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| Rule 21 Interconnection Rulemaking (R.17-07-007) |
| Working Group One Final Report |
| March 15, 2018 |

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| First Draft  2/22/2018 |

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# Executive Summary

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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]](#footnote-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 thanFebruary 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]](#footnote-2)

The Commission intends to issue a proposed decision on the Working Group One report in fall 2018, following completion of the second 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?
6. 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 developed the proposal for Issue 5 and shared with Working Group One for incorporation in the final report.

### 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:

* + CALSSA
  + Clean Coalition
  + IREC
  + ORA
  + PG&E
  + SCE
  + SDG&E
  + CESA
  + TURN
  + GPI
  + Tesla
  + Bosch
  + CalCom
  + JKB Energy
  + Chico Electric
  + Enphase
  + SunWorks
  + SunPower
  + …

### 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 utilities and 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]](#footnote-3) Proposals were drafted by the utilities and the stakeholder lead assigned to the issue, with input from Energy Division staff.

To meet the March 15 report deadline, proposal development often had to be completed offline while the working group moved on to the next issue. To ensure stakeholder transparency, 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.

#### Issue 5

[The Smart Inverter Working Group met X times between DATE and DATE to develop proposals to address Issue 5…]

#### 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 differences, the working group attempted to describe the various options for resolving the issue and their tradeoffs.

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

1. Expanding the existing Screen Q exemption for NEM facilities with net export less than or equal to 500 kW by:
   1. Changing the exemption size threshold to 1 MVA nameplate capacity
   2. Extending the exemption from NEM projects to all projects
   3. Increasing the exemption size threshold to a size larger than 1 MVA
2. Creating a soft link within Screen Q to the CAISO Tariff
3. Directing the utilities to identify engineering review guidelines related to the evaluation of Screen Q
4. Creating a “Cost Cap” for qualifying DERs that fail Screen Q to proceed despite transmission interdependence

This section represents a general summary of the proposals only. Some proposals are non-consensus. The “Working Group Proposals” section discusses the variations on the proposals and the different party support for 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]](#footnote-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]](#footnote-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 Wholesale Distribution Tariff.[[6]](#footnote-6)

The Transmission Cluster Study Process is administered by the utility and is designed to allocate costs for transmission system upgrades to responsible projects. 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 study is completed, typically 2 years later. Projects may need to wait an additional 1-2 years after that for construction of upgrades before they receive permission 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:

*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, is not well-documented, but working group members recall that 500 kW was deemed sufficiently large to potentially contribute to requiring transmission system upgrades, that NEM projects were deemed less likely to contribute to the need for upgrades, and that 500 kW was seen as a high enough threshold to cover the majority of customer-sited projects.

### 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 1 GW. This additional 50 kW represents a +0.00005% 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 solar 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 represent that within their respective territories only a small number of projects have failed Screen Q (PG&E 9 projects, SDG&E 0 and SCE 1). Furthermore, PG&E represents that the 9 projects would not have failed Screen Q if the updated CAISO Appendix DD had been in place. 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

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

#### ***Status***

Consensus on the core proposal. IREC objects to measuring system size by nameplate capacity instead of net export. TURN wishes to make clear that if there are any ratepayer cost impacts, they could be addressed in Phase 2 of this proceeding.

#### ***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.

In recognition of the limited time allocated to parties to recommend, review and pursue consensus on proposals to Issue 1, the Utilities are agreeable to changing the exemption size to 1 MVA based upon their expectation that projects of that size will commonly not be found to contribute to the need for Network Upgrades.[[7]](#footnote-7) The working group notes that the change from 500 kW to 1 MW aligns with other 1 MW thresholds for NEM cost allocation and telemetry requirements in Rule 21. 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 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. In most cases, it would result in a lower effective threshold than one based on net export, but 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 implement these recommendations, the working group proposes the following edits to Section G.3.a of Rule 21:[[8]](#footnote-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]](#footnote-9)

##### IREC Proposal to Keep Net Export Measure – Opposed by Joint Utilities

IREC would prefer 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. 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.*

The Joint Utilities 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 nameplate. This was not discussed in any of the working group discussions and includes projects that may be interdependent and may reasonably contribute to the need for Network Upgrades.

##### 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, and California Solar Energy Industries Association. Opposed by TURN and the Joint IOUs.

#### Discussion

This change could be accomplished simply 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 customer programs, such as Net Energy Metering.

##### Reasoning of Proposal Opponents:

The Joint Utilities 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.

1. *Equity among all DERs*: Extending the exemption to the Transmission Cluster Study Process that applies to NEM Tariff qualifying generators to generators that do not qualify for the NEM Tariff, including projects reviewed under a Wholesale Distribution FERC jurisdictional tariff, and creates potentially unfair cost or reliability based impacts on other proposed transmission or distribution level DER projects in the location of the exempt DER. The impacts are:
   * Costs above the CAISO’s cap of Reliability Network Upgrades are borne by developers, and costs that an exempt DER would have otherwise been assigned would therefore be transferred and shared amongst the other developers.
   * Other generators could be adversely impacted from an operations perspective. For example, a Remedial Action Scheme (RAS), which is classified as a Reliability Network Upgrade, could be required for an area that transmission generators and a proposed distribution level generator are connecting to as a way to mitigate circuit overload. This RAS system curtails generators when an overload on the circuit is imminent. If the proposed distribution level generator triggers or represents the “tipping point” for the overload, the exclusion of that DER will mean that that DER will not be interrupted but rather its neighboring generators will be.

The Joint Utilities believe that representation and input from other potentially impacted DER project owners and developers should be part of this discussion and have the ability to voice and document their concerns. DER developers who would typically only be subject to the utility’s wholesale tariffs under Federal Energy Regulatory Commission jurisdiction (including non-NEM DER developers) may not have requested to be included in the Rule 21 proceeding service list, which served as the basis for requesting working group membership participation. Expanding the scope of this Issue to include discussions that impact these other DER developers warrants proper communication of that scope expansion.

1. *Maintaining the integrity of an exemption intended for a specific class of generators*: The proposal to extend the exemption to non-NEM generators was raised during the October 18 workshop without prior indication and is considered by some parties to be out-of-scope of this Issue, i.e., the identified issue pertains to an exemption that applies to NEM generators and such an exemption is believed by some parties to have initially been implemented as a means to promote the growth of customer-owned NEM Tariff qualifying generators. The Utilities believe the history and integrity of language in Rule 21 that pertains to NEM Tariff qualifying generators vs. language that pertains to generators that do not qualify for NEM needs to be maintained, and that parties requesting an exemption that applies to NEM be expanded to non-NEM should provide a clear and explanation as to why the distinction between NEM and non-NEM generators should no longer apply.

###### 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 there is a *de minimis* likelihood that there will be substantial cost shifting for any project smaller than 1 MVA being exempted from Screen Q.

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.

### Proposal 1-C: The Commission should modify Rule 21 to increase the Screen Q exemption threshold to a size larger than 1 MW

#### ***Status***

Non-Consensus

Discussion

Some working group members believe that a higher threshold may be acceptable without the risk of exempting projects that are likely to fail Screen Q. The working group did not perform analysis to determine the precise level below which the vast majority of proposed systems would pass Screen Q.

##### Reasoning of Proposal Supporters

Proponents of Proposal 1-C did not provide language supporting their position. [If language supporting this position is provided, this section may be edited to include that language]

##### Reasoning of Proposal Opponents

The Utilities oppose extending an exemption above 1 MVA for the following reasons. TURN also opposes this proposal.

* *Equity among all DERs*: Raising the exemption above 1 MVA creates potentially unfair cost or reliability based impacts to other existing or future DER projects in the location of the exempt DER. As was mentioned by some parties during the October 18 workshop, the likelihood of a 1-2 MVA DER triggering or contributing to system upgrade is small. Projects under 1 MVA are very unlikely to be of sufficient size to reasonably anticipate a contribution to the need for Network Upgrades. However, exempting a project from the Transmission Cluster Study Process based upon size does create a possibility that its contributions to an upgrade are not fully addressed, which could result in additional costs to other projects. The IOUs believe 1 MVA is the appropriate threshold to limit this possibility.
  + Costs above the CAISO cap of Reliability Network Upgrades are borne by developers and costs that an exempt DER would have been assigned are shared with the other developers.
  + Other generators could be adversely impacted from an operations perspective. For example, a Remedial Action Scheme (RAS), which is classified as a Reliability Network Upgrade, could be required for an area that transmission generators and a proposed distribution level generator are connecting to as a way to mitigate circuit overload. This RAS system curtails generators when an overload on the circuit is imminent. If the proposed distribution level generator triggers or represents the “tipping point” for the overload, the exclusion of that DER will mean that that DER will not be interrupted but rather its neighboring generators.

The Utilities believe that other potentially impacted DER projects owners and developers should be part of this discussion and have the ability to voice and document their concerns.

* *Maintaining the integrity of the purpose of an exemption*: The practical impact of a removal of a size limitation is that it would nullify the benefit of the existing Transmission Cluster Study Process exemption. It would in effect be eliminating Screen Q which is problematic for proposed DERs that are impacting the transmission system. Section G.3.a of Rule 21 states:

*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*** *[no explicit size limitation] and located at a point of interconnection such that it is reasonably anticipated to require or contribute to the need for Network Upgrades.* (Emphasis Added.)

As voiced during recent Working Group One discussions, NEM projects up to 1 MVA are viewed as not of sufficient size to require study under the Transmission Cluster Study Process and can be reviewed in accordance with the Rule 21 Independent Study Process protocols. The 1 MVA exemption provides clarity as to what study process could be expected based on project size.

### 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]](#footnote-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]](#footnote-11) The other IOUs are reviewing procedural filings to make similar updates. PG&E’s advice letter is currently suspended pending Commission review [may need to update prior to submitting the report].

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.

See below for an 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 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

#### Discussion:

To assess a project’s electrical interdependence with the transmission system, the utility performs tests for determining electrical independence[[12]](#footnote-12) collectively called the “Electrical Independence Test” (EIT) as defined in Rule 21.[[13]](#footnote-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 under Rule 21.

Several working group members expressed 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 to be utilized 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 Working Group comments, the Joint Utilities propose to perform the additional engineering review when a project fails the EIT and further review is warranted, and to make these guidelines 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:

*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 a “Cost Cap” for qualifying DERs that fail Screen Q to proceed despite transmission interdependence

#### Status:

Non-Consensus. Supported by Green Power Institute. Opposed by the Joint Utilities.

#### Discussion:

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.

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 initial 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.

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 cheaper interconnection studies under the Rule 21 Independent Study Process.

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.

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

1. A proportionate share of the IOU’s applicable transmission-level RNU upgrades, based on historical average costs; or, at the discretion of the IOU:
2. 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.

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%).

##### Reasoning of Proposal Opponents:

The Utilities 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 Utilities to comply due to the lack of data.

* *Out of scope*: As is clear from its name, Issue 1 is 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 do end up as part of a Transmission Cluster Study are clearly beyond the scope of this issue. In addition, while the DER developers who requested this issue be scoped within the rulemaking identified costs as a concern, during the workshops they also stated that it was the time delay (up to three years) associated with being part of a Transmission Cluster Study that was their main concern and not the costs.
* *Lack of data to comply*: As was discussed during the workshop, 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. As was also discussed at the workshop during which this proposal was suggested, because there have been so few (and in some cases zero) examples from which a Utility would be able to extract data, 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.
* *Insufficient time to fully vet:* 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. The Joint Utilities believe 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.

## 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 Commission should expand upon the definition of complex metering solutions by directing the utilities to:

* Develop illustrative metering configurations and cost tables to provide more transparency in the application of complex metering solutions.
* Post information on their websites clarifying requirements for non-export relays and controls for DC-coupled solar plus storage systems to maintain Commission-required Net Energy Metering (NEM) Tariff integrity requirements.
* Support development of DC metering standards by participating in the EMerge Alliance initiative or other Nationally Recognized Testing Laboratories or Standards organizations as utility resources allow.

## 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 (GF). Specifically, for “large” storage facilities (those greater than 10 kW), 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 (excerpted from the SDG&E NEM Tariff):

*SDG&E will install standard metering equipment whenever possible. Standard metering equipment for this purpose is comprised of up to two 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.*[[14]](#footnote-14),[[15]](#footnote-15)

### Stakeholder Desire for Additional Guidance Regarding When Complex Metering is Necessary

Solar and storage companies find 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, CALSEIA spoke to instances represented to them where facilities that appeared to be similar in size and configuration had different metering solutions.

### Initial Stakeholder Concerns Regarding Complex Metering for DC-Coupled Systems

DC-coupled systems cannot be configured with the same type of metering solutions used for AC-coupled systems due to the different placement of inverters in the two system types. 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 seek 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 due to the potential for time-of-use rate arbitrage.[[16]](#footnote-16) The working group thus agree that, for DC-coupled systems, there is no need for the Commission to clarify the definition of standard and complex metering, as such solutions are not applicable to DC-coupled systems. However, they 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.

