2018 Interconnection Process Enhancements

Revised Straw Proposal

July 10, 2018

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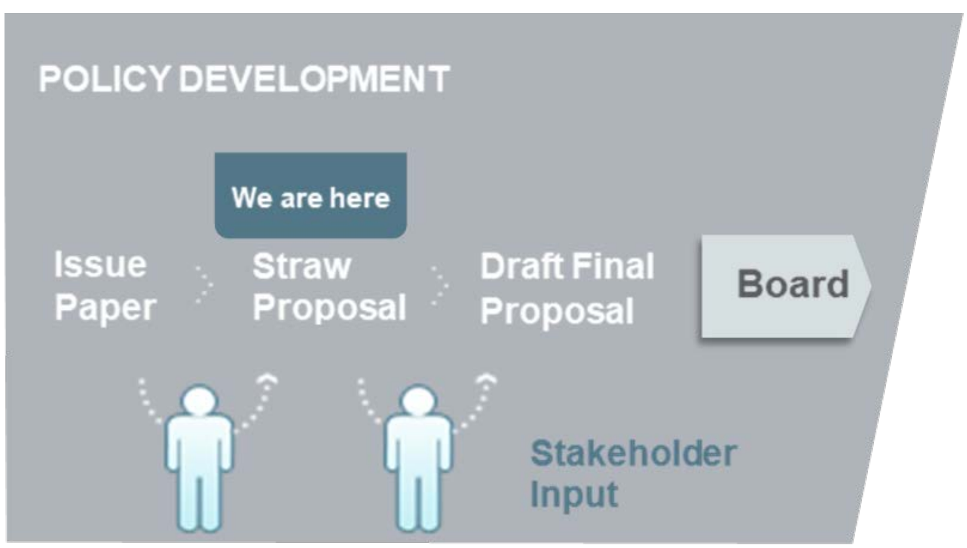
1. Introduction

Previous iterations of the California Independent System Operator Corporation's (CAISO) Interconnection Process Enhancement (IPE) initiative focused on several enhancements to the CAISO's interconnection and deliverability allocation procedures. 2018 IPE will address some substantial concepts, but also a myriad of minor concepts that have not been addressed in some time along with issue that have surfaced since 2015 IPE that need to be resolved. This revised straw proposal reviews topics still under development and identifies topics that have been finalized after the issue paper and are going to the July 2018 Board of Governors meeting. Topics fall into six broad categories deliverability, energy storage, generator interconnection agreements, interconnection cost responsibility and financial security, interconnection requests, and modifications.

2. Stakeholder Process

The CAISO is at the "Revised Straw Proposal / Partial Draft Final" stage in the 2018 IPE stakeholder process. Figure 1 below shows the current status within the overall 2018 IPE stakeholder process. The purpose of the revised straw proposal is to present the scope and proposed solutions to topics that are in track 2 or track 3 related to deliverability, energy storage, generator interconnection agreements, interconnection cost responsibility and financial security, interconnection requests, and modifications. Track 1 are the issues that are going to the July Board meeting. Track 2 are issues that will be taken to the September Board meeting for approval. Track 3 are issues in the revised straw proposal that are still being discussed and are anticipated to go to the November Board meeting. The CAISO has reviewed and considered stakeholder feedback provided through comments submitted on the straw proposal and have addressed these comments in this revised straw proposal.

Figure 1: Stakeholder Process for 2018 IPE Stakeholder Initiative



3. Scope

The CAISO plans to publish a Draft Final Proposal of the remaining issues early in the fourth quarter of 2018. Due to the substantial number of topics in this paper, the CAISO is planning to move forward with topics in three separate tracks. Topics included in track 1 were finalized in the straw proposal and are targeted for the July 2018 Board of Governors meeting, topics in track 2 are being finalized in the revised straw proposal are targeted for the September 2018 meeting, and topics in track 3 are targeted for the November meeting. The table below reflecting the scope for this initiative includes the identification of which Board of Governors meeting for each topic included in this initiative.

Table 1: Overall Topic Status

Category	Section	Topic	Targeted Board of Governors Meeting
Deliverability	4.1	Transmission Plan Deliverability Allocation	September 2018
	4.2	Balance Sheet Financing	September 2018
	4.3	Participating in the Annual Deliverability Allocation	September 2018
	4.4	Change in Deliverability Status to Energy Only	September 2018
	4.5	Energy Only Projects' Ability to Re-enter the Queue for Full Capacity	September 2018
	4.6	Options to Transfer Deliverability	September 2018
Energy Storage	5.2	Replacing Entire Existing Generator Facilities with Storage	September 2018
Generator Interconnection Agreements	6.1	Suspension Notice	September 2018
	6.2	Affected Participating Transmission Owner	September 2018
	6.3	Clarify New Resource Interconnection Requirements	July 2018
	6.4	Ride-through Requirements for Inverter-based Generation	November 2018
Interconnection Financial Security and Cost Responsibility	7.1	Maximum Cost Responsibility for NUs and potential NUs	September 2018
	7.3	Eliminate Conditions for Partial IFS Recovery upon Withdrawal	September 2018
	7.5	Shared SANU and SANU Posting Criteria Issues	September 2018
	7.6	Clarification on Posting Requirements for PTOs	July 2018
	7.7	Reliability Network Upgrade Reimbursement Cap	September 2018
	7.9	Impact of Modifications on Initial Financial Security Posting	July 2018
Interconnection Requests	8.1	Study Agreements	July 2018
	8.4	Project Name Publication	September 2018
Modifications	9.1	Timing of Fuel Type Changes	September 2018
	9.2	Commercial Viability – PPA Path Clarification	September 2018
	9.3	PPA Transparency	July 2018
	9.4	Increase Repowering Deposit	July 2018
	9.5	Clarify Measure for Modifications After COD	July 2018
	9.6	Short Circuit Duty Contribution Criteria for Repower Projects	BPM Change

Note: The topics in yellow were combined into one topic.

4. Deliverability

4.1 Transmission Plan Deliverability Allocation

Background/Issue

Transmission Plan Deliverability (TPD) is the transmission capacity needed to make a generating unit's output deliverable to the aggregate of load on the CAISO Controlled Grid during peak conditions. TPD is required for a project to be designated as Full Capacity Deliverability Status (FCDS) allows a generator to be eligible to provide Resource Adequacy.

The CAISO desires to allocate TPD, if available, to generating projects according to the interconnection customer's demonstration of having met the criteria identified in Section 8.9.2 of Appendix DD of the CAISO Tariff, namely being far enough along in the status of permitting, project financing and land acquisition. The project may either have a Power Purchase Agreement (PPA) or balance sheet financing (BSF) as a key threshold requirement. The current TPD allocation process provides four opportunities for all interconnection customers to obtain FCDS – (1) following the Phase II interconnection studies, (2) after 1 year of parking, (3) for projects that qualify after a second year of parking, and (4) the annual full capacity deliverability option. If after exhausting its applicable opportunities a project does not receive a TPD allocation the project must convert to energy only or withdraw.

In the 2018 IPE straw proposal, the CAISO proposed an opportunity to modify the allocation of deliverability and Commercial Viability Criteria (CVC). The proposal consisted of a new structure of Allocation Groups whereby projects are allocated TPD based on their commercial status, as depicted in the chart below. The proposal eliminates the use and terminology of BSF as part of a project seeking TPD affidavit process. The proposal also eliminates the Annual Full Capacity (AFC) Deliverability Allocation option such that the newly proposed allocation groups provide equal or greater opportunity for energy only projects to obtain a TPD allocation.

