bill to customer: Less than $20k

Issue 5: Activation of Latent Smart Inverters

Issue 5: Should the Commission require activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017 and, if so, how?

Proposal Summary

The following three proposals were developed by various stakeholders as part of the Smart Inverter Working Group process to address Issue 5. Proposal 1 is independent of Proposals 2 and 3. Proposals 2 and 3 are mutually exclusive alternatives, meaning none or one may be selected. Proposals 1 and 2 have consensus support; Proposal 3 is non-consensus.

- **Proposal 1**: The Commission should neither require nor incentivize activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017
    - **Consensus**.
- **Proposal 2**: The Commission should continue to allow customers to replace existing inverters with inverters of equal or greater ability, per D.14-12-035, and encourage, not require, customers to replace existing inverters with smart inverters at end of life.
    - **Consensus**. Non-IOU SIWG members support. IOUs and TURN support as well but prefer Proposal 3.
- **Proposal 3**: The Commission should modify Rule 21 to require customers to replace existing inverters with smart inverters at end of life.
    - **Non-Consensus**. ORA, TURN, and IOUs support. IOUs and TURN prefer Proposal 3 to Proposal 2. Non-IOU SIWG members oppose. Clean Coalition does not oppose but prefers Proposal 2.

This section presents a summary of the proposals only. The "Working Group Proposals" section further describes the proposals and the positions for and against.

Background

An inverter is a device that converts the direct current (DC) power from a generating resource to the voltage and frequency of the alternating current (AC) power on the distribution system. In early 2013, the Smart Inverter Working Group (SIWG) was formed by parties of R.11-09-011 to develop proposals to take advantage of the new, rapidly advancing technical capabilities of inverters. "Smart" inverters mitigate some of the adverse grid impacts of DERs, enable greater penetrations of DERs, and enhance DER value by enabling grid services.

In January 2014, the SIWG issued its "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources," which came to be known as the Phase 1 functions.[66] On

[66] For more information about Smart Inverter Working Group history and recommendations, please see Energy Division's webpage at (http://www.cpuc.ca.gov/General.aspx?id=4154).

December 22, 2014, the Commission issued D.14-12-035, which adopted the IOUs' revisions to Rule 21 with modifications incorporating the Phase 1 functions. On September 9, 2017, the Phase 1 functions become mandatory for all new Rule 21 inverter-based interconnections.

Some inverters installed prior to September 8, 2017 may be capable of the Phase 1 functions, but are not able to provide this functionality because they lack the appropriate certification and software, firmware, and/or hardware updates.

The Commission scoped this issue into the proceeding to explore the feasibility of activating advanced functionality in latent smart inverters and evaluate whether the benefits associated with activation outweigh the implementation costs. The SIWG was tasked with developing proposals to address this issue.

Working Group Findings

Inventory of Inverters

The SIWG spent considerable effort to determine what portion of existing inverters could be updated with all seven Phase 1 functions.[67] Three distinct groups of inverters were considered:

- **Group 1**: Inverters which can be updated remotely, and which already have firmware that is certified in compliance with Underwriters Laboratory 1741 Supplemental A;
- **Group 2**: Inverters which can be updated remotely, but require a firmware update that would not be certified; and
- **Group 3:** Inverters on systems larger than 500 kW which require a site visit to update, and the firmware update would be certified.

The SIWG sent an email survey to its members to attempt to quantify the number of inverters and the aggregate nameplate capacity in Groups 1, 2, and 3. Eight inverter companies responded, representing roughly 81% of market share. **Survey results showed that between 1% and 5% of inverter capacity can be updated**. The complete results are shown in Table 1, below.

Table 1. Inventory of Upgradable Inverters

	Utility	**Total Number of Inverters**	**Total Inverter Nameplate Capacity (MW)**	**% Updateable Inverter Capacity To Total Existing Capacity per Utility**	**Combined Inverter Nameplate Capacity (MW)**

[67] The SIWG also discussed updating inverters with some but not all of the Phase 1 functions, but chose not to pursue this scenario because of the lack of identifiable benefits and the accounting complexity that having inverters with the a spectrum of functionality would create.

Scenario #1	SDG&E	30,324	12	1.45%	235
	PG&E	56,688	197	5.00%	
	SCE	4,214	26	1.25%	
Scenario #2	SDG&E	166	4	0.47%	41
	PG&E	1,333	30	0.77%	
	SCE	138	7	0.34%	
Scenario #3	SDG&E	0	0	0.00%	0
	PG&E	0	0	0.00%	
	SCE	0	0	0.00%	

Costs to Activate Latent Smart Inverters, by Scenario Group

Non-IOU stakeholders represented that the cost of updating inverters remotely (Groups 1 and 2) is approximately $1-2/kW. This includes the time spent on engineering the update and troubleshooting and the cost of data bandwidth. With 276 MW of inverter capacity in Groups 1 and 2, this equals a total cost between $250,000 and $600,000.

In addition, non-IOU stakeholder representatives stated that updating inverters onsite (Group 3) by sending a service technician to a customer site to do an inverter upgrade typically costs approximately $500. It could be less if there is a local installer partner that can do the work. It can be a lot more if the Original Equipment Manufacturer has to visit a remote site.

Non-IOU stakeholders also represented that customers would want a monetary incentive to participate. For a customer with a 5 kW system, a one-time payment or credit of $10 (likely the minimum amount necessary to incentivize a system owner to participate) would equate to an additional $2/kW on top of the cost of the remote update. With almost 93,000 total inverters in Groups 1 and 2, this would equal an additional cost of approximately $930,000 on top of the potentially $250,000 to $600,000 cost of the remote update, for a total cost of approximately **$1.2 million to $1.5 million**. The actual cost may be many times more depending on the actual cost of the remote update, the incentive level chosen, and administration costs associated with any such program. If new interconnection applications must also be submitted, as determined by decisions related to Issue 3 Material Modifications, then administration costs may be higher.

Legal Issues Around Customer Consent

To require activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017, legal issues must be considered. Specifically, parties to CPUC-jurisdictional interconnection agreements must comply with Rule 21 and the Commission retains jurisdiction of its form agreements. Absent Commission action, most if not all of the current CPUC approved pro forma interconnection agreements provide for revision by mutual agreement, which would involve the consent of the customer.

Working Group Proposals

The following three proposals were developed by various stakeholders as part of the Smart Inverter Working Group process to address Issue 5. Proposal 1 is independent of Proposals 2 and 3. Proposals 2 and 3 are mutually exclusive alternatives, meaning none or one may be selected. Proposals 1 and 2 have consensus support; Proposal 3 is non-consensus.

Proposal 1: The Commission should neither require nor incentivize activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017

Summary

A program to require or incentivize systems to activate all seven Phase 1 functions is not justified because the cost of activation would exceed the benefits.

Status

Consensus.

Discussion

The Working Group agrees that although increasing the number of activated smart inverters on the grid may be beneficial, the benefits do not outweigh the costs and efforts to implement a mandatory or voluntary program. The small number of updatable inverters that were identified through data requests discussed previously do not produce many grid benefits because even in aggregate, the inverters are not sizeable enough in capacity to have a significant effect on the grid at large. However, the money and time required to implement a supporting retrofit program are considerable. Furthermore, there remain legal issues around obtaining customer consent to implement any program.

Proposal 2: The Commission should continue to allow customers to replace existing inverters with inverters of equal or greater ability, per D.14-12-035, and encourage, not require, customers to replace existing inverters with smart inverters at end of life.

Summary

The SIWG agrees that the majority of inverters at their end of life will be replaced with smart inverters because that is what will be commonly available. A requirement would need to include a litany of exceptions to avoid unnecessary burden to customers. Therefore, SIWG members recommend that the Commission should maintain language in Rule 21 Section Hh on inverters yet encourage replacement of existing inverters with smart inverters.

Status

Consensus. Non-IOU SIWG members support. IOUs and TURN support as well but prefer Proposal 3.

Discussion

After discussion of Proposal 1, the SIWG explored other opportunities that would increase the number of DER owners with smart inverters. Replacement at the end of life was chosen as a reasonable moment for encouraging the use of smart inverters.

Inverters wear out over time faster than solar panels. A typical inverter warranty is 10 to 15 years, while a typical solar panel warranty is 20 to 25 years. Most solar systems will need to replace their inverters one time during the system lifetime.

Rule 21 requires all inverter-based facilities applying for interconnection after September 9, 2017, to have inverters with the Phase 1 smart inverter functions. However, it does not require replacement inverters to include those functions. Section H.3.d.ii states, "The replacement of an existing inverter to an inverter that is of equal or greater ability than the original is allowed per Section H. Section Hh may be used in all or in part, for replacement inverter-based technologies by mutual agreement of the Distribution Provider and the Applicant."

This provision was established in D.14-12-035 due to concerns from inverter manufacturers that equipment replacements that are not like for like could void warranties, create conflicts with other inverters at a location, or be unreasonably difficult to install. Solar systems are designed with specific inverters, and the electrical configuration and physical space may not be able to accommodate a different inverter.