The IOUs support providing additional transparency on project factors that trigger the need for complex metering. Appendix B was presented during the WG 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

### Proposal 1: Utilities will develop illustrative metering configurations and cost tables to provide more transparency in the application of complex metering solutions

#### Status

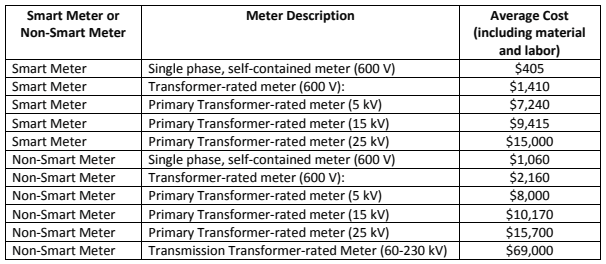
Consensus

#### 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:

An illustrative cost table based upon existing metering arrangements utilized by the IOU. The metering cost table is proposed to be provided for illustrative purposes only, and is not binding towards the actual metering costs. The metering cost table will include the anticipated cost[[17]](#footnote-17) of procuring, installing, and maintainingthe required metering arrangements and may vary among the IOUs. For each meter 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 during the Working Group One meeting held on November 9, 2017. The final metering cost table for each IOU will be developed upon the Commission’s adoption of the Working Group One Proposals.[[18]](#footnote-18)

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



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 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 DC-coupled 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)

The 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 for large DC-coupled solar plus storage projects 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. 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]](#footnote-19)

At the November 9, 2017 working group meeting, the IOUs clarified that a non-export *control* for purposes of interconnecting a DC-coupled solar and storage system under the NEM Tariff could also potentially be configured in a way that would comply with the NEM Tariff and maintain NEM integrity. The IOUs stated that non-certified control schemes can be reviewed, approved if compliant with IOU requirements, and validated via commissioning if deemed necessary.[[20]](#footnote-20)

The working group notes that while non-export relays represent a compliant path to interconnect under NEM rules, they are generally very expensive and thus impractical to implement. The working group anticipates customers will use a non-export control scheme rather than a relay to maintain NEM integrity for DC-coupled systems by limiting export.[[21]](#footnote-21)

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 engineering resources are available

#### 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. 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 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 supports involvement from the California IOUs to support the standard development. It was expressed by a couple 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.

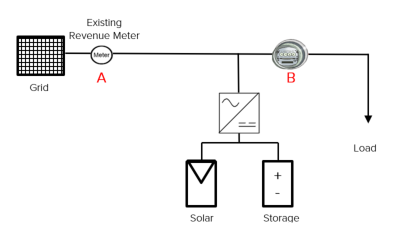
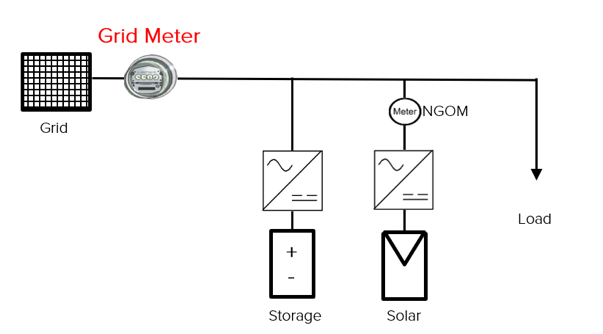
Additional support for development of DC metering standards, beyond the EMerge Alliance initiative, will require further analysis by the IOUs of the incremental costs to integrate DC meters into utility operations. This includes upgrades to billing systems, which are currently AC-based. The working group 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 scope of this Rulemaking.

## Issue 2 Appendices

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

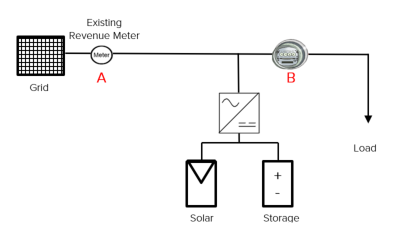
This appendix describes the technical rationale supporting the working group’s determination that a metering solution is not sufficient to maintain NEM integrity.

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.



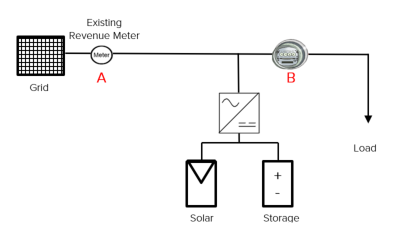
*Figure 1 – AC-coupled systems left with a NGOM directly metering the AC output of the solar and DC-coupled system right, where no AC point exists to directly monitor the solar*

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 up to two self-contained AC meters. As such DC-coupled systems cannot participate under the existing definition unless additional measures are taken such as blocking export.



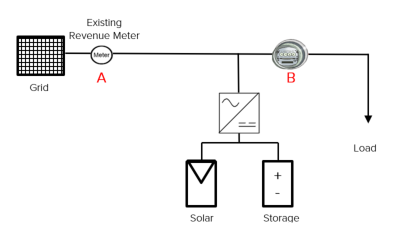
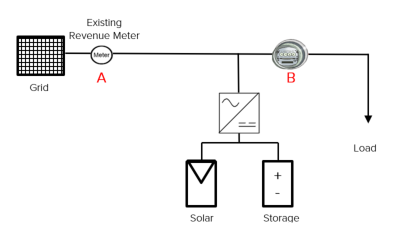
*Figure 2 – Proposed metering arrangement for DC-coupled solar plus storage systems*

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, this arbitrage is not acceptable.



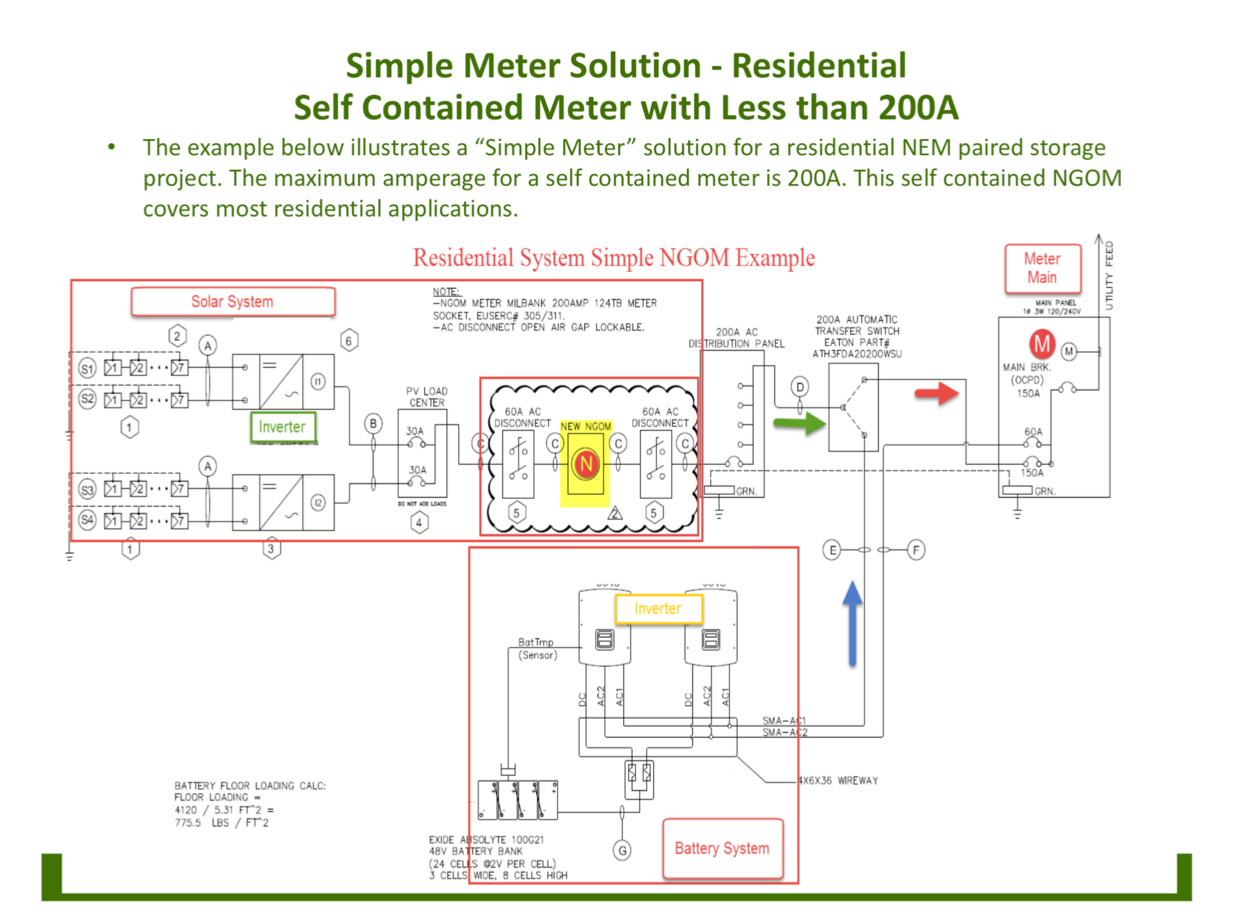
*Figure 4 – Proposed metering arrangement for DC-couple solar plus storage systems*

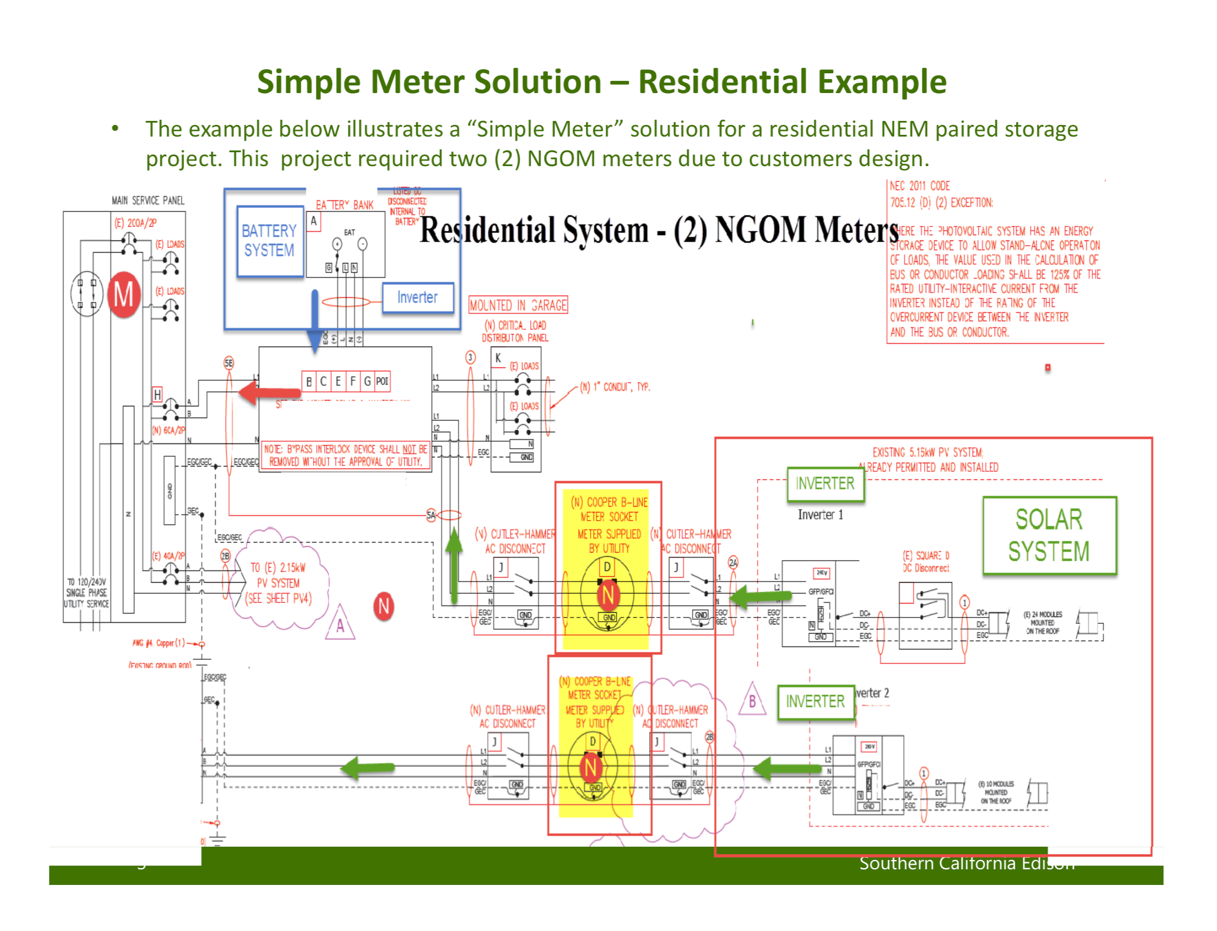
It is possible to know the time of charging as shown and if all charging is attributed the highest TOU tier rate it would protect against any arbitrage benefit. This becomes a complicated situation which may have unintended consequences (such as no disincentive to charge during peak) and is not recommended.

