ISSUE 8 PROPOSAL

Issue 8 Question: How should the Commission incorporate the results of the Integration Capacity Analysis into Rule 21 to inform interconnection siting decisions, streamline the Fast Track process for projects that are proposed below the integration capacity at a particular point on the system, and facilitate interconnection process automation?

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Proposal Summary

Issue 8 Question: How should the Commission incorporate the results of the Integration Capacity Analysis into Rule 21 to inform interconnection siting decisions, streamline the Fast Track process for projects that are proposed below the integration capacity at a particular point on the system, and facilitate interconnection process automation?

The following proposals were developed by stakeholders as part of the Working Group process to address Issue 8. Where a stakeholder's position is partial or qualified, it is labeled "qualified" and additional explanation is provided in subsequent sections where the proposal is detailed. If stakeholders' positions are not specifically noted, they neither "support" nor "oppose."

Proposals to modify the Rule 21 process include:

- **Proposal 8.a:** Remove Existing Fast Track Eligibility Limit
    - Consensus

- **Proposal 8.b:** Modification of Initial Review Process to Include Verification and Explanation of Updated ICA
    - Non-consensus
        - Supported by PG&E, SCE, SDG&E, IREC (qualified), Public Advocates Office (qualified), GPI, TURN, Clean Coalition (qualified), CALSSA (qualified)

- **Proposal 8.c:** Track When ICA Values are Updated Outside of the Required Monthly Update to Inform Future ICA Discussions
    - Non-consensus
        - Supported by SCE, SDG&E, IREC, Public Advocates Office (qualified), GPI, TURN, Clean Coalition, CALSSA
        - Opposed by PG&E

- **Proposal 8.d**: Modification of Projects if ICA Values are Out-of-Date to Stay Under ICA Limit and Maintain Queue Position
    - Non-consensus
        - Supported by CALSSA, GPI, Clean Coalition
        - Opposed by PG&E, SCE, SDG&E, TURN

- **Proposal 8.f1**: Adopt Additional Initial Review Screen F1
    - Consensus

- **Proposals 8.f, 8.g, 8.h, and 8.j**: Apply Screen F, G, H and J only to Projects Larger than 30 kVA; Provide Earliest Available Indication where Screen F and G Failure is Likely
    - Modification 1: Consensus
    - Modification 2: Non-consensus
        - Supported by PG&E (qualified), SDG&E (qualified), IREC (qualified), Public Advocates Office (qualified), CALSSA (qualified), GPI (qualified), Clean Coalition
        - Opposed by: SCE

- **Proposal 8.i:** Consider Applicability of Screen I for Non-exporting Projects Above 30kVA
    - Non-consensus
        - Option A:
            - Supported by PG&E, SCE, SDG&E, TURN
            - Opposed by IREC, Clean Coalition, CALSSA, Stem, GPI, Public Advocates Office
        - Option B:
            - Supported by CALSSA, IREC, GPI, Clean Coalition, Stem, Public Advocates Office
            - Opposed by PG&E, SCE, SDG&E, TURN

- **Proposal 8.k:** Modify Screen L to Include the Transmission Overvoltage and Transmission Anti-islanding Test
    - Non-consensus
        - Option A:
            - Supported by PG&E, SCE, SDG&E
            - Opposed by TURN, CALSSA
        - Option B:
            - Supported by CALSSA
            - Opposed by PG&E, SCE, SDG&E
        - Option C:
            - Supported by IREC, GPI, Clean Coalition
            - Opposed by PG&E, SCE, SDG&E

- **Proposal 8.l**: Provide Earliest Available Indication where Screen L Failure is Likely
    - Non-consensus
        - Supported by PG&E, TURN, Clean Coalition, GPI, IREC
        - Opposed by: SCE, SDG&E

- **Proposal 8.m:** Screen M should be modified to reflect ICA
    - Non-consensus
        - Option A:
            - Supported by PG&E, SCE, SDG&E, TURN
            - Opposed by IREC, GPI, Stem, Clean Coalition, Tesla, Sunrun, CALSSA, Public Advocates Office
        - Option B:
            - Supported by IREC, GPI, Stem, Clean Coalition, Tesla, Sunrun, CALSSA, Public Advocates Office
            - Opposed by PG&E, SCE, SDG&E, TURN
        - Options A or B:
            - Implementation Variation 1
                - Supported by Clean Coalition, IREC, CALSSA, SCE (qualified)
                - Opposed by SDG&E, PG&E
            - Implementation Variation 2
                - Supported by Clean Coalition, IREC, PG&E (qualified), SCE (qualified), CALSSA, SDG&E (qualified)

- **Proposal 8.n:** Update Screen N Methodology
    - Non-consensus
        - Supported by PG&E, SDG&E, SCE (qualified), IREC, Public Advocates Office (qualified), GPI, Clean Coalition, TURN

- **Proposal 8.q:** Modify Screen P
    - Consensus

- **Proposal 8.r:** The Interconnection Application Should have an Option to Combine Initial Review and Supplemental Review, With Applicants Pre-Paying for Initial Review and Supplemental Review
    - Consensus

- **Proposal 8.s:** Reduce interconnection application fee for non-NEM systems
    - Non-consensus
        - Supported by CALSSA, GPI, Clean Coalition (qualified)
        - Opposed by PG&E, SCE, SDG&E, TURN

- **Proposal 8.t:** Queue management
    - Non-consensus
        - Option A:

        - Supported by CALSSA, IREC, Clean Coalition (qualified)
        - Opposed by PG&E, SCE, SDG&E, GPI, TURN
    - Option B:
        - Supported by GPI, Tesla

- **Proposal 8.v:** Additional Automation and Streamlining Opportunities Proposal
    - Non-consensus
        - Supported by GPI, Clean Coalition, Stem
        - Opposed by PG&E, SCE, SDG&E, TURN

Background

Integration Capacity Analysis ("ICA") was developed under the Distribution Resources Plan ("DRP") proceeding (R.14-08-013) of the California Public Utilities Commission ("CPUC"). CPUC Decision ("D.") 17-09-026 adopted the use of ICA for online maps, interconnection streamlining and automation, and distribution planning, and the CPUC authorized system-wide implementation of ICA across the utilities' territories. This Decision reiterated that one of the key purposes of the DRP is to dramatically streamline the interconnection process and that ICA results can help customers design distributed energy resources ("DER") systems by providing accurate information about the amount of DER capacity that can be interconnected at specific locations without significant distribution system upgrades or study.[1]

ICA and Interconnection Overview

ICA provides information on the distribution system's hosting capacity, helping to inform interconnection applicants on project siting and sizing. This information is based on analyses of grid conditions accounting for thermal limitations of distribution components, voltage levels, power quality limits, protection, and safety requirements. The Distribution Resources Plan Working Group report described its expectations for using ICA to support interconnection as follows[2]:

> *Developers should be able to submit a Rule 21 Fast Track application for DER interconnection up to the identified ICA value at the proposed point of interconnection, based on ICA figures shown on the map, changes in queued DER since the last map update and the underlying data, and be able to pass those Screens representing criteria the ICA has evaluated…*
>
> *The ICA values identified at a point of interconnection are expected to replace and/or supplement the size limitations in the Fast Track eligibility criteria and will be able to*

[1] D.17-09-026, p. 27.

[2] ICA Working Group Final Report, p. 8-9 (https://drpWorking Group.org/wp-content/uploads/2016/07/ICA-Working Group-Final-Report.pdf)

> *address and/or improve the technical Screens in the Rule 21 Fast Track process which are part of the ICA methodology…. With few exceptions, interconnection customers should be able to use the ICA value at their point of interconnection to know whether a proposed project will pass these Screens in the Fast Track process. In the near-term, there will be additional Screens that still need to be evaluated due to data not currently analyzed in the ICA.*

D.17-09-026 further specified how ICA should be implemented and the specifics of the methodology that should be used but identified Rule 21 as the proceeding to decide how ICA can be incorporated into the Rule 21 tariff. The R.17-07-007 Scoping Memo identified three Phases of the proceeding and scoped issues to be addressed by various Working Groups. Working Group Two is tasked with discussing ICA and streamlining interconnection issues (Issues 8-11).

Threshold Considerations

The Working Group spent much of its effort identifying and developing consensus proposals and exploring issues where consensus may exist. Where consensus could not be reached many parties have offered proactive solutions for the Commission's consideration. In identifying changes to the Rule 21 tariff, members of the Working Group also identified where there are "threshold considerations" to adopting the recommended changes. These threshold considerations include 1) cost considerations, 2) implementation dependencies and 3) ICA validation.

Cost Considerations

The Working Group discussed whether and how to consider the costs of implementing proposals suggested here. While all proposals will come with some expenditure of resources to implement, the question of costs has been of particular concern for certain proposals. First, the question of cost comes up in Proposals 8.f, 8.g, and 8.l, in which some Working Group members propose the utilities present information related to the likelihood that interconnecting generators could pass Screens F, G, and L. Second, the question of cost comes up in Proposal 8.v, concerning additional automation and streamlining opportunities. As noted throughout, numerous stakeholders qualify their support for proposals on the reasonableness of the costs of implementing them.

The Working Group discussed the potential costs and benefits of each proposal, but did not reach consensus on how to handle determinations of whether potential costs are reasonable. Some proposals include a specified recommendation on how the Commission might consider cost implications, while others do not. As such, the Working Group requests guidance from the Commission on how it can best support the Commission's consideration of potential costs, benefits, and determinations of reasonableness.

Implementation Dependencies

New tools and processes will be needed to implement the Proposals herein. Those include:

1. Tool or process to efficiently reference the ICA values
2. Tool or process to efficiently update the ICA value during the interconnection application review (see Proposal 8.b)
3. Tools to reference external information (e.g., the National Renewable Energy Laboratory's PV watts) for processing of operational profiles
4. Processes related to new interconnection process flow (applications, forms)

This report recognizes the need for these tools and processes to be operational to implement these proposals. Implementation details of readying these tools and processes were beyond the scope of this Working Group report.

Proposed ICA Validation Study

Given the complexity of ICA and that ICA modeling is new, the IOUs are conducting quality control and assurance efforts to ensure the results of the analysis can be used in the ways proposed herein. The Working Group recognized that the quality of the data is essential for expanding the interconnection process while still maintaining safety and reliability of the system. The Utilities will conduct quality control and validation of data prior to the implementation of these proposals. In the event that significant issues are found in the verification process, the utilities will propose a plan to solve issues and will submit a request to the Commission for new implementation dates.

Proposal Summaries

Proposal 8.a: Remove Existing Fast Track Size Eligibility Limit

Proposal

Remove the existing Fast Track Eligibility Size Limits in Rule 21 E.2.b.i Fast Track Eligibility.

Status

Consensus

Discussion

Fast Track evaluation allows for rapid review of certain projects to interconnect without Detailed Study. Fast Track is comprised of an Initial Review and, if required, a Supplemental Review. Because a project's size has been a primary indicator of whether it is likely to be approved for interconnection under Fast Track, eligibility for Fast Track review currently is dependent on the project's size. PG&E and SCE currently use a 3 MW size limit to determine Fast Track eligibility, while SDG&E uses a 1.5 MW size limit.

The ICA provides an estimation about what size project can likely be interconnected at a specific point in a circuit without requiring distribution upgrades. In addition, in some cases projects that are proposed above the ICA limit may be able to be interconnected without study after Supplemental Review is conducted if minor upgrades or system changes are possible to address the limitation. Thus, this proposal will allow any applicant to select Fast Track as their preferred study track regardless of the size of their project.

All Working Group members supported the elimination of Fast Track Eligibility Limits. Three caveats to this proposal were emphasized by the Working Group.

- First, the ICA only evaluated certain technical criteria, and thus even projects that are below the ICA may still be required to go to Supplemental Review or Detailed Study even if they fail the other Screens not evaluated by the ICA.
- Second, elimination of the Fast Track eligibility limit does not increase an interconnecting generator's chances of passing through Initial or Supplemental Review if the project is sized above the ICA. Applicants are therefore encouraged to reference the ICA in determining their preferred study track.
- Third, net-energy metering ("NEM") projects under 30kVA are currently processed as Fast Track projects. The Working Group recommends this practice continue, regardless of the ICA.

Proposal 8.b: Modification of Initial Review Process to Include Verification and Explanation of Updated ICA

Proposal

The IOUs will modify their Initial Review processes to incorporate an additional run of the specific node/feeder ICA where updated ICA values may be required. The IOUs will provide an interconnecting generator with an explanation of the update if necessary. Different approaches to implementing this proposal are suggested by different IOUs. If needed, the update will be completed within the Initial Review timeframe. The IOUs will implement this proposal as part of their review under Screen M.

Status

Non-consensus

- Supported by PG&E, SCE, SDG&E, IREC (qualified), Public Advocates Office (qualified), GPI, TURN, Clean Coalition (qualified)

Discussion

Per implementation requirements from D.17-09-026, the ICA is currently updated on a monthly basis on circuits where significant system changes have occurred and those monthly updates are reflected in the ICA maps and public data portals. The Working Group noted that this frequency of updates means that sometimes Interconnection Requests could be sized based upon ICA values that are not up-to-date; that is, the ICA values reflected on the public data portal and online map may not reflect changes which have occurred in the grid (e.g., circuit reconfigurations, load changes, equipment changes, etc.) or changes in the interconnection queue (e.g., new interconnection applications and/or withdrawals) since the ICA was last run.

The following are examples of why the ICA values may have changed from the latest monthly update:

- Significant amount of DER on a distribution circuit: While not all DERs will trigger a verification of ICA values, larger single DER installations and the aggregation of small residential DERs will cause the need to validate the ICA value.
- Permanent distribution system modifications: These types of modifications are needed as part of daily grid operations in order to balance loading on circuits or substations.
- Significant modification in load: When it is known that a significant increase or loss in load (e.g., a factory closing) will occur.
- Upgrades to the grid: Such as upgrades in conductor size or installation of protection devices.
- New distribution system energized: Such energizing new housing tracks or new commercial services.
- Modification to existing device parameters: Changes to relay settings and changes to voltage regulation settings.

Each of the IOUs have proposed a different process for how they will verify whether the ICA values need to be updated. These are the two IOU proposals with stakeholder modifications or objections noted below each:

- SCE and SDG&E propose to use the Initial Review process to determine if the ICA values at the proposed Point of Interconnection ("POI") need to be updated. If it is determined that the ICA values at the POI need to be updated, SCE and SDG&E will use the ICA tool on the specific electrical node or will run the ICA on all the electrical nodes in the circuit, depending on future ICA tool capabilities.
- PG&E generally agrees with SCE and SDG&E's approach but proposes that verification of the ICA within the Initial Review process may also be accomplished through existing 15% of peak load calculations without rerunning the ICA.
- If 8.f, 8.g, 8.h, and 8.j are adopted, the IOUs will not perform additional analyses of Interconnection Requests with less than 30 kVA nameplate capacity.
- All utilities propose to implement this without changes to the existing timelines for Initial Review.

In addition to these questions of how ICA values would be updated, the Working Group discussed what steps the IOUs should take to share the results of their analysis with the interconnecting generator. Most Working Group participants agree an explanation of the following is warranted:

- Grid condition changes
- Interconnection queue changes

In the event disclosing ICA results fails any confidentiality provision, the IOUs will provide information in aggregation or at a level of granularity that would allow IOUs to continue to comply with the Commission's data redaction policies in place at the time of interconnection.

Finally, SCE agreed to consider future implementation of a system for "flagging" if the ICA values likely need an update. If possible, SCE would attempt this during Q1 2019.

Qualified Positions

The Working Group did not receive an explanation or any opportunity to consider alternative methods of PG&E's approach to verification, including the tools referenced by PG&E. Thus, several parties strongly object to PG&E's position. They are concerned interconnection applicants will not understand how the screening limit is derived and applied. They ask instead that the ICA should produce the values used in the screening process.

IREC and CALSSA support updating the ICA but do not agree with PG&E's specific proposal on how to do that. In particular, IREC is concerned with PG&E's suggested use of calculations other than the ICA. Clean Coalition agrees noting that any alternate methods used by the IOUs must provide effectively equivalent results to the applicant as an updated ICA value. In those cases where this is not clear, an updated ICA value must be used.

GPI suggests that with ICA updates at a monthly resolution it is likely that "stale" ICA values will be a large problem. GPI's suggested solution for this potential problem is to have the IOUs complete the automated ICA update process in the near-term, as discussed in Proposal 8.v. GPI regards their support for Proposal 8.b as an interim measure until alternatives delineated in 8.v can be adopted.

The Public Advocates Office supports Proposal 8.b, concluding it will help ensure that the online ICA tool is as accurate and as reflective of real-time conditions as possible. However, the Public Advocates Office recommends that, were this proposal to be implemented, the costs to the IOUs of performing these intra-month updates be reviewed as part of the long-term ICA refinements to see if they are placing an undue cost burden on the IOUs and, by extension, the ratepayers.

Proposal 8.c: Track When ICA Values are Updated Outside of the Required Monthly Update to Inform Future ICA Discussions

Proposal

The IOUs will track when the ICA is updated leading to Interconnection Requests failing Initial Review.

Status

Non-consensus

- Supported by SCE, SDG&E, IREC, Public Advocates Office (qualified), GPI, TURN, Clean Coalition
- Opposed by PG&E

Discussion

The Working Group discussed whether tracking of the deviations from the posted ICA values would help inform future discussions on the ICA.

Some Working Group participants suggested that the IOUs should track deviations from the posted ICA values that surface during the implementation of Proposal 8.b to inform future discussions of ICA refinement. Tracking of these deviations will help inform future discussions about how frequently the ICA needs to be updated systemwide and also in what manner and when ICA may need to be updated on a case by case basis for individual applications.

SCE and SDG&E expressed a willingness to track ICA updates for those projects that require Supplemental Review. PG&E opposes this proposal at this time, finding it better related to long-term ICA refinements within the DRP proceeding.

GPI expressed the need for comprehensive data in order to assess the effectiveness of the ICA, and tracking ICA posted value deviations is the first step in collecting the required diagnostic data to improve the system over time.

Qualified Positions

The Public Advocates Office supports Proposal 8.c, concluding it will help ensure that the online ICA tool is as accurate and as reflective of real-time conditions as possible. However, like Proposal 8.b, the Public Advocates Office recommends that, were this proposal to be implemented, the costs to the IOUs of performing these intra-month updates be reviewed as part of the long-term ICA refinements to see if they are placing an undue cost burden on the IOUs and, by extension, the ratepayers.

Proposal 8.d: Modification of Projects if ICA Values are Out-of-Date to Stay Under ICA Limit and Maintain Queue Position

Proposal

Applicants who apply based on the posted ICA should have an opportunity to make modifications to their applications should they fail any Initial Review Screens because the posted ICA values have changed by the time their application was reviewed. Applicants will have ten business days to modify their application or elect to go to Supplemental Review. If they do not respond, the project will proceed to Supplemental Review after ten days.

Status

Non-consensus

- Supported by CALSSA, GPI, Clean Coalition
- Opposed by PG&E, SCE, SDG&E, TURN

Discussion

The Working Group discussed that projects applying to be studied under Fast Track that submit an application based on the posted ICA values may want an opportunity to modify their application request if the ICA values have changed in a way that causes them to fail Fast Track before the time their application is evaluated in the queue.