The SIWG agrees that inverter manufacturers will soon phase out production of non-smart inverter models. **Thus it is likely that the majority of inverters at their end of life will be replaced with smart inverters because that is what will be commonly available**. The SIWG considered whether to ask the Commission to allow for revisions to Rule 21 to require replacement inverters to be smart inverters, but acknowledged that it would need to include exceptions. Any requirement that end-of-life inverters be replaced with smart inverters would need to include exceptions if:

- There would be an electrical conflict between existing and new inverters in solar systems with multiple inverters;
- The physical space could not host a smart inverter without substantial reconstruction;
- Codes would require substantial new switches, fuses, or other additional equipment to go along with a smart inverter;
- The appropriately sized smart inverter is not available; and
- It would void a warranty.

Non-IOU SIWG members: Given the number of exceptions that would be needed, the SIWG recommends not establishing such a requirement. Again, the expectation is that most inverters will be replaced with smart inverters even without a requirement.

IOU SIWG members: The IOUs support this proposal, but would prefer the Commission adopt Proposal 3. With the growing proliferation of DERs, the advancement of smart inverter functionality is timely in that it has the capability to reduce the impact of intermittent generation. These functions support both the installer and grid operations. Therefore, the IOUs continue to support replacement of non-smart inverters with smart inverters consistent with comments provided in response to D.14-12-035.

Proposal 3: The Commission should modify Rule 21 to require customers to replace existing inverters with smart inverters at end of life.

Summary

Revise Rule 21 Section Hh to make replacement of existing inverters with smart inverters the default requirement with exceptions when the existing inverter reaches end of life. Any requirement that old inverters be replaced with smart inverters would need to include exceptions if:

- There would be an electrical conflict between existing and new inverters in solar systems with multiple inverters;
- The physical space could not host a smart inverter without substantial reconstruction;
- Codes would require substantial new switches, fuses, or other additional equipment to go along with a smart inverter;
- The appropriate size smart inverter is not available; and
- It would void a warranty; and
- It would cause the interconnection customer financial harm.

To implement this proposal, IOUs would propose Rule 21 revisions, application modifications to include the exceptions “check boxes”, and any related modifications required by the Commission decision on Issue 3 Retrofit.

Status

Non-consensus. ORA, TURN, and IOUs support. IOUs and TURN prefer Proposal 3 to Proposal 2. Non-IOU SIWG members oppose. Clean Coalition does not oppose but prefers Proposal 2.

Discussion

IOU SIWG members: The IOUs continue to support the replacement of existing inverters with smart inverters to the extent possible consistent with comments provided in response to D.14-12-035. IOUs therefore recommend modifying Rule 21 and propose that the Commission modify D.14-12-035 to make replacement of existing inverters with smart inverters the default requirement and allow for exceptions.

The IOUs acknowledge that as non-IOU stakeholders have highlighted it is likely that the majority of inverters at their end of life will be replaced with smart inverters because that is what will be commonly available, but propose to support this with this proposed rule change.

The IOUs strongly support this proposal versus a program to retroactively update existing inverters with Phase 1 functionality. The IOUs argue that it would not be logical to have a requirement that allows inverters to be replaced with non-smart inverters and then implement a program to update inverters after the fact.

Non-IOU SIWG members: Non-utility stakeholders believe this question has been asked and answered in December 2014 and no new facts have been presented to warrant revisiting the issue. There is also concern that activation of advanced inverter functionality would not have been expected by customers that installed solar previous to activation being required.

Issue 6: Smart Inverter Aggregator Forms and Agreements

Issue 6: Should the Commission require the Utilities to develop forms and agreements to allow distributed energy resource aggregators to fulfill Rule 21 requirements related to smart inverters? If yes, what should be included in the forms and agreements?

On January 25, 2018, CALSSA filed a motion on behalf of Working Group One to reassign Issue 6 to Working Group Two. CALSSA explained that Issue 6 was originally assigned to the Smart Inverter Working Group but it has become apparent that this group does not contain the appropriate personnel to address Issue 6; the development of forms and agreements should be addressed by legal and regulatory representatives instead of engineers.

On February 14, 2018, Administrative Law Judge Kelly Hymes issued an email ruling approving the motion.[68]

[68] Email Ruling Revising Schedule and Reassigning Issue Six, February 14, 2018. (http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=211794527)

Issue 7: Income Tax Component of Contribution

Issue 7: Is there inconsistent application of the requirement to pay the Income Tax Component of Contribution (ITCC) charges across the Utilities? If yes, how should the Commission address this inconsistency?

Proposal Summary

The following four proposals were developed by various stakeholders as part of the working group process to address Issue 7. Proposals 1, 2, and 3 are mutually exclusive alternatives, meaning only one may be selected. Proposal 4 is independent of the other proposals. None have consensus support.

To address inconsistent utility application of the requirement to pay the Income Tax Component of Contribution (ITCC) charges, the Commission should:

- **Proposal 1**: Retain the status quo, in which each IOU is authorized and retains the discretion pursuant to CPUC Decisions 87-09-026 and 94-06-038 to collect or not collect ITCC security on safe harbor projects.
    - **Non-Consensus**. TURN, PG&E, SCE, and SDG&E support Proposal 1 as the preferred practice. GPI opposes this and no non-IOU stakeholders expressed support.
- **Proposal 2**: If consistency is the primary concern of the Commission, then the IOUs propose to all collect ITCC security for safe harbor projects, which provides consistency across the IOUs but the IOUs acknowledge is least desirable for non-IOU stakeholders.
    - **Non-Consensus**. TURN, PG&E, SCE, and SDG&E support Proposal 2, if Proposal 1 is not selected. Clean Coalition, Outback, and GPI actively oppose this, and no non-IOU, non-ratepayer advocate stakeholders expressed support.
- **Proposal 3:** Modify D.94-06-038 to prohibit the collection of security for "Safe Harbor" systems and authorize a recovery mechanism, whereby each utility recovers from ratepayers any actual costs realized as a result of ITCC charges.
    - **Non-Consensus**. Clean Coalition and GPI actively support. No non-IOU, non-ratepayer advocacy stakeholders oppose. PG&E, SCE, and SDG&E support Proposal 1 and 2, and do not support a prohibition on collection of ITCC security. If the Commission decides to proceed with Proposal 3, PG&E, SCE and SDG&E would support recovery through customer rates of costs incurred that are not recovered from the contributor for a taxable liability. However, any recovery mechanism needs further development and review. TURN and ORA oppose.

In addition, the Commission should:

- **Proposal 4**: Expand the scope of R.17-07-007 to consider whether there are ITCC practices which merit modification despite being consistent across utilities, and if so, how those practices should be modified.

- **Non-Consensus**. Clean Coalition, Outback, CalSSA, ORA, GPI, Foundation Wind Power, Borrego Solar, Chico Electric, CalCom Solar, and Sunworks support. SCE, PG&E and SDG&E oppose.

This section presents a summary of the proposals only. The "Working Group Proposals" section further describes the proposals and the positions for and against.

Background

Income Tax Provisions and the Safe Harbor IRS Notice 2016-36

Internal Revenue Code Section 118(b) generally treats contributions in aid of construction (CIAC) from customers as a taxable receipt to the utility. CIACs are provided by customers to a utility to construct utility owned assets that will benefit the customer by providing electric, gas or other services and can take the form of money and/or property.

Since IOUs are cost-of-service regulated and the CIAC results in taxable income, the IOUs are allowed to collect an income tax component of contribution (ITCC) from the customer in addition to the CIAC to make both the utility and ratepayers whole. The burden of the tax associated with the CIAC is borne by the contributor based on the premise that the person who causes the tax pays the tax. D. 87-09-026 provides the IOUs several methods for collecting ITCC.

ITCC is not applicable when a transaction is considered nontaxable. In the 1980s, after extensive lobbying efforts by the qualifying facility (QF) industry, the IRS issued Notice 88-129, which exempted certain generator contributions from being treated as taxable under IRC 118(b) if certain conditions are satisfied (referred to as the Safe Harbor or the Notice). These conditions included satisfying the 5% test (explained below) and other representations. Thus, these QF projects were no longer taxable upon contribution under IRC 118(a), and although the IOUs did not treat the contributions as taxable, they were authorized pursuant to D.94-06-038 to collect security for the tax exposure risk of the transaction subsequently becoming taxable either because the project triggered a disqualification event, there was a change in tax law, or there was an early termination of the power purchase agreement. Subsequently, the IRS has continued to modify Notice 88-129 to expand the scope of the exception, with each modification removing and superseding prior Notices. The most current iteration of the Safe Harbor is IRS Notice 2016-36. If a project that avails itself of the safe harbor fails the 5% test for the third time in a rolling 5-year period, then the transaction becomes taxable in the year of the failure and a tax liability is incurred by the utility triggering the need to paythe ITCC.