Allocation Group	Project Status	Commercial Status
1	Study/Parking Process	Executed or regulator-approved PPA requiring FCDS or interconnection customer is Load Serving Entity serving its own load
2	Study/Parking Process	Shortlisted in a RFO/RFP
3	Study Process (Following Ph. II Only)	Proceeding without a PPA (formerly BSF)
4	Converted to Energy Only	Executed or regulator-approved PPA requiring FCDS
5	Converted to Energy Only	Shortlisted in a RFO/RFP
6	Converted to Energy Only	Commercial operation achieved
7	Energy Only	Commercial operation achieved

With regard to California regulations, increased Renewable Portfolio Standard (RPS) requirements, and the CPUCs determination of a proper Resource Adequacy and procurement path forward: The CPUC has yet to determine the effective load carrying capability (ELCC) deliverability methodology for studying generator interconnection customers and without this methodology being finalized, the future impacts of allocating TPD to intermittent generators, such as solar and wind, is unknown. Moreover, while California has increased the RPS from 33% to 50%, the state has yet to make a decision on whether to increase deliverability requirements above the 33% RPS level to require the incremental amount to 50% to be deliverable. Other variables impacting TPD include the CPUC Integrated Planning Process that has not progressed to the point of providing actionable guidance to the jurisdictional utilities, or the CAISO and the California Legislature consideration of increasing the RPS above 50%, which could have a dramatic impact on the transmission planning assumptions and direction. As a result, the CAISO believes more information and direction is needed to guide a process for making significant modifications to the deliverability study process in order to accommodate an option that allows energy only projects the ability to reenter the deliverability study process to determine if Delivery Network Upgrades (DNUs) are needed to make a project deliverable and to provide an opportunity for projects to have those DNUs constructed within the GIDAP.

As drafted in the Straw Proposal, the CAISO combined multiple topics into one whereby we created one concise and consistent solution to the allocation and retention of TPD. As such, Section 4.2 -Balance Sheet Financing, Section 4.3 – Participating in the Annual Full Capacity Deliverability Option, Section 4.5 - Energy Only Projects Ability to Re-enter the Queue for Full Capacity, and Section 9.2 - Commercial Viability – PPA Path Clarification, will be discussed and any proposed revisions will be consolidated and provided within Section 4.1.

Stakeholder Input

Overall Stakeholder Comments

First Solar, San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and Pacific Gas and Electric (PG&E) support the CAISO's proposal to combine topics 4.1, 4.2, 4.3, 4.5, and 9.2, and believe the proposal is an improvement to the existing TPD allocation/ranking process. Further, they appreciate the proposed allocation ranking groups such that it allocates deliverability to those with a Power Purchase Agreement (PPA) ahead of those that propose to build without one. PG&E believes that this change will result in only projects with deliverability moving forward with construction and allow only the most viable projects to proceed.

CalWEA believes the proposed plan would clearly distinguish among generation projects based on their commercial status when allocating TPD capacity; as opposed to the current scheme in which a complex scoring mechanism based on projects' performance.

EDF Renewables (EDF-R) and sPower believe the CAISO's proposal contains flaws they have raised in their feedback. They are unsure of how or if any additional deliverability will be provided beyond the options now available. Further, they believe the CAISO should provide an opportunity for energy only projects to re-enter the queue and obtain deliverability on an equal basis with new projects.

SCE believes that the CAISO's proposal, which maintains a focus on limiting the risk to the PTOs, while affording greater opportunity for projects that have a PPA to obtain TPD, is reasonable approach and provides projects greater opportunities to participate in the TPD allocation process based on their project status.

SDG&E supports the proposal to create seven allocation groups and believes that replacing the current AFC deliverability option with groups 4, 5, 6, and 7 would be a big step forward. SDG&E appreciates the detailed descriptions given to each allocation group, especially groups 2 and 5, in which it is specified that the shortlisted project must execute a PPA by November 30th of the calendar year that such a TPD allocation was received. SDG&E appreciates the clarification that the CAISO will only allocate TPD to energy only projects provided no new DNUs are required.

LS Power notes that in reviewing the new TPD allocation groups proposed by the CAISO, it does not appear that existing energy only projects, which have not yet achieved commercial operation, fit in any proposed allocation group. As such, LS Power believes CAISO should create an option for these projects to seek deliverability.

<u>Stakeholder Comments on the Straw Proposal-specific Topics</u>

TPD Allocation & Scoring prioritization:

CalWEA suggested that the CAISO tariff, or at least the BPM, should clearly spell out how TPD capacity allocation would be prioritized within each Allocation Group.

EDF-R and sPower suggest that allocation groups 4 through 7 can currently request deliverability through the AFC Deliverability Study. However, those projects receive only “leftover” deliverability (e.g. are allocated deliverability only after new generation projects in the regular Interconnection Studies process, and further, do not have the ability to trigger, and pay for, DNUs).

EDF-R recalls the CAISO mentioning at the stakeholder meeting that the new allocation proposal includes some kind of methodology change that would make more deliverability available to such projects, and EDF-R believes this aspect should be better clarified in the proposal. EDF-R believes the CAISO should explain assumed changes to the deliverability availability methodology in the proposal that would increase available deliverability. EDF continues to advocate for the CAISO to also perform analyses in study areas where deliverability is now exhausted to show how much additional deliverability would be provided in those areas through the proposed change.

First Solar requested that the CAISO clarify the process for calculating deliverability and explain why this newly-structured ranking process provides an opportunity for allocation to the energy-only process. First Solar believes it would be valuable to have details that allow interconnection customers to better understand the methodology for the allocation and why the CAISO believes that the new process creates a better opportunity for TPD allocations to energy-only projects.

First Solar agrees with the logic behind the limitation on extensions of time in queue, however, for a project that successfully executes or receives regulator-approval for a PPA, First solar believes it makes commercial sense, and sense for ratepayers, to align the COD with the PPA requirements, including extensions beyond the 7 year time-in-queue limitation if need be.[1]

Elimination of Balance Sheet Financing

CalWEA and First Solar raise questions regarding the TPD allocation for projects that selected Balance-Sheet-Financing on their Seeking TPD Affidavit prior to this proposal becoming effective. CalWEA and First Solar suggest that CAISO clarify that the removal of the balance-sheet-financing option and all of its features is on a prospective basis only and clarify how it intends to make the delineation clear as to which projects will be subject to the new rules. Further, the CAISO should explain how the current balance-sheet-financed projects will be treated in the annual commercial viability and quarterly project status updates.

EDF-R believes the current options to select BSF on the seeking TPD affidavit has led to

[1] Section 6.7.5 of Appendix DD of the CAISO tariff already allows the alignment of the GIA COD with the PPA.

deliverability award and retention by less-viable and non-viable generation projects, and it should be eliminated. EDF-R agrees that projects without PPAs should be held to more stringent standards, as their viability is questionable (and more so the longer they remain in the queue). However, if and when they obtain PPAs, the CAISO should clarify that they can then be subject to rules applicable to projects with PPAs.

SDG&E and PG&E support the CAISO proposal to modify the concept of BSF and include stricter restrictions for those who plan to proceed regardless of their PPA status.

First Solar suggests that projects that elect to proceed without a PPA, in allocation Group Three, should be held to the limitation on extension of COD unless there are delays caused by the PTO or an affected system that are not under the control of the interconnection customer.

In addition, First Solar believes a project should not be required to move immediately into the notice to proceed if it is not yet ready for development. First Solar believes that requiring the notice to proceed within 30 days of executing the GIA establishes an artificial deadline that may not account for timing of permitting. Since the CAISO is already modifying the rules to tighten up the time-in-queue provisions for projects proceeding in Group Three, First Solar urges the CAISO to allow these projects the same rights granted to other projects to manage the commercial and environmental elements of the project in line with GIA terms to bring the project to commercial operation.

Elimination of Annual Full Capacity Deliverability Option

SCE, SDG&E, and PG&E support the CAISO's proposal to have Groups four, five, six, and seven in the TPD Allocation sequencing to replace the current AFC deliverability option. SCE believes this process will serve as an alternative to energy-only projects requesting to reenter the queue to seek TPD. Further, SDG&E believes the current AFC process is not very beneficial and is open to allowing Interconnection Customers to seek TPD after they have exhausted their opportunities through the standard allocation process.

LS Power states that the CAISO's current AFC Deliverability allocation does not require a project to be commercially operational whereas this proposal does. LS Power proposes to create an option for such non-commercially operational projects to obtain TPD.

Project's ability to re-enter the queue to seek deliverability

EDF-R, sPower, LS Power and CalWEA believe energy only projects, whether or not the project has achieved commercial operation, should have an opportunity to re-enter the regular queue study process, have an opportunity to construct DNUs, and receive deliverability awards on the same basis as new generation projects in the cluster study process. Additionally, CalWEA suggests that these energy only projects should be allowed to finance Local Deliverability Network Upgrades (LDNUs) that were once triggered by an earlier queued project that are no longer deemed necessary.