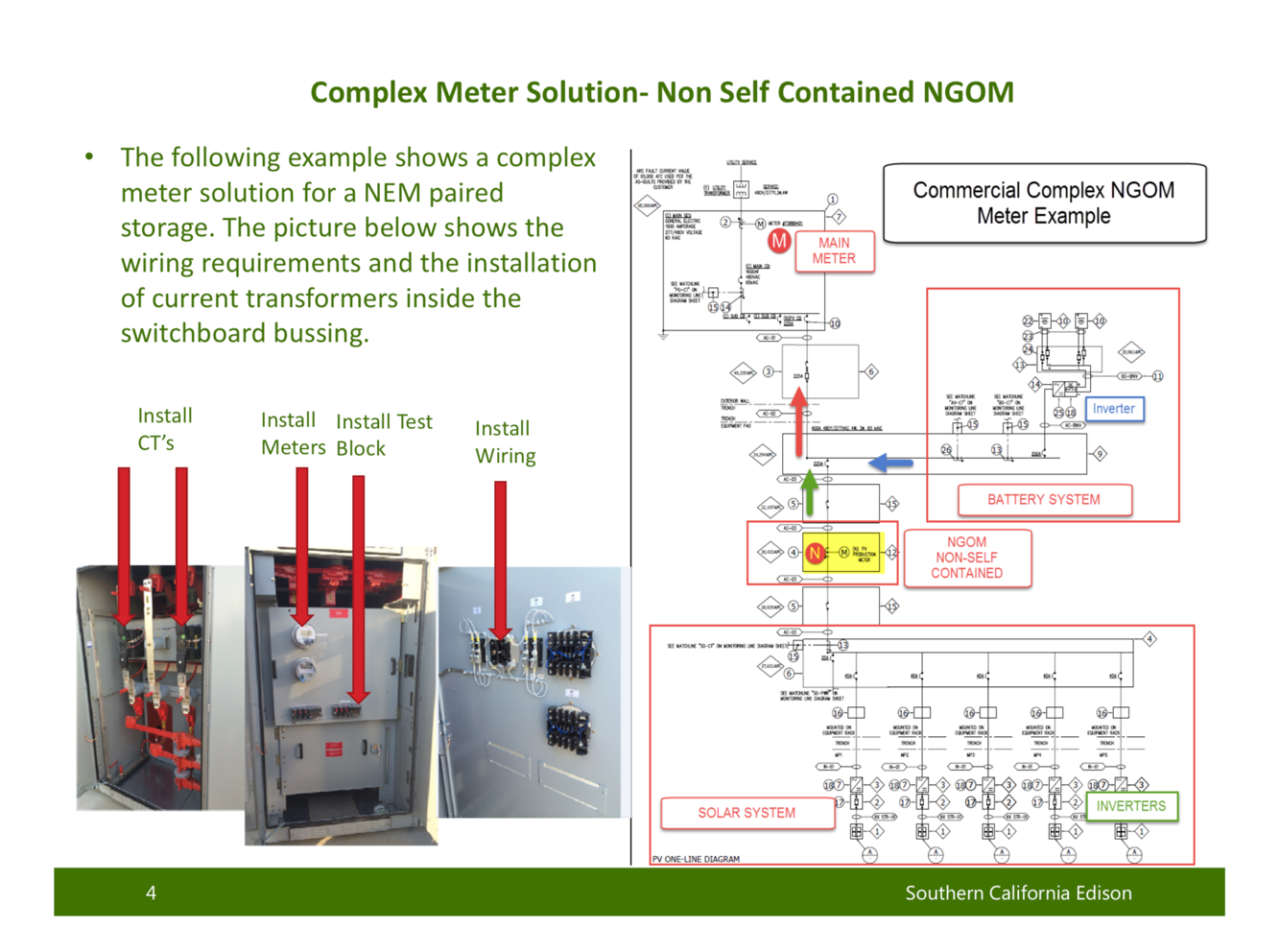
This situation does highlight the need for appropriate price signals for customers to respond to when operating energy storage beyond NEM. This also highlights the limitation of DC-coupled systems ability to interconnect under existing rules.

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)



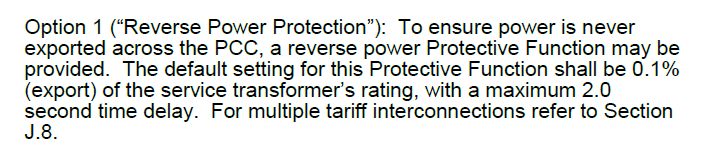




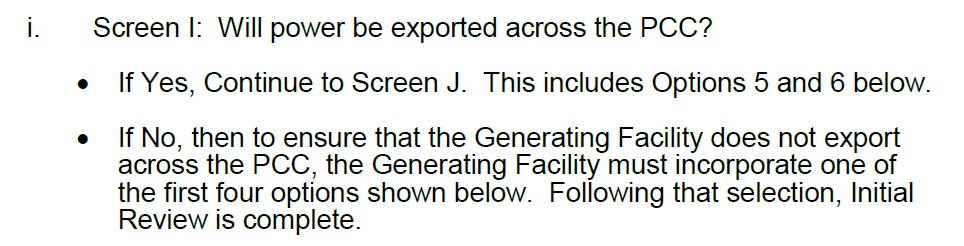
### Appendix C: PG&E Technical Requirements for Non-Export Relays and Controller (Illustrative Purposes Only)

**Rule 21Non-Export Relay and Controller**

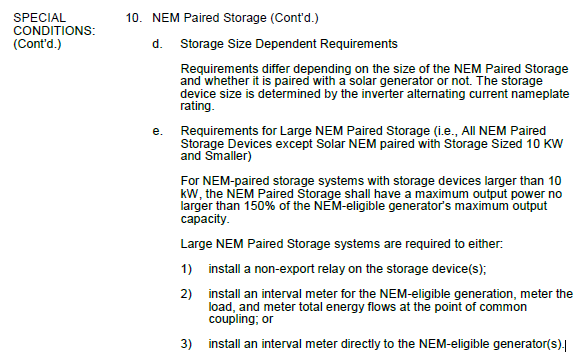
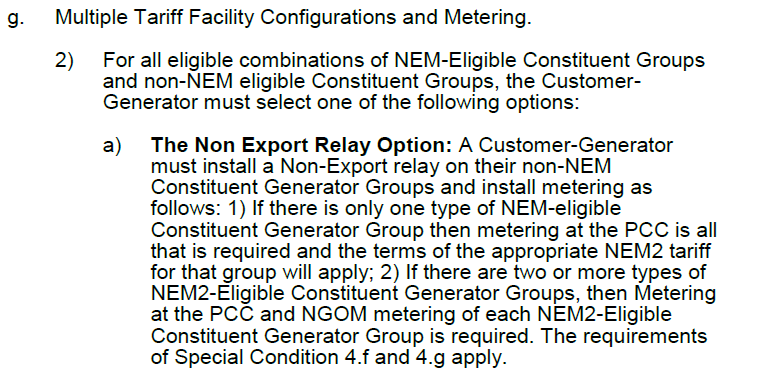
Non-Export Relays to date have been utilized by Interconnection Customers for non-exporting generating facility projects that select Option 1 under Screen I. As a result, technical requirements for relays are based on protection considerations and designed for non-export facilities. Rule 21’s Screen 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.



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.

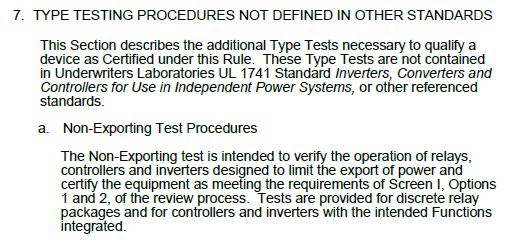


Under special condition 4 and special condition 10 (NEM paired storage) under the NEM tariff, an interconnection customer can elect 1 of 3 options to ensure the non-NEM eligible generator component is not receiving NEM treatment. Non-Export relay is an option currently and thus the Interconnection Customer can elect to install a non-export relay which is not required for interconnection but for the purposes of satisfying NEM program eligibility requirements.



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.



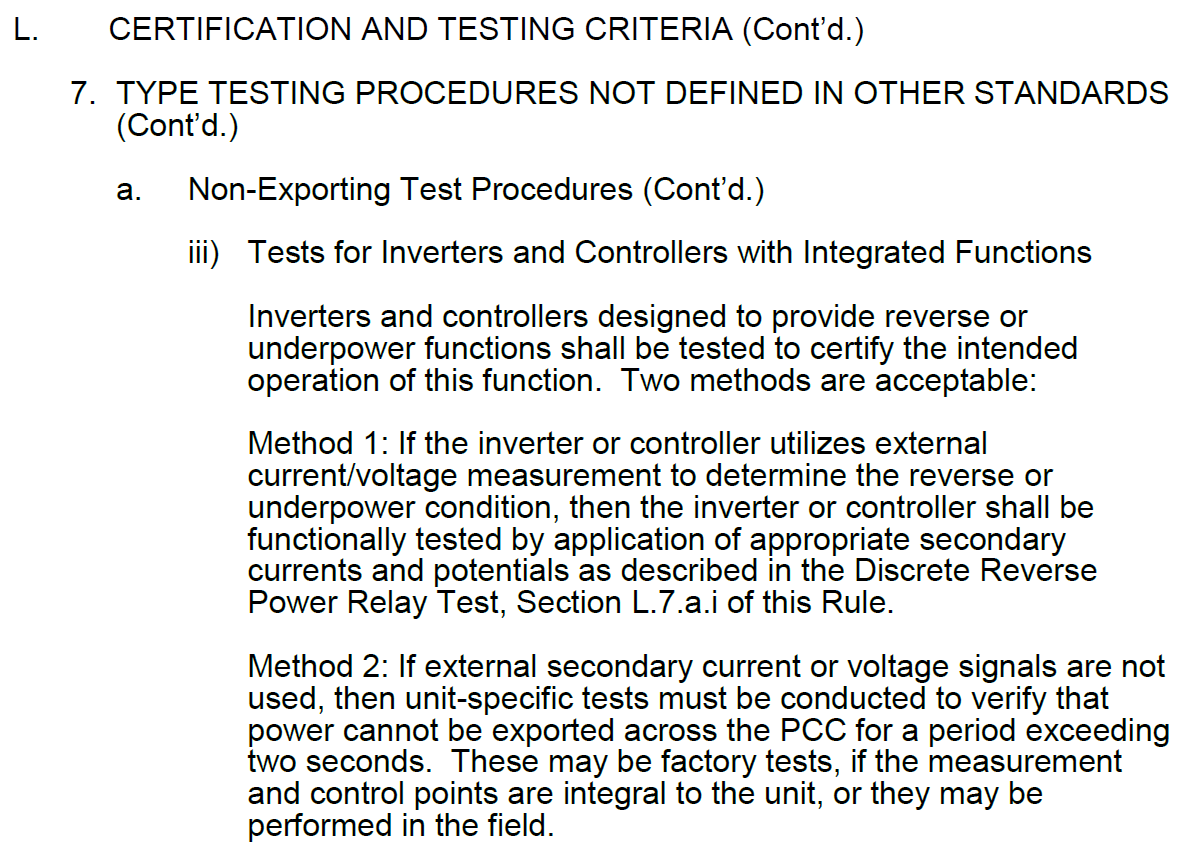
If a non-export relay is elected for NEM MT program eligibility, there are a few methods from which customers can elect. All relay schemes however must be reviewed and approved including during commissioning if deemed necessary. In response to Issue 2 per R.17-07-007, additional information on the non-export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

Current requirements for Battery Storage plus PV systems~~:~~

* Inhibit Output of Battery Controller

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.



* Non-Export Relay - Separate Inverters for Battery Storage & PV System

A Non-export relay device is installed at the PCC. It measures the power at 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 the discharging of the battery storage system.

* Non-Export Relay - Same Inverter for Battery Storage & PV System

A Non-export relay device is installed at the PCC. It measures the power at 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.

Under consideration for Battery Storage plus PV systems in R.14-07-002[[22]](#footnote-22):

* 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 the energy storage system discharging at any time there is power flow across the point of common coupling from the customer site to the distribution grid.
2. Prevent the energy storage system charging from the distribution grid.