The Commission, recognizing that the IOUs were exposed to tax risk for these projects availing themselves of the safe harbor (because the non-taxability treatment hinged upon satisfying certain conditions), permitted the IOUs in D.94-06-038 to collect ITCC security on these projects.[69] The decision

[69] CPUC Decision (D.) 94-06-038 established three options to assure payment to the purchasing utility for any future taxes: (1) pay the full ITCC; (2) provide the utility a letter of credit for the value of the full ITCC; or (3) execute an indemnity agreement and provide a guarantee for the value of the ITCC.

to collect ITCC security is subject to IOU discretion and was provided as a means for the IOU to protect itself from incurring costs for a future potential tax liability. The IOUs have allowed the risk of a potential tax liability to be satisfied by the collection of ITCC security in the form of cash or a letter of credit from the contributor, depending on the election of the contributor. Thus, even though a contribution is nontaxable for purposes of IRC 118(b) under the Safe Harbor notice, a project may still be required to post a security instrument to protect the utility and ratepayers from a future tax risk related to safe harbor failures.

December 2017 Federal Tax Reform Legislation

It should be noted that the December 2017 federal tax reform legislation amended Section 118 to expand taxable transactions under Section 118 to include "any contribution by any governmental entity or civic group (other than a contribution made by a shareholder as such)." The 2017 tax legislation may impact the relevancy of underlying court cases which the IOUs have relied upon previously to exempt contributions from taxable income on the basis of the safe harbor. Therefore, the implications of the recent tax reform legislation could impact the safe harbor. Due to its recent passage, the industry is now analyzing the recent changes to understand potential ramifications.

IOU Safe Harbor Provision Applicability Process

The IOUs rely on the generator's contractual representation that:

- In light of all the information available at the time the intertie is contributed, it is reasonably projected that, during the ten taxable years beginning when the intertie is placed in service, no more than 5% of the projected total power flows over the intertie will flow to the generator[70]
- Ownership of the electricity wheeled over IOU transmission system remains with the generator prior to its transmission onto the grid[71]
- The intertie will be used for transmitting electricity,[72] and
- The cost of the intertie is capitalized by the generator as an intangible asset and recovered using the straight-line method over a useful life that is treated as 20 years.[73]

SCE's Application of ITCC to Rule 21 Transactions:

- SCE applies the general concepts and principles of D.94-06-038 in its Rule 21 transactions.
- To the extent the CIAC from an IFOM generator provides written representation that it satisfies the requirement of IRS Notice 2016-36, SCE will not treat the CIAC as taxable and will collect the tax-related security equal to the ITCC amount in the form of a letter of credit, a corporate parent guarantee, or cash.

[70] Section III.C.1.a. of IRS Notice 2016-36
[71] Section III.C.2. of IRS Notice 2016-36
[72] Section III.C.4. of IRS Notice 2016-36
[73] Section III.C.5. of IRS Notice 2016-36

- To the extent the CIAC from a generator does not satisfy the requirement of IRS Notice 2016-36, SCE will treat the CIAC as taxable and will collect the tax-related the ITCC amount in the form of a cash payment from the contributor

PG&E's Application of ITCC to Rule 21 Transactions:

- PG&E acknowledges the general concepts and principles of D.94-06-038 in its Rule 21 transactions.
- To the extent the CIAC from an IFOM generator satisfies the requirement of IRS Notice 2016-36; PG&E will not treat the CIAC as taxable and will not collect any tax-related ITCC security. PG&E reserves the right to require—on a nondiscriminatory basis—an Interconnection Customer to provide such security.
- PG&E has also modified its practice to not collect ITCC security and require an indemnification for certain FERC jurisdictional projects involving interconnection of generators
- To the extent the CIAC from a generator does not satisfy the requirement of IRS Notice 2016-36, PG&E will treat the CIAC as taxable and will collect the tax-related the ITCC amount in cash.

SDG&E's Application of ITCC to Rule 21 Transactions:

- SDG&E acknowledges the general concepts and principles of D.94-06-038 in its Rule 21 transactions.
- To the extent the CIAC from an IFOM generator satisfies the requirement of IRS Notice 2016-36; SDG&E will not treat the CIAC as taxable and will not collect any tax-related ITCC security. SDG&E reserves the right to require—on a nondiscriminatory basis—an Interconnection Customer to provide such security.
- SDG&E does not treat CIAC from IFOM generators as taxable and currently does not collect any tax-related ITCC security.
- To the extent the CIAC from a generator does not satisfy the requirement of IRS Notice 2016-36, SDG&E will treat the CIAC as taxable and will collect the tax-related the ITCC amount in cash.

Historical Data on Realized Tax Liability for Safe Harbor Systems

On January 23, 2018, the IOUs provided historical data on realized tax liability for safe harbor systems, in response to a request from the working group. Their responses are summarized below and included in full in Appendix A.

As a reminder, the utilities are permitted to collect security from Safe Harbor customers to cover the tax exposure risk of the transaction subsequently becoming taxable. The IOU responses to the data request show that this risk has not materialized under a tax audit in the time period the utilities chose to report on (the last 10 years). The IOUs confirmed that the IRS has not identified in a prior audit review, a project receiving safe harbor treatment that should be reclassified as taxable in the last 10 years. However, the utilities note that one should not assume that the IRS couldn't in the future review a prior safe harbor transaction and determine that it no longer meets the eligibility requirements for safe harbor or that a project couldn't fail the 5% test and trigger a subsequent taxable event.

PG&E, SCE, and SDG&E have different numbers of Rule 21 interconnections claiming Safe Harbor, and different practices regarding ITCC security posting requirements, all of which are compliant with Commission rules and the Internal Revenue Code. PG&E has two (2) eligible applications and SDG&E has zero (0) eligible applications in the past ten years and neither currently require ITCC security, although they retain the authority to do so. SCE does require ITCC security, and has 61 Rule 21 projects interconnected under Safe Harbor, with current total project security postings of approximately $3.2 million. The scope of the data request did not include safe harbor eligible applications under FERC jurisdiction.

Non-Utility Stakeholder Concerns

Customers may meet ITCC security requirements by providing their choice of a letter of credit, corporate parent guarantee, or cash deposit. Clean Coalition finds that the carrying cost of a letter of credit generally adds 10-15% to the cost of upgrades associated with an interconnection request.[74] If the customer chooses to meet ITCC requirements by paying cash rather than providing security, ITCC adds roughly the same amount to the cost of the upgrade.[75] As SCE territory's average total in-front-of-the-

[74] When requesting a Standby Letter of Credit (SLOC), a business owner proves to the bank he is capable of repaying the loan. Collateral is required to protect the bank in case of default. The business owner must pay a SLOC fee for each year that the letter is valid. The fee is typically the greater of a percentage of the SLOC value or annual minimum dollar amount. Rates are not widely published, and vary greatly by circumstance. With strong collateral and low risk, fees as low as 1% per year appear to be available, however minimum fees of at least $300 will make the effective rate higher in many cases. In addition to fees that would likely exceed 10% over a ten year term, the collateral or other security requirements associated with qualifying for low risk rates reduces the availability of the business to obtain other credit. On this basis, the direct cost of providing an SLOC as security against a 24% ITCC for ten years would add 2.4% to the cost of the upgrade, not including the opportunity cost of the collateral. If the business owner puts down 20% in collateral, assuming a 10-year term and annual opportunity cost of 10% (based on the S&P 500's average annual earnings since its inception in 1928), the carrying cost of collateral would add an additional 7.6% (=24%*20%*((110%^10)-1)), raising the ITCC cost to 10% of the cost of the upgrade. Note the 10% assumes annual fees of 1%; fees could easily be double or triple that amount, raising the total additional cost to 12.5% or 15% of the cost of the upgrade. This is before considering either the business impact of consuming available credit or the transaction's administrative costs.

[75] If the customer chooses to meet ITCC requirements by paying cash rather than providing another form of acceptable security instrument, ITCC adds approximately 24% to the cost of the upgrade. This is refunded after 10 years, but the customer incurs the carrying cost of posting that security (plus any transaction/administrative costs). This also creates lost opportunity cost of not being able to invest this money where it would generate income greater than the financing cost. The cost of providing a cash deposit would be equal to the carrying cost of a loan for the amount, at 1.5 points fee + 8% annual rate. For an example $25,000 security on a $100,000 upgrade that would be $375 + $2,000 per year. The total payments would be $20,375 over ten years. Assuming a 8% discount rate, the Present Value of these payments would be $13,767. If this was offset by a 2% interest applied to the funds held as security, the effective net cost would be $12,630. This would be the applicant's actual net cost in 2018 dollars of posting the cash security for 10 years, excluding any administrative costs.

meter upgrade costs are approximately $150,000 per MW,[76] these charges represent the third largest contributor to interconnection costs,[77] despite the historically de minimis risk of actual liability being imposed.

Posting ITCC security represents a real cost to developers, adversely impacting project economics, as well as being an obstacle for some smaller developers who may not qualify for a letter of credit or loan. The more general question that needs to be addressed is whether it is good policy to require a developer to set aside substantial sums every year, over the term of an agreement, to protect the utility from risk of an event that has never occurred (see "Historical Data" section above). Given the limited risk to the utility and real cost to developer, and subsequent advice or rulings from IRS and FERC,[78] the ITCC security requirement warrants reconsideration.