The current Material Modification rules under Fast Track review do not allow an applicant to reduce the size of a proposed project without resubmittal. Rule 21 Working Group One made a recommendation to allow a size reductions up to 20% if it does not impact another project lower in the queue. That recommendation is pending. This proposal would address situations not contemplated within Working Group One; this proposal is to allow an interconnecting customer to maintain queue position when it would impact another applicant lower in the queue.

CALSSA provides the following example illustrating the impact of this proposal:

> *"Suppose there are published ICA values sufficient to interconnect 2 MW of south-facing solar. After that number is published, Customer A submits an application for a system for 900 kW, leaving approximately 1.1 MW. Without knowing that, Customer B for 1.5 MW based on the published ICA values, then Customer C submits an application for 600 kW. Customer B is informed that there is actually only 1.1 MW of capacity and chooses to downsize. If Customer B is allowed to downsize without resubmitting, Customer C will not be able to interconnect without upgrades. If Customer B is required to resubmit and goes behind Customer C, only 500 kW of capacity will available. This proposal would allow Customer B to interconnect 1.1 MW because that customer was acting on posted ICA data in the initial submittal and should not be punished due to another project that submitted right ahead of them. Customer C*

> *would have to pay for upgrades to interconnect, which is what would have happened if all customers had access to up-to-date information."*

CALSSA notes there are disadvantages to this proposal. Specifically, the proposal would add up to ten days to the interconnection process and some applicants would not be able to decide within the ten-day timeframe, which would slow things down without providing a benefit. However, CALSSA believes solar providers will become accustomed to presenting multiple options to customers ahead of time in order to make speedy decisions when these situations arise.

The IOUs take a different position. The IOUs assert this proposal adds complexity and makes the Fast Track process much slower than it is intended to be. It also reflects the challenges of the prior serial study process and why the Independent Study Process was introduced. It begs the question whether the Utilities should receive multiple interconnections requests under the Fast Track process with such interdependencies. Adding provisions to allow size changes that impact others in the queue means that completed interconnection studies would have to be re-done potentially impacting other customers project plans. The IOUs observe there is no data supporting this proposal and thus not prudent to add complex rules on a scenario that may or may not happen frequently. Today, the number of projects that fail the Fast Track process is small.

Further, the IOUs assert CALSSA's scenario is unfair to Customer C who also applied based on the posted information, and based on existing practices it is fair for Customer B to take responsibility of the upgrade. From the IOUs' perspective, the CALSSA proposal would not only create excessive complexities in the Fast Track process but also change the cost responsibility principles that exist in the tariff. Further, besides increasing the complexity of the Fast Track process, this also complicates the monthly updates to the ICA values. For example, if the IOUs allow ten days for a customer to decide if they want to change, then the IOUs will not be able to update the model for that circuit, which means that the IOUs will not be able to post updated monthly values for that circuit if this occurred towards the end of the reporting period.

Proposal 8.f1: Adopt Additional Initial Review Screen F1

Proposal

The proposal is to add Screen F1 to the Initial Review Screens to screen whether the generating system's short circuit contribution exceeds 1.2 per unit.

Status

Consensus

Discussion
Generating systems with 1.2 per unit short circuit contribution can reference the ICA value for meeting the reduction of reach ICA protection Screen. For Generating Facilities with short circuit current contribution greater than 1.2 per unit, the utilities will use the protection ICA value at the point of interconnection in conjunction with the project specific per unit short circuit contribution to determine if they pass Screen F1. If the project Screen fails Screen F1, it must be evaluated under Supplemental Review for impacts to reduction in reach.

The ICA cannot be used to evaluate synchronous or induction generators. The ICA uses 1.2 per unit short circuit duty contribution for inverter-based technology. Thus, an additional screen is proposed to evaluate whether a DER's short circuit duty contribution is under the allowable level; if yes, the Interconnection Request would pass Screen F1; if no, the Interconnection Request would fail Screen F1 and may need to be evaluated under Supplemental Review for impacts to reduction of reach. While the ICA was calculated using 1.2 per unit short circuit contribution, Screen F1 can be passed even when the DER short circuit contribution is greater than 1.2 per unit, so long as the DER nameplate value multiplied by its DER per unit contribution does not exceed the ICA value multiplied by 1.2 per unit. Below is an example to illustrate how the Screen would be applied.

Project MVA (MW) Nameplate capacity = 3 MW

Project Specific Short Circuit Contribution = 2.5 per unit

Updated protection ICA value at the Point of Common Coupling = 5 MW

Calculated project specific protection ICA value = 2.4 MW

Project fails Screen F1 because the project's nameplate capacity is greater than the Project Specific Protection ICA value

Therefore, a DER with a higher level of short circuit duty contribution needs to be adjusted to ensure consistency with ICA calculations.

Proposals 8.f, 8.g, 8.h, and 8.j: Apply Screen F, G, H and J only to Projects Larger than 30 kVA; Provide Earliest Available Indication where Screen F and G Failure is Likely

Proposal
This proposal has two parts:

- Modification 1: Raise the applicability limit for Screen F, G, H, and J from above 11kVA to above 30 kVA

- Modification 2: The IOUs provide earliest available indication where Screen F and G failure is likely, as detailed herein.

Status

Modification 1: Consensus

Modification 2: Non-consensus

- Supported by PG&E (qualified), SDG&E (qualified), IREC (qualified), Public Advocates Office (qualified), GPI (qualified), Clean Coalition, CALSSA (qualified)
- Opposed by: SCE

Discussion

Modification 1

The existing Rule 21 tariff language for Screen F, G, H, and J includes the following language:

> *Note: This Screen does not apply to Generating Facilities with a Gross Rating of 11 kVA or less.*

The Working Group discussed expanding the exemption from 11 kVA to 30 kVA to allow standard NEM and other small projects to easily pass the Screen and maintain the goal of streamlining the interconnection process for small projects. It is not anticipated that projects below 30 kVA would be likely to raise any safety or reliability concerns if they skipped these Screens.

To implement this change, the tariff language could be changed to:

> *Note: This Screen does not apply to Generating Facilities with a Gross Rating of 30 kVA or less.*

All Working Group stakeholders agree the increase from 11 kVA to 30kVA is an improvement. Some Working Group members are concerned the threshold could be larger than 30kVA. The IOUs emphasize the 30kVA is an acceptable number but not derived from technical analysis. Some stakeholders requested additional analysis and reasoning behind the 30kVA threshold, but none was provided. Supporting stakeholders nevertheless support 30kVA at a minimum.

Modification 2

Screen F (“Is the Short Circuit Current Contribution Ratio within acceptable limits?”) identifies whether a project may have an impact on the system’s short circuit duty, fault detection sensitivity, relay coordination, or fuse-saving schemes. Screen G (“Is the Short Circuit Interrupting Capability Exceeded?”) identifies and studies whether a Generating Facility, in aggregate with other Generating Facilities on the distribution circuit, cause disturbances to protective devices and equipment, risking overstressing the equipment. This Screen allows the IOUs to evaluate how a generation project on the distribution system affects interrupting devices on the entire system, including at the distribution substation level, sub-transmission substation level (where applicable), and at the transmission level.

The ICA Working Group report had indicated that the ICA could enable an updated methodology incorporating these Screens, the Working Group identified that all elements of the tests conducted under Screens F and G are not evaluated within ICA.

Screens F and G require the IOUs to study impacts in aggregate with other Generating Facilities on the circuit. In order to determine if a project fails Screen F or G it is necessary to run short circuit flow models. In sum, the ICA does not provide a complete indication whether a project will pass or fail these Screens.

In the place of the ICA, the IOUs considered whether/how they may provide an early indication of whether a project is likely to face challenges related to Screens F and G. Some Working Group members propose the utilities post information on the ICA maps that indicate whether these Screens are likely to be a problem at that location.

PG&E and SDG&E propose that Screen F results can be provided in the Pre-Application Report, given that CYME and Synergi, distributed generation screening tools, have the capability to analyze Screen F and G quickly. Information can be provided as an additional Screen in the pre-application report once a screening tool is modified to add this new feature.

SCE is evaluating the feasibility of displaying locations where projects would likely fail Screen F or G. If SCE determines it can develop this capability at a reasonable cost, SCE would display this information along with the ICA values in the ICA maps. For now, SCE opposes Modification 2.

Qualified Positions

The Public Advocates Office supports raising the kVA threshold for these four Screens, as it will make the Rule 21 process more efficient by not requiring that the IOUs spend time and resources unnecessarily investigating projects between 11 and 30 kVA that do not impact safety or reliability. The Public Advocates Office also supports IOU efforts to display locations where projects would likely fail Screens F and G and recommends that any standards for displaying this information be applied consistently across all three IOUs.

GPI does not support the Pre-application Report option suggested by PG&E because from their perspective this adds considerable expense and time to determine whether the posted ICA value is likely to be accurate or not, and the Commission's clear direction has been that the posted ICA values be accurate.[3] GPI prefers SCE's flagging solution as a

[3] D.17-09-026 is replete with mentions of the need for accurate ICA results.

temporary solution until ICA includes Screens F and G, or a better solution is identified. The automation options for Screens F and G discussed Proposal 8.v will likely, when implemented, be a better solution than flagging.

Finally, some stakeholders have reservations about this proposal, noting that a "pass/fail" flag for Screen F and G may have limited value, given that successfully passing these Screens is a function of the project's size. Other stakeholders emphasize that the value of the proposal depends on what exact information the IOU provides and what the information means, both questions which remain unanswered.

In light of these different positions, IREC, CALSSA, and Clean Coalition have proposed that the Commission require the utilities to file an Advice Letter 120 days after the Commission's Order which would set forth their proposed approach to posting or otherwise providing information on likely Screen F, G and L results including any analysis of the costs of providing this information. If parties disagree with the proposals, they can protest the advice letters.

Proposal 8.i: Consider Applicability of Screen I for Non-exporting Projects Above 30kVA

Proposal

Option A: Relocate Screen I so that non-exporting projects above 30 kVA are reviewed under all Screens.

Option B: Do not relocate Screen I so that non-exporting projects of all sizes still skip Screens K, L and M. This is status quo, with the expectation that the issue will be reviewed in Phase 2 of this proceeding or through some other docket as appropriate.

Status

Non-consensus

- Option A:
  - Supported by PG&E, SCE, SDG&E, TURN
  - Opposed by IREC, Clean Coalition, CALSSA, Stem, GPI, Public Advocates Office
- Option B:
  - Supported by CALSSA, IREC, GPI, Clean Coalition, Stem, Public Advocates Office
  - Opposed by PG&E, SCE, SDG&E, TURN

Background on responsibility for grid upgrades when load changes

Except for NEM projects below 1 MW, Rule 21 currently holds interconnecting generators responsible for grid upgrades that are necessary to accommodate the interconnecting generator (see Rule 21 Section E.4). In the event load changes (i.e., increases or decreases) subsequent to that interconnection, the utility has several approaches to cost allocation for the associated costs. If the change falls under Rules 15 and 16, which cover new line extensions, cost responsibility is determined by the customer's obligations under the line extension contracts. If the change is not covered by Rule 15 and 15, such as for load increases or decreases that emerge in forecasted load, the utility would plan for necessary upgrades, seek approval of those costs from the Commission through a general rate case during the utilities' filing period, and, if approved, collect the costs of the upgrade from all customers. In the past, DER penetration has been relatively low, so load decreases have not been considered and thus have not triggered the need for upgrades; load increases were handled through overarching grid planning as a normal course of business. This dynamic has been aided by Screen M, which provided a flag that would allow the utility an opportunity to do additional review before the generation on a circuit got too close to the minimum load. However, that Screen currently does not apply to non-exporting generators, which may be offsetting load onsite and therefore reducing the load on the circuit. The Working Group asked, because larger non-exporting systems are expected to become more common, what may be the effect of changing load by non-exporting generators? Would the Commission's approach to changes in load created by new non-exporting generators differ from its approach to other changes in load? How should these changes be evaluated and how should they be allocated under Rule 21?

The Working Group agreed this issue has broad implications, including some that are more appropriately considered in a ratesetting context where the Commission can make necessary determinations.

Discussion

Screen I ("Will power be exported across the PCC?") asks whether a project is export or non-export. Currently, if a project passes Screen I, it is allowed to bypass Initial Review Screens J, K, L, and M. Consequently, it also is not required to undergo Supplemental Review as long as it also passed Initial Review Screens A-H. The Working Group discussed whether non-export projects, which pass Screen I, should be required to be evaluated under subsequent Screens.

Option A

The IOUs' perspective is that, as levels of DER penetration are increasing in the distribution system, the level of ICA margin at various parts of the distribution system are diminishing to the point at which non-export projects which remove load from the system can potentially adversely affect the safety and reliability of the distribution grid by causing overvoltage conditions and possible overloads. In order to ensure that all DERs are connected to the grid in a safe and reliable manner, an adequate level of technical evaluation needs to be performed for all DER projects, including those that do not export power to the grid. This includes evaluating how non-export projects may affect the ICA parameters, including thermal, voltage, and protection. For these reasons, the IOUs propose to relocate Screen I in the Rule 21 technical framework so that non-exporting projects above 30 kVA are reviewed under all Screens.

Option A could result in new costs for interconnecting non-export projects. Option A would observe the existing cost responsibility rules in Rule 21 Section E.4.

Option B

CALSSA, Stem, Clean Coalition, and IREC's perspective is that customers may change the nature and quantity of their demand using a wide variety of tools for many different reasons. The utility proposal to relocate Screen I would cause some applicants to pay fees for Supplemental Review and to pay for distribution upgrades. This would be a major departure from existing cost responsibility and would discriminate between customers on the basis of the method they choose to use to reduce their load—even if the impacts are identical. For example, if a customer decreases their load by 20% via energy efficiency measures they would not be subject to any additional study or upgrade costs, but, by relocating Screen I, a customer reducing their load by 20% through the use of onsite non-exporting DERs would be subject to additional study and upgrade fees.

Furthermore, CALSSA and IREC assert that never in the past have customers been required to guarantee the utility any specific amount of load. Requiring them to pay for upgrades caused by decreases in load amounts to a departing load charge that is a major departure from current practice. It is not the reduced load itself that could cause a reliability concern; it is the fact that the line segment may no longer support the previously interconnected generation on that circuit segment. Thus, if a customer reduces consumption, they should not have cost responsibility for failing to support nearby DERs.

The Public Advocates Office maintains that one of the goals of Working Group 2 is to use the ICA tool to allow certain projects to bypass certain Rule 21 screens to make the Rule 21 process more efficient. This Joint IOUs' Issue 8.i Proposal makes the process less efficient by subjecting non-export projects to additional screens, and it does so with an insufficiently detailed technical justification from the IOUs. Therefore, the Public Advocates Office opposes the proposal and does not recommend subjecting non-export projects that have passed Screen I to additional screens they are not currently subjected to under Rule 21. If the IOUs provide a comprehensive technical assessment of the existing threats posed by non-export projects that pass Screen I that is complete with specific examples, stakeholders, including the staff of the Public Advocates Office, can re-assess the Issue 8.i Proposal in light of that new information.

Finally, CALSSA and IREC emphasize that the utilities have indicated that to-date this situation has never arisen and thus there is likely more time before this reaches the point where it is happening frequently enough to be of concern. In the meantime, the utilities retain the opportunity to review changing grid load conditions and take necessary measures at any time they deem warranted, without changing the processing of interconnection applications, Screens, timelines, or cost allocation principles.

GPI agrees with these concerns and suggests that since the identified issue has never occurred to date the Working Group should flag it as a potential issue and re-visit possible solutions when the projected impacts start to occur.

Proposal 8.k: Modify Screen L to Include the Transmission Overvoltage and Transmission Anti-islanding Test

Proposal

Option A: Screen L should be modified to include a transmission overvoltage and transmission anti-islanding test proposed by PG&E.

Option B: Screen L should be modified to include only a transmission overvoltage test.

Option C: Screen L should be modified to temporarily allow application of anti-islanding tests, as defined in writing by utility guidance documents, until the questions raised in Issue 18 can be addressed more thoroughly.

Status

Non-consensus

- Option A:
    - Supported by PG&E, SCE, SDG&E
    - Opposed by TURN, CALSSA
- Option B:
    - Supported by CALSSA
    - Opposed by PG&E, SCE, SDG&E
- Option C: IREC Proposal
    - Supported by IREC, GPI, Clean Coalition
    - Opposed by PG&E, SCE, SDG&E

Discussion

The existing Screen L (Transmission Dependency and Transmission Stability) tests whether the Interconnection Request is made in an area where there are known or posted transient stability limitations, or the proposed Generating Facility has interdependencies known to the utility with earlier-queued transmission system Interconnection Requests. The ICA does not identify the results of Screen L, because the analysis is not conducted up to the transmission level. However, PG&E contends that there are some areas where utilities have identified known transmission deficiencies that will impact the application of ICA.

Currently, Screen M ("Is nameplate generation > 15% of peak load?") evaluates whether there is a risk that aggregate generation could exceed 15% of peak load and, if so, identifies which projects should proceed to Supplemental Review. 15% of peak load is designed to approximate when generation on a circuit segment exceeds 50% of minimum load. PG&E has been using the 15% of peak load in Initial Review and 50% of minimum load calculations in Supplemental Review in conjunction with data on the presence of synchronous generators and substation grounding to identify when projects should undergo more detailed protection tests which are currently performed in Detailed Study such as traditional anti-islanding and transmission overvoltage.

SDG&E and SCE do not currently conduct this screening but have indicated a potential desire to do so in the future. PG&E identified that these transmission protection screens are not incorporated into ICA and therefore making Screen M less conservative by changing the current 15% of peak load methodology to the ICA means that these Screens need to be captured elsewhere. As detailed below, PG&E proposes that these screens be conducted in Screen L because Screen L is also evaluating transmission impacts.

It is noted that there is some overlap in this topic with Issue 18 ("should the Commission adopt changes to anti-islanding Screen parameters to reflect research on islanding risks when using UL 1741-certified inverters in order to avoid unnecessary mitigations? If yes, what should those changes entail?"). Working Group Four, tasked with Issue 18, is scoped to consider changes to the existing anti-islanding test while PG&E's Issue 8 proposal would move the screening from Screen M to L in the Initial Review.

<u>Option A</u>

PG&E proposes that the anti-islanding and over voltage evaluation screen be transitioned to Screen L from the current Screen M. Screen L will test for 15% of peak load for those circuits (based on proposal 8.l) that have a risk of anti-islanding and transmission overvoltage.

The proposal could be implemented with the following change to the tariff language (emphasis added):

> Is the Interconnection Request for an area where: (i) there are known, or posted, transient/dynamic stability limitations, or (ii) the proposed Generating Facility has interdependencies, known to Distribution Provider, with earlier queued Transmission System Interconnection Requests, or (iii<u>) islanding conditions are possible based on [PG&E, SDG&E or SCE's] currently adopted and published screening policies with respect to anti-islanding screening</u>. Where (i), (ii) or (iii) above are met, the impacts of this Interconnection Request to the Transmission System may require Detailed Study further study.
>
> - If Yes (fail), Supplemental Review is required.
> - If No (pass), continue to Screen M.