SCE is not opposed to allowing existing, currently operating, Energy Only projects opportunities to reenter the queue in order to seek deliverability as long as the interconnection customer bear the full cost responsibility of any needed deliverability upgrades.

Commercial Viability Criteria PPA Clarifications

PG&E and SDG&E support the elimination of the BSF reference for the purpose of meeting CVC and believe this will prevent unnecessary time and resources be spent on projects that are not likely to proceed.

SCE supports providing projects means, beyond an executed or regulator-approved PPA, for demonstrating their commercial viability. SCE believes that while the CAISO proposes to eliminate the ability of a generator to rely on BSF as part of the commercial viability process, the CAISO's proposal does allow a resource developer to demonstrate its viability absent a PPA.

Stakeholder Comments to the proposed Allocation Ranking Groups

Allocation Group One

CalWEA, EDF-R, sPower, the Six Cities, and LS Power believe that in order to place a LSE-developed resource in proposed Allocation Group One, CAISO should require the LSE to demonstrate (similar to a regulator-approved PPA) that the project must meet the LSE's own loads (e.g. being developed pursuant to a regulator-approved procurement plan or are otherwise sized to meet their loads (not just a project that is being considered by that LSE)).

LS Power also commented on the process in which projects are procured through a LSE, suggesting that only after the LSE has completed a competitive acquisition process should their project be considered as Group One.

Allocation Group Three

CalWEA suggested that, at the conclusion of the Phase 2 study, CAISO should allow projects with demonstrated "productive" commercial activities (*e.g.* advanced bilateral negotiations with one or more LSE), subject to verification by the CAISO (*e.g.*, attestation by the LSE), also to be included in Allocation Group Three.

CalWEA suggested that a project proceeding without a PPA, in Allocation Group Three, should be allowed to delay COD beyond 7 years if it can demonstrate that the source of the delay is outside of its control (*e.g.*, PTO delay in construction of interconnection facilities, distribution or network upgrades, or delays in securing environmental permitting).

CalWEA further suggested that a project proceeding without a PPA, in Allocation Group Three, that parks the energy only portion of its project should be allowed to change the status of its project to a "PPA-approved" project if, during the parking period, they can secure a PPA.

Allocation Group Four & Five

First Solar, EDF-R, and sPower share concerns that the TPD allocation ranking proposal does not match LSE procurement or market realities, and further believe the CAISO proposal structure is inconsistent with the ways in which projects are procured and developed. In particular, groups four and five assume that a developer would undertake the considerable effort needed to develop a project through an RFO shortlisted position (which typically requires a Phase II Study) and execute a PPA (which nearly always involves provision of significant development security to an off-taker) with no assurance that the project would receive deliverability.

Allocation Group Six & Seven

SDG&E feels it is counterintuitive that projects that have achieved commercial operation are allocated TPD after projects that have not achieved COD (Allocation Groups Six and Seven) and would like the CAISO to explain why these projects are given a lower priority in the proposed ranking.

CalWEA suggests Energy Only projects in proposed Allocation Groups Six and Seven should be allowed to apply for TPD allocation and deliverability capacity upon GIA execution, not necessarily waiting until COD.

CAISO Response

CAISO Comments on the Straw Proposal-specific Topics

TPD Allocation & Scoring prioritization

The CAISO's overarching intent is to modify TPD allocation process in the way in which the determination of what projects are allocated TPD is based on the project's business need or PPA requirement. The ISO is eliminating the concept of "leftover" capacity in the AFC process and defines specific criteria and groups to which TPD is allocated on an annual basis. Thus, the AFC allocation mechanism for seeking TPD will be eliminated.

Within each allocation group, the ISO intends to utilize the scoring mechanism currently established, with slight modifications. More specifically, the tariff and GIDAP BPM would be modified to include the proposed seven allocation groups, how projects would be scored within each allocation group, and confirmation of the project's PPA Status. The allocation ranking and scoring mechanism is proposed below.

In response to EDF-R suggesting that the CAISO discuss the concept of creating more TPD; the CAISO does not have the ability to increase available TPD. The decision on whether policy driven deliverability network upgrades to provide deliverability for renewable resources beyond the 33 percent Renewable Portfolio Standard (RPS) level to some higher level is within the purview of the CPUC. The CAISO's role in that process is to provide technical guidance on the impacts and effectiveness of such a decision on the transmission system and the identification of needed system upgrades in the implementation process following such a decision utilizing the CAISO's Transmission Planning Process (TPP). In addition, as discussed above, the CPUC has yet to determine the final ELCC methodology so any additional TPD that may be made available from that CPUC change is unknown at this time. However, the ISO believes that the proposed TPD allocation process will result in TPD being allocated to only those projects that have a demonstrated business requirement. As a result, over time more TPD may become available as projects who currently hold TPD allocations and do not obtain a PPA lose those allocations in the allocation retention process, freeing up TPD for those projects that can demonstrate a business requirement.

It is unclear the deliverability calculation First Solar is referring to. However, the CAISO believes this proposal allows energy only projects the opportunity to obtain TPD similar to the current AFC allocation process and further, provides energy only projects greater opportunity to receive TPD in the event they are able to enter into a PPA with a LSE that requires the project to be FCDS.

With regard to First Solar's suggestion to allow a project to align its COD with its PPA by extending its COD beyond the 7 year time-in-queue, the CAISO tariff Appendix DD Section 6.7.5 already provides an opportunity for COD extensions to align with a projects PPA. However, having a PPA is not the only factor that makes a project commercially viable and thus, projects exercising this extension provision must still demonstrate they meet the CVC.

Elimination of Balance Sheet Financing

The CAISO believes it would be considered retroactive ratemaking to apply this TPD allocation proposal to projects that previously received a TPD allocation based upon an attestation of balance sheet financing. If the schedule proposed below is acceptable, all projects that sought and received a TPD allocation in Cluster 9 and prior will not be subject to the new TPD allocation methodology. Any project in Cluster 8 or 9 who received an allocation, but declined it and parked, whether or not they claimed BSF, will be required to follow this new TPD allocation methodology. Cluster 10 and later clusters will be subject to the new TPD allocation methodology.

Regarding projects with an allocation currently subject to CVC, projects that used the BSF designation to demonstrate CVC prior to the new rules will see no changes. However, any project with an allocation and under CVC that submits an MMA to extend its COD further after the FERC approval date of this proposal will be subject to the new requirements and will no longer be able to cite BSF for CVC.

In response to EDF-R's BSF and PPA comments, the CAISO agrees that adjustments are necessary to ensure the most viable projects proceed appropriately. The CAISO also believes there is a difference and separation between how a project finances a project and the commercial/PPA status of such project. The CAISO is proposing to eliminate the concept of BSF from the current TPD allocation and retention model and shift to a mechanism that allocates/ranks projects based on their ability to obtain a PPA within the initial allocation and parking period following the Phase II studies, followed by an ongoing process for energy only projects that are able obtain a PPA that requires TPD or that achieves commercial operation.

The CAISO agrees with First Solar that an interconnection customer should not be impacted by PTO or affected system delays. However, historically, affected system issues have not impacted a project's ability to reach COD. Therefore, coordination to ensure that a project is able to move forward in accordance with the timeline specified in their GIA is done in accordance with the existing affected system process. With respect to PTO delays, the CAISO allows COD modifications through the modification process to ensure a project's COD aligns with a PTOs estimated timeline to constructed needed network upgrades.

In addition, upon further review, the CAISO agrees with First Solar that it may not be practical in all scenarios to require a project to provide a notice to proceed to the PTO immediately following the GIA execution. The CAISO has eliminated this requirement for Group Three. However, to ensure the intent of projects proceeding without a PPA proceed through the process without delay (to execute a GIA, proceed to construction, and achieve COD in a timely manner), the CAISO has adjusted the criteria for projects proceeding without a PPA, in Group Three, in the proposal below.

Elimination of Annual Full Capacity Deliverability Option

It is the CAISO's intention to shift to a mechanism where TPD is only allocated to those energy only projects that have a commercial or business need to obtain it. An energy only project that has achieved commercial operation or obtained a PPA will have an opportunity to seek and obtain TPD provided no additional network upgrades are required. The CAISO does not find it appropriate to allocate TPD to energy only projects that have not achieved commercial operation. Energy only projects may seek TPD in Groups four through seven as proposed below.