> IOU Response*:* The IOUs disagree with the use of the term "de minimis" risk without further support. As discussed previously, the IRS on audit can determine that a transaction should be classified as taxable, to which is why ITCC security can be collected to address this risk as consistent with current Commission allowances. In addition, as discussed above, the actual cost impact to the IC's project is the carrying cost of providing the ITCC security (developers have the choice of cash, letter of credit, or corporate parent guarantee). The cost of capital differs between the three (3) ITCC security options (cash, letter of credit, or corporate parent guarantee). It should be noted that generally IOUs should neither gain nor be harmed in undertaking these IFOM projects for contributors.

While requiring the interconnection customer to post ITCC security protects the utility from a potential tax liability, this policy may not be cost effective for ratepayers or best advance energy policy, particularly the objective to encourage the development of new renewable generation.

> IOU Response: CPUC Decision D.94-06-038 authorized options for the IOUs to protect themselves from a potential tax liability. The IOUs support the advancement of cost-effective renewable generation but cannot ignore the risk of potential tax liability given the likelihood of changes to IRS requirements, the project triggering a subsequent taxable event, and changes to external factors that drive generator economics. See also response above.

The IRS safe harbor notices provide the generator explicit and easy-to-comply-with rules to avoid a taxable event for transactions under interconnection agreements. Utilities report that, to date, no contribution under an interconnection agreement has caused a utility to incur an income tax liability

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[76] This figure is from a 2013 R.11-09-011 joint parties data request and reflects interconnections prior to 2013 (the working group does not have access to more recent data). Ignoring the highest 20% of reported costs as outliers, the mean cost across all three IOUs was $162,000/MW, and the median cost was $157,000. A summary of the data request and the raw data itself was too large to attach to this report but is available upon request (email Brian.Korpics@cpuc.ca.gov). The IOUs have not confirmed Clean Coalition's analysis of the data.

[77] Behind equipment costs and Cost of Ownership charges.

[78] IRS Notice 88-129 at *2-*3

(see “Historical Data” above) under a tax audit. The risk of occurance for any utility or ratepayer ITCC exposure, while admittedly greater than zero, is negligible; the corresponding cost to the developer of maintaining the security for the theoretically maximum amount of tax exposure exacts real costs and may impede project development.

> IOU Response: ITCC security is meant to protect the IOUs against a potential tax liability obligation, which should be considered akin to insurance. The lack of an accident should not be used as an argument to no longer maintain insurance and support a representation that the tax risk is "negligible". In addition, there are a number of factors that impact a generator’s ability to remain in compliance with the IRS Safe Harbor Provision. The majority of these factors are outside of IOU control. Examples of such factors include:
>
> - *IRS code changes*: The utility industry is still waiting for clarification if and how “The Tax Cuts and Jobs Act” signed on December 22, 2017 will impact the provisions of IRC Section 118(b) and the application of the IRS Safe Harbor Provision.
> - *Economics*: The energy market when the IRS Safe Harbor Provision was introduced is a very different energy market than today. IOU procurements are shorter term in nature and contractual terms are less fixed than procurement conducted previously which can contribute to increased risk that a generator may not remain operational.
> - *Generator Size and Interconnection*: Generators interconnecting in recent years are smaller in capacity and interconnecting to both transmission and distribution. It may be early to assess how the risks have changed over time, but it is important to note that past performance of existing generators is not a reliable indicator of how we can expect more recently interconnected generators to perform.

Working Group Proposals

The following four proposals were developed by various stakeholders as part of the working group process to address Issue 7. Proposals 1, 2, and 3 are mutually exclusive alternatives, meaning only one may be selected. Proposal 4 is independent of the other proposals. None have consensus support.

Proposal 1: Retain the status quo, in which each IOU is authorized and retains the discretion pursuant to CPUC Decisions 87-09-026 and 94-06-038 to collect or not collect ITCC security on safe harbor projects.

Summary

Each Utility evaluates its own risk tolerance level and decides which option under CPUC Decision 94-06-038 works best to protect against potential tax liability and has the discretion to adjust based on updates to risk and risk tolerance levels.

Status

Non-Consensus. TURN, PG&E, SCE, and SDG&E support Proposal 1 as the preferred practice. GPI opposes this and no non-IOU stakeholders expressed support.

Discussion:

This is the IOU preferred proposal. The IOUs are responsible for its risk and managing its risk. The 1987 and 1994 decisions authorize the IOUs to protect themselves and ratepayers from potential tax liability and hold the contributor responsible. Absent the contributor, there would be no potential tax liability imposed on the IOUs and therefore the responsibility to cover the costs should be borne by the contributor. This aligns with the cost causation principle and therefore remains as the Utilities' preferred approach. Furthermore, it should be remembered that IOUs should neither gain nor lose on taking on CIAC projects; therefore the IOU should retain the discretion to protect itself.

Proposal 2: If consistency is the primary concern of the Commission, then the IOUs propose to all collect ITCC security for safe harbor projects, which provides consistency across the IOUs but the IOUs acknowledge is least desirable for non-IOU stakeholders.

Summary

For consistency sake, each IOU under this proposal would collect security to protect against potential tax liability.

Status

Non-Consensus. TURN, PG&E, SCE, and SDG&E support Proposal 2, if Proposal 1 is not selected. Clean Coalition, Outback, and GPI actively oppose this, and no non-IOU, non-ratepayer advocate stakeholders expressed support.

Discussion

Currently, the CPUC has provided the IOUs discretion to choose a method to protect against potential tax liability and the IOUs have not selected the same option. To align and provide a consistent approach across California, the IOUs can all support the collection of security. The preference however is Proposal 1 where each IOU has the discretion to select whichever option is acceptable based on IOU's risk tolerance levels.

Proposal 3: Modify D.94-06-038 to prohibit the collection of security for "Safe Harbor" systems and authorize a recovery mechanism, whereby each utility recovers from ratepayers any actual costs realized as a result of ITCC charges.

Summary

As an alternative to the current authorized practice of requiring applicants to post ITCC security when seeking interconnection under "Safe Harbor" provisions, in the interest of ratepayers it is proposed that the Commission authorize each IOU to recover through customer rates any actual costs realized as a result of ITCC charges incurred by the IOU against interconnections applying under "Safe Harbor" provisions and deemed uncollectable subsequent to "Safe Harbor" eligibility being found inapplicable, and to establish this practice in lieu of requiring the posting of security by the applicant against such liability.

It is proposed that:

1. The Commission authorize each Investor Owned Utilities (IOUs) to recover through customer rates any actual costs realized as a result of ITCC charges incurred by the IOU against interconnections applying under "Safe Harbor" provisions. Recovery through customer rates shall only occur when both:
    a. "Safe Harbor" eligibility is ruled inapplicable by the tax authority, and
    b. Such costs are found to be uncollectable by the IOU from the responsible party.
2. The Commission shall establish this practice in lieu of requiring the posting of security by the applicant against such liability. To prohibit the collecting of security, the Commission shall modify D.94-06-038, which authorizes the IOUs to select between three options to protect against potential tax liability, collecting security being one.
3. The Energy Division may require posting of security, or limit ratepayer liability and authorize IOUs to require posting of security, for new projects if the Director of the Energy Division determines such actions to be in ratepayer interest.
    a. The Director may take this action upon its own initiative or as an interim response pending a ruling on a Petition for Modification.
    b. Energy Division may establish automatic review of these practices, and/or automatic requirement for new projects to post security in the event that ratepayer backstop results in realized costs greater than $500,000 -- equal to 20% of current security postings

Status

Clean Coalition and GPI actively support. No non-IOU, non-ratepayer advocacy stakeholders oppose. PG&E and SCE support Proposal 1 followed by 2. If Proposal 1 or 2 is not selected, PG&E and SCE conditionally support Proposal 3. TURN, ORA, and SDG&E oppose.

Discussion

Supporting Discussion:

The non-IOU Working Group expects that there will continue to be projects that request Safe Harbor. Interconnections qualifying under "Safe Harbor" have historically not created an ITCC liability for an IOU from a tax audit perspective; however, there is a degree of uncertainty regarding both whether the tax authority will agree that a project does qualify, and whether a project will maintain its qualification over time.

The interconnection agreement stipulates that the contributor is liable for any ITCC costs incurred by the IOU; however, the possibility exists that the contributor is unable to remit payment to the IOU for ITCC costs incurred. To insure against non-collection in the event that an IOU is subject to an ITCC liability for a project that was interconnected with a Safe Harbor qualification claim, the IOU is authorized to require a security to be posted by the applicant in a form consistent with D.94-06-038.

The posting of security creates a cost to the applicant, tying up cash or credit for a period of ten years. These costs increase the producer's Levelized Cost of Energy (LCOE) from these facilities, and the price these facilities must receive from ratepayers in market mechanisms to remain financially viable.

It is in ratepayer interest to reduce the cost of energy supplies, as well as the cost of any ratepayer risks associated with energy supplies. If the ratepayer value of cost reduction in energy prices from these facilities is greater than the value of ratepayer assumed risk that is associated with not requiring ITCC security to be posted, then ratepayers will a realize net benefit from backstopping IOU ITCC liability risk of non-collection.