These options are outlined in CalSEIA’s PFM1 which describe some suitable options for achieving these desired no grid charging and prevention of export functions. The IOUs support further exploration and certification of these schemes and look forward to participating in next steps related to the PFM.

**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](https://www.pge.com/includes/docs/pdfs/shared/rates/tariffbook/ferc/tih/app_r.pdf" \t "_blank)>

**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)

# 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?

## Proposal Summary

[…]

## Background

### Two Use Cases

Customers must sometimes make modifications to pending interconnection applications to accommodate changing business conditions. 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:

***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. (Rule 21, Section C)*

Customers must also sometimes make modifications to *existing* facilities to perform maintenance or do retrofits. Rule 21 requires customers to submit new applications when making modifications[[23]](#footnote-23) unless those modifications are not “material” per the definition above.

The definition of material modification requires clarification for both of these use cases. They are distinct enough that the working group addresses them separately: the first proposal addresses making modifications to pending interconnection applications, and second proposal addresses making modifications to existing facilities.

### Modifications to Pending Interconnection Applications

Rule 21 defines material modification as follows:

***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)*

Customers must sometimes make modifications to pending interconnection applications to accommodate changing business conditions. 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 definition above. For projects applying under Rule 21’s Detailed Study process, Rule 21 specifies several types of modifications that will not be considered material.[[24]](#footnote-24)

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 large 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 reduce processing speeds for all Fast Track projects.

#### Issue Presented

Current Rule 21 language addressing Fast Track modifications is as follows:[[25]](#footnote-25)

*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,”[[26]](#footnote-26) 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. Stakeholders raised concerns with the current language in that it (a) is unnecessarily restrictive and (b) the IOUs utilize discretion in different ways to allow modifications within the 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 changes have no adverse consequences.

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

* **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.
* **Un-Forecasted 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 a downsize request to avoid upgrades.

Stakeholders also raised concerns 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 at Appendix D.

#### 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:** 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. 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 impact 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, small Net Energy Metering projects represent significant volumes to each IOU and generally have been able to be processed under very expedited timelines that are much lower than what is common for larger projects. Another consideration to allowing modifications is to not compromise the current timelines that these projects benefit from.

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 that a system re-study is not required or that does not have a material impact on another party.

### Modifications to Existing Facilities (e.g. Maintenance, Retrofit)

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 characteristics, make, model, 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 writing, and signed by both Parties[[27]](#footnote-27). The Rule 21 interconnection process currently allows for retrofits as can be seen in the following definition of Interconnection Request in the current Rule 21 tariff:

***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 to accept time and monetary obligations associated with filing new interconnection requests, 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, 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:

* **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.
  + 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 Proposals Addressing Modifications to Pending 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 below modifications under the Fast Track Process.

* **Like-for-like**[[28]](#footnote-28) **equipment replacements** that meet the following criteria:
  + The equipment replacement does not increase system size[[29]](#footnote-29)
  + 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
* **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, unless further changes are agreed to by Distribution Provider. A modification request can incorporate more than one modification type.
* **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**: 10 business days for processing time and 20 business days for engineering re-study time. Timelines were mirrored on existing timelines for modification requests under the Cost Envelope option. See Appendix G for tariff language.
* **Cost Responsibility**: If a project downsizes and the revised size has a different cost responsibility than the original, the cost responsibility of the interconnection request does not adjust and remains based on the original interconnection request.
* **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, unless changes are agreed to by Distribution Provider (minor changes such as location of meter can be managed in the design/construction phase of the project. Changes to POI within the same land parcel is acceptable.)
  + Changes in the operational profile of storage (to be reviewed in a later working group)
  + 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.

As a part of this proposal, Rule 21 tariff language will need to be updated. Tariff language shall be drafted and proposed 30 days after Commission Decision.

## Working Group Proposals Addressing Modifications to Existing Facilities

### Working Group Findings

The working group discussed various scenarios and reasons for systems being modified. They generally fall within two categories: maintenance and expansions. See Appendix A for additional detail. Maintenance covers equipment failures and regular maintenance activities.. Expansion are for modifying the generating facility such that it has an increased capacity or capability, for example when adding battery capacity to an existing inverter. Within these two categories, the working group defined three levels of impact and the proposed process to address them. See Appendix A for additional detail.

* No notification required: There are times when equipment changes such as for warranty purposes and the replacement equipment is not different. This process type would entail:
  + 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
* Notification required: There are times when equipment changes but the replacement equipment is slightly different than existing equipment but within the already authorized amount of generating capacity in the existing permission to operate letter from the IOU (PTO). Under these conditions, this process type means:
  + May have requirement to amend an existing interconnection agreement
  + No engineering review is expected to be required
  + 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
* Abridged/Streamlined interconnection request: There are times when equipment changes and the replacement equipment is slightly different than existing equipment and may have greater capacity. Additional equipment or firmware could potentially be utilized to limit the output of the generating facility to match the existing PTO or within a certain acceptable limit thereby limiting the impact to the distribution system. Under certain conditions, a new engineering review may not be required and under those conditions, this process type entails:
  + Requirement to amend the existing interconnection agreement
  + Engineering review may be required
  + Program check may be required, such as what modifications are allowed under NEM
  + Need to update records

The working group also noted that some maintenance and expansion use cases result in increased capacity or materially different 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 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.

### Proposal 2: Clarify existing rules and maintain status quo

[Note SCE has not reviewed and this is subject to change]

#### Summary

Clarify that modifications require a new interconnection request except for “like for like” equipment swaps where no notification and no interconnect request is required.

#### Status

[…]

#### Discussion

The IOUs are today receiving interconnection requests for new generating facilities and modifications through the existing interconnection portals. The portals have greatly automated the process for both the interconnection customer / developer and the IOUs. 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.

At this time, the IOUs do not have processes for a notification only or an abridged interconnection request. The IOU interconnection portals would need to be modified to support new processes. 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. The IOUs currently 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 consider that the existing tools facilitate a streamlined interconnection and are capable of processing thousands of interconnection requests a month. To keep the processes, forms and agreements simple, the IOUs propose:

* Maintain a single interconnection process and leverage existing tools to manage modifications
* Clarify that like-for-like equipment swaps do not require an interconnection application

### Proposal 3: Modify Rule 21 and associated forms/agreement to implement a notification only process and an abridged interconnection application process

[Note SCE has not thoroughly reviewed and this is subject to change]

#### Summary

Adopt the proposed recommendations from the working group and modify Rule 21 and related forms/agreements to facilitate the notification only process and abridged interconnection application process. The implementation of this process requires funding for the IOUs which is contingent on GRC funding and may take 2+ years.

#### Status

[..]

#### Discussion

In this proposal, the IOUs would need to create two new process types and make modifications to interconnection tools to implement these new processes. IOUs would request funding under this proposal to facilitate the development of these processes which is contingent on Commission approval.

The proposal implementation would involve:

* Forms/Agreement update: New modification request form will be proposed after Commission decision. Modifications to existing agreements will 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 added to Interconnection Agreements to reflect the customers’ requirement to follow local jurisdiction requirements, NEC codes and other related requirements.
* Rule 21 update: new tariff language will be proposed after Commission decision to reflect the new processes. Tariff language will allow for receiving automatic approval and automatic passing of engineering screens if certain conditions are met making that retrofit request eligible for the new process.
* Interconnection/Tools update: As noted above, new processes will 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 criteria should be limited to updates that could not pose a safety or reliability concern. The IOUs also consider the implementation costs high relative to the added benefit from migrating from the existing automated process to a new automated process. 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 arounds on interconnections. Introducing additional complexity with this proposed process may be counter to stakeholder goals.

## Issue 3 Appendices

### Appendix A: Use Cases and Process Options

*The frame up below reflects SDG&E’s and PG&E’s position on various use cases*

*The frame up below does not SCE’s position on various use cases and is subject to change*

**Maintenance Use Cases**

**Process Option 1: Customer is not required to notify the utility of maintenance.**

**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 1b:** Maintaining equipment, defined as cleaning, aligning, adjusting. Does not include making functional changes to the operational mode of inverters, or changing settings on inverters that would affect system output capability. Does not include equipment replacement**.**

**Process Option 2: Customer must notify utility of maintenance and may proceed without waiting for approval.*[[30]](#footnote-30)***

**Use Case 2a**: 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 kW/kWh nameplate of equipment components (PV panels, inverters, batteries) does not exceed what is listed in the original interconnection agreement and operating mode is not adjusted. System capacity is the CEC-AC rating of the system plus module degradation (see module degradation lookup table[[31]](#footnote-31))

**Use Case 3**: Adding or replacing equipment such that firmware controls limit the real power output to the inverter listed size in the original interconnection agreement. Firmware controls must be certified by a NRTL.

**Use Case 4**: Replacing PV panels such that the Manufacturer Rating (STC rating) of PV Panels or CEC AC-Rating of System does not exceed 110% of the listed size in the original interconnection agreement so long as DER’s “limiting factor” does not exceed what is listed in the original interconnection agreement

**Use Case 5**: Adding storage capacity (kWh) to an existing storage facility without changing inverter (e.g. increasing a 1-hour system to a 2-hour system)

**Process Option 3: Customer must submit an abridged interconnection request and wait for utility approval to proceed with maintenance.[[32]](#footnote-32)**

**Use Case 6**: Replacing equipment such that the system ’s “limiting factor” does not exceed 110% of the listed size in the interconnection agreement, and firmware controls limit the real power output to the inverter listed size in the original interconnection agreement

**Process Option 4: Customer must submit a normal interconnection request and wait for utility approval to proceed with expansion.**

**Use Case 7**: Adding or replacing equipment such that system capacity increases.

**Use Case 8**: Adding storage to an existing generating facility that does not have storage

**Use Case 9:** Changing inverter operating characteristics (e.g. smart inverter settings, operating set points)

### Appendix B: 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 C: Sections of Rule 21 Addressing Modifications

**Section C. Definitions**

*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.

**Section D.5. Design Reviews and Inspections**

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

**Section F. Review Process for Interconnection Requests**

*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:

1. a decrease in the electrical output (MW) of the proposed Generating Facility;
2. modifying the technical parameters associated with the Generating Facility technology or the Generating Facility step-up transformer impedance characteristics; and
3. 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 D: Stakeholder Preliminary Scoping Brief for Issue 3

*Prepared 11/27/17*

***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?*

Please note that this is a preliminary draft. Not all Stakeholders have had a chance to add input. Many key stakeholders are unavailable due to the Thanksgiving Holidays. However, this captures the theme of Issue 3 whilst some detail will still be added. In an effort to progress the working group’s activities and manage the time pressures created due to the Thanksgiving holidays as best possible, this draft serves to provide clarity on the theme and stimulate discussion but is not a finalized scope for Issue 3 Working Group 1.

**Overview (by CESA)**

A “material modification” is:

*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, page 25)**[[33]](#footnote-33)*

A “material modification” triggers a new interconnection review process, which in some cases can be unnecessary and cause additional time and cost. In other cases, developers may not wish to pursue a project if exposed to a new interconnection assessment. Finally, today there is a perceived inconsistency in what constitutes a “material modification’ and how these rules are being applied across the IOUs.

We seek to clarify “material modification” in order to provide a clear and consistent pathway for modifying DER installations. The definition should be reflective of the impact to the grid and ensure triggering a new interconnection assessment is only carried out when appropriate. A framework with appropriate thresholds can inform the market to both facilitate non‑material modifications with reduced burden, time and cost impacts and provide certainty and consistency for undertaking material modifications.

**The Problem**

The current definition of what a Material Modification does not offer the market enough information to pursue non-material modifications or understand the process for material modifications, nor does it appear to be applied consistently across IOUs. The definition that is being applied may also cause new interconnection reviews to be conducted when unnecessary, adding cost and time to projects.

**Additional Information**

Some relevant definitions from Rule 21 are:

***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.*

*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.*

*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.*

The purpose of a behind‑the‑meter storage in most cases is to reduce demand charges, increase self‑generation and other customer bill benefits. Therefore, retrofitting energy storage to a PV installation typically does not add to the site’s peak load, such as defined as Operational Mode 2 in the Rule 21 definitions. [[34]](#footnote-34) In addition, by charging energy storage from local generation reduces export to the grid which generally increases hosting capacity. Therefore, the operating profile rather than additive nameplate ratings are important when considering a material modification. The buffering of the draw and export from and to the grid by energy storage is favorable compared to a previous solar PV only configuration. Therefore, to block, add cost or slow down a modification that can assist the grid is not desirable to get the best outcome for all ratepayers.

**Questions That May Assist Progress**

* What is the cost threshold used in determining Material Modification?
* What is the time threshold used in determining Material Modification?
* Is operating profile considered or is additive nameplate considered when assessing size?