Project's ability to re-enter the queue to seek deliverability

The CAISO understands the desire for energy only projects to have an ability to re-enter the cluster study process to be restudied and have an opportunity to build and pay for DNUs necessary to achieve FCDS and to seek and obtain a TPD allocation. The CAISO is still considering its position on this issue. The CAISO requests that stakeholders provide comments on this issue and provide specific proposals on how the deliverability study process within the current two-phase study process would be modified to allow projects to re-enter the queue cluster study process to be restudied for FCDS, eek TPD, and pay for DNUs if necessary.

Commercial Viability Criteria PPA Clarifications

The CAISO appreciates the feedback in support of the proposal to eliminate the BSF criteria from the CVC process. The CAISO will proceed with this modification.

<u>CAISO Comments, clarifications, and additions to the proposed Allocation Ranking Groups</u>

Allocation Group One

The CAISO agrees with stakeholders that a requirement should be established such that an LSE must demonstrate it has received regulator-approved authority to develop such project in order to meet their own load (similar to an independent project having a regulator-approved PPA). An LSE will be prohibited from receiving TPD under allocation Group One in the event the LSE is developing a project with the intention of selling such energy (or project) to market or otherwise, unless the project can demonstrate it has an executed PPA with an LSE located within the CAISO Balancing Authority Area.

The CAISO understands that LSEs may have various paths for procuring projects or resources based on business need, regulatory requirement, or otherwise. It is not the intention of the CAISO to require LSEs to procure projects and obtain TPD via a specific mechanism. However, as stated above, if an LSE is developing a project for the purpose of serving its own load and doing so under a regulator-approved requirement, the LSE can seek TPD under allocation Group One.

Allocation Group Three (and relative to Groups Two and Five)

CalWEA suggests that projects with demonstrated "productive" commercial activities (negotiations) also to be included in Allocation Group Three. The intention of Group Three is to provide customers an opportunity to develop a project without a PPA and therefore will not have an opportunity to claim they are negotiating or seeking to obtain a PPA as a method of acceptance or otherwise delay of their project. However, the CAISO will consider active negotiations, outside of an RFO/RPF process, as shortlisted commercial status. More specifically, if a project is in productive commercial activities, such as negotiating a PPA (and that PPA ultimately requires the project to be FCDS), and outside of a formal RFO/RFP procurement process (with attestation to and verification by the CAISO), those customers or projects will be permitted to seek a TPD allocation under allocation Group Two or Group Five, based on the project's location/status within the TPD allocation process (proceeding through the study/parking process or converted to energy only). As such, the CAISO will confirm the status of such negotiations with the LSE.

Allocation Group Three

In response to CalWEA (and First Solar's comments on section 4.2), the CAISO agrees that a PTO delay is a permissible reason to delay a projects COD. The CAISO has adjusted the criteria for projects proceeding without a PPA in Group Three.

In response to CalWEA's suggestion that a project proceeding without a PPA in Allocation Group Three, that parks a portion of its project (due to it not receiving all or a portion of a TPD allocation), should be allowed to change the status of its project if they can secure a PPA during the parking period. The CAISO agrees with the suggestion by CalWEA and has provided clarification to the proposal below.

Allocation Group Four & Five

The CAISO understands stakeholder concerns regarding the likelihood of energy only projects opportunity to bid into and be selected in an RFO/RFP, and further the likelihood of a project to commit significant development security without surety that the project will obtain TPD. The CAISO's intent is to provide more opportunity for all energy only projects, with a business or regulatory need, to obtain TPD. Further, the CAISO believes that there may be opportunity to improve coordination between the LSE procurement processes and timing and the CAISO queue cluster study process. The CAISO is soliciting input and suggestions of how to initiate and establish such coordination.

The CAISO does not plan to remove these groups based on current stakeholder feedback. However, in consideration of seeking additional input, the CAISO has additional questions for stakeholders:

1. In the event, through an RFO/RFP evaluation process, a project is determined to be least cost/best fit for a LSE, do developers/customers have an opportunity to and/or are LSEs willing to execute a PPA contingent on receiving TPD? None of the allocation groups have a guarantee of obtaining a TPD allocation prior to the allocation process, so even a project in Group One who has an executed PPA enters the TPD allocation process with no guarantee of receiving an allocation. Furthermore, it seems that PPAs would be contingent, ultimately, on obtaining regulator-approval and therefore, could a PPA be executed contingent on obtaining TPD?

2. If the reality of a project's opportunity to obtain TPD and proceed under allocation Group Four or Group Five is unrealistic, are stakeholders in favor of eliminating these groups from the proposed allocation groups?

Allocation Group Six & Seven

The CAISO provides the following response to the stakeholder question about why energy only projects that have achieved commercial operation should be allocated TPD ahead of those projects that have executed a PPA or are shortlisted and have not yet reached commercial operation. The CAISO's intent for this proposal is to provide those projects with a regulatory-approved and/or business need to obtain a TPD allocation ahead of those projects that do not have a regulatory-approved and/or business need.

The CAISO will not consider projects under the circumstances where such project could obtain TPD just by executing a GIA. This would likely provide a majority, if not all, projects the opportunity to seek and obtain TPD and leave nothing available for those with a regulatory and/or business need for it.

CAISO TPD Allocation Proposal

Allocation Groups

Allocation Group One includes those projects that are active as FCDS projects, have just completed the Phase II study process or and are seeking a TPD allocation following their parking opportunity(s), and have an executed or regulator-approved PPA with an LSE that requires the project to be FCDS or projects being developed by an LSE that already has regulatory authority to construct such project. An LSE seeking TPD in Group One must be constructing its project for the purposes of fulfilling a regulatory requirement and for serving its own load. More specifically, an LSE may not build a project to serve load outside its service area and seek TPD under Group One, unless the project can demonstrate it has an executed PPA with an LSE located within the CAISO Balancing Authority Area that requires the project to obtain FCDS. The parking opportunities for the projects in this group will remain unchanged.

Allocation Group Two includes those projects that are active as FCDS projects, have just completed the Phase II study process, and are seeking a TPD allocation following their parking opportunity(s) and are included on a commercially recognized method of preferential ranking of power providers (*i.e.*, shortlisted) by a prospective purchaser (LSE) that require the project to be FCDS. If a shortlisted project receives a TPD allocation, the interconnection customer must execute a PPA by November 30th of the calendar year such allocation was received. If a PPA is executed, the interconnection customer must attest that the PPA has been executed in the retention affidavit, typically due on or around December 1st, to solidify the allocation. Otherwise the TPD is released and becomes available for the next allocation cycle. Further, regulatory approval of such executed PPA must be received by the following year's TPD retention affidavit due date to solidify the allocation. If not, the TPD is released and becomes available for the next allocation cycle.

Allocation Group Three includes those projects that are active as FCDS projects, have just completed the Phase II study process, and have declared that it is their intent to proceed with developing their project regardless of whether they obtain a PPA. The only point in the GIDAP process a project can proceed in Allocation Group Three is following the project's Phase II Study. More specifically, the only time a project can declare it will proceed without a PPA is in the seeking TPD affidavit and allocation cycle immediately following the project's Phase II study. If a project claims that it will proceed without a PPA and receives an allocation, it must accept the allocation (whether full or partial) or withdraw. If a partial allocation is received, the project may elect to park the remaining portion of the project that did not get TPD and seek TPD in the next allocation cycle, or downsize to the size corresponding with the TPD allocation they previously received. In the event a TPD allocation is not received, that project may elect to park with their respective queue cluster and seek a TPD allocation, in Group Three, in the following allocation cycle. However, if a project 1) receives a partial allocation and parks that portion of the project that did not receive an allocation, or 2) does not receive an allocation and parks all of its project, and the project can demonstrate that it has improved its commercial status (executed a PPA) by the next seeking/retention affidavit due date, then the project may seek TPD for the parked portion of the project by claiming a higher allocation group (Group One or Group Two) in the next seeking TPD Affidavit.