A review of IOU experience with Safe Harbor interconnections has not identified any instances to date of disqualifications resulting in ITCC costs being incurred as a result of a tax audit; however, it is not possible to predict the likelihood of this changing in the future. In addition, IOUs have substantial enforcement options to support collection, including the right to disconnect a generation facility for failure to cure a breach under the applicable interconnection agreements.

The estimated energy price impact for new interconnections in service territories that require ITCC security (currently, only SCE) is 1%. Prior data requests have indicated average interconnection upgrade costs of $150,000 per MW,[79] resulting in an ITCC potential of $36,000 per MW (The current ITCC rate is 24%). Assuming that 10% of generator LCOE costs for Safe Harbor projects are related to interconnection upgrades,[80] with an ITCC potential liability of 20% of the value of the upgrades, security posting will equal 2% to the project cost.[81] Cash posting at the developer's election will be fully refunded after 10 years with interest in accordance with SCE's tax security practices, but the net present value of the refund over that period will be less than current business value. Alternative use of credit or collateralized security will incur carrying costs over the same period. Thus, the estimated energy price impact for applicable interconnections is around 1%. The net impact will vary depending on the actual time value of money as reflected in interest rates and (foregone) return on investment.

Non-utility stakeholders emphasize that it is the intention of the proposal not to have any impact on ratepayers. If no safe harbor systems lose safe harbor status, there will be no impact. If a safe harbor system loses its safe harbor status, non-utility stakeholders believe it is highly likely that the project owner will pay the tax rather than negating all value for the project by voiding the interconnection agreement. Further, it is not true that any proposal that has the potential to result in a revenue shortfall must be considered in a ratesetting proceeding. (1.3.e and 7.1.e.1)

Opposing Discussion:

The IOUs object to modification of D.94-06-038. The IOUs consider it best practice for each IOU to assess its own risk tolerance levels and choose a method that best protects against potential tax liabilities. The IOUs object to not having the ability to collect security.

[79] See discussion in Footnote 76.

[80] MW scale PV projects succeeding in current solicitations for commencement of delivery in 2020 typically must achieve an installed cost on the order of $1.50/W to be financially viable. At this cost, grid upgrade charges of $150,000 per MW represent 10% of the total installed cost, including developer margin reflected in the contracted energy price. The IOUs have not confirmed Clean Coaltion's analysis of the data.

[81] On the basis of grid upgrade charges representing 10% of total costs, and ITCC rates of 24% of that cost, the ITCC charge or safe harbor security posting is equal to 2.4% of the total cost.

The IOUs must be permitted to recovery reasonably incurred interconnection costs. Should the Commission decide to prohibit the collection of security for costs an Interconnection Customer may cause a utility to incur, the recovery of costs through customer rates is one option for cost recovery if a utility cannot recover costs incurred from contributors.

However, as noted above, the IOUs see many complications with this Proposal, such as how the recovery mechanism will be structured, tracked, reviewed, and/or approved. More consideration about how this recovery mechanism should be structured will be required. The IOUs strongly support the status quo proposal of Proposal 1. PG&E, SCE, and SDG&E do not support a prohibition on collection of ITCC security. If the Commission decides to proceed with Proposal 3, PG&E, SCE, and SDG&E would support recovery through customer rates of costs incurred that are not recovered from the contributor for a taxable liability. However, any recovery mechanism needs further development and review.

The IOUs believe the energy price analysis offered by Clean Coalition fails to offer sufficient evidence to support its broad conclusions.

TURN opposes this proposal because there is no evidence to show that the savings that would be passed on to ratepayers, if any, would outweigh the additional risks that the ratepayers would inherent by backstopping the potential liability.

Proposal 4: Expand the scope of R.17-07-007 to consider whether there are ITCC practices which merit modification despite being consistent across utilities, and if so, how those practices should be modified

Summary

The scope of R.17-07-007 should be expanded to consider whether there are ITCC practices which merit modification despite being consistent across utilities, and if so, how those practices should be modified. Such practices may include the following:

- Interpreting IRS Safe Harbor rules that Safe Harbor does not apply to behind the meter interconnections
- Requiring transfer of ownership of Interconnection Facilities and Distribution Upgrades from the customer to the utility, thereby triggering ITCC

Status

Non-consensus. Clean Coalition, Outback, CalSSA, ORA, GPI, Foundation Wind Power, Borrego Solar, Chico Electric, CalCom Solar, and Sunworks support. SCE, PG&E and SDG&E oppose.

Discussion

Supporting Discussion

The R.17-07-007 scoping ruling directs Working Group One to develop proposals addressing ITCC practices that are inconsistent across utilities. The working group finds the utilities to be consistent in their ITCC practices other than requiring or not requiring security for Safe Harbor projects. Proposals 1-3 address this inconsistency.

However, some non-IOU stakeholders believe that some aspects of utility application of ITCC may merit reform despite being consistent across utilities. These practices include:

- Interpreting IRS Safe Harbor rules that Safe Harbor does not apply to behind the meter interconnections.
    - Non-utility stakeholders have asserted that behind-the-meter projects may be eligible for Safe Harbor and should receive this option. From CALSSA: "IRS notices make clear that non-qualifying facilities (i.e. not merchant generators) can qualify for safe harbor if they meet the conditions for safe harbor. The primary condition is that the quantity of power consumed at a facility cannot exceed 5% of the amount of power generated at the facility. Until recently, this was never true of behind-the-meter generation. With the creation of meter aggregation, however, customers now install generators on accounts that have no load. Those accounts meet the 5% requirement. In addition, interconnection facilities that only facilitate generation and do not also help the utility serve load may qualify for safe harbor. This could apply to reclosers but would not apply to equipment like voltage regulators."
        - *IOU Response*: Utilities do not agree with this interpretation of the Notice and request specific language in IRS codes for IOU review and discussion.
    - CALSSA also represents that "If the utilities agree to allow certain behind-the-meter generators to use the safe harbor or the IRS clarifies that they may do so, and the Commission creates a backstop provision to insure against loss of safe harbor, the Commission should apply the same backstop to behind the meter systems that qualify for safe harbor."
- Requiring transfer of ownership of Interconnection Facilities and Distribution Upgrades from the customer to the utility, thereby triggering ITCC
    - Under current practice, the customer is required to contract for and pay the utility for procurement and installation of Interconnection Facilities, , Distribution and Network Upgrade equipment from the host utility, and subsequently transfer ownership of this equipment back to the same utility. This creates potentially unnecessary costs and the practice should be reviewed in this proceeding. At least two alternatives warrant consideration.
        - The first option is to allow the applicant a method to retain ownership, while still granting the utility necessary rights and control. This would avoid the issues with the ITCC identified above while more significantly allowing the applicant to apply the 30% Federal Income Tax Credit and depreciation value on these costs, significantly reducing the cost of DER development and the services it provides.
        - Alternatively, converting to an interconnection fee to cover utility costs may allow the utility to hold original and continuing ownership of the facilities, while avoiding the classification of the fee as a contribution in aide of construction

(CIAC) that would trigger the ITCC as well as the not insignificant administrative costs and delays associated with transfer of ownership.

IRS Clarification Regarding Safe Harbor Eligibility of Behind the Meter Systems

If the Commission chooses to amend scope to address utility interpretation that IRS Safe Harbor does not apply to behind the meter interconnections, it may find that a request for a Notice or Ruling by the IRS is needed regarding:

- The eligibility of behind the meter generation for Safe Harbor
- Application of the 5% rule when the upgrade is:
  - Not required by generation export but triggered by increased load in conjunction with a generation interconnection request;
  - Future load increases unrelated to the generation application.

Utilities have indicated that they feel it is most appropriate for industry representatives to lead a request for clarification to the IRS, and not the Utility nor the Commission. Non-IOU stakeholders recognize that the request for clarification may not ultimately be made by the Commission, but believe support from the Commission is important to help ensure all appropriate issues are identified and to encourage timely attention and response. Non-IOU stakeholders also ask that the Commission plan to address utility practices in response to a clarification by the IRS.

> *IOU Response*: The Utilities and the Commission if the Commission deems necessary, can participate in the industry led effort as resources allow. As discussed below, the prior safe harbor notices in this area were sponsored by project developers as they hold the underlying project details that would be reviewed as part of the tax analysis.

Opposing Discussion

The IOUs oppose a broad, vague expansion of scope to "to consider whether there are ITCC practices which merit modification in conformance with IRS rules." Some of the specific scoping examples offered in the non-IOU stakeholder discussion do not even concern ITCC practices or rules. Rather, they seek to propose significant interconnection policy changes (in a manner that would allow an Interconnection Customer to avoid ITCC or the posting ITCC security under existing ITCC-related rules). While Proposal 4 does not set forth any specific proposed actions at this time, and is focused only on the issue of potential scope expansion, the IOUs still wish to provide a response to those specific scoping examples, below, to highlight issues.

IRS Safe Harbor rules application to behind the meter interconnections:

- As mentioned above, the IOUs believe that non-utility stakeholders are the appropriate party to undertake this effort, which is consistent with the establishment of prior safe harbor guidelines and because they develop the underlying project that would be reviewed by the IRS. Further, if the IRS provides clarification, the IOUs would conform their practices to adhere to the clarification. There is no need to include this as a scoping issue.