*Some specific Scenarios:*

* Does retrofitting a 10kW energy storage system to an existing 10kW PV system constitute a material modification?
* Does retrofitting a 10kW energy storage system, that adheres to operation mode 219, to an existing 10kW PV system constitute a material modification?
* Does increasing the amount/capacity of solar panels behind an existing inverter constitute a material modification?
* Does a NEM 1 solar system transition to NEM 2 if a non-material modification is made?
* Does a NEM 1 solar system transition to NEM 2 if a material modification is made?

**Goal**

* Develop a standard definition for material modification that includes appropriate thresholds (time, cost and/or change in capacity) to offer guidance to the market and allow consistency. These should be appropriate with respect to potential grid impacts.
* Clarify the operating profile is considered rather than an just additive nameplate capacity approach which is likely inappropriate.
* Clarify or establish that retrofitting existing PV facilities with energy storage does not constitute a material modification unless it changes the impact on the grid beyond a defined threshold. i.e. increases export or peak by more than (x) %.
* In addition to a general definition, defining if some common examples are a material modification would be useful for the market.

### Appendix E: Utility Preliminary Scoping Brief for Issue 3

*Prepared 11/27/17*

*Draft for Discussion Purposes Only and Subject to Additional Review and Management Approval*

1. **Material Modification Tariff Overview**

In accordance with Section C of Rule 21 (Definitions), a “Material Modification” is defined as "***[a modification] or modifications that have a material impact on cost or timing of an Interconnection Request with the same or later queue priority date or change in Point of Interconnection. A Material Modification does not include a change in ownership of a Generating Facility."***

In addition, R21 Section 3.b.v (“Modifications” under the Independent Study Process) and Section 3.c.vii (“Modifications” under the Distribution Group Study Process) state *“[a]ny 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.b.v [or Section F.3.c.vii, respectively], shall constitute a Material Modification.”*

1. **Working Group Issue Presented**

***How should the Commission clarify the definition of a “material modification” to a project and what should be the procedures for processing these modifications?)***

**A*.* Pre-Interconnection Agreement Execution Project Modifications**

R21 Section F.3.b.v. and Section F.3.c.vii recognize that "[a]t any time during the course of 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." Both Sections of R21 further highlight that "project modifications including project decreases, modification to technical parameters or interconnection figurations, are reviewed pursuant to the governing Material Modification definition of ***whether the proposed modification of the interconnection request has a material impact on the cost or timing of other projects either sharing or later within the interconnection queue***.

By way of further example, R21 Section F.3.b.v. and Section F.3.c.vii do allow for certain modifications which include decrease of electrical output, changes on technical parameters or changes to the project’s configuration. However, any of these permitted changes, although not “*material*”, may require a review of the technical studies that have been performed for the project prior to the modification request. This review requires consent from the interconnection customer (following the utility’s proposed cost and schedule of the review) and commonly impacts the timing of the final interconnection agreement for the project to allow for utility review of the proposed change. If the project’s project modification does rise to the level of a Material Modification, the Interconnection Customer is given an opportunity to decide whether to proceed with the project without the proposed modification or withdraw the interconnection request from the utility’s interconnection queue and submit a new interconnection request with the desired changes.

The concept of impact to another “later queued party” whether in cost or time has been utilized as a best practice in viewing whether a proposed project change can be accommodated within an Interconnection Applicant's existing application or whether a new application is warranted.

Based on review of CESA's initial comments, stakeholders are requesting illustrative examples to support transparency regarding how modifications are addressed within the interconnection process, including how the IOU application of the material modification standard discussed above. The IOUs look forward to working through these items with stakeholders and determine what, if any, R21 revisions may be appropriate as compared to additional stakeholder guidance.

**B. Post Interconnection Agreement Project Modifications**

The IOUs recognize that interconnection applicants may also need to propose project modifications after interconnection agreement due to equipment availability, final design arrangements and other factors. In particular, no R21 procedures exist directly governing how project modifications are addressed after an Interconnection Agreement is executed.

At the Wholesale Distribution Tariff level, existing procedures exist regarding how to address such changes and address critical questions such as cost responsibility, system reviews and transparency on process. As part of this Working Group discussion, it may be appropriate to discuss the issue of "post Interconnection Agreement" changes and whether existing procedures utilized at the wholesale level should be applied within R21.

### Appendix F: 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](mailto:Heather.Sanders@cpuc.ca.gov)>  
**Cc:** Evans, Mary Claire E. <[MaryClaire.Evans@cpuc.ca.gov](mailto:MaryClaire.Evans@cpuc.ca.gov)>; Charipar, Kristin <[KDCI@pge.com](mailto:KDCI@pge.com)>; Diana Genasci ([diana.s.genasci@sce.com](mailto:diana.s.genasci@sce.com)) <[diana.s.genasci@sce.com](mailto:diana.s.genasci@sce.com)>; Kathryn Enright <[Kathryn.Enright@sce.com](mailto:Kathryn.Enright@sce.com)>; joe mccawley <[JMcCawley@semprautilities.com](mailto: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 G: November 30 Working Group Meeting Notes

**Notes from Afternoon Session**

*Taken by Mary Claire Evans, CPUC and Will Chung, PG&E. Represents technical discussion only. Other considerations such as NEM eligibility, interconnection processing, costs and time to manage modifications, and forms/contracts were not taking into consideration when developing this draft.*

**Fast Track applicants who make the following modifications will likely maintain their queue position:**

* Reducing System size so long as no mitigations were originally required or the customer agrees to pay for mitigation
* Increasing equipment size so long as the size of the “limiting factor” equipment does not increase. The “limiting factor” is defined as Inverter Nameplate for Inverter technology or
  + PG&E & SDG&E: in the case of a PV system, the lessor of the Inverter Nameplate or the Aggregate CEC AC Rating of the PV Panels.
  + SCE: in the case of a PV system, Inverter Nameplate.
* Replacing equipment with “equivalent” models. (Note that certain changes such as connection type (e.g. delta, wye) may require restudy)
  + For inverters, equivalency is defined as being certified and having the same or lower nameplate rating and fault current.
  + For batteries, equivalency is defined having the same or lower kWh rating, and same operating profile.
  + For transformers, equivalency is defined as same connection type, same or higher impedance and same or lower capacity.

**Fast Track applicants who make the following modifications will likely lose their queue position:**

* Changing the Point of Interconnection (POI)
  + POI changes within the interconnection request’s parcel (i.e. moving it from one side of the building to another area within the building) are often resolved in the design/construction phase, in which case they would be evaluated to determine if a restudy is required.
* Adding a new battery is considered an increase in capacity of an existing Generating Facility and would require a new application.
* Making any change in connection types (e.g. delta to wye).
* Reducing system size to avoid mitigations (potential impact to later-queued projects).
* Increasing the size of the “limiting factor”. As described above the “limiting factor” could be the Inverter Nameplate or in the case of a PV system, the lessor of the Aggregate CEC AC Rating of the panels or the Inverter Nameplate for PG&E and SDG&E.

**Other notes from discussion:**

* Regarding making modifications to the operational profile of a smart inverter or charge controller, IOUs consider operational profiles in limited cases at this time. It is mainly evaluated for storage projects which would require a new application. This topic will be addressed further in a later R.17-07-007 working group.
* The working group needs to address making modifications to existing facilities (e.g. replacing inverters at end of life, retrofitting with storage) separately from making modifications to pending applications

**Matrix on Common Modifications - FAST TRACK ONLY:**

|  |  |  |
| --- | --- | --- |
| **Modification Category** | **Requires low level of review; allowed without losing queue position** | **Requires high level of review; will likely lose queue position** |
| Size reduction  [Max 10%?] | * No mitigations are required or the customer agrees to pay for mitigations * Change of equipment must meet equivalency requirements except size |  |
| Minor size increase in “limiting factor” | * None * Note that so long as the “limiting factor” doesn’t increase in size, other equipment may increase in size without losing queue position (i.e. if inverter nameplate is the limiting factor on a PV system, the project could increase the number of DC panels or replace the panel such that the rating of the panels increase without triggering material modification) |  |
| Equivalent equipment replacements  [Define equivalency ] | * Inverters: equivalent means certified, same nameplate or smaller, same fault current or smaller * Batteries: equivalent means same kWh rating, and same operating profile, * Transformers: same connection type, same or smaller impedance and capacity | * Any change in connection types (e.g. delta, wye) |
| Changing the point of interconnection | * None. * Minor changes within the project’s parcel (i.e. location of meter within facility) are often resolved in the design/construction phase, in which case it would be evaluated whether engineering re-review is required. |  |
| ~~Minor design changes (i.e. changing the location of the inverter)~~ |  |  |
| Changing the operational profile of a smart inverter or charge controller | * IOUs consider operational profiles in limited cases at this time. This topic will be addressed in a later R.17-07-007 working group. |  |
| Adding storage to a pending application | * None | * Requires new application |
| Adding storage to an existing, interconnected facility | * Requires new application | * Requires new application |

### Appendix H: 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

This is a non-consensus item.

Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric and (collectively, the IOUs) propose:

1. Reduce threshold for requiring telemetry from 1 MWac to 250 kWac only if estimated IOU proposed telemetry equipment cost is less than $20,000; such projects remain responsible for actual cost of the telemetry solution. Telemetry equipment costs represent all equipment directly related to the allowance of telemetry, (including the Income Tax Component of the Contribution and Operation and Maintenance related costs).[[35]](#footnote-35) Metering required in support of program eligibility (for example, metering requirements related to Net Energy Metering Paired Storage projects) is not addressed within this proposal.
2. As discussed in Section II (Background) real-time telemetry is a critical component that allows the utility to allow for grid operators to make safe and reliable system decisions on for projects connected on its distribution system
3. $20,000 telemetry requirement threshold would proposed to be applied for projects up to 10MW connected to the distribution system. Allowing projects up to 10MW to qualify for this represents an improvement of the existing Rule 21 1MW and above telemetry requirement as such requirement is not currently triggered by an IOU cost estimate of $20,000 or lower.
4. IOUs will develop technical specifications in support of the telemetry solution within ninety calendar days after the final Commission decision on Working Group One.
5. IOUs will develop Interconnection Agreement revisions if the Interconnection Customer is providing for third party ownership is utilized as part of telemetry solution. The Interconnection Agreement revisions will allow for thirty days to repair or replace equipment malfunction as notified by the IOU utility. If equipment is not repaired within the thirty day period, IOUs reserve the right to make such repairs and charge the Interconnection Customer for related costs.
6. To provide transparency regarding estimated vs. actual cost of telemetry solution for such projects, the IOUs propose to supplement existing Commission data reporting.
7. Continue to utilize existing Rule 21 telemetry threshold based upon the Generating Facility Nameplate Rating Capacity,[[36]](#footnote-36) which includes the generating facility aggregate nameplate rating capacity (where it includes multiple resources, including storage).
8. Continue to allow IOUs existing flexibility in development of lower cost telemetry solutions in accordance with specific needs.

Non-utility stakeholders propose:

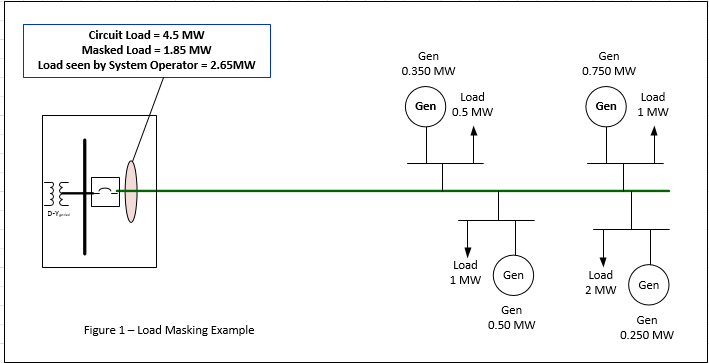
1. Maintain the threshold for requiring telemetry at 1 MWac.
2. Require the IOUs to adopt the following technical requirements for telemetry for systems larger than 1 MWac:
   1. Facilities can report measurements in 15-minute increments using customer-owned, non-revenue-grade metering and a data aggregation device comparable to the serial device server currently required by SCE.
   2. Customers can choose to connect the reporting device to the utility Energy Management System via cellular modem or dedicated internet connection.
   3. 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 more costly utility-owned Net Generation Output Meter.
3. 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 resources on the site.
4. Do not apply the telemetry requirement if telemetry utility costs exceeds $20,000.[[37]](#footnote-37)
5. 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. Maintenance of the equipment and required uptime metrics will be specified in the interconnection agreement.

## Background

Telemetry involves the real-time transmittal of information from a resource on the distribution system to the utilities. Rule 21 currently allows utilities to require distributed energy resources (DERs) larger than 1 MWac to provide telemetry.[[38]](#footnote-38) This data can include how much real power a generator system is producing, how much reactive power the system is producing or absorbing, how much a battery is charging or discharging, and voltage conditions.