Initial Review's 15% of peak load and Supplemental Review's 50% of minimum load calculations are used in conjunction with data on the presence of synchronous generators and substation grounding to identify when projects should undergo more detailed protection tests that are currently performed in Detailed Study.

The detailed evaluation of anti-islanding and transmission overvoltage for those projects that fail Supplemental Review is conducted pursuant to the current PG&E standard.[4] No changes to the technical evaluation is proposed at this time but the technical evaluation is in scope in Issue 18 in the proceeding.

Below is some additional detail on islanding and transmission overvoltage:

- Islanding is generally considered possible when the ratio of machine-based synchronous generation to inverter-based generation is over 40% and aggregate generation is greater than 50% of min load. 15% of peak load is used as the initial screen or filter to conduct additional screening on projects that exceed 15% of peak load.
- Transmission overvoltage is generally considered possible when a transmission breaker opens on a substation that has an ungrounded high side and aggregate generation is greater than 50% of min load. 15% of peak load is used as the initial screen or filter to conduct additional screening on projects that exceed 15% of peak load.

Option B

CALSSA contends that PG&E is misinterpreting the risk of anti-islanding failing to work. For Issue 8, CALSSA opposes PG&E's proposal not to use ICA values on circuits with machine-based synchronous generation. CALSSA does not oppose the addition of the transmission overvoltage screen. The reasoning for this position follows.

Anti-islanding is an essential function that requires DERs to shut down during a grid failure. It prevents DERs from operating as an unintentional "island" of generation that could pose a safety risk to utility personnel repairing equipment that they expect to be de-energized. Anti-islanding functionality is required by UL 1741. For years, the UL 1741 committee, which includes utility and non-utility representation, has thoroughly addressed this important issue.

[4] The current standard for anti-islanding tests can be found here:https://www.pge.com/includes/docs/pdfs/shared/customerservice/nonpgeutility/electrictransmission/handbook/TD-2306B-002.pdf

The overarching policy proposed as part of 8.k. is being driven by PG&E's protection engineering department based on several studies conducted by Northern Plains Power Technology in cooperation with Sandia National Laboratories. These studies are:

1. "Unintentional Islanding Detection Performance with Mixed DER Types", Ropp Ellis, July 2018.
2. "Risk of Unintentional Islanding in The Presences of Multiple Inverters or Mixed Generation Types", Northern Plains Power Technologies, May 2015
3. "Suggested Guidelines for Assessment of DG Unintentional Islanding Risk", Ropp Ellis, November 2012

In addition, PG&E has engaged Northern Plains Power Technology to conduct its own internal study surrounding the impact of synchronous generators combined with UL 1741 certified inverters. This PG&E-funded study has been completed but the results have not been published.

All four of these studies were conducted using computer modeling programs, and their applicability is limited due to the lack of substantive real-world testing data. CALSSA takes no exception to the methods employed in the study process, but as with any study, the theory should be proven before it is incorporated into wider policy.

One independent study that reviewed real world UL 1741 inverter testing and grid conditions was conducted by General Electric in cooperation with PG&E for the Commission and is titled "Quantification of Risk of Unintended Islanding and Re-Assessment of Interconnection Requirements in High Penetration of Customer Sited PV Generation", Bebic – 2016, (the "GE Study"). Within this study, much of the anti-islanding theory proposed by Northern Plains Power Technology's first two studies (1&2 above) was proven to be inaccurate. PG&E used the results of this study to relax some of their islanding review requirements. However, on a broader scale, the discrepancy highlights an inherent inconstancy between computer models and real-world testing. In addition, PG&E's current review standards omit some of the recommendations proposed in the report.

Proposal 8.k stipulates that islanding becomes a concern when the ratio of machine-based synchronous generation to inverter-based generation is over 40% and generation is more than 50% of minimum load. Breaking down the criteria in the proposal, we note the following:

1. <u>50% minimum load</u> – The GE report states, "Power factor of the circuit has significant impact on island duration." The proposed 50% of minimum load check in 8.k. completely omits any check of reactive power matching possibility. The GE report goes on to recommend the following changes to the review process to more accurately assess the risk of islanding. Note the use of the term *simultaneous* load, not minimum loading.

a. **In initial review**: raise the Screening limit from 15% peak load to 60% of estimated simultaneous load; the estimated simultaneous load will be based on conversion factors as was defined and implemented in [3].

b. **In supplemental review**: Keep the existing minimum daytime load Screen when SCADA data is available and allow 80% of estimated simultaneous load by maintaining the power factor of the section below 0.98 inductive.

c. **In detailed review**: Allow up to 105% of simultaneous load by de-tuning circuits to maintain the power factor between 0.95 and 0.98 inductive, to address islanding concern if needed.

Based on the recommendations in this report, CALSSA proposes adding a and b to replace the 50% minimum loading condition. In addition, we propose that c be allowed in circumstances that meet the defined criteria.

2. <u>40% Synchronous Generator Mix</u> – This component of proposal 8.k is unproven. Adding it to Screen L as part of this Working Group is premature. No field testing has been conducted to verify the applicability of the research conducted by NPPT. Questions exist surrounding the field conditions that produce an extended run-on and whether the computer simulated grid are feasible in practice.

From a policy perspective, the intent of Issue 8 is to coordinate the implementation of the ICA, not to add in an unsubstantiated technical review measure. The question of anti-islanding review is going to be addressed by Issue 18 in this proceeding. From a policy perspective, Issue 18 is the more appropriate venue to address adding additional review points to the Rule 21 process.

PG&E has stated that the current approximate percentage of circuits impacted by the PG&E anti-islanding standard is approximately 7%.[5] This appears to be understated based on customer experience. Stakeholders should have the opportunity to independently verify this data point before any additional criteria are added to the anti-islanding standard. In addition, PG&E has implemented only one mechanism to address anti-islanding and that is to install Direct Transfer Trip at the substation level. Direct Transfer Trip results in typical costs above $1 million (either customer or ratepayer borne) and delays to interconnecting generation of up to 24 months. These results commonly cause projects to be withdrawn from the interconnection process.

Based on the impact of PG&E's anti-islanding policies and the fact that the results are still unproven, there should be no changes to the Rule 21 anti-islanding policy at this time. Stakeholders should have an opportunity to challenge the theoretical data and propose alternative, more cost- and time- effective measures to manage islanding.

[5] PG&E discussion slides for May 16, 2018 Working Group meeting, slide 7, which can be found at https://gridworks.org/initiatives/rule-21-working-group-2/.

Option C

Increasing the transparency and predictability of the Rule 21 interconnection process has been a fundamental principle that the Commission has been working towards since at least 2011, and the creation of the ICA was intended to significantly advance this goal in a transformative way. Throughout this Working Group report, nearly all of the proposals are intended, in one way or another, to enable interconnection customers to be able to identify particular locations for projects where interconnection hurdles would be minimal and to predict with greater certainty whether they will pass the Fast Track Screens and be able to interconnect swiftly and at a low cost. In addition, the ICA was a necessary step forward to enable the state to move away from the use of the 15% of peak load Screen, which is quite conservative and has become, by a wide margin, the most commonly failed Screen. This will only become more common as penetration increases in the state. The other proposals in this report advance this goal, but the original IOU proposal to insert a layer of specific screens for anti-islanding that have not been vetted by stakeholders and researchers could dramatically and almost entirely undermine this goal.

The extent to which UL 1741-certified inverter-based systems create a risk that unintentional islands will be created is an area of significant dispute. PG&E currently has assessed that risk to be significant enough that it actively screens for the risk. SCE and SDG&E currently do not screen for this but have indicated that there is a possibility that they could do so in the future. The risk of a generation to load match that could create the potential for an island, while somewhat challenging to characterize, has been shown to be very low (e.g., 10-5 /second – see IEA PVPS task 5 report). In order for stable islands to occur, a close match in active and reactive power must also be present at the moment an interrupting device opens. For this reason, some Working Group members are skeptical about whether screening is really needed, and if so, whether the Screens currently used by PG&E (via their protection handbook) are sufficiently narrow as to target the real risks.

Currently, the consequences of determining that a project could create the risk of an unintentional island forming are significant. PG&E requires that a project install Direct Transfer Trip, which is both very costly (for ratepayers in the case of NEM projects, or developers/customers in the case of non-NEM projects) and can extend the timeframe for interconnection by 18 months or more.

After some discussion, PG&E modified its proposal and rather than defining the screens in Initial Review (as part of Screen L), and they then proposed to have projects fail Screen L where: "(iii) islanding conditions are possible based on currently accepted conditions and standards," which is highly problematic in two ways. First, rather than defining what the actual screen for anti-islanding or transmission overvoltage is, the proposed language vaguely referred to "accepted conditions and standards." This would have created a completely open-ended screen that would not specify what test will be used to screen the projects, undermining both the transparency and predictability concerns.

Second, there are no "accepted conditions and standards." Indeed, as noted above, there is considerable dispute about what is the "acceptable" way to screen for anti-islanding conditions, and there are not any nationally accepted standards that fully address this. This is evidenced by the fact that the three IOUs engaged here currently take very different approaches when it comes to screening for anti-islanding. The approach used by PG&E is accepted by them but not by others.

That said, IREC understand that a more thorough discussion of whether a screen for anti-islanding is necessary, and if so, what the screen will be, will happen when the Working Group gets to Issue 18, as outlined in the Scoping Memo. While IREC has significant concerns that the approach currently utilized by PG&E is unduly conservative, we recognize that use of the ICA for Screen M will impair their ability to apply their current screening method. Thus, in the interim, IREC recommends that the Commission adopt a more specific but temporary language in Screen L that would allow current Screening practices to continue until the Working Group reaches Issue 18.

Rather than referring vaguely to "accepted conditions and standards", the Commission should adopt the following language in Screen L:

> Is the Interconnection Request for an area where: (i) there are known, or posted, transient/dynamic stability limitations, or (ii) the proposed Generating Facility has interdependencies, known to Distribution Provider, with earlier queued Transmission System Interconnection Requests, or (iii) islanding conditions are possible based on [PG&E, SDG&E or SCE's] currently adopted and published screening policies with respect to anti-islanding screening. Where (i), (ii) or (iii) above are met, the impacts of this Interconnection Request to the Transmission System may require ~~Detailed Study~~ further study.
>
> - If Yes (fail), Supplemental Review is required.
> - If No (pass), continue to Screen M.

This proposed language would allow PG&E to utilize their current screening practices, as identified above, that look at whether a project has failed 50% of minimum load AND where 40% or more of the generation on the substation comes from rotating machines. SCE and SDG&E currently do not screen for anti-islanding, but should they determine that it is necessary in their opinion to do so prior to the Issue 18 discussion, this proposal would allow this so long as they publish a guidance document, similar to PG&E's, that identifies the specific screening approach they intend to use.

This is a subtle but important change to some of the Working Group members because it enables the customer to identify the specific screening approach that will apply to them and it does not memorialize any particular screening approach prior to the Issue 18 discussion. It is important that the Commission recognize that by allowing PG&E to screen using its current approach a significant number of projects that are proposed within the ICA limits are likely to fail Initial Review. Thus, it is important to ensure a thorough and fair discussion of this topic in Issue 18 and to only adopt this change on a temporary basis at this time. We have significant concerns that overly broad anti-islanding screening will undermine the progress on the ICA and result in unnecessary upgrade costs in some cases. PG&E has modified their proposed language to mimic IREC's proposal which is appreciated, but IREC wants to make clear that our support for this change is temporary and must be followed with a rigorous discussion in Issue 18 of whether these screening methods are indeed appropriate.

Proposal 8.l: Provide Earliest Available Indication Where Screen L Failure is Likely

Proposal

The IOUs will post an indication of potential Screen L results on ICA maps.

Status

Non-consensus

- Supported by PG&E, TURN, Clean Coalition, GPI, IREC
- Opposed by: SCE, SDG&E

Discussion

The Working Group discussed how identifying locations where certain pre-existing grid conditions exist would be useful for developers in understanding where they may fail Screen L. These conditions are:

- fused high side of substation transformer;
- existing direct transfer trip or hard wire tripping scheme;
- synchronous generators present; and
- known transmission constraint areas.

Identifying where projects are "likely to fail" upfront will facilitate the transparency, predictability and streamlining of the interconnection process by allowing developers to make informed development choices. Thus, this proposal would provide more information for developers but is not an "actionable" number.

PG&E proposes to list this data with other feeder-summarized data (e.g., feeder name, circuit voltage, customer counts, generation totals, etc.). PG&E proposes two fields to help identify locations that could be of concern for Screen L:

- Substation High Side Fuse: Y/N
- Substation Direct Transfer Trip/Hard Wire Trip Installed: Y/N

As part of a potential future enhancement to SCE's ICA map, SCE is evaluating the feasibility of displaying locations where projects would likely fail Screen L. If and when this capability and information is available, SCE would display this information along with the ICA values in the ICA maps. SCE notes that what PG&E proposes as new fields are not applicable to SCE because SCE currently does not apply Screen L in the same way as PG&E. Instead of the two PG&E proposed fields, SCE would publish an additional notice in the ICA information field that would read:

> *Studies have shown that this area has transmission stability issues or dependencies which may cause the failure of Screen L.*

SDG&E does not support this proposal. IREC, Clean Coalition, and GPI support requiring all three IOUs to post information on their maps that helps to flag known conditions that might indicate whether a project may fail Screen L. CALSSA notes that circuits will not need to be highlighted for potential to fail the anti-islanding Screen if the anti-islanding Screen is not adopted in Proposal 8.k.

Proposal 8.m: Screen M should be modified to reflect ICA

Proposal
Screen M should be modified to reflect ICA

Status
Non-Consensus

- Option A:
  - Supported by PG&E, SCE, SDG&E, TURN
  - Opposed by IREC, GPI, Stem, Clean Coalition, Tesla, Sunrun, CALSSA, Public Advocates Office
- Option B:
  - Supported by IREC, GPI, Stem, Clean Coalition, Tesla, Sunrun, CALSSA, Public Advocates Office
  - Opposed by PG&E, SCE, SDG&E, TURN
- Options A or B:
  - Implementation Variation 1

        - Supported by Clean Coalition, IREC, CALSSA, SCE (qualified)
        - Opposed by SDG&E, PG&E
    - Implementation Variation 2
        - Supported by Clean Coalition, IREC, PG&E (qualified), SCE (qualified), CALSSA, SDG&E (qualified)

Discussion

There are five key limiting factors to whether a new DER can be integrated without impacting safe and reliable service and without requiring additional grid upgrades: thermal, voltage, power quality, protection and safety (i.e., operational flexibility). The ICA is a methodology to assess the system's hosting capacity reflecting these limits, with each assessed independently.

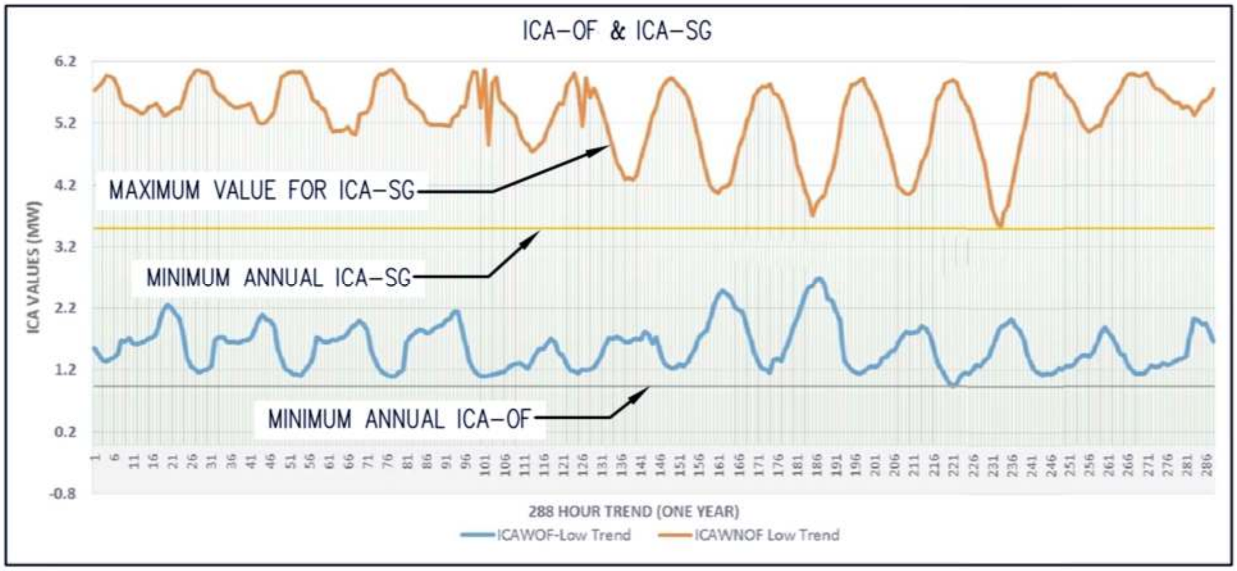
There are two types of ICA profiles being developed by the IOUs under direction from the Commission.

- ICA-Static Grid ("ICA-SG") 576 profile: This profile is the minimum ICA values at each of the 576 hours for the most limiting of these categories: thermal, voltage, power quality and protection.
- ICA-Operational Flexibility ("ICA-OF") 576 profile: This profile is the minimum ICA values at each of the 576 hours for the most limiting of these categories: thermal, voltage, power quality, protection *and safety*.

Where the safety ICA is not the lowest of all the categories, ICA-OF and ICA-SG are the same.

The ICA produces 576 values, a minimum and maximum load day for every month, for 12 months. Several points within the 576 values warrant emphasis, as illustrated in the following figure:

- The minimum annual ICA-OF value is the ICA's most conservative assessment of the system's ability to interconnect new DER.
- The maximum value for ICA-SG is the least conservative scenario.
- In between lies another operative value, the minimum annual ICA-SG



How the ICA impacts a DER interconnection depends on which of these limits constrains the hosting capacity at the Point of Interconnection and what DER generation profile you compare against that constraint. Different scenarios require different procedures. The scenarios considered by the Working Group are as follows:

- Scenario 1: A request to interconnect a generator at a point of interconnection constrained by the safety (or operational flexibility) criterion (ICA-OF).
- Scenario 2: A request to interconnect a generator at a point of interconnection constrained by either thermal, voltage, power quality, or protection criteria (ICAW-SG).
- Scenario 3: A request to interconnect a generator at a point of interconnection where an ICA value cannot be determined.