It is expected that a project electing to proceed without a PPA will continue developing their project in a timely manner. As such, there should be no need for the interconnection customer to delay the negotiations of the GIA, start of construction, or progress towards achieving commercial operation. Therefore, at the time a project has declared it will proceed without a PPA and is allocated TPD, the following requirements would apply to the project:

- Project must accept the TPD allocation. If the project chooses to not accept the TPD allocation, the project must withdraw from the queue;
- Project will not be afforded any suspension provisions in its GIA;
- Project will lose TPD allocation if Notice To Proceed is not provided to the PTO as established in the GIA milestones;
- Project agrees that the CAISO and PTO will not consent to COD extensions beyond the earlier of 1) the COD established in the interconnection request, or 2) 7 years in queue, under any circumstances except a PTO delay.

Allocation Group Four includes those projects that selected FCDS on their interconnection requests, have been converted to energy only following the cluster study and parking opportunities, and have an executed or regulator-approved PPA with a LSE that requires the project to be FCDS. For energy only projects, the CAISO will only allocate TPD provided no new DNUs are required.

Allocation Group Five includes those projects that selected FCDS on their interconnection request application, have been converted to energy only deliverability status following the cluster study and parking opportunities, and are included on a commercially recognized method of preferential ranking of power providers (*i.e.*, shortlisted) by an LSE that requires the project to be FCDS. If a shortlisted project receives a TPD allocation, the interconnection customer must execute a PPA by November 30th of the calendar year such allocation was received. If a PPA is executed, the interconnection customer must attest that the PPA has been executed in the retention affidavit to solidify the allocation (*e.g.*, affidavits were due December 1st in 2017). If the steps described here are not completed, the TPD is released and becomes available for the next allocation cycle. Further, regulatory approval of the PPA must be received by the following year's TPD retention affidavit to solidify the allocation. If not, the TPD is released and becomes available for the next allocation cycle. For energy only projects, the CAISO will only allocate TPD provided no new DNUs are required.

Allocation Group Six includes those projects that selected FCDS on their interconnection requests and have been converted to energy only following the cluster study and parking opportunities and have achieved commercial operation. For energy only projects, the CAISO will only allocate TPD provided no new DNUs are required.

Allocation Group Seven includes those projects that selected energy only and have achieved commercial operation. For energy only projects, the CAISO will only allocate TPD provided no new DNUs are required.

Allocation Group Summary

Allocation Group	Project Status	Commercial Status	Can Build DNUs for Allocation?	Allocation Rank
1	Study/Parking Process	Executed or regulator-approved PPA requiring FCDS or interconnection customer is a LSE serving its own load	Yes	Allocated 1st
2	Study/Parking Process	Shortlisted in a RFO/RFP	Yes	Allocated 2nd
3	Study Process (Following Ph. II Only)	Proceeding without a PPA (f.k.a., BSF)	Yes	Allocated 3rd
4	Converted to Energy Only	Executed or regulator-approved PPA requiring FCDS	No	Allocated 4th
5	Converted to Energy Only	Shortlisted in a RFO/RFP	No	Allocated 5th
6	Converted to Energy Only	Commercial operation achieved	No	Allocated 6th
7	Energy Only	Commercial operation achieved	No	Allocated 7th

Timing and implementation of proposed TPD Allocation methodology: The CAISO's target is to implement this TPD allocation proposal in the upcoming 2018/2019 allocation cycle. The CAISO is planning to present this topic to the CAISO Board of Governors at the September Board meeting and file with FERC no later than September 30, 2018. Assuming FERC approves the filing as proposed and without delay, the CAISO will implement this aspect for the 2018/2019 TPD allocation cycle. This would include a modification to the seeking and retention TPD affidavits typically due December 1st. If the proposed schedule above works, all projects that sought and received a TPD allocation in Cluster 9 and prior will not be subject to the new TPD allocation methodology and will be subject to meeting CVC. Any project in Cluster 8 or 9 allocated TPD, that declined their allocation and parked, whether or not they claimed BSF, will be required to follow this new TPD allocation methodology. Cluster 10 and later clusters will be subject to the new TPD allocation methodology.

TPD Allocation Process and Scoring Methodology: The TPD Allocation Process for TPD, as currently identified in Tariff Appendix DD Section 8.9, the GIDAP BPM Section 6.2.9, and the Seeking TPD affidavit, will be modified to reflect the following:

1. **TPD Allocation Group (Select one)**

   (1) In Study/Parking Process and
      a. Executed/regulator-approved PPA requiring FCDS status
         or
      b. Load Serving Entity with regulator-approved authority to develop and serve own load

   (2) In Study/Parking Process and shortlisted in RFO/RFP
   (3) Proceeding without a PPA
   (4) Project was studied as FCDS, converted to Energy Only, and has executed/regulator-approved PPA requiring FCDS status
   (5) Project was studied as FCDS, converted to Energy Only, and shortlisted in RFO/RFP
   (6) Project was studied as FCDS, converted to Energy Only, and has achieved Commercial Operation
   (7) Project was studied as Energy Only and has achieved Commercial Operation

2. **The project's PPA Status (Allocation Groups 1 and 4 Only)**

   A. (10 points) The Interconnection Customer represents to the CAISO that it has a regulator-approved power purchase agreement with a Load-Serving Entity that serves end users in its service area requiring the project to be FCDS status or an executed power purchase agreement that does not require any further regulatory approval.

   B. (7 points) The Interconnection Customer has an executed power purchase agreement requiring the project to be FCDS status, but such agreement has not yet received regulatory approval.

3. **The project's PPA Status (Allocation Groups 2 and 5 Only)**

   A. (Minimum criteria, no points) The Interconnection Customer does not have an executed power purchase agreement, but the Interconnection Customer is included on an active short list or other commercially recognized method of preferential ranking of power providers by a prospective purchaser Load Serving Entity in the CAISO balancing authority area requiring the project to be FCDS status.

4. **The Project's permitting status (All allocation Groups 1 – 7)**

   A. (10 points) The Interconnection Customer has received its final governmental permit or authorization allowing the Generating Facility to commence construction.

   B. (5 points) The Interconnection Customer has received a draft environmental report (or equivalent environmental permitting document) indicating likely approval of the requested permit and/or which indicates that the permitting authority has not found an environmental impact which would likely prevent the approval. For purposes of this requirement, a draft environmental report can take the form of a draft environmental impact report, draft environmental impact statement, environmental assessment, mitigated negative declaration, or CEC preliminary staff assessment. Findings that would qualify as those which would indicate likely approval include no environmental impacts found that cannot be mitigated to insignificance, or in the case of a National Environmental Policy Act document, the Project has been identified as the preferred alternative. If Federal or State Endangered Species Act permits are required, draft environmental reports for such permits have been received and similarly either indicate likely approval or do not find an impact that would likely prevent approval.

C. (3 points) The Interconnection Customer has applied for the necessary governmental permits or authorizations and the authority has deemed such documentation as data adequate for the authority to initiate its review process.

D. (1 point) The Interconnection Customer has applied for the necessary governmental permit or authorization for the construction.

5. The Project's land acquisition status (All allocation Groups 1 – 7)

A. (3 points) The Interconnection Customer can demonstrate a present legal right to begin construction of the Generating Facility on one hundred percent (100%) of the real property footprint necessary for the entire Generating facility.

B. (2 points)The Interconnection Customer can demonstrate Site Exclusivity.

Groups Four, Five, Six, and Seven will replace the current AFC deliverability option specified in CAISO Tariff Section 9.2.1. These energy only allocation options are intended to serve as the opportunity where stakeholders have requested that a project be able to reenter the queue to seek TPD. For reasons described above, while these options do not allow for a project to reenter the queue to seek TPD, (*e.g.*, to be restudied for and allowed to fund additional DNUs) it serves as an opportunity where an energy only project can seek a TPD allocation without triggering new network upgrades.

The CAISO will perform a TPD allocation assessment within the annual reassessment study to determine what energy only projects are eligible receive a TPD allocation. An initial step of the allocation assessment is a process to determine if any energy only projects seeking an allocation are located behind a local constraint. This will ensure that no energy only project seeking a TPD allocation require a LDNU to be deemed deliverable. This process has been used for projects seeking FCDS through the AFC Deliverability Option. To ensure that local deliverability is retained for all FCDS projects, including projects in the most recent Phase I study, the methodology to determine project's impacts on local constraints is to include all active interconnection queue projects seeking FCDS in the study model, including the FCDS projects that have just completed their Phase I study. Additionally, all transmission upgrades approved in the Transmission Planning Process (TPP) and all interconnection related network upgrades that are under construction are modeled. No capacity associated with area deliverability is retained for any projects that have not yet received a TPD allocation. Energy only projects that are not located behind a local constraint are eligible to receive a TPD allocation up to the point where all local deliverability and area deliverability is fully allocated.