The IOUs believe that increased use of real-time telemetry is necessary to allow for grid visibility to allow for grid operators to continue to make decisions to 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 awarenessof 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. Figure 1 is an example of load masking and its impact to what grid operators actually see on the system depicts the issue with load masking an operation awareness. 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 decision during normal operation (switching) or abnormal operation (restoration of power).



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-$180,000.

See Appendix B for a detailed description of the current utility requirements for telemetry. The costs are summarized below:

SCE’s current telemetry solution generally has a total Telemetry Equipment Cost of approximately $20,000.

PG&E’s current telemetry solution and all utility related costs are approximately $160,000. PG&E requires circuit breakers called reclosers that can be controlled remotely. The main purpose of this device is telemetry but it also provides grid protection when the utility has reason to believe there is risk of inappropriate power flow. However, the circuit interruption functionality is not needed for the purpose of telemetry. 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 telemetry solution and all related utility related costs are $19,000-$46,000[[39]](#footnote-39). SDG&E is working to develop lower cost options as summarized in Exhibit A (solutions could also be memorialized within this proposal.

Telemetry is one of the functions that were considered by the Smart Inverter Working Group, which was co-sponsored by the Commission and the California Energy Commission. The Phase 3 recommendations of that group include a requirement that generating facilities be capable of reporting operating data. Many stakeholders have assumed thought that smart inverters will make telemetry cheap and easy once the new functions are enabled. However, that is not the case given that additional equipment is needed to connect the Smart Inverter to utilities.

Utility telemetry rules require reporting facility-level data rather than inverter-level data. A majority of customer-sited solar installations have multiple inverters, and the required inverter communications functionality therefore may not by itself reduce the costs of providing telemetry for customers. It is not as simple as turning on the communications capabilities that will be designed into inverters. The solar provider will have to aggregate and report the data, which cannot be done by the inverters themselves.

More background on this issue is contained in the appendices to this proposal.

## Utility Proposals

As highlighted within Section II, without the use of telemetry, the IOUs have limited system visibility or situational awareness for DERs under 1 MWac. This lack of visibility creates operational issues due to the masking/no visibility to customer electrical load as shown above in Figure 1. In addition, use of real-time data assists the IOUs’ electrical planning assumptions in relation to DER load, as the IOUs maintain the obligation to serve in cases where the DER is not available (see Appendix A for operational use cases). Therefore, the IOUs propose the following revisions to the existing Rule 21 1 MWac telemetry requirement.

### Proposal 1: To address lack of grid operator visibility, require telemetry at 250 kWac if all estimated utility related telemetry equipment costs are estimated to be less than $20,000; Proposal would also be applied for projects up to 10MW (representing a progression from current Rule 21 telemetry requirements not tied to utility costs)

As highlighted within Section II (Background), without the use of telemetry, the IOUs have limited system visibility or situational awareness to make grid operation decisions for DERs under 1 MWac. For example, at higher levels of penetration, the lack of DER visibility contributes to lack of operational awareness for grid operators, which then leads to real time operational system concerns. Also, the lack of DER visibility also impacts the IOUs’ electrical planning in relation to DER load as the IOUs maintain the obligation to serve in cases where the DER is not available. 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 operators don’t see the full electrical load served by circuits on the system (see Figure One – Load Masking Example). Although the vast majority of Rule 21 projects are of a small project size, the aggregate amount of projects totals to **xx** generation. This is generation for which SCE has no real time system visibility or situational awareness. 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 sophistication of telemetry solutions has improved and is expected to continue to do so. For example, 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.[[40]](#footnote-40) Thus, they have proposed to only require telemetry for projects between 250Kw and 10MW where telemetry equipment costs are estimated to be less than $20,000.

Finally, the use of telemetry is 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.

### Proposal 2: Continue Existing Method for Rule 21 Telemetry Project Size Requirements for Rule 21 Telemetry in Support of Grid Operator Visibility (aggregate nameplate rating capacity of the Generating Facility where it includes multiple DERs)

The size of a generating facility for purposes of determining whether telemetry is required should be based upon the aggregate generating facility nameplate rating, with any storage device counted as a generator at its full capacity. 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) 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.

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.

### Proposal 3: Continue Existing IOU Flexibility in Development of Cost Effective Solutions

Current Rule 21 telemetry requirements are based on project system size (Nameplate capacity rating) and not based upon the type of telemetry solution. No prescriptive telemetry solutions should be established. It is critical that the IOUs have enough flexibility in order to reach the telemetry cost goals. This is necessary because SCE, PG&E, and SDG&E may have different Operations Distribution Networks (ODN) and SCADA systems along with back-office capabilities and different IT requirements among other differences which may leverage different communication protocols (DNP3 or secure DNP3). For these reasons, 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.

## Non-Utility Stakeholder Proposals

Operational data can be reported to utilities in a manner that is far less expensive than what has been required of many customers. Even at a controlled cost, the Commission must ensure that the benefits outweigh the costs.

### Proposal 1: Maintain the threshold for requiring telemetry at 1 MWac.

Non-utility stakeholders believe the IOUs have not shown the need for real-time data for systems smaller than 1 MW. Additionally, 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.

### Proposal 2: Require the IOUs to adopt the following technical requirements for telemetry for systems larger than 1 MWac:

* 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 currently required by SCE.
* 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 more costly utility-owned Net Generation Output Meter.

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, which allow a system larger than 1 MWac to provide telemetry for an All-In Cost of approximately $20,000.

Non-utility stakeholders appreciate that the IOUs are considering termination of previous technology requirements for cost control purposes, but the IOU proposal does not commit to any cost control for systems larger than 1 MWac. There must be either a cost cap or clear technology parameters that are intended to meet a target cost.

In addition, this proposal leverages the existing Advanced Metering Infrastructure (smart meters) that customers paid billions of dollars to install. Part of the reasoning behind making the smart meter investment was for “Management of distributed energy resources” and to obtain “situational data in near real time.”[[41]](#footnote-41)

IOU Response:Please refer to Sections III.A.1 and III.A.2 from IOU Response that highlight the need for real time visibility to allow for operations decisions to be made. “Near” real time 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 Figure One – Load Masking, without telemetry the utility does not see the entire electrical load served on a circuit.

As discussed above, telemetry is not being proposed for all projects under this proposal, only for projects 250kW and above which for SCE represented only an additional 250 projects annually.

### Proposal 3: 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.

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 that limit export to 50 kW. 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

IOU Response*:* Please refer to Sections III.A.1 and III.A.2 from IOU Response that 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.

### Proposal 4: Telemetry should not be required for systems smaller than 10 MW if the All-In Cost would exceed $20,000.

The IOUs appear to agree for systems smaller than 1 MW but not for systems larger than 1 MW. The reason that non-utility stakeholders urged the Commission to address this issue in this proceeding is because the cost of telemetry for systems larger than 1 MW has been onerous in many cases. Controlling those costs is the largest issue under consideration.

IOU Response*:* As discussed within Section III.A.1, the IOU proposal for a reduced telemetry threshold would not be triggered unless the utility related estimated telemetry costs are less than or equal to $20,000 for up to 10MW.

### 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 (ITCC) and cost of ownership (COO) charges.

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.

IOU Response*:* 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 if customer ownership should be considered. If the developer does not timely service their owned equipment supporting telemetry, the IOUs reserve theright to repair at developer cost as discussed within the IOU proposal.

### Proposal 6: Utilities and DER providers should explore annual data reporting for systems smaller than 1 MWac.

Utilities use data from DERs for operational and planning purposes. Data for operational considerations may be needed in real time. Data for planning like the load masking issue could be reported in monthly or annual communications. In some cases where real time data is needed, sufficient data may be available from existing smart meters. See Appendix A for more on the different utility uses of DER data.

Non-utility stakeholders recognize that data from smaller systems would be beneficial for planning purposes, but the benefit does not support a cost of $20,000 per system. Utilities should develop a process for annual reporting.

IOU Response*:* This proposal does not address the need to have real time data to assist in real time grid operations which is the critical need addressed in this proposal. As discussed previously, having this requirement only applied up to 250kW projects does not require telemetry for all Rule 21 projects and represents an improvement for projects subject to the existing 1MW telemetry R21 threshold that is not tied to a cost estimate requirement.

## Issue 4 Appendices

### Appendix A. Operational and Distribution Planning Telemetry Uses

In accordance with Section C of Rule 21, telemetry refers to the technology that transmits generator or DER data to the utility. This information is provided on a real time basis primarily for operations related purposes as highlighted below:

1. **Temporary Connection** – In some cases, generators are granted permission to operate with operational conditions. Telemetry information is used to monitor the generator’s compliance and whether any reliability concerns may surface.
2. **Moving Load Between Electrical Circuits (“Switching”)** – Circuits a generator is tied into may need to be switched, which currently limits a DER’s operations. Telemetry information may facilitate the Distribution Provider’s allowance of a DER to remain operational in an abnormal configuration.
3. **Diagnostics** – In the event of an outage or system disturbance, telemetry information along with grid operational data can be analyzed to diagnose what may have triggered the event. Without telemetry, utility personnel may need to physically diagnose the situation.
4. **Planning** – With the growth of DERs, the difference between true load vs the net load is becoming a non-trivial amount. The utility needs to understand the amount of load that aggregate DERs on a feeder are serving or often termed as “masking” to plan for total load. A utility has an obligation to serve and in the event a DER is not available the utility must provide “standby service” to be able to serve the load that particular DER is offsetting.
5. **Automatic Reclosing/Restoration** – When an electric feeder experiences a disturbance, DERs on the feeder trip offline. Upon correction of the system disturbance, the line is re-energized but there typically is a delay before DERs come back online. During this time, the load the aggregate DERs were serving is no longer “masked.” The utility leverages telemetry data to plan and reserve capacity for this atypical scenario. The absence of this planning can lead to further system disturbances.
6. **Operation Switching** – For planned or unplanned maintenance work, feeders or line sections must be de-energized to allow work to be performed. Telemetry information is utilized to determine total load, including load that may be “masked” by local DERs, and determine if that load can be adequately served from a different source.

#### Non-utility stakeholders make the following observations on these use cases:

* Use cases 1 and 2 are optional to the customer. Telemetry could be required solely for customers utilizing these options.
  + IOU Response*: Without real time data, IOUs have to assume conservative planning values that diminishes the use of operational flexibility. The increase in DERs without telemetry further compounds this issue and could contribute to electrical restoration delays and reliability.*
* Use cases 4 and 5 can be achieved with monthly or annual data reporting rather than real time telemetry.
  + IOU Response*: Real time constant telemetry data from DERs supports grid operator decisions; monthly or annual data reporting will not support grid operator decisions*
* For use case 6, utilities likely use planning values rather than real time data when making decisions about switching operations.
  + IOU Response *See above response*

### Appendix B. Current Telemetry Requirements

**Table B-1. Summary of Telemetry Requirements**

|  | **SCE** | **SDG&E** | **PG&E** |
| --- | --- | --- | --- |
| **Physical Measurements Required**  1=Net facility load (e.g. net export)  2=Total generation output | **Current:**  For less than 10 MW only #2 required, #1 not required. | **Current:**  #2 only | **Current:**  Requires #1  **Under Consideration:**  Upon adoption of pending cheaper solution, will require #2 only (total generation output). |
| **Source of Measurements and Ownership of Measuring Equipment** | **Current:**  Source can be producer-owned data acquisition system. Does not need to be revenue grade equipment --e.g. Net Generation Output Meter (NGOM) not required. Customer data acquisition system and data logger can be connected via serial connection directly to Serial Device Server.  **Under Consideration:**  Plans to replace Serial Device Server with alternative, but serial connection from customer owned data logger will still be acceptable. | **Current:**  .   * Metering equipment (Meter, CTs, PTs): * Telemetering equipment (RTU, Modem): * Total (metering + telemetering)   **Under Consideration:**  Revenue grade not required; willing to explore lower cost alternative from customer data acquisition system (serial connection would be required). | **Current:**  Net facility load made via utility owned SCADA recloser. Because utility owned, cost basis of $80k is subject to 2.25x multiplier for COO & ITCC.  **Under Consideration:**  PG&E exploring approach comparable to SCE. PG&E willing to allow measurements from customer-owned data acquisition system. |
| **Required Sampling Rate** | **Current:**  SCE requires ~5s sampling rate, which requires a higher end data logger for customer data acquisition system, but is still cheaper incremental cost than requiring measurements be made with utility owned NGOM. | **Current:**  SDG&E requires ~3-4s sampling rate. This would require a higher end data logger for customer data acquisition system, but that would still be cheaper than requiring measurements to be made with utility-owned NGOM. | **Current:**  N/A currently since utility owned recloser is all-in-one solution. [PG&E to confirm approximate sampling/refresh rate for baseline?]  **Under Consideration:**  [PG&E to comment on what they are allowing in pilots] |
| **Bridging Connection –Measurement Source to Facility Terminal** | **Current:**  Hardwire RS-485 serial connection. | **Current:**  RS-485 connection from NGOM to RTU. | **Current:**  N/A since utility-owned recloser is connected directly to PG&E SCADA system.  **Under Consideration:**  [PG&E to comment on what they are allowing in pilots] |
| **Bridging Connection –Facility Terminal to Utility Energy Management System** | **Current:**  Serial Device Server (SDS) connected via Virtual Private Network (VPN) tunnel (dedicated internet connection at customer cost). Utility owned.  **Under Consideration:**  SCE exploring LTC cell modem approach due to issues with SDS/VPN approach. SCE consider customer ownership to eliminate COO & ITCC burden. | **Current:**  Higher cost Remote Terminal Unit (RTU). Primary requirement of concern is that alternative meets Critical Infrastructure Protection.  **Under Consideration:**  The below explanation highlights options under consideration | **Current:**  NA as data is transferred to PG&E EMS via PG&E operated SCADA system. Ongoing cost covered in COO.  **Under Consideration:**  [PG&E to comment on what they are allowing in pilots] |

# 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 working group process to address Issue 5.

* Proposal 1: Do not require activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017 or establish a voluntary program.
  + This is a consensus proposal.
* Proposal 2: Encourage, but do not require, replacing non-smart inverters with smart inverters when non-smart inverters fail.
  + This is a consensus proposal.
* Proposal 3: Modify Rule 21 to make replacement of non-smart inverters with smart inverters to be the default requirement when non-smart inverters fail.
  + This is a non-consensus proposal.
  + The IOUs do support.