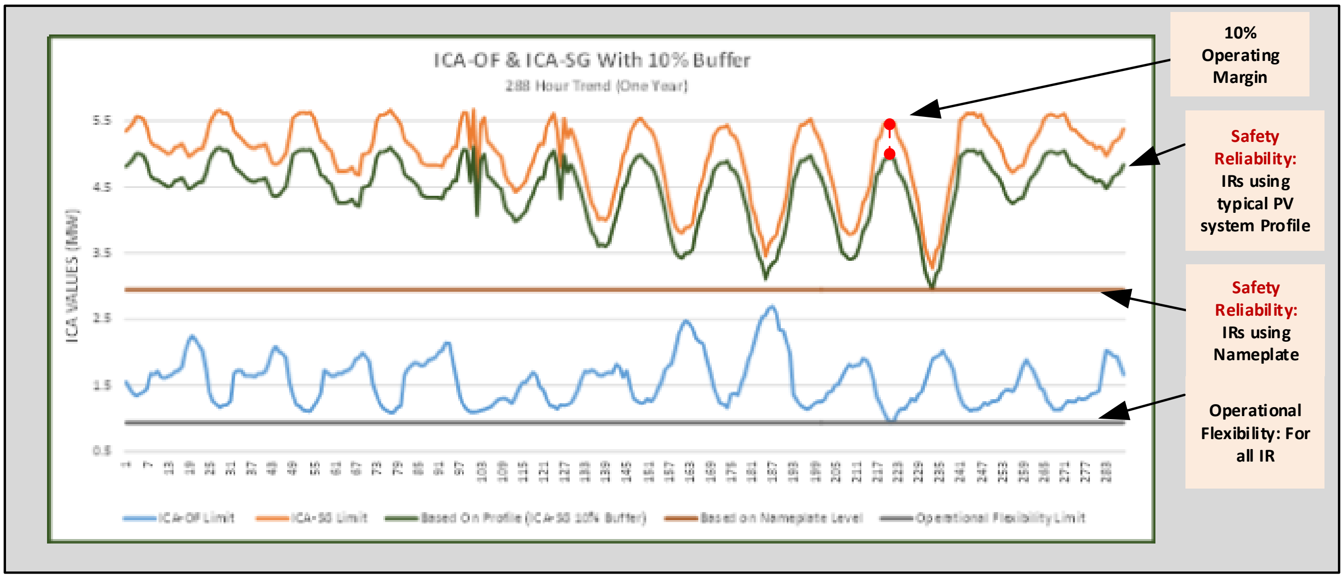
For all proposals under Issue 8, it is assumed that the generator has a fixed PV generation profile. Issue 9 considers these scenarios with a Limited Generation Profile.

When projects interconnect up to or near the point where generation and minimum load meet (i.e., 100% of minimum load), there is a risk that the load on a circuit may change after the project is interconnected, which can lead to safety and reliability issues without an opportunity to remedy the condition. If generation exceeds load, certain types of technical impacts could emerge. When interconnecting projects using the Initial Review Screens, the IOUs do not have a chance to verify the potential risks of load changes, and thus, the Working Group proposes to integrate a buffer into Screen M, effectively leaving space between the amount of expected interconnecting generation and the ICA value. As detailed in each of the following proposals, the applicability of the buffer varies by proposal.

<u>Option A</u>

The IOUs suggest a hybrid approach, applying a 10% buffer to the ICA-SG and no buffer to ICA-OF. Under this proposal, when the ICA-SG and ICA-OF are separated at each hour by more than 10%, (as depicted in the figure below) the following would occur:

- Safety (i.e., operational flexibility) would be evaluated with the ICA-OF. If the Interconnection Request is greater than ICA-OF, it would be sent to Supplemental Review for further evaluation.
- Thermal, voltage, power quality and protection would be evaluated against the ICA-SG with 10% buffer curve. If the Interconnection Request crosses this 10% buffer, then the necessary upgrades would be implemented to maintain the 10% buffer at minimum. Cost responsibility would apply per existing rules.



The IOUs propose the following language for Screen M:

- For Interconnection Request Based on Nameplate –
    a. Is the Interconnection Request aggregate nameplate capacity greater than 90% of the lowest value in the ICA-SG 576 profile; or
    b. Is the Interconnection Request aggregate nameplate capacity greater than 100% of lowest value in the ICA-OF 576 profile?

  If the response is "yes" to either (a) or (b), project must be evaluated under Supplemental Review or Detailed Study to determine mitigation requirements

- For Interconnection Request Based on Typical PV Output Profile –
    c. Is the PV Interconnection Request real power production based on PV Watts® or equivalent greater than 90% of the ICA-SG 576 value in any hour; or

d. Is the PV Interconnection Request real power production based on PV Watts® or equivalent greater than 100% of the lowest value in the ICA-OF 576 profile?

If the response is "yes" to either (c) or (d) project must be evaluated under Supplemental Review or Detailed Study to determine mitigation requirements

- ICA information not available – Use current Screen M.

Further, the IOUs propose if a project is interconnecting to an area of the system without ICA, the project is evaluated against 15% peak load using the current process. If ICA is not available due to customer confidentiality, ICA will still be used, with certain details withheld, consistent with current Commission data confidentiality rules for aggregating customer data.

If a project fails Screen M, it is sent to Supplemental Review to further study the project, which may include evaluating the impact on the operational flexibility of the system, thermal, protection, and power quality, including studying probable switching configurations in order to determine mitigation requirements

<u>Application Submittal Process</u>
For Interconnection Request Based on Typical PV Output Profile, CALSSA and SCE propose customers specify the incremental equipment details necessary for PV Watts or equivalent to generate project hourly output. This information should provide sufficient detail on the proposed equipment along with basic information about the configuration. This information can be used to calculate location specific generation capacity to be compared to hourly ICA values. Uniform generation will also be compared to the hourly ICA values, but there will be no need to create an hourly production profile for that comparison.

Note that this revision to the application submittal process will require an adjustment to the PV Watts tool to generate best-case generation capability data and integration of this tool to each of the IOU's application portals.

The exceedance of an ICA value during any hour evaluated will constitute a failure of Screen M. Further investigation in Supplemental Review will determine whether there are simple ways to address this failure.

<u>Option B</u>
IREC, Clean Coalition, Stem, CALSSA, Tesla, Sunrun, and the Public Advocates Office support a counter proposal, which aligns with the Option A except for the treatment of the ICA-OF.

CALSSA objects to the enormous buffer proposed by the utilities for review against the ICA-OF for Interconnection Requests based on a typical PV profile. CALSSA notes that it is incorrect to view the IOU proposal as having a buffer on ICA-SG and no buffer on ICA-OF.

100% of the lowest value is much more conservative than 90% of hourly values. In D.17-09-026, the Commission set the ICA as having 576 data points. The IOUs have agreed to evaluate proposals against that hourly and seasonal data for ICA-SG but are proposing not to use hourly and seasonal data for ICA-OF.

The Public Advocates Office argues that the ICA is a tool that is being invested in by the IOUs and it should be used as much as possible to derive maximum efficiency for Rule 21. This option will get the most value out of ICA while maintaining grid safety and reliability.

Proponents of Option B propose that section (d) of the utilities' proposed language for Screen M be changed to:

> *Is the PV Interconnection Request real power production based on PV Watts® or equivalent greater than 100% of the ICA-OF 576 values in any hour?*

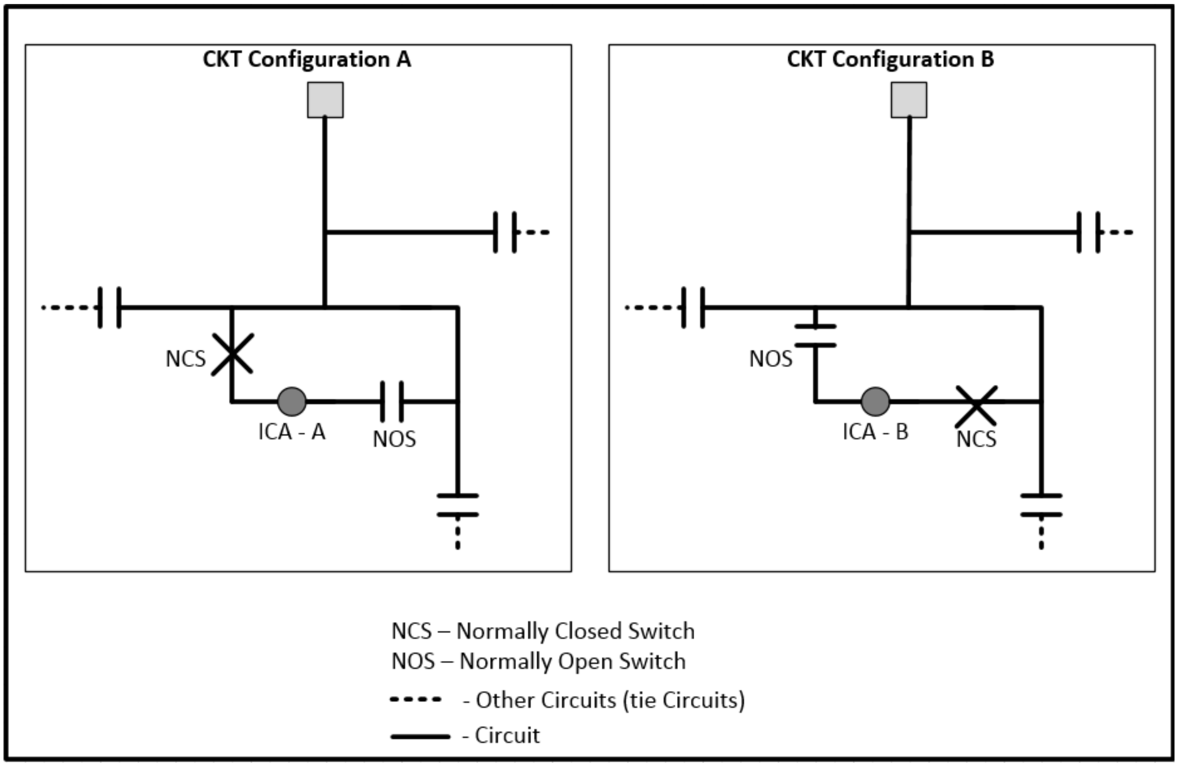
IOU Response

The ICA methodology accounted for operational flexibility between multiple circuits where minimum load at SCADA devices is used to determine the ICA-OF. However, the ICA methodology did not account for operational flexibility within a single individual circuit.

In many cases, distribution feeders have internal loops, which if modified could reduce the ICA values because of the way the circuit itself has been reconfigured. In the figure below, the ICA value is for the same electrical three phase node. However, if there is a need to internally reconfigure the feeder (e.g., for maintenance or operations) then the ICA values from configuration A and the ICA values for configuration B will be different even though the circuit has not been reconfigured with other circuits as intended for ICA-OF. Not accounting for this internal reconfiguration can lead to reliability and safety issues during normal operation of the grid.

Therefore, the IOU's reinforce that using the lowest value of ICA-OF is essential to ensure that the internal system can be reviewed as part of the interconnection process to ensure the safety and reliability for the DER connection up to ICA-OF can be maintained during normal operations of the grid.

The IOU's propose that this limitation to lowest value of ICA-OF would only be a condition to allow Supplemental Review to conduct review of the feeders' potential reconfiguration that could lead to grid reliability and safety issues.



In addition, having interconnection limits not based on a flat line would require a system to track those limitations and control a DER to prevent it from exceeding the limitations. This is subcomponent of Issue 9. With that, the IOUs are providing the same concerns here under this alternate proposal as it does for Issue 9:

- Error in forecasting of generation: uncertainty as to whether an actual generator profile may be faithfully represented by the forecasted Limited Generation Profile;
- ICA vs Operational Values: uncertainty as to whether the ICA-SG, the least conservative output of the ICA process, which is based on a forecast, will reflect actual grid conditions.
- Lack of experiences and infrastructure to work with generator controls: uncertainty as to whether the inverter and Data Acquisition System controls will meet expectations and consequent need for a utility system to supervise site controller.
- Lack of infrastructure to realized needed generation reductions: recognize grid operations happen in real-time, whether and how the IOU would know with certainty if/when the generator's output needed to be reduced, whether the IOU could effectively communicate the needed change to the DER, and whether the DER would respond in a timely and accurate manner.
- Questions about impact on subsequent interconnections: if an upgrade is avoided due to an operational constraint but the next customer elects to upgrade, does the operational constraint remain? Do utilities set rules that states that this line is now an operational constraint line and no upgrades will be allowed even if customer funded? What systems would be needed to operationalize such rules?

- Modeling Challenges: currently modeling of future planning and generation assume a typical PV output. Limited Generation Profiles adds new complexity to modeling.
- Applicability not well understood: do all customers need this option? Projects of all sizes and asset types?

The Joint IOUs note that an ongoing PG&E Distributed Energy Resource Management System ("DERMS") 2.0 pilot under the Electric Program Investment Charge ("EPIC") is actively exploring both how Limited Generation Profiles could be defined and enforced. This experimentation may lead to integration of solutions like the one being proposed here, but rigorous study is needed before that is possible.

<u>Options A or B</u>

Implementation Variation 1

CALSSA, IREC, and Clean Coalition oppose applying the buffer to the protection constraint. The ratio of load to generation does not determine whether a protection issue will arise, thus the reasoning behind the need for a buffer does not apply to protection. This variation would change the Screen to the following:

> *If the aggregate Generating Facility capacity on the line section is less in each hour evaluated than the lowest of 90% of the thermal ICA value, 90% of the voltage ICA values, 90% of the power quality ICA value, 100% of the protection ICA value, and 100% of the safety ICA value for that hour the Screen passes. If Screen fails, project is further evaluated under the Supplemental Review*

Implementation Variation 2

CALSSA and IREC believe the ICA would be much more user-friendly if the buffer were incorporated into the ICA values on the back end. If the thermal and voltage ICA values are de-rated by 10% before posting, it would be much more straightforward for the Screen to simply follow the adjusted ICA values. The ICA values could be posted in the adjusted form such that customers can use them without adding an additional buffer.

Utilities have expressed concern over their ability to include this before mapping ICA. If that is the case, the scripts can be adjusted at a later date. However, because there is still plenty of time before the ICA is put into practice, CALSSA and IREC suggest that this change can happen at some point before full implementation. If Implementation Variation 1 is adopted, PG&E and SCE are supportive of Implementation Variation 2 as well since it will better reflect where the buffer is required in the analysis and be less complicated for customers.

Proposal 8.n: Update Screen N Methodology

Proposal

Update Screen N to allow the evaluation of thermal overload, steady state voltage deviation, and protection reduction-of-reach when the Interconnection Request fails Initial Review due to exceeding the ICA values or Screen F1. This evaluation will also account for the default Volt-Var settings for inverter-based Generating Facilities.

Status

Non-consensus

- Supported by PG&E, SDG&E, SCE (qualified), IREC, Public Advocates Office (qualified), GPI, Clean Coalition, TURN

Discussion

Background

Screen N is a test of DER penetration. The Screen asks:

> *Where 12 months of line section minimum load data is available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate Generating Facility capacity on the Line Section less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the Generating Facility?*
>
> - *If yes (pass), continue to Screen O.*
> - *If no (fail), a quick review of the failure may determine the requirements to address the failure.*

If the failure cannot be addressed through this review, Electrical Independence Tests and Detailed Studies are required. If Electrical Independence Tests and Detailed Studies are required, Applicants will continue to the Electrical Independence Tests and Detailed Studies after review of the remaining Supplemental Review Screens if Applicant elects to proceed.

The significance of the Screen is that penetration of Generating Facility capacity that does not result in power flow from the circuit back toward the substation will have a minimal impact on equipment loading, operation, and protection of the distribution system.

Tesla Perspective

Tesla would like to see this approach expanded to include profiles that are dictated by software controls as opposed to limiting the evaluation to "natural" profiles, like the standard solar profile.

Reasons for updating screen

Like the Screen M penetration test, the Screen N penetration test needs to be updated from its current methodology to a methodology based on ICA. In Screen N, projects that exceed ICA values will be evaluated to determine if there is indeed an impact on the distribution system and, if so, whether there are simple mitigations that can be identified without Detailed Study.

Screen N was originally designed to provide a method of determining possible negative impacts (e.g., thermal overloads and overvoltage) by verifying whether flow of electrical power from the distribution circuit to the low side bus of the substation would occur under typical DER operating conditions (i.e., 10am to 4pm for fixed panel solar Generating Facilities and 8am to 6pm for solar Generating Facilities utilizing tracking systems). This reverse power flow would not occur as long as the verifiable minimum load was greater than the DER real power output, thus maintaining this level of aggregate DER would insure that no electrical distribution systems would become overloaded and/or no overvoltage in the distribution circuit would occur. When the aggregated DERs exceed the minimum load, then the IOUs could perform additional analysis under Supplemental Review or Detailed Study, depending on the complexity of the distribution system and Interconnection Request.

Voltage conditions are a particular concern for solar interconnections because solar can cause voltage on the line segment to increase slightly. If a circuit segment already has voltage near the high end of the acceptable range and a new solar system is proposed, the proposed system must be studied carefully to make sure it does not push the voltage out of range. However, Rule 21 Section Hh now contains requirements that all new interconnections have certain smart inverter functions enabled. Among these is the Volt-Var function, which is designed to force each solar system to mitigate its own voltage impacts.

The voltage constraint may cause the application to fail Initial Review, but in Supplemental Review, the utility will consider the impact of Volt-Var and may conclude that there is no negative impact on voltage. Alternatively, the utility may find that an adjustment to the standard Volt-Var settings is needed due to the electrical characteristics of the specific line segment.

As part of the long-term refinements to the ICA methodology, the utilities are working with software vendors to incorporate Volt-Var and other smart inverter functions into the calculation of ICA values. Until that time, this impact can be considered in Supplemental Review.

With the implementation of ICA values that account for thermal overload, overvoltage conditions, and protection, Screen N needs to be adjusted for each of following scenarios that an Interconnection Request falls into relative to ICA:

1. When the Interconnection Request is below the updated ICA value and passes Screen F1: a new condition needs to be added in Screen N that states that Screen N can be bypassed if the Interconnection Request is below the updated ICA and has passed Screen F1.
2. When the Interconnection Request is above the updated ICA value or fails Screen F1: a new condition needs to be added to Rule 21 to address Interconnection Requests that are above the updated ICA or fail Screen F1. The IOU will determine if a quick review of the Interconnection Request may determine the requirements of interconnecting. If a quick review cannot determine the requirements to interconnect, then Electrical Independence Tests and Detailed Studies are required If voltage is a prevailing constraint, then the smart inverter default volt/var function will be used in power flow analysis for the evaluation of the proposed project. This will reveal if the proposed project causes any voltage impacts of concern. If concerns related to steady state voltage, thermal, or protection exist and the utility can identify simple upgrades through power flow analysis (e.g., installation of voltage regulator devices or protection devices to mitigate reduction of reach), then the Interconnection Request will use screen N to determine the mitigation requirements. When larger upgrades or complex protection evaluation is required, Screen N will fail and the technical evaluation will be conducted under the Detailed Study process.
3. When ICA information is not available: no changes to the existing process and Rule 21 are required. The utility will utilize the existing tariff language.

Proposal 8.q: Modify Screen P

Proposal

Update Screen P to account for new smart inverter capabilities.

To account for new smart inverter capabilities, the Working Group proposes to add the following item to the list of factors in Rule 21 Section G.2.c which may affect the nature and performance of an interconnection:

- Advanced inverter functionality and settings.

The following would be added to Rule 21 Section G.2.c as example of an item that may be considered under this Screen P:

- Will the proposed system cause any voltage impacts considering the settings of the Volt-Var function and the characteristics of the circuit segment?

Status

Consensus

Discussion
Screen P in Supplemental Review is used to determine if there are mitigations that can avoid having the project move to Detailed Study. The Working Group recommends the list of issue types that are considered be expanded to include advanced smart inverter functionality.