All projects, regardless of whether a project is seeking a TPD allocation, must submit a seeking TPD affidavit. The seeking TPD affidavit, available on the CAISO's public website, must be completed annually and is typically due on or around December 1st.

For all projects with an energy only status that submit a seeking TPD affidavit, consistent with the downsizing process, the CAISO will require a $60,000 deposit for each project requesting TPD allocation. The CAISO will utilize this deposit to cover costs associated with the evaluation and TPD allocation process. The CAISO will deposit all TPD allocation deposits in an interest-bearing account at a bank or financial institution designated by the CAISO. The TPD allocation deposit will be applied to pay for reasonable costs incurred by the CAISO, the PTOs, or third parties at the direction of the CAISO or PTOs. The interconnection customer will be charged the actual cost incurred and once the evaluation is completed, excess funds will be returned with interest or, in the event the deposit is utilized entirely, an invoice will sent to the interconnection customer requesting additional funds.

CAISO Commercial Viability – Elimination of Balance Sheet Financing Proposal

When interconnection customers request an extension to a project's COD the CAISO evaluates the request under the material modification assessment (MMA) process. The CAISO requires interconnection customers to prove their project meets CVC to extend their milestones beyond the 7/10 year threshold, as it applies to project's studies under the cluster and serial study processes, respectively.[2] The current CVC are:

- Having, at a minimum, applied for the necessary governmental permits or authorizations and that the permitting authority has deemed such documentation "as data adequate" for the authority to initiate its review process;
- Having an executed power purchase agreement, attesting that the Generating Facilities will be balance-sheet financed, or otherwise receiving a binding commitment of project financing;
- Demonstrating Site Exclusivity for 100% of the property (in lieu of a Site Exclusivity Deposit);
- Having executed a GIA; and
- Being in good standing with its GIA such that neither the PTO nor the CAISO has provided the interconnection customer with a Notice of Breach of the GIA (where the breach has not been cured or the interconnection customer has not commenced sufficient curative actions).

The CAISO's current CVC were designed to complement the TPD allocation criteria. The current CVC can be thought about in broad terms as "TPD criteria plus", in other words, commercial viability is as stringent as TPD allocation criteria with respect to financing and GIA requirements, and is more stringent with respect to permitting and site exclusivity requirements.

[2] The In-Service Date ("ISD") for Generating Facilities studied in the serial study process shall not exceed ten (10) years from the date the Interconnection Request is received by the CAISO. For Generating Facilities studied in the cluster study process, the COD shall not exceed seven (7) years from the date the Interconnection Request is received by the CAISO.

The CAISO proposes to eliminate the ability to claim BSF as part of the commercial viability process. In this proposal, interconnection customers requesting an extension to a project's COD beyond the 7/10 year threshold will have three options:

- The interconnection customer could demonstrate CVC with a PPA that provides a later in-service date of such project, then the COD extension would be approved to that delivery date and deliverability is maintained. This option would apply for all projects with a PPA, as part of Group One or Four above. This does not apply to those projects that elected to proceed without a PPA (i.e. Group Three above).
- The project could have a COD extension approved absent commercial viability demonstration, move forward with the project as energy only (if desired), and then seek deliverability through the new processes proposed in this Section 4.1. This option would apply for all projects except those that elected to proceed without a PPA (i.e. Group Three above).
- If the PTO is delayed in construction of the network upgrades, then the COD extension would be approved and deliverability is maintained. The extension would consist of a day-for-day slip based on the new in-service date provided by the PTO, regardless of the projects allocation group.

In consideration of and consistent with the revised TPD allocation criteria above, the CAISO proposes to eliminate BSF as an option in the commercial viability process. Therefore, the CAISO is also proposing to modify the CVC in Appendix DD, Section 6.7.4 of the CAISO Tariff.

4.2 Balance Sheet Financing

The CAISO has decided to include this topic in 2018 IPE and combine this topic with topics 4.1, 4.3, 4.5 and 9.2. This combined topic will seek to enhance the GIDAP in a manner that addresses all five issues under one topic to be addressed in Section 4.1.

4.3 Participating in the Annual Full Capacity Deliverability Option

The CAISO has decided to include this topic in 2018 IPE and combine this topic with topics 4.1, 4.2, 4.5 and 9.2. This combined topic will seek to enhance the GIDAP in a manner that addresses all five issues under one topic to be addressed in Section 4.1.

4.4 Change in Deliverability Status to Energy Only

Background/Issue

The CAISO is seeking to clarify when projects may elect to convert to energy only deliverability status, when the CAISO will convert projects to energy only regardless of customer election, and the consequences for such conversions.

Currently, projects may voluntarily convert from FCDS or Partial Capacity Deliverability Status

(PCDS) to energy only deliverability status only at certain times during the interconnection process. A project may convert to energy only deliverability status between Phase I and Phase II studies, or immediately following the TPD allocation process (either after the Phase II study or after parking for parked projects). This restriction minimizes impacts on other projects and the PTOs. Projects that convert to energy only deliverability status at these times are no longer responsible for DNU costs going forward.

Although the CAISO tariff is specific on when a project can voluntarily convert to energy only deliverability status, it does not specify whether a project can request energy only deliverability status at other times during the interconnection process, nor does the tariff describe the consequences of such conversion, particularly with regard to financial obligation for DNUs.

Projects are currently required to convert to energy only deliverability status for failure to meet commercial viability or TPD retention criteria. If the CAISO converts a project to energy only deliverability status under these conditions, all DNU costs are removed from the converting project's cost responsibility. However, the CAISO believes that some project developers may seek to utilize the conversion requirements associated with failure to meet CVC and TPD retention criteria to reduce their cost responsibility and then withdraw. The CAISO believes this outcome is problematic because it potentially allows projects to shift costs to other project developers inappropriately or to the PTOs. Failing to be commercially viable effectively becomes an attractive option for interconnection customers contemplating withdrawal.

The CAISO proposed that projects that change to energy only deliverability status as a result of failure to meet commercial viability or TPD retention criteria will retain the cost responsibility for all DNUs.

The CAISO also proposed that projects may request to change their deliverability status to energy only at any time after the Phase II study. These requests will be evaluated in the annual reassessment study to determine cost responsibility for the project. If the DNUs are still required, the project will be converted to energy only, but will retain the cost responsibility for those upgrades. If, however, the DNUs are no longer needed, the upgrades will be removed from the project's cost responsibility.

Stakeholder Input

SDG&E and Six Cities support the proposal. CalWEA supports the proposal and requests clarification that a project should be allowed to seek conversion to PCDS in the proposed process. SCE would support if the Interconnection Customer retains cost responsibility for all DNUs still required for queued generators.

EDF-R and sPower believe that it would be unfair for generators seeking such changes to continue to fund DNUs for which they arguably receive no benefit and that there should be a preliminary assessment of whether the need for DNUs would remain.

First Solar opposes the proposal to require projects to continue to pay for DNUs when the conversion is required due to failure to meet commercial viability.

CAISO Response

The CAISO proposes two clarifications from the straw proposal based on stakeholder comments. First, projects that change to energy only deliverability status as a result of failure to meet commercial viability or TPD retention criteria will retain the cost responsibility for all DNUs unless the annual reassessment study shows that the DNUs are no longer needed for other queued projects. If the DNUs are no longer needed, the upgrades will be removed from the project's cost responsibility. The CAISO believes that without this requirement, interconnection customers will be incentivized to remain in queue and then purposely fail the CVC to reduce their non-refundable IFS. The CAISO already has seen examples of this behavior.

The second clarification is that projects may request to change their deliverability status to energy only or PCDS at any time after the Phase II study.

In response to comments submitted by EDF-R and sPower, the CAISO does not have the ability to perform a preliminary assessment of whether the need for DNUs would remain if a project were to convert to energy only or PCDS. This determination requires a study. The proposal to have the evaluation performed as part of the annual reassessment study is consistent with the requirements that are in place for projects seeking to downsize. This approach has proven effective for the downsizing process and we believe that it is the best approach for this application as well. As with the downsizing process, if a project requests to change to energy only, the project is making a commitment to that change, regardless of the result of whether any DNUs are removed or continue to be required for other projects.