## Background

The Commission initiated Rulemaking (R.) 11-09-011 on September 22, 2011 to review and, if necessary, revise the rules and regulations governing the interconnection of generation and storage facilities to the electric distribution systems of the investor-owned utilities (IOUs). The IOUs’ rules and regulations pertaining to the interconnection of generating facilities are set forth in Electric Tariff Rule 21 (Rule 21). A generating resource interconnecting to the utility’s distribution system via Rule 21, which produce direct current (DC) power require an inverter to convert the DC from the generating resource to the voltage and frequency of the alternating current (AC) 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. 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.

On December 22, 2014, the Commission issued Decision (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.

On July 13, 2017, the Commission initiated R.17-07-007 in order to consider refinements to the interconnection of distributed energy resources (DERs) under Rule 21, a successor proceeding to R.11-09-011. On October 2, 2017, the Commission circulated the Scoping Memo for the proceeding which established the issues including Issue 5. The [Scoping Memo](http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M196/K476/196476255.PDF) assigned the Smart Inverter Working Group to develop a final report for recommending proposals to address Issue 5.

## Working Group Findings

### Inventory of Inverters

The Working Group spent considerable effort to determine what portion of existing inverters could be updated with advanced inverter functionality. Three scenarios were considered:

* **Scenario 1**: All seven Phase 1 functions can be updated remotely via software update to inverters that already have firmware that is certified in compliance with Underwriters Laboratory 1741 Supplemental A;

**Scenario 2**: All seven Phase 1 functions can be updated remotely, but require a firmware update that would not be certified; and

**Scenario 3:** Systems larger than 500 kW for which all seven Phase 1 functions can be updated with a site visit and the firmware update would be certified.

A fourth scenario was discussed but not quantified, in which inverters could get updated to have some but not all of the Phase 1 functions.

A survey was sent to the SIWG mailing list to assist with quantifying the amount of inverters and nameplate capacity for each of the three scenarios and for each of the three utilities. 8 inverter companies responded, representing roughly 81% of market share. The results from the inverter companies who responded are shown in Table 1. Only 1% - 5% of inverter capacity can be updated.

**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)** |
| **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 Associated with Each Group

Non-IOU stakeholders represented that the cost of updating inverters remotely (Scenario 1 and 2) is approximately $1-2/kW. This includes the time to engineer the update, the cost of data bandwidth, and the time of troubleshooting problems.

In addition, non-IOU stakeholder representatives stated that the cost of updating inverters onsite (Scenario 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. Non-IOU stakeholders provide an example, if the minimum amount that would begin to be interesting to a customer with a small rooftop system is a one-time payment or credit of $10, this equates to approximately $2/kW (assuming a 5 kW system).

### 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:

1. Parties to CPUC-jurisdictional interconnection agreements must comply with Rule 21 and the Commission retains jurisdiction of its form agreements.

See for example the following provisions in SCE’s Form 14-731 (Non-Exporting Generating Facility Interconnection Agreement) that is representative of provisions in the IOUs’ pro forma agreements:

* + Section 5.1: “Producer is responsible for operating the Generating Facility in compliance with all SCE’s tariffs, including but not limited to SCE’s Rule 21, and any other regulations and laws governing the Interconnection of the Generating Facility.”
  + Section 13.2: “13.2 This Agreement shall, at all times, be subject to such changes or modifications by the Commission as it may from time to time direct in the exercise of its jurisdiction.”[[42]](#footnote-42)

1. Absent Commission action as described in #1, 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

### Proposal 1: Do not require activation of advanced functionality in Phase 1-compliant inverters installed before September 9, 2017 or establish a voluntary program.

#### Summary

A program to require systems to update to all seven Phase 1 functions is not justified because there is a small percentage of systems which could be updated.

#### Status

Consensus.

#### Discussion

The Working Group agrees that while Phase 1 functions are beneficial, it does not outweigh the costs and efforts to implement a program that either (1) mandates or (2) offers a voluntary program to activate Phase 1 functions in existing inverters. In particular, the low number of inverters that were identified through data requests discussed previously, highlights that the money and time required to implement a supporting retrofit program would not yield worthwhile results.

### Proposal 2: Encourage, but do not require, replacing non-smart inverters with smart inverters when non-smart inverters fail.

#### Summary

Encourage replacement of existing inverters with Smart Inverters but maintain language in Rule 21 Section Hh.

#### Status

Consensus, IOUs prefer Proposal 3 but support Proposal 2.

#### Discussion

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

Rule 21 requires all newly installed solar systems 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, if a full replacement is required instead of only a firmware update.

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 Working Group 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 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;
* The National Electric Code 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.

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

IOU Working Group 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.

### Proposal 3: Modify Rule 21 to make replacement of non-smart inverters with smart inverters to be the default requirement when non-smart inverters fail.

#### 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;
* The National Electric Code 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, IOUs prefer Proposal 3.

#### Discussion

IOU Working Group 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 to modify Rule 21 and propose that the Commission to 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 versus a program to retroactively update existing inverters with Phase 1 functionality. It would also 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.

# 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.

# 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. None have consensus support.

* Proposal 1 - Status Quo: remain in the status quo, which is consistent with CPUC Decisions 87-09-026 and 94-06-038, and where each IOU is authorized and retains the discretion pursuant to CPUC rules to collect or not collect ITCC security on safe harbor projects.
  + All the IOUs support Proposal 1 as the preferred practice on the issue of ITCC security.
* Proposal 2 - All Collect: 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 stakeholders.
  + All the IOUs support Proposal 2, if Proposal 1 is not available.
* Proposal 3 – Modify D94-06-038 to prohibit collection of ITCC security and authorize a recovery mechanism:

This proposal is (a) Modify D94-06-038 to prohibit collection of ITCC security and (b) authorize a recovery mechanism.

* + Non-utility stakeholders propose that all IOUs stop collecting ITCC security and the CPUC authorize a recovery mechanism, which is borne by ratepayers, to make the IOUs whole should projects lose its safe harbor eligibility status and ultimately be subject to a tax liability not covered by the generator (contributor).
* The IOUs prefer to have the option to protect against a potential tax liability as the best practice. The IOUs note that they 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 an option for cost recovery if a utility cannot recover costs incurred from contributors.
  + However, 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 IOU s also note that because this proposal would have an impact on customer rates, if the Commission wishes to support this proposal, then the Commission should move the proposal to Phase 2 (the resetting track of this proceeding) for further evaluation.
* Proposal 4 – Expand Scope of this issue:
  + …

## 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 or advancer based on the premise that the person who causes the tax pays the tax. D. 87-09-026 provides the IOUs method for collecting ITCC.

ITCC is not applicable when a transaction is considered nontaxable. In the 1980s, after extensive lobbying efforts by the qualified generator (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 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, a change in tax law, or early termination of 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 any of the required conditions 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 for ITCC.

The Commission, recognizing that the IOUs were exposed to tax risk for these projects availing itself 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.[[43]](#footnote-43) The decision to collect ITCC security is subject to IOU discretion and was provided as a means for the IOU to protect IOUs 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. 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.

It should be noted that the December 2017 tax reform legislation amended by Section 118 to expand transactions that are taxable income 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 has the potential that the underlying court cases, which have been previously relied upon by the IOUs to exempt contributions from taxable income on the basis of the safe harbor, could now be in jeopardy. Therefore, the implications of the recent tax reform legislation could impact the safe harbor and due to its recent passage, there has not been adequate time for the industry to fully analyze or understand potential ramifications.

### Applicability to the OIR

The IOUs interpret the Safe Harbor provisions as applying to In-Front-of-the-Meter (IFOM) generators that are either Qualifying Facilities (under CPUC jurisdiction) or wholesale generators selling to third parties, including the host utility or the CAISO market (under FERC jurisdiction). Generally, the IOUs perform an assessment of the tax risk related to a project requesting and receiving safe harbor status, and may require a generator or customer (i.e. contributor) to provide ITCC security or an indemnity to guard against a future potential tax liability, should the project lose its safe harbor eligibility status. The ITCC security requirement imposes a financial obligation on the generator, the carrying costs associated with posting a letter of credit for a potential tax liability.

Additionally, based on recent data responses, 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, 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. Thus, the tax exposure remains related to the safe harbor projects.

### 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[[44]](#footnote-44)
* Ownership of the electricity wheeled over IOU transmission system remains with the generator prior to its transmission onto the grid[[45]](#footnote-45)
* The intertie will be used for transmitting electricity,[[46]](#footnote-46) 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.[[47]](#footnote-47)

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.
* 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 project developer (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.

SEMPRA’s Application of ITCC to Rule 21 Transactions:

* SEMPRA acknowledges the general concepts and principles of D.94-06-038 in its Rule 21 transactions.
* SEMPRA does not treat CIAC from IFOM generators as taxable and currently does not collect any tax-related ITCC security.

### Stakeholder Concerns

ITCC security, when required, can add roughly 30%[[48]](#footnote-48) to the cost of upgrades associated with an interconnection request if cash is the method selected (Letters of Credit and Corporate Parent Guarantees are also acceptable methods to meet security requirements). As SCE territory’s average total in-front-of-the-meter upgrade costs are approximately $150,000 per MW[[49]](#footnote-49), these charges represent the second largest contributor to interconnection costs, despite the de minimis risk of actual liability being imposed.

Posting ITCC security represents a real cost to developers, depriving them of capital necessary to develop the project. 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 a risk that most likely will never arise. Given the limited risk to the utility and real cost to developer, and subsequent advice or rulings from IRS and FERC, 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 Utilities to protect itself from a potential tax liability. The IOUs support the advancement of cost-effective renewable generation but cannot ignore the risk of a potential tax liability given the likelihood of changes to IRS requirements 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. We are aware of no contribution under an interconnection agreement that has caused a distribution owner to incur an income tax liability. The risk of 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 necessarily impedes 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.

### Current Status

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 $2.4 million . The scope of the data request did not include safe harbor eligible applications under FERC jurisdiction.

## Working Group Proposals

### Proposal 1: For “Safe Harbor” systems, the Commission should continue to authorize the IOUs to protect against potential tax liability under the options provided in D 94-06-038 (Remain Status Quo)

#### 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] SCE, PG&E and SDG&E support.

#### Discussion:

##### IOU Discussion:

This is the IOU preferred proposal. The IOUs are responsible for its risk and managing its risk. The 1987 and 1994 Decisions authorizes the IOUs to protect itself and ratepayers from potential tax liability and hold the contributor responsible. Absent the contributor, there would be no potential tax liability 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 be permitted discretion to protect itself.

### Proposal 2: For “Safe Harbor” systems, the Commission should require the IOUs to protect against potential tax liability consistently by collecting security (All Collect)

#### Summary

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

#### Status

[Non-Consensus] SCE, PG&E and SDG&E support this proposal but prefer Proposal 1.