Voltage conditions are a particular concern for solar interconnections because solar can cause voltage on the line segment to increase slightly. If a circuit segment already has voltage near the high end of the acceptable range and a new solar system is proposed, the proposed system must be studied carefully to make sure it does not push the voltage out of range. However, Rule 21 Section Hh now contains requirements that all new interconnections must have certain smart inverter functions enabled. Among these is the Volt-Var function, which is designed to force each solar system to mitigate its own voltage impacts.

The voltage constraint may cause the application to fail Initial Review, but in Supplemental Review, the utility will consider the impact of Volt-Var and may conclude that there is no negative impact on voltage. Alternatively, the utility may find that an adjustment to the standard Volt-Var settings is needed due to the electrical characteristics of the specific line segment. The proposal made here allows the IOUs to account for such changes in its determination under Screen P whether Detailed Study is needed.

As part of the long-term refinements to ICA methodology, the utilities are working with software vendors to incorporate Volt-Var and other smart inverter functions into the calculation of ICA values. Until that time, this impact can be considered in Supplemental Review.

Proposal 8.r: The Interconnection Application Should Have an Option to Combine Initial Review and Supplemental Review, With Applicants Pre-Paying for Initial Review and Supplemental Review

Proposal
With the publication of the ICA results, which customers may use to size their projects, and the additional transparency elements discussed in this Working Group report, customers will have additional information to help determine if their projects may fail certain Initial Review Screens. Thus, it is proposed that customers can opt to combine the Initial Review and Supplemental Review processes to skip to and increase the efficiency of the overall process.

Status
Consensus

Discussion

This proposal is to add an upfront option on the interconnection application to allow a customer to pre-pay for Supplemental Review, alongside paying for Initial Review, and opt to proceed straight to Supplemental Review without the optional Initial Results meeting. The utility would then be authorized to combine the Initial and Supplemental Reviews into one analysis and to skip the time and steps that normally occur between those reviews. Applicants and the utility would benefit from additional time savings by opting to skip the Initial Results meeting. The applicant would still need to pay both fees for Initial Review and Supplemental Review, and the utility would still review the project under both the Initial Review and Supplemental Review Screens, except for the Initial Review Screens made redundant by the Supplemental Review. For example, Screen M is made redundant by Screen N.

In discussing this proposal, project developers were asked how often they take the option to review the Initial Review results report and schedule an Initial Review results meeting with the IOU engineers. A number of developers, including Sunworks, Sunpower, Tesla and CalCom Energy responded, giving a range anywhere from 0-50% of projects electing to take the Initial Review results meeting before heading to Supplemental Review. Even when they decline the meeting, there is a time lag which could be avoided by customers who elect to combine both processes without the need to have an Initial Results meeting.

Proposal 8.s: Reduce Interconnection Application Fee for Non-NEM Systems

Proposal

Option A: Change the application fee for non-NEM systems smaller than 1 MW to match the application fee for NEM systems.

Option B: Review actual costs and determine whether a $300 fee is appropriate for significant application categories.

Status

Non-consensus

- Supported by CALSSA, GPI, Clean Coalition (qualified)
- Opposed by PG&E, SCE, SDG&E, TURN

Discussion

Option A

An $800 application fee applies to non-NEM systems of any size. This includes relatively small non-export storage systems along with large wholesale systems. Until recently, most projects were either NEM solar systems smaller than 1 MW or solar systems larger than 1 MW that were not eligible for NEM. As energy storage has become more common, some of which is not paired with solar, there are applications for non-NEM systems far smaller than 1 MW that are proposing to interconnect. These small-scale projects bear more resemblance to small solar projects than large wholesale projects.

With implementation of the NEM successor tariff, NEM systems pay an application fee that is based on actual utility costs to process applications. Because applications for non-NEM systems smaller than 1 MW require roughly the same amount of work to process as NEM systems, they should pay application fees at the new NEM level rather than the full $800.

The IOUs disagree with CALSSA's characterizations. IOUs assert their data does not support these statements because for NEM projects, the overall average cost is based on thousands of residential NEM systems that average about 8 kW. The nearly 100,000 per year of small residential systems cause the average cost to be much lower for all NEM applicants. For these residential NEM projects, most of the complicated Initial Review Screens (e.g., Screens F, G, H, and E) are not evaluated for individual projects, which makes the overall technical study simple, fast and cost effective. This NEM-style technical review cannot be compared to non-export storage projects up to 1 MW because non-export storage projects require an evaluation of Screens F, G, H, and E and potentially an evaluation of loading profiles, which are all bypassed for small residential NEM projects. Therefore, is not appropriate to compare small NEM projects to large non-export projects up to 1 MW.

CALSSA further suggests that through the use of ICA data and other efficiency measures, it may be determined that smaller non-NEM applications result in average costs of less than half the standard $800 fee. CALSSA concludes that, because the fee is disproportionately burdensome on small projects, it should not be set significantly higher than the average cost for applicants in this category. The IOUs disagree with this statement as ICA does not evaluate all the Screens that require evaluation under the $800 fee. None of the Initial Review Screens, including Screens F, G, H, and E, are evaluated by ICA, and thus, the $800 application cost is appropriate to evaluate non-export project.

Option B

Clean Coalition offers an alternative to the CALSSA proposal. Clean Coalition asserts that the current $145 fee for NEM systems is based on an average of all NEM applications, the vast majority of which are <30 kW. Initial Review of smaller non-NEM project applications are likely less costly to review than larger project applications and may warrant a lower fee, however it is not clear that a fee based on systems <30 kW is reflective of projects of all sizes up to 1 MW. In addition, any reduction in the $800 fee would be more meaningful to smaller projects than those closer to 1 MW.

Clean Coalition believes that the fee should reflect actual average costs, and these costs should be determined. Clean Coalition suggests that implementing a separate lower fee category would only be warranted where it is a significant reduction. Therefore, if it is determined that a defined class of applicants has substantially (>50%) lower average actual costs for Initial Review, then these applicants should be subject to a lower fee. Project review cost data is needed to establish whether this class includes all applicants <1 MW or only a subset (e.g., applicants <200 kW).

The IOUs oppose the Clean Coalition's inclusion of this proposal in the report, finding their opportunity to review the proposal was insufficient.

Gridworks determined inclusion of both Option A and B in the report was prudent, but agrees consideration of the proposal was limited. Gridworks suggests the Commission consider further input from parties on Proposal 8.s through comments on the record where supporting data can be gathered and analyzed.

Proposal 8.t: Queue Management

Proposal

Option A: Require justification for extending Commercial Operation Date; tighten deadlines; and allow small projects to interconnect if they do not impact larger projects that are in front of them in the queue.

Option B: Modified Option A with alternative approach to extending Commercial Operation Date.

Status

Non-consensus

- Option A:
    - Supported by CALSSA, IREC, Clean Coalition (qualified)
    - Opposed by PG&E, SCE, SDG&E, GPI, TURN
- Option B:
    - Supported by GPI, Tesla

Discussion

Developers of wholesale, front-of-the-meter DER projects must normally apply for interconnection before they have a counterparty to buy the energy or have a clear sense of whether they can obtain financing, secure environmental permits and satisfy other relevant factors that may affect a project's viability. This is the case whether the power is sold to the distribution utility under Rule 21 or to a different buyer under the Wholesale Distribution [Access] Tariff ("WD[A]T"). It has been necessary for wholesale developers to invest the resources to take these steps because the Commission's IOU procurement programs, as well as other energy purchasers, such as Community Choice Aggregators or direct access customers, have requirements for participants in their solicitations to have an interconnection agreement or at least have completed a phase 2 interconnection study or its equivalent. Those purchasers want to have confidence that a winning bidder has determined interconnection constraints and that any costs are reflected in the bids, such that the proposed project is financially viable. As such, completing interconnection studies is the first major development step after securing site control.

A downside of this situation is that until a developer wins a contract in a solicitation, they have a project with no buyer and are motivated to hold the reserved grid capacity for as long as it takes to find a buyer. This "queue sitting" impacts customers that want to invest in behind-the-meter DERs, as well as later queued wholesale projects, in locations where there is not enough existing capacity for their projects in addition to previously queued projects. Developers of behind-the-meter systems sized to serve onsite load always have a counterparty buyer because they are designing a system for the customer at that site.

Different stakeholders hold differing opinions on the current magnitude of this problem, but stakeholders agree it may worsen with the advent of the ICA. If a developer knows how much solar can be interconnected at a location without upgrade costs, they will be motivated to lock it in.

Currently developers expect there will be upgrade costs for large projects, so even though acting sooner will create a higher likelihood that there will be some amount of existing hosting capacity, the existing hosting capacity is not a known value and is expected to be low. As soon as the developer knows there is, for example, exactly 2.2 MW of hosting capacity at a location, there will be a lot of motivation to quickly design a system of that size and to worry about market opportunities later.

As noted, some stakeholders, including the Clean Coalition and GPI, disagree that the problem seeking to be addressed is yet a problem and are less concerned that the introduction of the ICA will make much difference. This opinion is based on their experience with earlier iterations of hosting capacity, expectations for whether ICA values will be up-to-date or stale (see Proposal 8.b), and their review of interconnection queues to date. Clean Coalition and GPI therefore oppose Part 1 of Option A, as detailed below.

Option A

The Commission should take steps to make sure the rollout of ICA does not result in a "land grab" of available hosting capacity. The proposals below are mild, in recognition that wholesale developers do need a lot of flexibility, but they head in the direction of addressing the problem.

1. Require justification for extending Commercial Operation Date

A developer with an approved project but no power purchase agreement should not be allowed to extend the Commercial Operation Date without having made real progress in construction or making clear efforts to find a buyer. If the developer is actively moving the project forward, they should have to resubmit and lose queue position.

Rule 21 currently states the following (PG&E Rule 21 Section F.3.e.iii) [**emphasis added**]:

> *Extensions of the Commercial Operation Date will be agreed upon in the executed Generator Interconnection Agreement. Reasonable Commercial Operation Dates will be discussed at the DGS Phase II Interconnection Study results meeting, or the DGS Phase I Interconnection Study results meeting if the DGS Phase II Interconnection Study results meeting is waived, in the case of the Distribution Group Study Process, the Interconnection Facilities Study results meeting, or the Interconnection System Impact Study results meeting if the Interconnection Facilities Study is waived in the case of the Independent Study Process.* ***A request for an extension of the Commercial Operation Date after the Generator Interconnection Agreement is executed will be agreed to provided that, the Producer is still responsible for funding any Distribution Upgrades and Network Upgrades as specified in the Generator Interconnection Agreement and under the same payment schedule agreed upon in the Generator Interconnection Agreement.*** *This provision has no impact on any power purchase agreement terms.*

CALSSA proposes the following changes:

- Commercial Operation Date must be set by mutual agreement, considering the intended counterparty, reasonable construction time, and grid upgrades. The developer must demonstrate progress in construction and in securing a power purchase agreement when requesting an extension. The utility will grant extensions of up to a year at a time due to construction delays, failure to secure a buyer despite good faith efforts, or circumstances outside of the control of the developer.
- If the Commercial Operation Date is more than two years in the future, developers should be required to submit an annual Summary of Activity beginning two years after the results of Initial Review or Detailed Study. Utilities will undertake an Activity Review of that summary. The utility will notify the developer that the application is deemed withdrawn if the developer does not demonstrate evidence of activity toward securing a buyer and constructing the project. Evidence of attempting to secure a buyer includes recently submitted bids and specific bids under development. Evidence of progress in constructing the project includes obtaining permits, securing financing, and actual construction. Failure to make progress toward construction should not lead to application withdrawal if it is due to circumstances outside of the control of the developer, such as waiting for the utility to make distribution system upgrades.

2. Tighten deadlines

The current interconnection milestones for wholesale projects in Rule 21 include the following.

- Developer must have “site exclusivity” – own or lease the land or have an agreement for such – at the time of application.
- Developer must pay a deposit for the interconnection study.
- Developers must pay a financial security posting within 60 business days of signing the Generator Interconnection Agreement, per language that the utilities include in the Generator Interconnection Agreement, or lose their queue position. After ICA is made available, there may be very large projects that go through Fast Track and thus are not required to put down study deposits, which would greatly diminish the significance of this step.
- After agreeing to pay upgrade costs, if any, the utility sends a draft interconnection agreement to the developer within 15 business days and the developer has 90 calendar days to negotiate changes and sign the agreement. The agreement includes schedules for work to be completed by the developer and the utility associated with the distribution upgrades and interconnection facilities.
- Developer must make good faith efforts to meet the schedules in the interconnection agreement.
- If a project fails Screen R, developer has 40 business days to indicate whether they intend to be included in a Distribution Group Study. If a study window closes during that time, the project will be studied approximately six months later in the next Distribution Group Study.
- Applicant has 30 business days to agree to scope of study.
- Developer has 60 calendar days to post initial financial security for grid upgrades and interconnection facilities.
- Developer proposes a Commercial Operation Date and can request extensions of that date without restriction. Utility is obligated to approve extensions as long as the developer has paid the required deposits.

All of these steps add up to a very long timeline, especially when developers are intentionally moving slowly. CALSSA proposes the following changes to these milestones.

- Developers must pay the Detailed Study deposit within ten business days.
- Timeline for negotiating an interconnection application should be reduced from 90 calendar days to 60 calendar days.
- After failing Screen R, a developer has 20 business days to decide whether to enter the Group Study process with extension for an additional 20 days.
- Agreement on the scope of the Detailed Study should be completed within 20 business days rather than 30.

3. Allow small projects to interconnect if they do not impact larger projects that are in front of them in the queue

Large projects that take years to study can hold up small projects that would not impact the results of the study of the larger project. If there is 1.5 MW of hosting capacity at a location and a 5 MW proposed project is undergoing detailed study to identify needed upgrades, a 1 MW project behind the larger project in the queue should be allowed to move forward if it would not impact the extent of the upgrades needed for the larger project, or if the associated cost responsibility will follow the tariff obligations of the project with the later queue position.

Qualified Support

While supporting the proposals to enable later queued projects to advance, some Working Group members, including the Clean Coalition, have expressed concern that the proposed new annual proof of progress requirement may impose a reporting and enforcement burden which is not currently warranted. A review of the interconnection queues indicates a relatively small number of Rule 21 projects currently exceeding planned Commercial Operation Date, and no evidence of either increasing delay or a "land rush" associated with the ICA exists. Clean Coalition supports the approach but recommends development of evidence that the measure is warranted prior to implementation of this component of the proposal.

IOU Perspective

The IOUs oppose these proposals. PG&E finds there are aspects which may be beneficial, but the topic needs further discussion. PG&E highlights an upcoming surge in Zero Net Energy homes and potentially Rule 21 applications being submitted before construction begins on new home constructions. It is unclear whether timelines proposed here would work for majority of applications. PG&E does, however, support better queue management.

SCE notes the proposal refers to aspects of the Wholesale Distributed [Access] Tariff, a Federal Energy Regulatory Commission regulated tariff similar to Rule 21. SCE notes any recommendations relying on changes to the Wholesale Distributed [Access] Tariff are misplaced.

SCE also would modify Part 1 of Option A to set a firm deadline—a maximum extension of 18 months from the original Commercial Operation Date would be allowed—which would be enforceable regardless of construction status. SCE suggests extension requests greater than 18 months would require a reapplication and new queued position. This position, which is supported by PG&E and SDG&E, is designed to eliminate the need for subjective assessments of a project's progress which the IOUs contend will lead to contentious disputes with their customers.

With regard to Part 2 of Option A, the IOUs are reluctant to alter timelines as suggested.

With regard to Part 3, SCE opposes this proposal. While this sounds simple, it is not. In the scenario described above, it necessary to first determine what type of mitigation the 5 MW project is required to implement in order to determine if the 1 MW project can be interconnected without additional upgrades. Using the example above, because the 5 MW project came into the queue prior to the 1 MW project, the 5 MW project has the right to use the 1.5 MW of ICA-identified capacity first and its only required to pay for mitigation for the additional 3.5 MW of generation. In this scenario it is unlikely that the 5 MW project will install upgrades that would allow the 1 MW project to also interconnect without additional upgrades. For example, the 5 MW project may cause some sections of the circuit to get close to thermal overload, but the 1 MW project would cause those sections to be over the thermal limits, making the 1 MW project responsible for the upgrades. This type of analysis cannot be performed until the utility fully studies the 5 MW project.

If both projects have received their full studies and the 5 MW project takes longer to complete construction then the 1MW project, then SCE believes that it is reasonable to allow the 1 MW project to be interconnected ahead of the 5 MW project, as long as the 1 MW project pays for the upgrades identified in its study.

Option B

GPI's Option B is identical to Option A, except for one deviation on Part 1 of the CALSSA proposal.

Instead of Option A's suggested approach to continuations of a project's Commercial Operation Date, GPI suggests the utilities continue to rely on the negotiation phase of the interconnection process, which takes place before finalizing the Generator Interconnection Agreement. GPI notes that the milestones negotiated within that process can be numerous and detailed. As such, there is already a process in place that holds wholesale interconnection customers accountable for moving ahead judiciously, with the risk of being removed from the queue if these milestones are not met and not cured within the time allotted.

Tesla supports GPI's proposal.

Proposal 8.v: Additional Automation and Streamlining Opportunities

Proposal

The Commission should consider the Interconnection Automation and Streamlining Opportunities report (attached as Appendix A) and provide guidance on further action within this proceeding regarding:

1) how future Working Group schedules can include additional discussion of the automation opportunities identified;

2) review of the likely costs and benefits of implementing automated data processes to reduce costs and streamline interconnection processes and schedules;

3) coordination of related IOU investments in line with the Commission's Distribution Resources Plan precedent, the DER Action Plan, and the merits of

including automation goals in the DER Action Plan or a separate automation roadmap.

Status

Non-consensus

- Supported by GPI, Clean Coalition, Stem
- Opposed by PG&E, SCE, SDG&E, TURN

Discussion

In discussing Issue 8, the Working Group identified that certain actions that facilitate automation are not necessarily related to integration of ICA, but are part of the Working Group 2 scope.

GPI and Clean Coalition led the development of recommendations and identified additional automation and streamlining opportunities for the Rule 21 process, beyond the automation of ICA that is already taking place. The intent of the draft Interconnection Automation and Streamlining Opportunities report included in Appendix A is to form the starting point for an actionable "roadmap" for further automation and streamlining of the interconnection process for adoption by the CPUC, after additional discussion in this proceeding.

GPI and Clean Coalition, with support from Smarter Grid Solutions as engineering consultants, took the lead in drafting the report and solicited input from stakeholders, including IOU and non-IOU Working Group members, to refine the understanding of opportunities and develop recommendations. GPI and Clean Coalition had several opportunities to present their research and recommendations to the larger Working Group and circulated the report for written comment during the course of Working Group 2. The result is a GPI and Clean Coalition proposal informed by other stakeholders. It is not a comprehensive reflection of input received, and it is only representative of the views of stakeholders identified as "supporters."

The Working Group has several discussions of the potential cost implications of this proposal. TURN repeatedly and clearly expressed the need for a high-level cost estimate of these automation opportunities before a roadmap should be developed. As the Report shows, to date only a *relative* cost-benefit analysis has been provided. GPI and Clean Coalition identify cost estimates as a topic worthy of further discussion and invite utility proposals of those potential costs.