4.5 Energy Only Projects' Ability to Re-enter the CAISO Queue for Full Capacity

The CAISO has decided to include this topic in 2018 IPE and combine this topic with topics 4.1, 4.2, 4.3, and 9.2. This combined topic will seek to enhance the GIDAP in a manner that addresses all five issues under one topic to be addressed in Section 4.1.

4.6 Options to "Transfer" Deliverability

Background/Issue

Currently interconnection customers have some ability to effectively "transfer" deliverability to a different owner through the repower process and within a generating facility at the same Point of Interconnection (POI) through the material modification analysis. The CAISO clarifies that deliverability is not a property right and may not be sold or otherwise assigned; only transferred with an entire interconnection customer itself. The CAISO calculates deliverability based on the deliverability assessment methodology.

Interconnection customers also may "transfer" their deliverability capacity among their own generating units (new and old) at their generating facility. Adding new generating units is generally done through the behind-the-meter expansion option under an independent study request. Any expansion using the independent study process is energy only unless the capacity expansion uses the same technology as the original generating facility. If it is, the interconnection customer can elect to request to transfer its deliverability from the original generating units to the capacity expansion facility.

In the straw proposal, the CAISO clarified the methodology of deliverability transfers under various scenarios.

Opportunities to Transfer Deliverability

1. Deliverability Reservation from Repowering Generators

   When a generator with FCDS or PCDS plans to retire, the generator owner may request that the deliverability of its existing generator be preserved for its repowered project. The repowered project is either approved through the repowering process, if the total capability and electrical characteristics of the generating unit remain substantially unchanged, or by submitting it into the generation interconnection queue. As such, deliverability is transferred between the same owner, old and new generating units at the same site.[3]

2. Deliverability Transfer among Generating Units at a Generating Facility

   Upon request from the generator, the CAISO will transfer deliverability between existing generating units at the same POI, if owned by the same generator owner and under the same generating facility GIA. The CAISO will reduce deliverability from the transfer-from generating unit and assign to the transfer-to generating unit using the deliverability transfer calculation below. The transfer-to generating unit will have:

   - FCDS if the transfer-from generating units had FCDS or PCDS and the full deliverability is calculated for the transfer.
   - PCDS if the transfer-from generating unit had FCDS or PCDS and the partial deliverability is calculated for the transfer.
   - Interim Deliverability Status (IDS) if the transfer-from generator had IDS.

3. Deliverability Transfer within the Same Interconnection Request

   Interconnection customers are allowed to shift deliverability between different portions (*i.e.*, generating units) of the same interconnection request based on the deliverability transfer calculation below. This includes transferring deliverability to energy storage capacity conversions or additions made through the MMA review process. The CAISO will perform a deliverability transfer calculation and notify the interconnection customer of the resulting deliverability for each component of the project.

4. Deliverability Transfer for Behind-the-Meter Capacity Expansion

[3] The CAISO notes that for all of these, "generating units" are a generating facility capable of having their output separately metered such that they are able to have separate resource IDs and participate in the CAISO markets separately (where the interconnection customer elects to do so). Typical examples include bifurcations of large solar or wind resources (X turbines/panels are one unit, Y turbines/panels are another) and storage resources paired with any other generator. There are a myriad of other possibilities.

Currently, section 4.2.1.2 of Appendix DD requires that the behind-the-meter capacity expansion is metered separately from the original generating facility and assigned a separate resource ID, unless the expansion is the same technology as the original generating facility. When the behind-the-meter capacity expansion is metered separately, the expansion is energy only. The CAISO proposes to allow the interconnection customer to designate all or partial deliverability from the original generating facility to the capacity expansion. The CAISO will perform a deliverability transfer calculation to determine the resulting deliverability for the original generating facility and the capacity expansion.

Calculation of Transferred Deliverability

A major principle of a deliverability transfer is that the transfer results in the same or lower maximum output tested in the deliverability assessment, based on the methodology adopted at the time of the transfer request. The table below shows the maximum output in the deliverability assessment for different type of resources:

Table: Maximum Output Assumptions in Deliverability Assessment

	Existing	New
Non-intermittent Resources	Highest NQC value in last 3-year summer months	Requested Pmax
Intermittent Resources (solar and wind)	CAISO calculated exceedance level expressed as percentage of the interconnection capacity	

The deliverability transferred is calculated as:

$$(Deliverability\ \%)_{transfer-to} = \max\left\{100\%, \frac{(Max\ Deliverability\ Output)_{transfer-from}}{(Max\ Deliverabiity\ Output\ if\ FC)_{transfer-to}}\right\}$$

Stakeholder Input

CalWEA, EDF-R, First Solar, LS Power, SDG&E and PG&E support the CAISO's proposal. LS Power recommends that CAISO should make public the information regarding deliverability transfer review so that the interconnection queue can be informed of impacts of such requests on TPD.

CAISO Response

The CAISO does not propose any additional modifications to this aspect of the straw proposal. Because the deliverability is transferred on the basis that it would keep the same or lower the maximum output tested in the deliverability assessment, the transfer does not affect availability of TPD to any other interconnection requests. The publicly available generation interconnection queue information and BPMs reflect the approved changes, regarding the technology, size, and deliverability status. The CAISO does not believe there is a need to post more information regarding deliverability transfers.

5. Energy Storage

5.2 Replacing Entire Existing Generator Facilities with Storage

Background/Issue

In the prior Straw Proposal the CAISO proposed that for generating facilities that are retiring a portion of the project and want to continue to operate the storage unit that was added under the MMA process; the CAISO and PTOs will assess the impact of the system without the original generating facility and only the energy storage remaining. If there are no identified reliability issues then the energy storage can stay interconnected and continue to operate and any FCDS or PCDS that is available could be transferred from the retiring unit to the energy storage. If there are any identified reliability issues, then the generator cannot retire unless a mitigation is determined, or the energy storage will need to be disconnected at the time the unit retires. If a generating facility wants to retire and repower as energy storage, then it would need to go through the repowering process and the repowering rules will apply, including the potential transfer of FCDS or PCDS if the original generating facility has such status.

Stakeholder Input

The CAISO received five comments on this aspect of the straw proposal. Four comments supported the concepts the CAISO proposed with clarifications and one comment opposed policy that has been in place since the 2015 storage initiative.

Able Grid commented that they were concerned that some of the proposed procedures for converting an existing generating facility to energy storage would allow converted projects to leapfrog other energy storage projects in the interconnection queue. Able Grid believes this potentially compromises the equitable nature of the interconnection study process by giving incumbent generators a competitive advantage over new generators. Able Grid suggested that the operating range of a project be used as a simple metric to determine whether or not a repowered project is consistent with the original interconnection application. For example, if a 100 MW generator was originally studied as having an operating range from 0 MW to 100 MW, adding storage without re-entering the interconnection queue would be permissible as long the project is not charging from the grid and stays within the 0 MW to 100 MW operating range. By contrast, replacing the generator with a 100 MW energy storage facility that charges from the grid and operates in the range of -100 MW to 100 MW would be a material change that requires resubmission into the interconnection queue. Able Grid believes that this simple framework is consistent with past precedent under which an expansion of the operating capabilities of a project is a material change to the interconnection requiring a new interconnection application, and that it maintains the competitive nature of the interconnection study process while providing a clear framework for market participants.

CalWEA commented that 1) the “automatic” acceptable level of converting generation resource capacity (after the project signs it’s GIA) to storage should be 25% (rather than the current 10%), subject to a standard material modification assessment (MMA). This would be similar to the rules for behind-the-meter capacity expansion; and 100% conversion of an existing project to storage should be allowed subject to the project adhering to CAISO charging instructions.

CESA observed that the current BPMs do not always provide clarity on pathways, such as through the material modification process, for the aforementioned repower-and-replace scenarios. Specifically, CESA raised ideas for the CAISO to consider in developing the study and interconnection processes for these scenarios:

> Consider whether the criteria for *de minimus* impact for repowering existing generation facilities with energy storage could apply to the criteria for *de minimus* impact for keeping the energy storage system online even as the original generation facilities retire.
>
> Consider whether the same fuel source requirement for repowering existing generation facilities with energy storage is necessary for keeping the energy storage system online even as the original generation facilities retire – *i.e.*, allowing energy storage to charge from the grid without a full cluster study review of load impacts.
>
> Consider whether and how deliverability transfers can occur when repowered energy storage systems remain online even as the original generation facilities retire.