#### Discussion

##### IOU 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 within each IOU’s risk tolerance levels.

### Proposal 3: For “Safe Harbor” systems, the Commission should modify D.94-06-038 to prohibit the collection of security and authorize a recovery mechanism, whereby each utility recovers from ratepayers any actual costs realized as a result of ITCC charges

#### Summary

##### Clean Coalition Version of 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 Investor Owned Utility (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:
     + “Safe Harbor” eligibility is ruled inapplicable by the tax authority, and
     + 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.
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.
   * The Director may take this action upon its own initiative or as an interim response pending a ruling on a Petition for Modification.
   * 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 $x [$500,000? -- equal to 20% of current security postings]

##### IOU Version of Summary:

Collection of security would be prohibited. Should the Interconnection Customer's project fail the IRS Notice 2016-36 safe harbor requirements thereby triggering a tax liability that is incurred by the IOU and the Interconnection Customer (contributor) is unable to remit payment for the tax liability, the IOU would be exposed to a loss. Therefore, permitting the IOU to establish a security requirement that covers the potential cost consequence of any current tax liability is appropriate.

This proposal is for the Commission to:

1. Modify its prior decision D94-06-038 that authorizes three options for the IOU to select to protect against potential tax liability to not allowing the collection of security
2. Establish a recovery mechanism to recover prudently incurred costs

Under this proposal, IOUs would not collect a security from eligible contributors. If the interconnection fails the IRS Notice 2016-36 safe harbor requirements, a taxable event is triggered whereby the contributor is required to remit payment to the IOU for taxes incurred. In the event the contributor is unable to remit payment, the IOUs would recover its actual costs incurred through customer rates. Utilization of the recovery mechanism and recovery through customer rates shall only occur when both:

1. “Safe Harbor” eligibility is found inapplicable either by the IOU or tax authority, and
2. Such costs are found to be uncollectable by the IOU from the responsible party.
   * The Energy Division should be given responsibility to monitor the cost recovery mechanism. If an IOU’s cost recovery mechanism exceeds [XX] costs, the prohibition on security collection is automatically ended and the IOU may collect security on a going forward basis.

#### Status

[Non-Consensus] SCE, PG&E and SDG&E oppose.

#### Discussion

##### Clean Coalition 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; 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 ITCC 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 delinquency under the applicable interconnection agreements.

Estimated energy price impact for applicable interconnection is 1%. Prior data requests have indicated average interconnection upgrade costs of $150,000 per MW, 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, with an ITCC potential liability of 20% of the value of the upgrades, security posting will equal 2% to the project cost. 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.

##### IOU Discussion:

The IOUs object to modification of D94-06-038. 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.

The IOUs must be permitted to recovery reasonably incurred interconnection costs. Should the Commission decide to prohibits 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.

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

### Proposal 4: The Commission should amend the scope of R.17-07-007 to consider whether there are ITCC practices which merit modification in conformance with IRS rules despite being consistent across utilities, and if so, how they should be modified

#### Summary

The scope of R.17-07-007 should be expanded to consider whether there are ITCC practices which merit modification in conformance with IRS rules despite being consistent across utilities, and if so, how they 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. CalSEIA, ORA, GPI, Foundation Wind Power, Tesla, Borego Solar, Chico Electric, CalCom Solar, and Sunworks have indicated by email support in concept. SCE, PG&E and SDG&E oppose.

#### Supporting Stakeholder 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.
    - IOU Response: Utilities do not agree with this interpretation of the Notice and request specific language in IRS codes for IOU review and discussion.
  + The WG has identified a need for the Commission to facilitate clarification regarding Safe Harbor applicability to aggregated net energy metering (NEMA) projects, which often have a no-load POI that is a new service, and similar facilities not selling energy to the host utility.
    - IOU Response: Utilities do not agree with this interpretation and request specific language in IRS codes for IOU review and discussion.
* 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.

#### Utility Discussion

##### IRS Safe Harbor rules application to behind the meter interconnections:

* The IOUs collectively are indifferent towards the expansion of Issue 7 in this OIR to include approaching the IRS to gain clarification on whether behind-the-meter (BTM) projects are eligible for safe harbor. However, the IOUs believe expansion is unnecessary. 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.
  + 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 support their position.
* Additionally, the IOUs wish to clarify that the Commission cannot order the IOUs to interpret the tax rules in a certain manner. The application and interpretation of the internal revenue code, regulations, rulings, and other authorities is not within the jurisdiction of the CPUC to dictate. .
  + Furthermore, the IOUs wish to reiterate that stakeholders should lead the effort to pursue their desired change in tax policy 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 the developer as it develops its request for a PLR.

##### Changes in ownership structure of Interconnection Facilities and Distribution Upgrades:

* The IOUs strongly oppose this proposal’s attempt to fundamentally alter the ownership and operation of the distribution system. It is unsound policy, with serious safety implications.
  + The IOUs have a statutory obligation to own and control their respective distribution systems. *See*  Pub. Utils. Code Section 399.2.
  + Generally, the reason why CIACs are provided to the IOUs in the first place is because the IOUs are in the best position to perform the construction of these specially requested projects (e.g. interties, mainline extensions, etc).
  + The IOUs possess the technical expertise, knowledge, and resources to complete the work safely and are capable of considering the broader implications of the immediate project, due to their oversight of the entire system and specialization in operating the grid.
  + 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 are in the must own, operate and maintain these assets to ensure system reliability and safety for all of its customers.
* Stakeholders are proposing to compromise system safety and reliability simply to permit an Interconnection Customer to evade a tax obligation. Critically, however, neither of 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. 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.
* Stakeholders are proposing to compromise system safety and reliability simply to evade tax liability and, as mentioned above, it is unlikely their proposed transfer of ownership would permit them to avoid the tax liability even if adopted.
* 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 would be sacrificed is system oversight over the entire grid, which poses many serious concerns and constitutes bad policy. 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 operate the grid to another party, even if the other party wishes to assume that responsibility. Ultimately, the IOUs are mandated with ensuring the safety of the system and therefore are heavily regulated to ensure that this occurs. Therefore, for the sake of safety and system reliability, the IOUs should be the party that owns and operates these CIAC special projects 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. Allowing this proposal would constitute bad policy and undermine the CPUC’s power to regulate the operation of the electrical grid.
* Therefore, for the reasons discussed above, the IOUs strongly oppose this proposal for customers to retain ownership, at the expense of safety, of assets solely to avoid ITCC.

##### Converting system upgrade cost recovery from actual costs to fees:

* 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.

#### 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 BTM 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 above, 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.

# Appendix

## Acronyms

* CALSSA: California Solar and Storage Association
* CPUC or Commission: California Public Utilities Commission
* DER: Distributed Energy Resources
* GPI: Green Power Institute
* ICA: Integration Capacity Analysis
* IOU: Investor Owned Utilities
* PG&E: Pacific Gas & Electric
* SCE: Southern California Edison
* SDG&E: San Diego Gas and Electric
* WG: working group

## Working Group Participants

The following stakeholder groups attended at least one meeting of the working group:

* + CALSSA
  + Clean Coalition
  + IREC
  + ORA
  + PG&E
  + SCE
  + SDG&E
  + CESA
  + TURN
  + GPI
  + Tesla
  + Bosch
  + CalCom
  + JKB Energy
  + Chico Electric
  + Enphase
  + SunWorks
  + SunPower
  + …

## 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  9:30 a.m. - 12:00 p.m.  *teleconference* | Determine process for editing final report  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 |

## Working Group Materials

The Working Group One Work Plan, which outlines a process and schedule for completing the report, may 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 may be found on the California Solar and Storage Association (CalSSA) webpage at [www.calssa.org/rule21workinggroup](http://www.calssa.org/rule21workinggroup).

1. R.17-07-007 Scoping Ruling, October 2, 2017. (http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M196/K476/196476255.PDF) [↑](#footnote-ref-1)
2. Email Ruling Revising Schedule and Reassigning Issue Six, February 14, 2018. (Hyperlink TBD) [↑](#footnote-ref-2)
3. The working group spent seven meetings on Issue 3; it requested and received a one-month extension to complete a proposal addressing material modifications to both pending applications and existing facilities. [↑](#footnote-ref-3)
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. [↑](#footnote-ref-4)
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. [↑](#footnote-ref-5)
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. [↑](#footnote-ref-6)
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. [↑](#footnote-ref-7)
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. [↑](#footnote-ref-8)
9. Specific language is from PG&E’s Rule 21. Edits to Rule 21 for other IOUs may differ. [↑](#footnote-ref-9)
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. [↑](#footnote-ref-10)
11. PG&E Advice 5129-E. [↑](#footnote-ref-11)
12. These tests are defined in Section 4.2 of Appendix DD of the CAISO Tariff. [↑](#footnote-ref-12)
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.” [↑](#footnote-ref-13)
14. Similarly, SCE defines 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. [↑](#footnote-ref-14)
15. PG&E definition of complex meter is identical to SCE’s definition. [↑](#footnote-ref-15)
16. Appendix A provides more detail on why metering solutions are not available to DC-coupled systems. [↑](#footnote-ref-16)
17. Costs incurred by the interconnection customer, e.g., the meter enclosure, are not represented. [↑](#footnote-ref-17)
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. [↑](#footnote-ref-18)
19. The non-export relay (or non-export control) would be installed to monitor the main meter side. 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). [↑](#footnote-ref-19)
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. [↑](#footnote-ref-20)
21. CALSEIA notes that the other use case in its petition, maintaining NEM integrity via solar-only charging, will likely still be the preferred option for most customers seeking to install DC-coupled solar and storage systems, but that is not under consideration in this proceeding. [↑](#footnote-ref-21)
22. [↑](#footnote-ref-22)
23. Per the definition of Interconnection Request in Section C of 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.”* (emphasis added) [↑](#footnote-ref-23)
24. See Appendix A 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)). [↑](#footnote-ref-24)
25. See Appendix A for all relevant Rule 21 language addressing Fast Track modifications. [↑](#footnote-ref-25)
26. After the conclusion of the Fast Track Initial Review process, the existing Rule 21 tariff does allow discussion of modifications in accordance with Section F.2.b (Optional Initial Review Results Meeting). [↑](#footnote-ref-26)
27. See Appendix B [↑](#footnote-ref-27)
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, and same operating profile. For transformers, like for like means same connection type, same or smaller impedance and capacity. [↑](#footnote-ref-28)
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, the limiting factor is determined by both the inverter nameplate capacity (kW) and the capacity of the storage device (kWh). For all other generation types, the limiting factor is the gross nameplate rating of the generator. [↑](#footnote-ref-29)
30. Contingent on Commission direction on Proposal 2 [↑](#footnote-ref-30)
31. Customers need to show the annual degradation factor on a manufacturer spec sheet if they wish to use a degradation factor. [↑](#footnote-ref-31)
32. Contingent on Commission direction on Proposal 2 [↑](#footnote-ref-32)
33. <https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf> [↑](#footnote-ref-33)
34. (Page 6) <https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/GuidetoEnergyStorageChargingIssues.pdf> [↑](#footnote-ref-34)
35. A reduction in telemetry requirements to 250kW is consistent with SCE’s General Rate Case request related to infrastructure for increased monitoring and automation of the grid. Telemetry remains necessary for adequate visibility of individual DERs to maintain operational awareness and to safely and reliably operate the distribution system. If SCE’s 2018 General Rate Case request relating to its Field Area Network (FAN) is approved, then – once the FAN is established – the FAN communication system will replace existing communication systems for DERs greater than 100 kW. However, regardless of the communication system, SCE will need the Distributed Energy Resource to provide real-time transmittal of telemetry to SCE across that system. [↑](#footnote-ref-35)
36. Generating Facility Nameplate Rating Capacity: The net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple Generators. [↑](#footnote-ref-36)
37. [↑](#footnote-ref-37)
38. 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. [↑](#footnote-ref-38)
39. In all cases, customer will incur costs to purchase and install metering section equipment. [↑](#footnote-ref-39)
40. As discussed within Working Group discussions, discussions remain underway in support of Smart Inverter Working Group, including forms and agreements that would address aggregator or aggregator akin use in support of Smart Inverter capabilities. This discussion is slated for additional discussion within Working Group Two. For purposes of this proposal, refined telemetry solutions have been focused upon and their associated cost. [↑](#footnote-ref-40)
41. SCE, “AMI Overview and Metering Framework,” May 2, 2006. [↑](#footnote-ref-41)
42. Language like this is required by GO 96-B, Energy Industry Rule 6.3. [↑](#footnote-ref-42)
43. 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. [↑](#footnote-ref-43)
44. Section III.C.1.a. of IRS Notice 2016-36 [↑](#footnote-ref-44)
45. Section III.C.2. of IRS Notice 2016-36 [↑](#footnote-ref-45)
46. Section III.C.4. of IRS Notice 2016-36 [↑](#footnote-ref-46)
47. Section III.C.5. of IRS Notice 2016-36 [↑](#footnote-ref-47)
48. cite [↑](#footnote-ref-48)
49. This figure is from the Clean Coalition data request and reflects interconnections prior to 2013. Confidential quarterly interconnection cost reports from the IOUs were subsequently initiated and available to Commission staff. [↑](#footnote-ref-49)