A summary of the most promising opportunities identified by the GPI/Clean Coalition draft report and resulting discussions are as follows:

1. Automating the application process and completeness review
    a. Reduce review time from 1-40 business days to as little as 1 day for projects that don't require corrections

    b. Reduce turnaround time for corrections from 10 business days for each round of corrections to 1-2 days with automated interconnection portals
    c. Issue 22 has already scoped potential revisions to the interconnection portals, and this contributes to that work
2. Automating (at least partially) Initial Review
    a. Automating analysis of refined Screens toward reducing time from 15-17 business days to 1 day <u>for eligible projects</u>
    b. Further evaluation of costs and benefits is required
3. Automating (at least partially) Supplemental Review
    a. Reduce time from 20-22 business days or inclusion of the Supplemental Review Screens in Initial Review (no additional time required for Initial Review) <u>for eligible projects</u>
    b. Screens N and O have been automated as part of ICA, leaving the catchall Screen P for engineering review
4. Frontloading and automating the Generator Interconnection Agreement drafting process
    a. Provide template Generator Interconnection Agreement to customer after application deemed complete, in order to frontload customer review of GIA terms
    b. Automated population of template Generator Interconnection Agreement with Initial Review/Supplemental Review results so that draft Generator Interconnection Agreement can be generated in 1 day rather than 15 business days

- Work to identify additional automation and streamlining items

Opposing Party Perspective

TURN opposes the inclusion of the report from Smarter Grid Solutions. TURN's perspective is that the proposal needed to be supported by a high-level cost estimate of automation opportunities. The report instead provided arelative cost-benefit analysis. TURN concludes these materials are interesting but insufficient. TURN reasons that just because Proposal A is worse than Proposal B doesn't make B a good proposal. In addition, the IOUs have not indicated that they agree with the analysis conducted by Smarter Grid Solutions on behalf of GPI and Clean Coalition. Thus, TURN opposes the inclusion of the report by Smarter Grid Solutions. Furthermore, TURN recommends that the Commission not treat GPI's proposal as a roadmap. Rather, GPI's proposal should be seen as identification of potential opportunities to be analyzed later, including conducting a cost-benefit analysis, identifying stakeholders that benefit from the proposals, and discussing the proper cost allocation for these costs.

SCE appreciates GPI's and Clean Coalition's efforts to identify aspects of the interconnection process that could be streamlined through changes to relevant IT tools. However, SCE cautions that scoping, development and implementation of such IT tools will require time and cost. CPUC authorization for additional funding will be required to accomplish many of the aspects of the GPI and Clean Coalition "report." Such funding approval is typically addressed in a utility's General Rate Case.

SCE points to a few areas in the report that are especially concerning to SCE.

- **Automation of completeness review:** The proposal to automate the completeness review does not account that verification of PDF Single Line Diagrams requires engineers to physically verify details that cannot be done by an automated system. For example, the engineer needs to verify connection points for current transformers, potential transformers, metering, and other devices. It necessary to verify this information to prevent safety issues and costly modification. In many cases, these Single Line Diagrams need corrections by the customer as part of the application review process.
- **Automation of Initial Review Screens:** Several of the screens (e.g., Screens F and G) require significant work to prepare and maintain very complex databases that are continually changing. Even the ICA work did not include these Screens due to their complexity and thus automation of these screens should be a long-term goal.
    - GPI response**:** our report identifies how Screens F and G could be automated with existing tools and databases.
- **Automation of Supplemental Review:** The Screens in Supplemental Review are complex to automate as proposed:
    - Screens N and O requires power flow analysis to be completed. This means that the automation tool would have to call a power flow tool (e.g., CYME) and automatically update network models with the right point of interconnection and the correct DER level. This level of automation is, at this point, not available and should be a long-term goal
        - GPI response: Screens N and O are already automated as part of ICA, including map integration.
    - Screen P cannot be evaluated by a power flow tool as this Screen evaluates safety issues that cannot be evaluated by the other Screens. To perform this evaluation, the engineers need to look at characteristics of the overall system in conjunction with proposed and existing Interconnection Requests.
        - GPI response: we are not proposing at this time that Screen P be automated, and the report states as such.
- The report confuses the automation being done as part of the ICA development process with automation for the Rule 21 interconnection process. It is correct that the ICA working group final report mentions automation multiple times, but, the context of the automation in the ICA report in development of monthly ICA values not automation of the Rule 21 interconnection process.
        - GPI response: our report does not confuse or conflate automation of ICA with automation of Rule 21 more generally; we are clear in distinguishing these two issues. We also note that Issue 8 specifically

scopes “interconnection process automation” and how ICA can facilitate such automation.

PG&E’s perspectives:

- In general, PG&E supports improving automation and IT systems, but we have to make sure we do it properly and that Rule 21 timelines remain what they are now. There are times when systems fail and manual workarounds have to be engaged, so compliance timelines should reflect the manual process
    - GPI response: our report discusses the need to phase in automation for most projects, but not all projects; so projects that still need to go through manual review can do so under existing timelines, but most projects should be automatable and subject to much faster timelines.
- Since this recommendation involves consideration of costs, if supported by the Commission, it should be considered as an element of funding approval which is typically addressed in a utility’s General Rate Case. Consideration of any IOU expenditures should not be addressed in the Rule 21 proceeding. Such funding approval is typically addressed in a utility’s General Rate Case.
    - GPI response: many tasks utilities are assigned from legislation or the Commission do not require General Rate Case funding approval, including the ICA itself; our view is that much of the automation and streamlining work can be funded outside of the General Rate Case process.
- Note that IT costs were covered in the IOU responses to the ALJ’s August 15th Ruling question 5 under Issue 3. (If the Commission orders development of Process Options 2 and/or 3, should the Utilities recover their costs through the General Rate Cases, balancing accounts, or increasing the interconnection application fees? Explain the reasoning for your preferred approach.) Cost treatment to the extent appropriate should be consistent.
- It is important to note that these timeline reductions should not be carried over into Rule 21 itself. Efficiency gains and automation are what we should be striving for, but they are not infallible solutions. As such, Rule 21 compliance timelines should reflect what the manual process of performing the task entails, keeping in mind the volume of projects that the IOUs are experiencing.
    - GPI response: our report discusses the need to phase in automation for most projects, but not all projects; so projects that still need to go through manual review can do so under existing timelines, but most projects should be automatable and subject to much faster timelines.

Appendix A

Interconnection Automation and Streamlining Opportunities: Preliminary findings and recommendations

Tam Hunt, GPI

Sahm White, Clean Coalition

With review and assistance by Smarter Grid Solutions, Inc.

This document was drafted as part of the R.17-07-007 Working Group 2, to be included as an appendix to the Working Group's final report. GPI and Clean Coalition intend that this document, with further deliberation and cost-benefit analysis, be used as guidance in consideration of an actionable "roadmap" for adoption by the Commission in a later phase of the current proceeding.

This document is representative of the authors' perspectives with various rounds of input from working group members received as of Oct 3, 2018. Due to differences in party opinions the document as a whole does not necessarily reflect the perspective of any individual Rule 21 Working Group member.

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Proposal 8.v for Commission action in relation to this report:

That the Commission review this document and provide guidance on further action within this proceeding regarding:

1) how the Working Group can best schedule additional discussion of the automation and streamlining opportunities identified;

2) review of the likely costs and benefits of implementing the Working Group's automation and streamlining recommendations;

3) coordination of IOU automation investments in line with the Commission's Distribution Resources Plan (DRP) precedent, the DER Action Plan, and consideration of including automation goals in a new DER Action Plan or a separate automation "roadmap."

I. Summary of recommendations and background

The Green Power Institute and the Clean Coalition presented, on April 25, 2018, to Working Group 2 a preliminary review of opportunities for either full or partial automation of the various aspects of the Rule 21 interconnection process in support of the Commission's goal of dramatic interconnection streamlining. After significant dialogue between various Working Group parties, this report describes the initial findings and recommendations for the most promising automation and streamlining opportunities.

The automation engineering firm Smarter Grid Solutions was engaged by GPI to provide feedback to the working group on the proposed recommendations included, and provided broad cost-benefit review of the report's key recommendations.

<u>Most of the recommendations in this report are intended to apply to behind-the-meter projects over 500 kW as well as front-of-meter projects of any size, because these projects don't currently enjoy the benefits of automation or low/no-cost interconnection that small behind-the-meter projects do enjoy.</u>

In terms of the benefits of the recommendations below, the authors of this report see three major time savings opportunities, as follows: 1) saving as much as 10-40 business days in the application and completeness review stage; 2) saving as much as 10-30 business days in the Initial Review and Supplemental Review; 3) saving as much as 30-60 calendar days in the GIA review and negotiation process. These potential savings add up to as much as six months savings for each Fast Track interconnection application.

Time savings are significant wherever projects are operating under a restricted schedule, such as in solicitations for DER to meet location-specific needs, compliance mandates, or funding opportunities. These savings can also be substantial because many developers, particularly for front-of-meter projects, must go through an interconnection process multiple times before a viable location is found. While ICA and Pre-application Reports (PAR) help with this, the ICA only addresses some factors, and the PAR require $1,100 and 40 days each for detailed information, and PAR information is not definitive (only interconnection studies are definitive). As such, time savings for going through the interconnection process each time can add up quickly and lead to substantially reduced overall development timelines and related costs. These cost savings will be passed on to ratepayers.

It is also important to note the distinction between behind-the-meter and front-of-meter projects in terms of development timelines and prioritization. For front-of-meter projects, completing interconnection studies early in the development process is imperative, in order to test project viability in light of the expected interconnection costs. Smaller wholesale projects (ReMAT and RAM, for example) are particularly sensitive to project costs because profit margins are thin. Moreover, utilities are increasingly requiring Fast Track studies (phase 2 studies or their equivalent like Fast Track) to be completed before bids may be submitted into RFPs.

A summary of key opportunities for automation and streamlining follows, with information about each utility's status with respect to each automation:

- **Automating the application process and completeness review**. Utilities must inform the applicant whether the application is deemed complete, or must be corrected, within 10 business days (BDs) after receipt of the Interconnection Request (E.5.a). In practice, this step can take two months or longer if multiple corrections are required (as is common for larger projects). Automation of the interconnection portal and application processing could reduce this step to one day for those projects that don't need corrections, as well as dramatically reduce the time required for each round of corrections, and can build upon existing on-line application portals for net-metered projects, which already significantly reduce application processing times through partial automation. PG&E states that it has already planned for the work required to automate the application portal and its small NEM application review is already automated. SCE has gone out to bid for similar work to update and partially automate its interconnection portal, but the full extent of this effort is not known at this time. SDG&E's DIIS portal is already partially automated but SDG&E has no plans to further automate its portal.

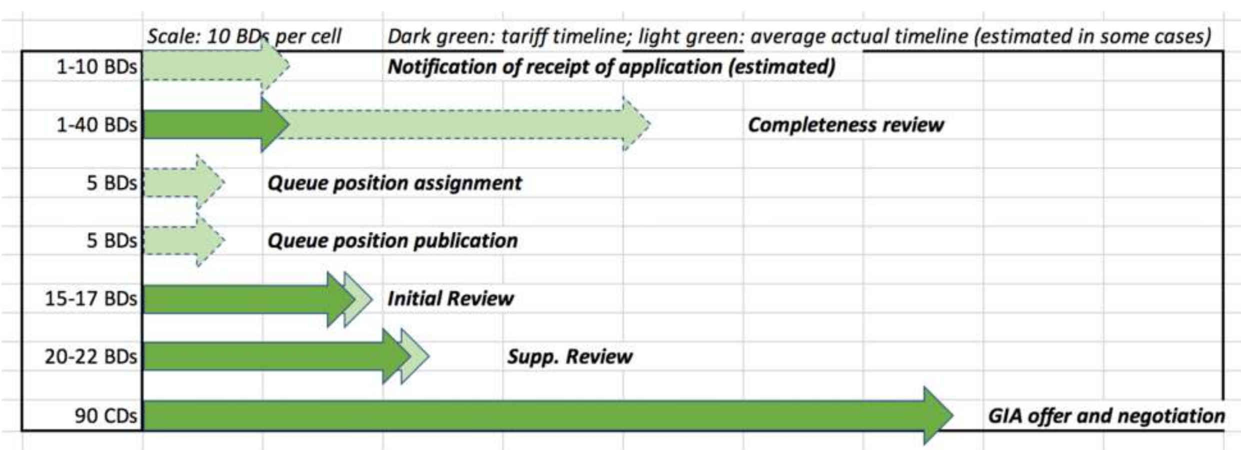
- **Automating (at least partially) Initial Review**. Initial Review must be delivered within 15 BDs of the application being deemed complete (F.2.a). If applicable Screens can be cleared automatically through use of data from the online application inputs and ICA data, it may be feasible to reduce the Initial Review to 1 BD. This report identifies feasible ways for achieving this level of automation. PG&E agrees with the merits of automating IR, and notes that all Screens except F and G are already automated, but considers it necessary to maintain the 15 BD review in order to allow engineers to study mitigation options for projects that fail IR.[6]
- **Automating (at least partially) Supplemental Review**. Supplemental Review must be completed within 20 BDs (F.2.c). Parts of SR may already be automated with the existing ICA (Screens N and O are already automated with the current ICA). Under the currently-defined SR Screens, this leaves only Screen P, a "catch all" safety and reliability Screen, to be completed in SR. PG&E agrees that parts of SR can be automated but note that a cost/benefit analysis should be completed before a decision on full automation is made by the Commission.
- **Frontloading Supplemental Review Screens N and O into Initial Review.** Projects that are less than or equal to displayed ICA value, or otherwise expect to interconnect without need for Supplemental Review, may be susceptible to largely automated initial review. Frontloading Screens N and O into IR will allow an easier automation of Initial Review because Screen N makes Screen M redundant and Screen O renders some IR Screens, or at least part of those Screens, redundant. (This recommendation may be mooted by changes contemplated in the Issue 8 draft proposal for changes to Screens M and N)
- **Combining Initial Review and Supplemental Review**. Only applies to projects that select this option, which will generally be 500 kW and larger behind-the-meter and front-of-meter projects of any size. Combined review could either be a serial study process, skipping the IR results meeting, or a concurrent study process. Revised timelines and fees for the combined IR/SR to be determined as part of the working group process.
- **Frontloading and automating the Generator Interconnection Agreement** (GIA) generation and offer process. A GIA currently must be offered to most applicants

[6] GPI notes that the utilities don't generally offer mitigation options until Supplemental Review is completed, so it is not clear that a 15 BD timeline for IR is necessary if this is the case, even for projects that fail IR. In GPI's experience, IR results in a short report stating which Screens, if any, are failed, with information about the applicant's choices for how to proceed.

within 15 BDs of passing Initial Review or 15 BDs of applicant's request after passing Supplemental Review (F.2.c.iv). This step could be "frontloaded" by offering a fully or partially populated provisional GIA once an application is deemed complete, allowing the applicant to begin detailed review of the draft GIA much earlier than under the existing process. Execution of the final GIA may be streamlined by such frontloading and also by including the key IR or SR results in a second, automatically-generated, GIA, such that the fully populated draft GIA generation process takes only 1 BD for the large majority of projects instead of the 15 BDs currently allowed in the tariff. Frontloading of the initial GIA should also reduce the 90 CD negotiation period. PG&E is already planning this work but notes that it will be difficult to automate inclusion of mitigation options into the GIA. SCE has recently completed a behind-the-meter energy storage interconnection pilot that included frontloading the GIA; SCE has no plans currently to expand this pilot approach to additional technologies.

Figure 1 illustrates the Rule 21 Fast Track tariff-specified timelines (darker green arrows) and average actual timelines (lighter green arrows), with estimates in dashed arrows, for projects over 500 kW. Where there is no dark arrow there is no tariff-specified timeline.[7]

Figure 1. *Fast Track timelines under Rule 21.*



The utilities have already significantly and effectively leveraged automation to streamline the application submission process and some additional aspects of application

[7] Sources: IREC R.17-07-007 2018 data requests and responses from PG&E and SCE (SDG&E is excluded because data set was so small); interconnection experience by GPI attorney Tam Hunt working with his private clients over the last decade; and other developers such as Tesla working with thousands of C&I solar projects.

management and review, as described below. Existing utility automation efforts have, however, focused on smaller net-metered systems, but those existing efforts can in many cases be expanded to include over 500 kW behind-the-meter and front-of-meter projects of any size seeking to interconnect under Rule 21. Costs and benefits of expanding these existing procedures is discussed at the end of this report.

There are also a number of pilot projects that will be useful for automation and streamlining efforts in this proceeding, including the DOE and CEC-funded EASE pilot project that is hosted by SCE, and the Interconnection Online Application Portal (IOAP) pilot being developed by AVANGRID in New York. These efforts are described further below.

We describe below how many aspects of the interconnection process could be automated for the large majority of projects. While achieving such automation sounds ambitious, we want to stress the phrase "for the large majority of projects." Reaching full automation of interconnection for all projects is a longer-term goal that may not be warranted given the costs of achieving such wide-scale automation—if, for example, only a small number of projects per year would benefit from these improvements. But increasingly robust automation, or even full automation of review for the large majority of projects, is an attainable and probably cost-effective task (more work will be required in examining costs for some aspects of automation)[8] at this time.

We must also consider the intent of AB 327 and the Commission to encourage DER, rather than only reacting to DER interconnection issues, by proactively creating a dramatically streamlined interconnection process.[9]

II. How does the existing Rule 21 interconnection process work?

[8] We include some considerations on cost-effectiveness at the end of this report.

[9] D.17-09-026 in the DRP proceeding, created by AB 327, echoes the DRP's Final Guidance document in calling for "dramatic streamlining" of the interconnection process as a key step for helping DERs (p. 26)."

It is helpful to consider the following Figures 2 and 3 showing the full timeline for Fast Track interconnection for both front-of-meter projects and a 1 MW behind-the-meter project, including pre-application items and post Interconnection Agreement items.

Figure 2. *Interconnection costs and timelines for Rule 21 Fast Track 1 MW front-of-meter.*[10] [11]

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[10] These charts are meant to show comparison data for real-world experience developing front-of-meter and behind-the-meter projects, not idealized timelines based only on tariff-required timelines. For example, PAR costs and timelines cover 1-2 PARs per project b/c it's almost never "one and done" in terms of finding a site that works.

[11] Tesla offers the following comments on Figure 2:

> Timelines can be longer if there is a line-side tap or AC Disconnect variance review is required, or non-standard equipment is utilized for the functionality of the design. Extensive NEM-A arrangement causes longer than normal land review (sometimes this can take 20 to 40 business days). Additional delays in timelines are incurred when PV is paired with battery energy storage systems (BESS).