  - The IOUs believe that IRS guidance is clear that the Safe Harbor Notice as issued by the IRS does not apply to the BTM projects and therefore the burden is on non-utility stakeholders to present the IOUs with tax authority that supports their position. The Joint IOUs believe owners of BTM projects continue to fundamentally act in the capacity, for CPUC tariff purposes, as retail end user customers of IOUs' that do not appear to satisfy the nontaxable requirements of IRS Notice 2016-36 as generators whose exclusive purpose is to export electricity, nor would they appear to be able to satisfy the 5% test that, if in light of all information available to the utility at the time of transfer, it is reasonably projected that during the ten taxable years of the utility beginning with the taxable year in which the transferred intertie was placed in service, no more than 5% of the projected total power over the intertie will flow to the BTM project cite. [IRS Notice 2016-36, Section II,B,1]
- Additionally, the IOUs would like to reiterate this Commission's acknowledgement of its limited authority in its *Findings of Fact #9* from CPUC D.87-09-026 with regard to whether or not the IRS would impose a tax on particular CIAC-related transactions, and that "it would be imprudent for this Commission to find that one form of transaction or another would avoid the tax. That decision is for the IRS and the courts."
  - Furthermore, the IOUs wish to reiterate that non-utility stakeholders should lead the effort to pursue their desired change in tax policy through potentially the issuance of IRS guidance notice, and not the Commission or the IOUs. Should developers wish to pursue a private letter ruling (PLR) for a novel transaction, then the IOUs are willing to work with developers as it develops its request for a PLR.

Changes in ownership structure of Interconnection Facilities and Distribution Upgrades:

- The IOUs strongly oppose extending this proposal's scope to include fundamentally altering the ownership structure and operation of the distribution system. This proposal has far reaching implications beyond the ITCC, and appears to be far beyond even the non-utility stakeholders' proposed scoping of examining IOU "ITCC practices." Changes in the ownership structure can result in unsound policy, with serious safety and system reliability implications.
  - The IOUs have a statutory obligation to own and control their respective distribution systems. *See* Pub. Utils. Code Section 399.2.
  - The interconnection facilities become integral to the operation of the electrical system. System operators count on established practices, operating protocols, maintenance practices, and planning criteria to effectively manage the grid. Allowing third parties to own these facilities jeopardizes the IOUs' ability to effectively carry out grid operating requirements, especially during emergency conditions. Thus, because of this expertise, the IOUs must own, operate and maintain these assets to ensure system reliability and safety for all of its customers.
- Non-utility stakeholders' proposal to consider changing the ownership structure as part of an ITCC practices review creates potential impacts to system safety and reliability simply to permit an Interconnection Customer to avoid posting ITCC security for a potential tax obligation.

Critically, however, neither of the Proposal's alternative ownership arrangements would likely survive tax muster, such that the form of the transaction would be respected (i.e. that the customer would be treated as the tax owner of the property). Whether or not the customer retains title, the substance of the transaction still controls for determining tax liability and tax ownership.[82] Thus, the determination of which party has the benefits and burdens of ownership is based on all relevant circumstances. Here, the IOUs would still have the burden of maintaining and operating these assets and are ultimately liable to third parties if something goes wrong. Thus, for tax purposes, even if the form of the transaction specified that the customer was the owner, the IOU would likely be considered the tax owner regardless and a taxable CIAC has occurred, triggering ITCC.

- Developers and Interconnection Customers are not regulated like the IOUs and do not possess the technical expertise to own, maintain and operate these assets. What is at risk is system oversight over the entire grid, which poses many serious concerns. For example, a utility's ability to repair and replace equipment in emergency conditions could be delayed and complicated if a third-party owns that equipment.
- Furthermore, the IOUs cannot transfer its ability to safely and reliably operate the grid to another party, even if the other party wishes to assume that responsibility.[83] Ultimately, the IOUs are mandated with ensuring the safety and reliability of the system and therefore are heavily regulated to ensure that this occurs.[84] Therefore, for the sake of safety and system reliability, the IOUs should be the party that owns and operates these upgrades after completion because they are regulated and can be held accountable to perform the work of maintaining and operating these assets properly to ensure they support the safety and reliability of the grid.
- Therefore, for the reasons discussed above, the IOUs strongly oppose this proposal for the expansion of scope to consider customers retaining ownership, at the expense of safety and reliability, of assets solely to avoid ITCC.

> ***Clean Coalition Response***: In their discussion, IOUs state that the proposal attempts to "fundamentally alter the ownership and operation of the distribution system." This misstates the proposal. The proposal is to consider the current practice of requiring transfer of ownership to the extent that this may unnecessarily incur ITCC and negatively impact ratepayers.
>
> While alternatives are suggested, in which the ownership of new facilities may remain with either the utility or the party for whom the facilities are being added, no specific alternative is proposed at this time, and no proposal is being made to consider changing

[82] The IRS will apply the well formulated "substance over form" doctrine first articulated by the Supreme Court in *Gregory v. Helvering*, 293 U.S. 465 (1935). See also Internal Revenue Service Notice 87-82, IRS Bulletin No. 1987-51 (December 21, 1987).
[83] Pub. Utils. Code Section 399.2
[84] See Id.

the operation of the distribution system. The issue to be addressed is only the transfer of ownership of the facilities, not the operation of those facilities. If ownership can remain with either party, then the cost impacts associated with transfer of ownership may be mitigated.

IOUs further argue that they "are in the best position to perform the construction of these specially requested projects" and "possess the technical expertise, knowledge, and resources to complete the work safely and are capable of considering the broader implications of the immediate project"

These issues are off topic -- third-party construction is separately scoped and is not related to this proposal, which only addresses the need for transfer of ownership after construction, regardless of who completes the construction. No proposal is made here regarding construction by any party other than the utility, and the issues of "broader implications" are addressed in the interconnection review and study process, including the Facilities Study, which is again unrelated to the narrow scope of this proposal.

IOUs further state that "Stakeholders are proposing to compromise system safety and reliability". Again, this fundamentally mischaracterizes the proposal, which in no way suggests any change in utility operations or responsibility. Safety and reliability are paramount considerations, and only options will only be move forward if they are compatible with maintaining or improving safety and reliability.

The IOUs state that they "must own, operate and maintain these assets to ensure system reliability and safety for all of its customers." This begs the very question we are seeking to address – namely, is it actually necessary for the utility to own the assets in order to operate and maintain them, or can the utility assume full control under a long term lease or other contractual arrangement. If actual ownership by the utility is necessary, then we seek to determine whether ownership may originate with the utility and remain there such that no transfer is necessary.

The IOUs further mischaracterize the purpose of looking into this issue as "simply to permit an Interconnection Customer to evade a tax obligation." Firstly, it is both inaccurate and pejorative to equate selection of options that do not incur a tax obligation with the evasion of a tax obligation, which would be prima fascia both improper and illegal. Secondly, the utilities are unreasonably dismissive in referring to the tax obligation. The transfer of ownership from the applicant to the utility has not just one but two substantial tax implications. Not only does the transfer of assets create an Income Tax Contribution Charge equal to approximately 24% of the value of the assets, but it also removes the assets from eligibility for the Federal Income Tax Credit programs applicable to solar and some other renewable technologies. The Income Tax Credit currently refunds 30% of the value of the *owner's* eligible capital investment associated with the generating facility. As a result, the ownership transfer currently results in a 54% effective increase in costs on these assets – costs which are reflected in the price of energy for ratepayers. In failing to support scoping and review of this issue, IOUs are remiss in their responsibility to ratepayers.

Converting system upgrade cost recovery from actual costs to fees:

- This proposal has far reaching implications beyond the ITCC, and appears to be far beyond even the stakeholders' proposed scoping for examination of "ITCC practices." This additional scoping must be rejected.
- Infrastructure upgrade costs (i.e., interconnection facilities and distribution upgrades) that are triggered as a result of an Interconnection Customer's requested interconnection are necessary to ensure safe and reliable interconnection of that Interconnection Customer's generating facility to the distribution system pursuant to state laws and regulations, and are directly related to the utility's obligation to serve in accordance with safety and reliability standards. The IOUs have an unavoidable obligation to serve their customers safely and reliably. Thus, cost-of-service ratemaking principles require that the reasonable costs of service relating to such infrastructure upgrades are recoverable.
    - The IOUs do not believe a switch to a fee based system can adequately meet these principles.
    - Further, such a dramatic change in cost recovery should not adopted simply to attempt to help an Interconnection Customer avoid a tax liability.

Clean Coalition Response: In responding to the concept of converting cost recovery to a fee based system, the IOUs again argue the merits of a potential option, not the proposal to allow such discussion within this proceeding's scope.