Wholesale DG timelines and costs

Clean Coalition

WDG Rooftop 1 MW Fast Track Project Development (Project where ICA map indicates sufficient capacity)	Timeframe (BD) Max	Timeframe (BD) Min	Timeframe (BD) Typical	Fees Max	Fees Min	Fees Typical	Costs Max	Costs Min	Costs Typical
PRELIMINARY WORK AND SITE CONTROL	371	113	216						
Site Selection	2	1	1	$-	$-	$-	$600	$200	$300
Preliminary site evaluation and project screening	2	1	2	$-	$-	$-	$600	$150	$300
Preliminary layouts and performance models	7	1	3	$-	$-	$-	$4,000	$1,000	$2,000
Site control (Lease Option Agreement)	180	60	100	$-	$-	$-	$40,000	$15,000	$25,000
Preapplication reports	60	30	35	$600	$300	$600	$1,500	$500	$1,000
Other site research and selection	120	20	75	$5,000	$500	$1,500	$15,000	$3,000	$9,000
INTERCONNECTION REQUEST AND INITIAL REVIEW	50	23	37						
Prepare and submit interconnection application	10	3	5	$800	$800	$800	$20,000	$5,000	$10,000
Utility deems application complete	10	5	7	$0	$0	$0	$0	$0	$0
Initial review results	15	15	15	$0	$0	$0	$4,000	$2,000	$3,000
Developer requests initial review results meeting or proceeds to supplemental review	10	0	5	$0	$0	$0	$0	$0	$0
Initial review results meeting (if clear, go to GIA cost estimate or GIA)	5	0	5	$0	$0	$0	$1,000	$500	$750
INTERCONNECTION SUPPLEMENTAL REVIEW	110	50	70						
Decide to proceed to Supplemental Review	15	0	5	$2,500	$2,500	$2,500	$600	$150	$300
Supplemental review results	60	20	30	$0	$0	$0	$4,500	$2,100	$3,300
Developer requests supplemental review results meeting	15	0	5	$0	$0	$0	$0	$0	$0
Supplemental review results meeting	5	0	5	$0	$0	$0	$1,000	$300	$500
Decide to proceed to GIA draft	30	30	30	$0	$0	$0	$0	$0	$0
POWER SALES CONTRACT	340	100	180						
Review power sales options	100	20	60	$0	$0	$0	$5,000	$2,000	$3,500
Obtain Power Purchase Agreement	240	80	120	$2,000	$0	$1,000	$20,000	$5,000	$12,500
Negotiate GC/EPC and engineering contracts	30	10	20	$-	$-	$-	$10,000	$1,000	$5,000
GENERATOR INTERCONNECTION AGREEMENT (GIA)	60	1	30						
GIA negotiations and signatures (90 Calendar Day max time allowed)	60	1	30	$0	$0	$0	$5,000	$2,000	$3,500
GRID UPGRADES CONSTRUCTION**	250	0	100						
Grid upgrade costs				$0	$0	$0	$300,000	$0	$150,000
O&M costs (Cost of Ownership or COO)***				$0	$0	$0	$150,000	$0	$75,000
Coordinate upgrade construction with utility, deed transfers				$0	$0	$0	$10,000	$2,000	$6,000
PTO				$0	$0	$0	$1,000	$500	$750
COD				$0	$0	$0	$1,000	$500	$750
Totals (accounting for overlapping times)	1181	287	723	$10,900	$4,100	$6,400	$594,800	**$42,900**	$312,450
"Typical" Totals			**723**			**$6,400**			**$312,450**

Figure 3. *Interconnection costs and timelines for 1 MW NEM projects.*

Net Energy Metering (NEM) timelines and costs

Clean Coalition

NEM Rooftop 1 MW Project Development (TPO)	Timeframe (BD)			Fees			Costs		
	Max	Min	Typical	Max	Min	Typical	Max	Min	Typical
PRELIMINARY WORK	245	30	45						
Customer acquisition and site selection	75	5	20	$-	$-	$-	$10,000	$2,500	$5,000
Preliminary site evaluation, Preapplication Reports, and project screening	60	5	10	$2,500	$600	$1,500	$10,000	$2,500	$5,000
Preliminary layouts and performance models	30	5	5	$-	$-	$-	$4,000	$1,000	$2,000
Avoided cost and project models	20	5	5	$-	$-	$-	$3,000	$1,000	$1,000
Proposal and LOI	60	10	5	$-	$-	$-	$3,000	$1,000	$1,000
POWER SALES CONTRACT	140	40	50						
PPA/lease negotiation	60	10	20	$-	$-	$-	$3,000	$1,000	$1,000
Site due diligence (structural, roof condition, soils, electrical/services, etc)	50	20	20	$-	$-	$-	$10,000	$1,000	$5,000
Negotiate GC/EPC and engineering contracts	30	10	10	$-	$-	$-	$10,000	$1,000	$5,000
INTERCONNECTION REQUEST AND GENERATOR INTERCONNECTION AGREEMENT	150	50	105						
Prepare and submit interconnection application; receive response from IOU	90	20	60	$145	$145	$145	$20,000	$5,000	$10,000
Negotiate NEMEXP IA (Form 79-978, for 1,000 watts or less)	60	30	45	$-	$-	$-	$3,000	$250	$500
GRID UPGRADES CONSTRUCTION**	200	0	180						
Grid upgrade costs				$0	$0	$0	$0	$0	$0
Coordinate upgrade construction with utility				$0	$0	$0	$5,000	$500	$1,000
PTO				$0	$0	$0	$1,000	$250	$500
COD				$0	$0	$0	$1,000	$250	$500
Totals (accounting for overlapping times)	590	75	302.5	$2,745	$745	$1,745	$83,000	$17,250	$37,500
"Typical" Totals			**302.5**			**$1,745**			**$37,500**

III. What is automation?

For the purposes of this report, partial automation is defined as follows:

> Partial automation of the Rule 21 interconnection process constitutes automation of various sub-components of the process in the near-term (1-2 years) and mid-term (3-4 years).

Full automation is defined as follows:

> Full automation of the Rule 21 interconnection process would be a procedure that requires *de minimis* human intervention for the large majority of applications from receipt of application through final review and draft Interconnection Agreement (for Fast Track).

It should be stressed that full automation efforts will likely apply to the "large majority" of projects, not all projects, since issues will very likely arise for some projects that may always require some human intervention.

Our intention is not to pursue automation and streamlining for its own sake but in order to improve rates, to increase the delivery of renewable energy, and to help the state meet its energy and climate change goals. Accordingly, this document outlines efforts that will help to meet these objectives.

IV. The DRP and automation: DRP ICA Working Group Final Report

The DRP's ICA Working Group Final Report (R.14-08-013) adopted a number of recommendations with respect to automation. Perhaps the key passage states, with respect to automation:

> As a long-term vision, and not part of the ACR's [six-month] scope, some members of the WG envision that the ICA should be updated on a real-time or daily basis to the extent possible to allow the reflecting values to be used in **an automated interconnection process**. Future enhancement should work towards this goal, while considering issues such as the following in coordination with the Rule 21 proceeding:
>
> - **Development of automated interconnection studies which considers specific application information that cannot be known ahead of time to be reflected in ICA**. Generation queuing, commercial operation dates, and planned work/transfers can all have a unique impact on certain locations in the system and currently must be considered application-by-application with manual engineering review.

Automation is mentioned over 20 times in the Final Report; some examples are as follows:

- "PG&E notes that if full automation is desired, then <u>focus must shift to automating more of the interconnection process versus the proactive ICA</u>, which can only improve portions of the interconnection review."

- “SCE reiterates that it would incorporate significant changes to new circuit models on a monthly basis. SCE is currently developing automated processes to maintain the accuracy of network models and data as changes on the distribution system occur, as part of full system-wide deployment of ICA.”
- “SDG&E currently automatically updates its models daily, but those are not currently validated for ICA purposes. SDG&E would need to validate those models that have monthly changes for the ICA update.”

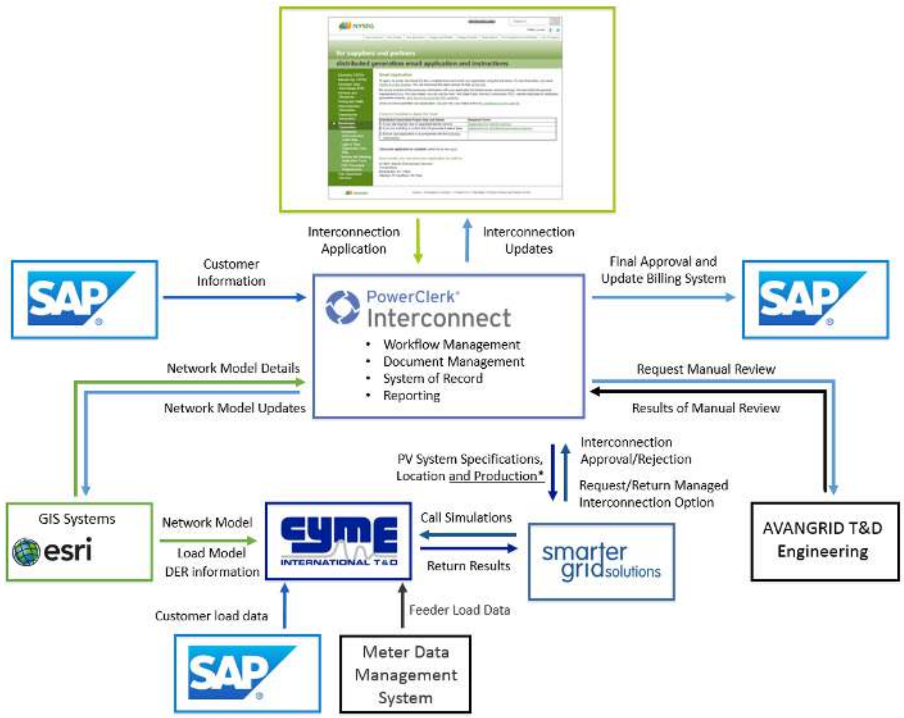
The DRP proceeding (R.14-08-013) Track 1 decision (D.17-09-026) adopts the Final Report and also the DRP Final Guidance language with respect to the need to “dramatically streamline” interconnection (p. 26): “[O]ne of the key purposes of the DRP is to dramatically streamline the interconnection process.”

V. Similar automation efforts

There are a number of similar efforts that we can look to for guidance in this proceeding. Specifically, the following efforts are helpful as guidance (arranged chronologically):

- EnergyNet 2011 and 2013 (final report) >> this is a precursor to the ICA; funded by CEC
- SP Energy Networks in the UK “Utility Map Viewer” (the model for IOAP)
- AVANGRID’s (NY) Interconnection Online Application Portal (IOAP), is a partnership between Clean Power Research, Eaton (provider of the distribution simulation software CYME), and Smarter Grid Solutions. The proof of concept is finalized, with final product rollout expected in 2018/2019, pending regulatory approvals and funding. Relevant program details are as follows:
    - Clean Power Research to automate the administrative side of the interconnection process
    - CYME to automate the technical Screening/power flow analysis
    - Smarter Grid Solutions (SGS) to automate its Flexible Interconnection analysis
    - Objectives:

  - Fully-automated interconnection processes
  - Hosting capacity maps – Static and Flexible hosting capacity
  - Data transparency for developers
- IOAP intends to automate the full range of Screens within the NY Standard Interconnection Requirements in the final product rollout, and has successfully demonstrated automation for a number of Screens within the proof of concept:
  - Screen A: Anti-Islanding
  - Screen B: Fault Duty Contribution
  - Screen C: Primary Distribution Interconnection
  - Screen D: Transmission Interconnection Adjudication
  - Screen H: Distribution Equipment
  - Screen K: Voltage Rise
  - Screen L: Voltage
- The schematic for the IOAP automation effort is as follows:



- New York State has created [functional requirements]() for an Interconnection Online Application Portal. Each of the utilities in the state must submit plans for its implementation as part of their distribution system integration plan (DSIP) filings.

- DOE/CEC-funded EASE project, hosted by SCE
    - This is a broad-ranging effort to automate much of the interconnection process for all DER, as well as a management system (DERMS) for interconnected projects
    - EASE is <u>focused</u> on, *inter alia*, reducing interconnection time for >100 kW DER to five days or less (as described by the Smarter Grid Solutions program brochure)
    - This effort is also underway in 2018, with the project design basically complete, according to Smarter Grid Solutions, and testing set to begin in 2019, with field trial beginning in late 2019

VI. What is already automated in Rule 21?

A number of different aspects of Rule 21 have already been automated to varying degrees, including the following:

- NEM application acceptance and review for projects under 30 kW is partially automated for some utilities, starting in 2013 for PG&E and 2012 for SDG&E
- SCE, e.g., has at least partially automated the following:
  - Power Clerk Interconnect (PCI) for Online Application for NEM and Rule 21-non-export projects
    - While the intake process is through PCI, several internal handoffs are still required to process certain type of projects (New services NEM-aggregation, Meter adopters, NGO, etc.)
  - Customers are able to see the project status and can provide documents via the tool until PTO is issued
    - Limited integration with back-office systems which requires data from multiples sources gathered for technical review
    - Not all projects go through PCI, requiring additional handoffs and thus delays
    - Tesla notes that C&I projects have 3-5 changes to applications over their lifespan. This results in 4-12 weeks of avoidable delay on average per project when waiting for a simple update in the portal to resubmit and/or submittal of documentation in a timely manner
- Planned future efforts for SCE:
  - PCI or a similar tool is envisioned to support all projects seeking to interconnect to the distribution grid
  - Envisioned to integrate with existing and future back-office systems
  - Envisioned to streamline the DER Interconnection process through business process Optimization and Automation

    - Funding review is underway and although initial funding for limited scope was authorized, additional funding may be required at a future date and functionality may be contingent on funding allowances
    - Final scoping and related timelines remain under review
- PG&E has also automated standard NEM under 30 kW
    - PG&E is also undertaking several initiatives to further enhance its automation. This would include expanding its online invoicing, to projects submitted through the ACE-IT portal greater than 30 kW and less than 1 MW.
    - PG&E has partially automated the Preapplication Report process
    - Has already partially automated a number of Initial Review Screens: A, B, F, G, J, K, M
- The ICA value generation process is automated and the final ICA is to be completed by late 2018 (pushed back from July 2018)

VII. How can Rule 21 interconnection be automated?

This section looks at the various aspects of the Rule 21 interconnection process and identifies opportunities, at a high level, for partial or full automation.

A. Automating the application portals

- IOUs already have online portals for submitting NEM solar interconnection applications, representing partial automation of this aspect of the interconnection process. Much more can be done, however, to further automate these portals, particularly expanding the automated process above the 30 kW limit to all distribution-connected DERs (behind-the-meter and front-of-meter)
    - E.g. PG&E "standard NEM interconnection" is mostly automated
    - SCE here
    - SDG&E here

- Potential revisions to utility interconnection portals is scoped as Issue 22 in the R.17-07-007 Scoping Memo, but this scoping item does not specify automation or "dramatic streamlining," which is the focus of the present report.
- Automation of front-of-meter DER and over 500 kW behind-the-meter should be map-interactive, with ICA values displayed on the interconnection maps plus a link to the application portal
    - This is the beginning of the "Click n Claim" process that GPI has advocated in the present proceeding
- NY's IOAP (Interconnection Online Application Portal) is a good model to emulate for the "nuts and bolts" of a comprehensive automated application portal, as discussed above. The IOAP will be a fully automated application portal and interconnection process, similar to the Click n Claim proposal, once completed

B. Automating application processing and the "deemed complete" determination

- An application must be processed by the utility within 10 Business Days (BDs), applicant notified of receipt, and if the Interconnection Request is deemed complete or not (E.5)
- If the online portal application is populated correctly, this is automatable in two different ways:
    1. Provide template single-line diagrams (SLDs), that can be modified as required, for simpler projects. SDG&E's DIIS system has largely automated this process for NEM projects, including an automated SLD process template that applies to many straightforward projects by allowing the customer to select a generic generator configuration from the DIIS tool instead of supplying a project-specific SLD, and that generic configuration then serves as the SLD
    2. Larger behind-the-meter and front-of-meter projects require more complex SLDs and for this type of project dialogue windows should specify the needed information in order to safely interconnect such projects without requiring individualized SLD review

- If deemed complete, applicant is notified automatically by email that Initial Review will be completed within 15 BDs (E.5.a, F.2.a)
- If not deemed complete, applicant is notified automatically of the deficiencies and that it will have 10 BDs (per the tariff) to cure (E.5.b). Deficiencies will often result in multiple rounds of corrections, with each round requiring 10 BDs by the IOU. With an automated application portal, the need for corrections should be significantly diminished and the turnaround time for notifying applicants of deficiencies may also be significantly diminished.

C. Automating the queue position assignment

- Applies to all front-of-meter applicants; queue position assigned based on date application received if no deficiencies were found, but otherwise assigned when "deemed complete" (E.5.c)
- This can be automated by linking the required databases

D. Automating queue publication

- Queue is published monthly by each utility (E.5.d)
- Updates to the queue can be automated by linking databases, and then published in real-time or defined time periods
- Should be linked to ICA updates, eventually in real-time. Tesla and GPI note that "the key word here is actionability." That is, ICA results should not be stale and developers should be able to consider ICA figures to be reliable.

E. Automating ICA

- ICA was intended to be a highly automated process from the outset.
- SCE, for example, describes their process for automating ICA: "Three software suites are being developed to support the ICA system-wide implementation. The Grid Connectivity Model (GCM) develops and orchestrates interfaces to provide various data (e.g., substation capacity results, fault duty calculation, circuit configuration, load profiles, line regulator settings, etc.) to the System Modeling Tool (SMT) which

utilizes the data from GCM to automate the ICA calculations. The scope of SMT also includes license fees for software like the Power System Analysis Tool. The Distribution Resources Plan External Portal (DRPEP) integrates with modeling and calculation tools that provide ICA results and publishes those results externally on the web map interface known as DERiM." (SCE ICA Interim Report Jan. 2018)

- Final ICA results are set to be produced in late 2018 (originally set for mid-2018 but delayed)

F. Automating ICA updates

- The frequency of updates to the grid-wide ICA has been set by the Commission as monthly for now, but with the admonition that the frequency of such updates will be improved once the utilities gain some experience with monthly updates (D.17-09-026, pp. 29-30). In order to ensure actionability (and avoid stale ICA values), IOUs will need to move quickly to real-time automated ICA value updates
- ICA updates should occur in real-time, as new applications are submitted and processed, in order to eliminate stale data issues. Computational resource issues are implicated with real-time updates, but it is our view that updating the model in real-time, based on automatic inclusion of new interconnection applications, should be automatable with the use of CYME or other power flow software that is already being integrated by IOUs. As discussed below, there are questions about timing and costs that need to be addressed before automated queue updates can occur.
- IOUs are already planning to automate ICA updates, however, as described in the DRP ICA Working Group Final Report (emphases added):
    - "PG&E has a gateway tool for incorporating circuit updates into its circuit models on a weekly basis. PG&E also creates yearly planning models from a snapshot of the gateway model which contains specific modifications and planned worked on the circuits. Recommendations from the WG would require additional work to merge the planning models with the gateway models." PG&E reiterated in response to the present report that automating ICA updates is already planned work.
    - "SCE reiterates that it would incorporate significant changes to new circuit models on a monthly basis. SCE is currently developing automated processes to maintain the accuracy of network models and data as changes on the distribution system occur, as part of full system-wide deployment of ICA."

- “SDG&E currently automatically updates its models daily, but those are not currently validated for ICA purposes. SDG&E would need to validate those models that have monthly changes for the ICA update.”

G. Automating Screens not included in ICA

The Fast Track review Screens are divided into Initial Review (A through M) and Supplemental Review (N, O, P)

IREC provided comments on the potential for automation the Fast Track Screens in informal comments to the working group on March 26, 2018. IREC identified possible software automation for Screens A, B, H, J, K, and L, and also identified ways in which Screens other than the ICA Screens could be deemed inapplicable or otherwise resolved. We include IREC’s full comments on the Fast Track Screens as Attachment A. GPI and Clean Coalition comments below, with additional suggestions from SGS, consulting engineers retained by GPI for this purpose, reflect and incorporate IREC’s comments on potential automation and streamlining.

This section reviews the potential for automation of the Screens but doesn’t include any cost-benefit analysis of doing so. The authors of this report have made clear that our High-level cost-benefit considerations are included in the last section of this report.

The following abbreviations are used in the below discussion:

- **OK/NA**: automation already completed or not applicable for inverter-based systems
- **ST**: Short Term (1-3 years)
- **MT**: Medium Term (3-5 years)
- **LT**: Long Term (>5 years)

Power simulation software providers are beginning to incorporate automated Screen functionality (e.g. Eaton – CYME). The application processing software should be designed to connect easily to the specific power simulation software package to access this functionality. Triggering the updates for projects based upon relevant changes should also be relatively easy to incorporate within the application processing software.

Suggestions for automation or streamlining of each of the Screens follows below. The net result of the recommendations is at least a partial, and potentially a fully, automated Initial Review and Supplemental Review process, if the identified issues can be resolved for each Screen:

- **Screen A: Networked Secondary**
  - This is a Screen that should be automatable through software as it only requires verification of whether the applicant's POI is on a Networked Secondary System. These networks should be clearly mapped and also indicated on the ICA maps. (ST)
- **Screen B: Certified Equipment**
  - This only requires verification against a database and could be automated through the application process, no engineering time should be required. (ST)
- **Screen C: Voltage Drop**
  - This only applies to motoring generators and thus will be automatically passed by most DERs today. (OK/NA)
- **Screen D: Transformer Rating**
  - Projects with a primary connection are covered by ICA. (OK/NA)
  - Since the secondaries were not included in the ICA this Screen will still require verification for projects connecting to a secondary (which isn't the case for 500 kW and over behind-the-meter or for front-of-meter projects). (MT)
- **Screen E: Does the Single-Phase Generator Cause Unacceptable Imbalance?**
  - Projects with a three-phase connection will not go through this Screen. (OK/NA)
  - Projects with inverters connect across 240V will require some verification but this will rarely be associated with the larger behind-the-meter/front-of-meter customers targeted in this roadmap, which will tend to be connected to three-phase. (MT)
  - Since single-phase secondaries were not included in the ICA this Screen will still require verification for projects connecting to a single phase secondary. (MT)
- **Screen F: Is the Short Circuit Current Contribution Ratio w/in Acceptable Limits?**

    - As long as the generator model is added correctly, fault simulation functionality already exists in the distribution simulation software (ST)
    - Protection is analyzed in the ICA. Coordination is not modeled in the ICA currently, but may be able to ID the substations where this is an issue.
- **Screen G: Is the Short Circuit Interrupting Capability Exceeded?**
    - As long as the generator model is added correctly, fault simulation functionality already exists in the distribution simulation software. Substantial database development and maintenance may be required. (MT)
    - ICA partially covers, substation needs to be reviewed. <1 MW may pass, or can utilities use a modified version of the PG&E automated Screening tool?
- **Screen H: Line Configuration**
    - Should be able to be addressed quickly through software or manual verification if the information about wire configurations on the system is available. (MT)
- **Screen I: Will Power Be Exported Across the PCC?**
    - This is allowed to fail for larger projects which will be analyzed further in Screens N and O.
    - This Screen should be automated through the export/non-export selection on the IOU application portals– Filtering Screen only (ST)
- **Screen J: Is the Gross Rating of the Generating Facility 11 kVA or less?**
    - Not applicable to the larger projects considered here
    - This Screen can be automated – Filtering Screen only (ST)
- **Screen K: Is the Generating Facility a NEM Generating Facility with nameplate capacity less than or equal to 500 kW?**
    - Not applicable to the larger projects considered here
    - This Screen can be automated – Filtering Screen only (ST)
- **Screen L: Transmission Dependency and Transmission Stability Test**
    - This may require IOUs to ID and flag those substations with either transient stability limitations or interdependencies with earlier queued generation. (ST)
- **Screen M: Aggregate Generation ≤15% of Line Section Peak Load**
    - Uses available data automated as part of ICA for existing and proposed modified Screen M as part of Working Group 2 Issue 8 proposals. (ST)
- **Screen N: Penetration Test (100% of Min. Load)**
    - Pass if within ICA value; readily automatable if over ICA value or ICA not available (OK/ST)
- **Screen O: Power Quality and Voltage Fluctuation**
    - Pass if within ICA value; readily automatable if over ICA value or ICA not available (OK/ST)
- **Screen P: Safety and Reliability Test**
    - Used in Supplemental Review as a "catch all" applied only when one of the earlier Initial Review Screens is failed, so we are not proposing at this time to automate Screen P. (LT/NA, "safety valve")

We summarize in the below chart SGS' conclusions with respect to the feasibility of automating the Fast Track Screens, as described above. Power simulation software providers are beginning to incorporate this functionality (e.g. Eaton – CYME). The application processing software should be able to connect easily to the power simulation software and access this functionality.

As mentioned previously for the ICA and initially discussed in the application processing automation section, relevant changes to projects could automatically trigger updates to projects lower in the queue. Relevant changes to all projects affected could trigger automated communication of the changes with the applicant.

Assumptions:

- Applies mostly to behind-the-meter over 500 kW and front-of-meter projects of any size
- Online interconnection portals supported by business administration process software are being used.
- The interconnection portals contain the automation functionality required as described in relevant 'Required Effort(s)' in the table below, or a separate software application is developed that integrates the interconnection portals with the required utility systems and databases.
- The circuit model has been updated to include the application of interest. If it is too difficult for the POI to be automated for inclusion in the circuit model, the operator would need to perform this task manually after successful application submission through the online interconnection portals.

Screen	***Required Effort(s)***	***Automation Feasibility***
A – Networked Secondary	POI links to utility system with GPS to identify if it is a networked secondary.	High -- if this attribute exists in utility database
B – Certified Equipment	Can be incorporated into Interconnection Portal with list of certified equipment types when specifying system details.	Very High – already demonstrated in other tools
C – Voltage Drop	Only applies to motoring generators. Can be skipped for solar PV applications.	N/A -- only applies to motoring generators
D- Transformer Rating	Interface with appropriate utility database. Large projects will only connect to the primary, so irrelevant to this study case.	N/A – large projects would have their own dedicated voltage transformation
E – Single-Phase Generator Causing Unacceptable Imbalance?	Large projects will only connect to the primary, so irrelevant to this study case.	N/A – same as above
F – Short Circuit Current Contribution Ratio within Acceptable Limits?	Requires integration with the utility distribution simulation software. Easily automated using fault simulation.	Medium – As long as the generator model is added correctly, fault simulation functionality already exists in the distribution simulation software
G – Short Circuit Interrupting Capability Exceeded?	Requires integration with the utility distribution simulation software. Easily automated using fault simulation.	Medium – similar to Screen F
H –Line Configuration	Reference appropriate database indicating type of line at the POI.	High – assumes the database for line types and parameters exists.
I – Will Power be Exported Across PCC?	This is allowed to fail for larger projects which will be analyzed further in N and O.	N/A -- for larger and wholesale projects
J – Gross Rating of the Generating Facility 11 kVA or less?	This is allowed to fail for larger projects which will be analyzed further in N and O.	N/A -- for larger and wholesale projects
K – Is the Generating Facility a NEM Generating Facility with Nameplate Capacity less than or equal to 500 kW?	Not applicable to the application types being considered (larger and exporting projects), but easily referenced with the application data within the interconnection portal.	N/A -- for larger and wholesale projects
L – Transmission Dependency and Transmission Stability Test	Based on the Rule 21 description, this would probably require IOUs to flag those substations with either transient stability limitations or interdependencies with earlier queued generation.	Low – variability associated with the analysis used to support this screen makes it difficult to automate the exact efforts on an individual case basis.
M – Aggregate Generation <u>≤15% of Line Section Peak Load</u>	Could be difficult if CIM not included in modelling software – i.e. need to detect if there is a switch upstream of PCC. Or, a database kept of data on all line sections.	Easy if IR/SR are combined. Medium to Low if not combined – automating the detection of relevant line sectionalizers simple with CIM, otherwise a database identifying line sections is required.
N – Penetration Test (100% of Min Load)	Automated as part of ICA, rendering screen M redundant for combined IR/SR	Already completed
O – Power Quality and Voltage Fluctuation	Automated as part of ICA	Already completed

H. *Frontloading Supplemental Review Screens N and O into Initial Review*

- Projects that are less than or equal to the displayed ICA value, or otherwise expect to interconnect without need for Supplemental Review, may be susceptible to largely automated review. Frontloading Screens N and O into IR will allow an easier automation of Initial Review because Screen N makes Screen M redundant and Screen O may render some IR Screens at least partially redundant.
- Given the automation of Screen N and Screen O as part of the ICA tool and the ability to apply this functionality to meet the analysis requirements for a specific project, minimal effort would be required to assess the complete fast track potential for a given application that passes all IR Screens.
- Moving all automatable Screens to the IR would be beneficial as a whole while providing as much information as possible up front to the customer with minimal effort.
- A single review from the utility engineer and reduced communication requirement to the customer offer significant process time and reduced fee improvements.

I. *Frontloading and automating offer of Generator Interconnection Agreement*

- A standard Generator Interconnection Agreement (GIA) must be offered within 15 BDs of passing Initial Review (F.2.a), or 15 BDs from applicant's request after passing Supp. Review (F.2.e)[12]
- 90 Calendar Days are allowed for negotiation and signing of the GIA (F.2.e)
- Utilities could instead "frontload" a partially populated draft GIA offer immediately after the application is deemed complete, allowing the agreement to be reviewed by the applicant before IR and SR are complete

[12] Tesla notes that PG&E is inconsistent with when it provides this form and how complete it is when received. Some utility reps fill it out and some leave it blank and request that the contractor fill it out. There are also inconsistent practices in how this form is prepped by specific utility reps. For SDG&E, depending on the type of agreement needed for the application Tesla is sometimes required to fill out a template rather than have a filled out agreement drafted and provided for customer signature by the u

tility rep.

- Or utilities could offer the option to generate this document auto-filled from the application portals, as is currently available with the SCE Power Clerk portal.
- Once Fast Track Review is completed, the draft GIA will be fully populated with the relevant results and this second draft will be sent automatically to the applicant, within one BD

VIII. Cost/benefit analysis initial considerations

This section offers preliminary cost-benefit analysis of the top recommendations from this report, as described in the summary above, along with related considerations about costs and benefits more generally. Most of this section was provided by SGS, automation engineers retained by the Green Power Institute to assist with this report.

TURN stressed the need for cost-benefit analysis prior to further action on automation opportunities. Parties generally agreed that cost-benefit analysis is important but that the Commission regularly conducts analysis of opportunities for policy improvements, prior to any cost-benefit analysis. The middle ground in this case was for GPI to retain SGS as consulting engineers to both vet this report's analysis and recommendations and to complete a preliminary cost-benefit analysis, which is described below.

PG&E notes with respect to costs and benefits: "We continue to support automation and note the importance to highlight the cost benefit analysis on all automation efforts. Ratepayer funding should focus on benefitting the largest populations and then move into targeting smaller areas, with the benefit to rate payers as the deciding factor. Efficiency gains and automation are what we strive for but not infallible solutions, and Rule 21 Compliance timelines should reflect the manual process of performing the task, as needed, until the benefits of automation are determined."

A. General cost-benefit considerations

The general cost and benefit elements associated with implementing the various automation options are as follows:

Utility Perspective (in the experience of SGS):

- Single source of interconnection information provides greater internal efficiencies.
- Significantly reduces manual effort (see above timeline reductions) both for initial project Screening and updates based upon changes to applications ahead in the queue. This includes automated communication with the applicant.
- Power system simulation software, such as CYME, already demonstrate functionality for the automation of relevant Screens. Further messaging to CYME, Synergi around what Screens are required would ensure that functionality finds its way into the software.
- Integration of systems requires effort where needed.
- If administrative software, e.g. Power Clerk, does not possess the functionality to access required systems and process information accessed for Screens, some form of custom software wrapper must be developed to do so; this may or may not include results from the power simulation software.
- Interconnection application processes can be modified to leverage automation efforts to significantly reduce processing times and required customer interaction.
- Maintaining an up-to-date published ICA map will greatly reduce the number of nonviable interconnection applications and consequently the processing time for those that are feasible. Once automation is developed for the Screening, keeping maps up-to-date simply requires translation to a map service assuming that the processing of hosting capacity across the nodes on the network does not require significant processing requirements (e.g. this is not possible with flexible hosting capacity). The benefit of directing developers towards circuits with greater headroom has already been witnessed in SP Networks pilot, avoiding applications with a low probability of going to construction.
- Accurate positioning of generation within the associated power simulation model could be difficult and require engineer confirmation (as noted during conversations with AVANGRID).
- Scoping, development and implementation of such IT tools will require time and funding. CPUC authorization for additional funding will be required to accomplish many of the aspects of the Report. Such funding approval is typically addressed in a utility's General Rate Case but may be addressed in this case independently.

Developer Perspective (in the experience of SGS):

- Lower project development costs means lower barriers to entry

- Reduced application time means realizing project revenue sooner – time value of money
- Increased automation should also lead to significantly lower application and study costs
- Lower risk of losing project funding, land rights, etc.
- Lower project risk can be passed on to ratepayers due to lower project cost and thus lower bids for front-of-meter/wholesale RFPs
- Can survey best opportunities for project development at very low cost

B. *Cost-benefit considerations specific to top automation recommendations*

The following sections discuss how these benefits relate to the automation efforts listed above:

a. *Automating the Application Portals and Application Processing with Queue Management and Updating Publicly Available Interconnection Queue*

This is the first task that should be accomplished while offering the best returns and providing the basis for other automation efforts to grow upon. Instead of having multiple resources in separate locations, there is a single "one-stop shop" for interconnection applications.

Interconnection portal software should be able to be modified to handle alterations to a given application, while also being the resource that maintains the interconnection queue.

It should be easy to implement alerts that indicate those projects affected by a change to a project ahead in the interconnection queue. The automatic updating of Screens to accommodate the project change, including those projects affected, is discussed later on.

b. *High-level cost-benefit considerations for opportunities identified in this report*

SGS developed the following information for Working Group discussion and to provide a basis for identifying the best near-term automation and streamlining opportunities. Again, this analysis applies mostly to behind-the-meter projects over 500 kW and front-of-meter projects of any size. Costs are evaluated on a per project basis, considering a default 1 MW project size.

Automation Action	**Estimated process streamlining (days)**[1]	**Utility savings (person days)**[2]	**Type of investment needed (labor, license, other)**	**Relative cost / complexity**	**Relative benefit-cost ratio**
Application Portal, Queue Mgmt, Queue publishing	5+	5+	• SaaS license • IT (labor) • Design of UI (labor)	Medium	High
ICA and ICA updates	n/a	5+	• Power system analysis tool license (toolbox) • Dist Planning (labor) • IT (labor)	Medium to Hard	Medium
Automating Screens not in ICA	2-5 days	2-5 days	• Dist. Planning (labor) • IT (labor)	Medium	Medium
Frontloading SR Screens N and O into IR[3]	5+	1-2 days	• Process design (labor)	Easy but contingent of previous steps	High but depends on stakeholder
Frontloading and automation of GIA	5+	n/a	Process design (labor)	Easy once process management tool implemented	High, particularly for projects w/o upgrades

1- Here we estimate savings as being 1-2 days, 2-5, or greater than 5 days.
2- Savings here reflect the reduction in time due to meetings, analysis, and administration (emails, documentation, other)
3- Assumes that Screens N and O have been automated, whether through ICA (as is currently planned) or independently.

Attachment A: IREC informal comments on Working Group 2 Issue 8, May 26, 2018, on automation and streamlining of Rule 21 Fast Track Screens

- Evaluate Initial and Supplemental Review Screens and determine which Screens are addressed directly by the ICA results and which may further be streamlined using software or other methods.
    - The ICA Working Group report found that the ICA results would be able to replace or make the determinations for Screens F, G, M, N & O.[13] An initial assessment of the Screens and the discussion of them follows:
      Initial Review
        - Screen A: Networked Secondary – This is a Screen that should be able to be addressed automatically through software as it just requires verification of whether the applicants POI is on a Networked Secondary System. These networks should be clearly mapped and also be able to be indicated on an ICA map at some point.
        - Screen B: Certified Equipment – This is also something that requires verification but could be automated through software potentially, no engineering time should be required.
        - Screen C: Voltage Drop – This only applies to motoring generators and thus will be skipped by most DERs today.
        - Screen D: Transformer Rating – Since the secondaries were not included in the ICA this Screen will still require verification for projects connecting to a secondary. Projects with a primary connection do not go through this Screen however.
        - Screen E: Does the Single-Phase Generator Cause Unacceptable Imbalance – Since single-phase secondaries were not included in the ICA this Screen will still require verification for projects connecting to a single phase secondary. Projects with a connection to a three phase primary should not go through this Screen however.
        - Screen F: Is the Short Circuit Current Contribution Ration w/in Acceptable Limits? – Per the WG report this Screen should be addressed by the ICA.
        - Screen G: Is the Short Circuit Interrupting Capability Exceeded? – Per the WG report this Screen should be addressed by the ICA.
        - Screen H: Line Configuration – This Screen was not directly addressed by the ICA but should be able to be addressed automatically through software/ manual verification if the information about wire configurations on the system is available.

[13] There was an oversight on this in the final report as the approved ICA methodology does not fully account for Screens F & G, as came to light early in the Working Group 2 process in the first half of 2018.

- Screen I: Will Power Be Exported Across the PCC? – This Screen is not addressed by the ICA. It is essentially a yes or no question based upon information provided in the application form, however, it likely requires utility verification (automatic or manual tbd) to make sure the facility correctly meets one of the non-export configurations. *However, for purposes of expediting review it is not clear whether this question retains its importance in the review process if the ICA results are in place.*
- Screen J: Is the Gross Rating of the Generating Facility 11 KVA or less? – This Screen can be automated and is likely no longer relevant with the ICA in place.
- Screen K: Is the Generating Facility a behind-the-meter Generating Facility with nameplate capacity less than or equal to 500 kW? – This Screen can be automated and is likely no longer relevant with the ICA in place.
- Screen L: Transmission Dependency and Transmission Stability Test – It is possible that this Screen may be able to be automated. We should have a thorough discussion of how this Screen is really being used (if at all) and what information is required to apply it.
- Screen M: Aggregate Generation ≤15% of Line Section Peak Load – This Screen is addressed by the ICA.

Supplemental Review

- Screen N: Penetration Test (100% of Min. Load) – This Screen is addressed by the ICA
- Screen O: Power Quality and Voltage Fluctuation – This Screen is addressed by the ICA
- Screen P: Safety and Reliability Test – This Screen is not directly addressed by the ICA, however it is also used in Supplemental Review as a "catch all" that should only be applied when one of the earlier Initial Review Screens is applied. It may make sense to discuss how it will be used and structured with the ICA in place and what evaluation will be done under this Screen.