We note further that:

1. The tax liability is incurred by the IOU, not the interconnection customer, who is responsible for compensating the IOU
2. As noted above, the interconnection customer is the energy provider, passing these costs on to ratepayers in the energy prices offered. The purpose here is to lower energy costs for ratepayers.
3. Cost recovery remains a fundamental principle. The question will be whether a fee structure, such as that applied for load service when interconnecting a customer, can recover cost-of-service without being considered CIAC.
4. While ITCC factors alone may not warrant a change in cost recovery, it should be recognized as a factor in such considerations. Individual cost assignment has long been the primary barrier to streamlining interconnection review and agreements, and a more standardized fee based approach (aligned with cost causation) is among the greatest opportunities for streamlining interconnection.

We remind the Commission that <u>the proposal is only for an expansion of scoping</u> to allow for parties to make proposals and discuss the topic in order to determine whether appropriate alternatives can be identified. If scoped, then proposals would be requested and vetted – the exemplars were merely offered to clarify the issue, and should not be considered part of the actual proposal itself.

Issue 7 Appendices

Appendix A: Utility Responses to Working Group One's Request for Historical Data on Realized Tax Liability for Safe Harbor Systems

SDG&E

SDG&E provided the following response in lieu of data:

> *SDGE believes that zero (0) projects have qualified for the safe harbor to ITCC under Rule 21, and therefore, SDGE believes that zero 'ITCC safe harbored" projects under Rule 21 have lost their safe harbor designation.*
>
> *SDGE does have projects under the Wholesale Distribution Open Access Tariff (WDAT) that are safe harbored from the ITCC.*
>
> *As was discussed during the workshops, SDGE's procedures regarding the safe harbor designation is reliant upon the project developer completing a "safe harbor" application. SDGE does not typically audit the information on the application, and reserves the right, as is allowed by the Commission, to impose a fee to a safe harbored project if and when applicable SDGE risk tolerance thresholds are triggered.*

SCE

January 23, 2018

Draft for Discussion Purposes Only

Request:

Provide historical information on realized tax liability associated with Rule 21 export projects that were given a safe harbor designation to the ITCC charge, losing that safe harbor, and the IOU being required to pay the associated taxes?

SCE Response:

Tax authorities have not, as of the date of this response, audited and assessed a tax liability associated with SCE's 61 Rule 21 projects[85] in which generators attested to satisfying the initial Internal Revenue Service safe harbor provisions to be excluded from SCE's taxable income. SCE relies on the generator's contractual representation that 1) in light of all the information available at the time the intertie is contributed, it is reasonably projected that, during the ten taxable years beginning when the intertie is placed in service, no more than 5% of the projected total power flows over the intertie will flow to the generator,[86] 2) ownership of the electricity wheeled over SCE's transmission system remains with the generator prior to its transmission onto the grid,[87] 3) the intertie will be used for transmitting

[85] A ten year period was utilized for purposes of this response.

[86] Section III.C.1.a. of IRS Notice 2016-36

[87] Section III.C.2. of IRS Notice 2016-36

electricity,[88] and 4) the cost of the intertie is capitalized by the generator as an intangible asset and recovered using the straight-line method over a useful life that is treated as 20 years.[89] If any one of these representations made by a generator are inaccurate, the entire contribution will be taxable to SCE in the year it was placed in service. SCE relies on the generator's representations and does not independently audit these representations. As such, SCE cannot independently stipulate that these 61 Rule 21 interconnection are not taxable without performing initial audits on each of these transactions when they were placed in service. The Internal Revenue Service can decide to audit SCE's 61 Rule 21 interconnections to verify their nontaxable treatment in the year they were placed in service.

In addition, the tax audit risk exposure does not end for SCE in the year the intertie is placed in service. An initial nontaxable interconnection transaction under the IRS safe harbor provisions can become taxable to SCE in any future tax year if any of the following events occur. Proportionate Disqualification – If, for each of any three taxable years within any period of five consecutive taxable years, more than 5% of the total power flows over the intertie flow from the utility to the generator, then the generator will be deemed to have made a transfer to the utility that constitutes a taxable contribution in aid of construction pursuant to Internal Revenue Code Section 118(b).[90] Termination of Power Purchase Contract – Upon the termination of a power purchase contract between a generator and a utility, if the utility obtains or retains ownership of the intertie, the generator will be deemed to have made a taxable contribution to the utility if circumstances indicate an intention by the parties to characterize a contribution of the intertie as a transaction that in substance constitutes a taxable contribution.[91] The Internal Revenue Service can decide to audit SCE's 61 Rule 21 interconnections in any subsequent tax years to verify whether they should continue to be treated as nontaxable to SCE.

The 61 Rule 21 projects over the past ten years in which generators attested to satisfying the initial Internal Revenue Service safe harbor provisions to be excluded from SCE's taxable income represent a total nontaxable contribution amount of approximately $15.0 million with a related total ITCC security amount of approximately $3.2 million. Should an interconnection customer be unable to make the indemnification payment, the utility would be exposed to a loss since the facility cost responsibility is directly assigned to the interconnection customer and the utility is not able to recover these costs from other customers. Accordingly, the collection of a security instrument that covers the cost consequence of the tax liability is appropriate.

PG&E
January 23, 2018

QUESTION

[88] Section III.C.4. of IRS Notice 2016-36
[89] Section III.C.5. of IRS Notice 2016-36
[90] Section IV.A. of IRS Notice 2016-36
[91] Section IV.B. of IRS Notice 2016-36

Provide historical information on realized tax liability associated with projects that were given a safe harbor designation to the ITCC charge losing that safe harbor and the IOU being required to pay the associated taxes?

ANSWER

Within the last ten (10) taxable years, no taxing authorities have audited and assessed any tax liability related to PG&E's generator interconnections falling under the safe harbor provision of Internal Revenue Service (IRS) Notice 2016-36 (referred to as IRS Safe Harbor or Safe Harbor Provision).1 Previously, the IRS reviewed certain generator interconnections as part of PG&E's 2001 through 2004 audit. PG&E generally relies upon the representations made by the Generator at the time of the interconnection that the provisions of the IRS Safe Harbor are met. However, based upon PG&E's review of the limited set of projects that currently fall within the CPUC jurisdiction under this rulemaking, there has not been any known instance of a generator violating the Safe Harbor Provision. Despite no known violation of the Safe Harbor Provision, this does not mean that there is no tax risk pertaining to these interconnections as further discussed below.

Background on CPUC jurisdictional Safe Harbor Provision eligible generators

The IRS provides a Safe Harbor Provision for certain generators, exempting them from the application of the Income Tax Component of Contribution (ITCC), provided that these generators maintain compliance with the Safe Harbor Provision. If a generator fails the Safe Harbor Provision, then the transaction becomes taxable and the ITCC is applicable to the transaction in that year.

For PG&E, there are a number of Safe Harbor eligible generators interconnected to PG&E's electric system, which fall under the CPUC's jurisdiction. These interconnections fall into two categories:

- Qualifying Facilities from the 1980s – constitutes the majority of projects claiming the safe harbor
- Rule 21 Export Fast Track agreement or Rule 21 Export Distribution Group Study Process agreements – two (2) projects have interconnected recently and are claiming the safe harbor

It should be noted that over the years, Rule 21 has evolved to focus on behind the meter generators and it was only until recently, that interconnection agreements and processes were developed for wholesale generators that are subject to the Safe Harbor provisions to interconnect under CPUC jurisdiction.

IRS assessments

The IRS has audited PG&E and examined certain transactions availing itself of the Safe Harbor Provision during its 2001 through 2004 audit. Since that time, neither the IRS or the Franchise Tax Board (FTB) have audited or assessed any tax liability associated with the Safe Harbor Provision. However, due to the nature of IRS and FTB audits, that does not necessarily mean that all transactions since the previous audit are not at risk of being reviewed and any possible tax liability assessed.

PG&E relies on the generator's attestation that they will behave like a generator and will not violate the Safe Harbor Provisions. This is a consistent practice across all the utilities. The attestation is discussed further below.

Safe Harbor Provision process

PG&E relies on the generator's contractual representation that:

1. In light of all the information available at the time the intertie is contributed, it is reasonably projected that, during the ten taxable years beginning when the intertie is placed in service, no more than 5% of the projected total power flows over the intertie will flow to the generator,2
2. Ownership of the electricity wheeled over PG&E's transmission system remains with the generator prior to its transmission onto the grid,3
3. The intertie will be used for transmitting electricity,4 and
4. The cost of the intertie is capitalized by the generator as an intangible asset and recovered using the straight-line method over a useful life that is treated as 20 years.5

If any of the representations above are not met, then the transaction no longer qualifies for the Safe Harbor and the ITCC (i.e. tax) is assessed in the year that the generator fails the Safe Harbor.

In practice, PG&E relies on the generator's representations and does not independently audit these representations. As such, PG&E cannot independently stipulate that these eligible interconnections are not taxable without performing initial audits on each of these transactions when they were placed in service. It is important to note that the IRS or FTB can at any time, decide to audit PG&E's eligible generator interconnections both under CPUC and FERC jurisdiction to verify their nontaxable treatment upon contribution or any subsequent taxable year.

An initial nontaxable interconnection transaction under the IRS safe harbor provision can become taxable to PG&E in any future tax year if any of the following events occur:

- Proportionate Disqualification – If, for each of any three taxable years within any period of five consecutive taxable years, more than 5% of the total power flows over the intertie flow from the utility to the generator, then the generator will be deemed to have made a transfer to the utility that constitutes a taxable contribution in aid of construction pursuant to Internal Revenue Code Section 118(b).6
- Termination of Power Purchase Contract – Upon the termination of a power purchase contract between a generator and a utility, if the utility obtains or retains ownership of the intertie, the generator will be deemed to have made a taxable contribution to the utility if circumstances indicate an intention by the parties to characterize a contribution of the intertie as a transaction that in substance constitutes a taxable contribution.7

The IRS or FTB can decide to audit these interconnections in any subsequent tax years to verify whether they should continue to be treated as nontaxable to PG&E.

Factors that impact Safe Harbor Provision Compliance

There are a number of factors that impact a generator's ability to remain in compliance with the IRS Safe Harbor Provision. The majority of these factors are outside of PG&E's control. Examples of such factors include:

- IRS code changes: The utility industry is still waiting for clarification if and how "The Tax Cuts and Jobs Act" signed on December 22, 2017 will impact the provisions of IRC Section 118(b) and the application of the IRS Safe Harbor Provision.
- Economics: The energy market when the IRS Safe Harbor Provision was introduced is a very different energy market than today. PG&E's procurements are shorter term in nature and contractual terms are less fixed than procurement conducted previously which can contribute to increased risk that a generator may not remain operational.
- Generator Size and Interconnection: Generators interconnecting in recent years are smaller in capacity and interconnecting to both transmission and distribution. It may be early to assess how the risks have changed but it is important to note that historic performance of existing generators may not be an indication of performance of more recently interconnected generators.

Therefore, there is a continuing tax risk that the generator may no longer qualify for the Safe Harbor.

Recently Interconnected CPUC jurisdictional eligible generators – PG&E Testing of 2 Projects

PG&E has interconnected two (2) Rule 21 projects over the past ten years in which generators attested to satisfying the initial IRS Safe Harbor Provision and were excluded from PG&E's taxable income.

PG&E reviewed these two (2) Rule 21 projects and found that no disqualification event has occurred. I.e. through examination of power-flows over the past 5 years from PG&E meter data.

Appendix

Acronyms

- AHJ: Authority Having Jurisdiction
- CIAC: Contribution In Aid of Construction
- COO: Cost of Ownership
- CPUC or Commission: California Public Utilities Commission
- DER: Distributed Energy Resources
- ICA: Integration Capacity Analysis
- IOU: Investor Owned Utilities
- ITCC: Income Tax Component of Contribution
- PCC: Point of Common Coupling
- SIWG: Smart Inverter Working Group
- TURN: The Utility Reform Network
- WG: working group

Working Group Participants

The following stakeholder groups attended at least one meeting of Working Group One:

- Borrego Solar
- Bosch
- CalCom
- California Solar and Storage Association (CALSSA)
- California Energy Storage Alliance (CESA)
- California Independent System Operator (CAISO)
- Chico Electric
- Clean Coalition
- Enphase
- Green Power Institute (GPI)
- Interstate Renewable Energy Council (IREC)
- JKB Energy
- Office of Ratepayer Advocates (ORA)
- OutBack Power Technologies
- Pacific Gas & Electric (PG&E)
- Southern California Edison (SCE)
- San Diego Gas and Electric (SDG&E)
- Tesla
- The Utility Reform Network (TURN)
- Sunrun
- Sunworks

The following stakeholder groups attended at least one meeting of the SIWG's deliberations on Issue 5:

- ABB
- California Solar and Storage Association (CALSSA)
- California Energy Commission (CEC)
- California Energy Storage Alliance (CESA)
- California Independent System Operator (CAISO)
- Clean Coalition
- Enphase Energy
- Interstate Renewable Energy Council (IREC)
- Office of Ratepayer Advocates (ORA)
- Pacific Gas & Electric (PG&E)
- Southern California Edison (SCE)
- San Diego Gas and Electric (SDG&E)
- SMA America
- SunPower
- Sunrun
- SunSpec Alliance
- Tesla
- The Utility Reform Network (TURN)
- Underwriters Laboratories
- Xanthus Consulting International

Working Group Meetings and Topics

The table below shows the date, location, and topics covered for each meeting of Working Group One.

10/13/2017 9:30 a.m. - 12:00 p.m *WebEx*	• WG Introduction and Process Discussion • Overview of *Issue 1* (*Should the Commission modify Fast Track Screen Q to minimize the number of distributed energy resource projects subjected to transmission cluster studies and, if so, how?)*
10/18/2017 10:00 a.m. - 2:30 p.m *San Francisco and WebEx*	WG discusses proposed solutions to Issue 1
10/31/2017 9:30 a.m. - 12:00 p.m *WebEx*	WG provides feedback on draft proposal for Issue 1
11/6/2017 9:30 a.m. - 12:00 p.m. *WebEx*	• Given the complexity of Issue 4 (*telemetry*), the working group will take the first hour of this meeting to hold a pre-discussion of the issue. • Overview of Issue 2 (*Should the Commission clarify the definition of "complex metering solutions" for storage facilities and, if so, how?)*

11/9/2017 1:00 pm – 4:45 p.m. *San Francisco and WebEx*	Issue 2
11/21/2017 9:30 a.m. - 12:00 p.m. *WebEx*	WG provides feedback on Issue 2 proposal
11/28/2017 9:30 a.m. - 12:00 p.m. *WebEx*	Overview of Issue 3 (*How should the Commission clarify the definition of a "material modification" to a project and what should be the procedures for processing these modifications?)*
11/30/2017 10:00 a.m. - 2:30 p.m. *San Francisco and WebEx*	Review Issue 2 Proposal Proposed solutions to Issue 3
12/15/2017 9:30 a.m. - 12:00 p.m. *WebEx*	Issue 3
12/19/2017 10:00 a.m. - 2:30 p.m. *San Francisco and WebEx*	Overview of Issue 4 (*As the penetration levels of distributed energy resources increase, what changes to telemetry requirements should the Commission adopt to ensure adequate visibility while minimizing cost?)*
1/8/2018 9:30 a.m. - 12:00 p.m. *WebEx*	Working Group Two Process, Schedule, and Facilitation Overview of Issue 7 (*Is there inconsistent application of the requirement to pay the Income Tax Component of Contribution charges across the Utilities? If yes, how should the Commission address this inconsistency?)*
1/11/2018 9:30 a.m. - 12:00 p.m. *WebEx*	Overview of Issue 7 (*Is there inconsistent application of the requirement to pay the Income Tax Component of Contribution charges across the Utilities? If yes, how should the Commission address this inconsistency?)*
Tuesday, 1/16/18 10:00 a.m. - 2:30 p.m. *In-person (CPUC) and teleconference*	Feedback on proposals for Issues 3 (material modifications) and 4 (telemetry)
Friday, 1/26/18 9:30 a.m. - 12:00 p.m. *teleconference*	Proposed solutions to Issue 7 (ITCC) (cont.)
Thursday, 2/1/18 9:30 a.m. - 12:00 p.m. *teleconference*	Call to begin discussion of Issue 3 Retrofit
Thursday, 2/8/18 10:00 a.m. - 12:00 p.m. *teleconference*	Utility update on IOU internal discussions addressing Issue 3 Retrofit
Thursday, 2/15/18	Determine process for editing final report

9:30 a.m. - 12:00 p.m. *teleconference*	Discuss Issue 3 Retrofit Provide feedback on Issue 7 proposal
Friday, 3/2/18 10:00 a.m. - 2:30 p.m. *San Francisco and WebEx*	Final meeting to provide feedback on complete report, including Issue 3 Retrofit proposal

The table below shows the date, location, and topics covered for each SIWG meeting on Issue 5.

Thursday, 12/7/17 1:00 p.m. - 2:30 p.m. *WebEx*	SIWG Introduction and Process Discussion Overview of Issue 5
Thursday, 12/14/17 1:00 p.m. - 2:30 p.m. *WebEx*	Discussion on creating inventory of inverters
Thursday, 12/21/17 1:00 p.m. - 2:30 p.m. *WebEx*	Discussion of value of functions and costs to update inverters
Thursday, 1/4/18 1:00 p.m. - 2:30 p.m. *WebEx*	Review of initial IOU findings on inverters
Thursday, 1/11/18 1:00 p.m. - 2:30 p.m. *WebEx*	Discussion of legal concerns
Thursday, 1/18/18 1:00 p.m. - 2:30 p.m. *WebEx*	Review of final inventory of inverters and development of proposals
Thursday, 2/15/18 1:00 p.m. - 2:30 p.m. *WebEx*	Final meeting to provide feedback on draft proposal

Working Group Materials

The *Working Group One Work Plan*, which outlines a process and schedule for completing the report, can be found on Energy Division's webpage at http://www.cpuc.ca.gov/General.aspx?id=6442455170#Working_Group_One.

Drafts of various issue proposals and other working group materials can be found on the California Solar and Storage Association (CalSSA) webpage at www.calssa.org/rule21workinggroup.