With respect to the reliability assessment, CESA noted that energy storage systems can provide synthetic inertia that replicates the inertial response of the rotating mass from the gas generation it intends to replace. New provisions may be required (*e.g.*, state of charge and minimal energy requirements similar to how synchronous generators have minimum loading levels) in the interconnection agreement for the repowered energy storage resource to ensure that synthetic inertial response is provided.

As the CAISO has noted, short circuit duty is a grid service that may not be sufficiently provided by inverter-based technologies such as energy storage at this time, which may present reliability issues if the existing generation facilities are retired. CESA commented that there is potential for the provision of short circuit duty by alternative sources, such as synchronous condensers, where the costs could be borne by the remaining energy storage system which could resolve the concern.

Overall, CESA supports the CAISO's reliability study processes and understands that the charging impacts of the standalone energy storage facility must be studied. CESA aims to ensure that there is clarity on the reliability assessment in the facility study and that there are alternative pathways for repowered energy storage facilities to remain online.

With respect to Order 845 implementation, CESA believes that interconnection issues scoped into the 2018 IPE Initiative will need to be viewed and addressed within the context of the Order 845 issued by the Federal Energy Regulatory Commission (FERC) on April 19, 2018 that amended the pro forma Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreements (LGIA)[4] in many different ways. Specifically around repower-and-replace scenario, Order 845 mostly deferred this issue as being outside the scope of this rulemaking and as appropriate for being addressed elsewhere, except to "ameliorate

[4] Reform of Generator Interconnection Procedures and Agreements, Docket No. RM17-8-000, issued April 19, 2018.

business and financial risk" to the surplus interconnection service customer.

SDG&E supports allowing a generating facility to add 100% (storage) of its approved capability to the project provided the output of the project does not exceed the interconnection capacity at the POI and the generator has a limiting mechanism to ensure that the additional capacity is not put on to the grid. SDG&E also accepts the proposal to allow up to a 10% change when decreasing the amount of proposed generation to replace it with energy storage. SDG&E also agrees that this is something that could be on a case-by-case basis moving forward. SDG&E appreciates the clarifications in regards to these projects following CAISO dispatch instructions since they are not considered a firm load, but are negative generation. SDG&E thinks it is important that the projects install an automatic generator tripping scheme and give the CAISO authority to trip the generating facility or take any other necessary actions to limit the output of the generating facility so the total output of the generating facility does not exceed the approved interconnection request capacity at the POI.

PG&E supports the CAISO's explanation of energy storage and understands that while a bright-line test for the maximum amount of transferred generation capacity from the original generation type to energy storage is not possible, the CAISO is open to generators transferring generation capacity more than 10%, depending on the specifics of the request.

CAISO Response

With respect to Able Grid's feedback, the CAISO already had a stakeholder process in 2015 that determined that storage was negative generation and interconnection customers could use the CAISO's generator interconnection process to request storage. The CAISO's MMA process can be used to revise existing projects that have already gone through the interconnection queue process. Stakeholders agreed that storage need not be studied initially as firm load and must respond to CAISO's dispatch instructions for both charging and discharging.

CalWEA and CESA may misunderstand the CAISO's position on the percentage of generation resource capacity that could be converted to storage via the MMA process. The CAISO is willing to consider anything short of 100% conversion to storage using the MMA process. In other words, provided the total MW capacity at the POI does not increase and the electrical characteristics are substantially unchanged the conversion to storage would be allowed. SDG&E and PG&E agree that the amount of conversions should be determined on a case-by-case basis.

CESA raised questions as to the reliability assessment when generating units request retirement. As stated in the GM BPM, the CAISO evaluates the reliability of the system without the retiring generating unit. The reliability studies include but are not limited to dynamic stability assessment, post-transient power flow, short circuit duty, contingency analysis, etc. If the storage unit were to remain the CAISO would determine if there is a reliability impact with only the storage unit connected to the grid and if there is an issue, can that be mitigated to allow the storage unit to remain.

For repowering, the GM BPM already outlines the requirements for repowering and the criteria that is applied. The CAISO has also worked with the repowering generators that had minor issues that were impeding the ability to repower, including revising equipment, to allow the repower request to be approved. The CAISO believes that all of CESA concerns regarding repowering are already addressed in that BPM. However, if CESA has additional suggestions on modifying the BPM it can do so using the CAISO's BPM change management process.

Regarding Order No. 845, the CAISO is developing its compliance plan concurrently with IPE and will address related issues in future publications and consultation with stakeholders.

For generating facilities that are adding storage above 100% of their maximum MW, the CAISO and PTO have required the within 10 days of approving the modification, the interconnection customer must provide information regarding the mechanism by which the interconnection customer will limit the generator output to the approved MW capability.

Based on the clarifications above, the CAISO does not propose additional modification to this aspect of the Straw Proposal and will implement the proposed retirement clarifications through the GM BPM.

6. Generator Interconnection Agreements

6.1 Suspension of Notice

Background/Issue

The CAISO believes that modifications to the LGIA are needed to allow for request and approval of a project to suspend. Article 5.16 of the LGIA requires interconnection customers to notify the CAISO and PTO if a project will be suspended. This article is not specific in that requests are not required to include a start and end date for the suspension. The provisions also do not provide an opportunity for the CAISO to approve the terms of the suspension to ensure that the project is not in breach of the generator interconnection agreement (GIA) when suspension is requested. The current provisions also do not provide the CAISO the ability to ensure that the suspension will not impact other interconnection customers, or to the extent that it does impact other customers, to require the interconnection customer requesting the suspension to agree to continue paying for the joint network upgrades.

Stakeholder Input

EDF-R and sPower commented that CAISO's attempts to restrict unilateral suspension rights is understandable but not warranted. The requirement for firm suspension end dates (as opposed to the expected dates now required) is unrealistic. Often, the conditions dictating the need for suspension involve conditions with unknown timelines (*e.g.*, permitting problems) that do not allow for date certainty. At a minimum, a project should be permitted to extend its suspension end dates after the suspension begins, if the conditions driving the suspension have not been resolved, as long as the three-year COD delay is not exceeded.

EDF-R commented that the current rules already prohibit suspension of financial obligations for upgrades "common to multiple generating facilities," so a study or other analysis should not be required to process the suspension request. EDF-R believes any Material Modification Assessment (MMA) request to modify milestones should not be required until the project is ready to exit suspension, and it should be considered part of the obligation of the parties to negotiate revised milestones in good faith. In addition, EDF-R believes the CAISO should clarify that the suspension of financial obligations should be effective upon submission of the suspension notice, and that those obligations should not continue during any lengthy CAISO processing.

First Solar agreed with CalWEA's comments that the start and end dates would be highly hypothetical but are supportive of the CAISO conducting a material modification assessment to ensure the suspension will not impact other interconnection customers and provide conditions to mitigate those impacts if identified.

SCE and SDG&E supported the CAISO's proposal to require the Interconnection Customer to include a proposed start and end date of the suspension in its suspension request (with the caveat that the end date be no more than three years from the originally proposed COD, as is currently the case in the pro-forma LGIA or three years from the date the suspension request is submitted, whichever is earlier). SCE and SDG&E believe the CAISO also should have the authority to approve the suspension, with concurrence from the PTO, by ensuring the project is in good standing and in determining how the milestones set forth in the GIA and later queued customers may be impacted during the suspension period. To address the potential of projects lingering without making an earnest effort to move towards achieving commercial operation or adversely impact queued behind projects, SCE also supported the proposed GIA modification to include language requiring the interconnection customer to negotiate in good-faith to expeditiously revise the milestone dates (at the end of the suspension period).

PG&E supported the CAISO's proposed requirement to Interconnection Customer's to submit the start and end date of their requested suspension in the suspension notice delivered to the CAISO and PTO. This change will allow the CAISO and PTO to confirm the suspension of the Project will not adversely affect the interconnection other Interconnection Customers.

<u>CAISO Response</u>

The CAISO believes that EDF-R and sPower may misunderstand the CAISO's proposal. The CAISO is not proposing to require firm dates, as the CAISO recognizes most generators do not know the extent of the suspension if there are permitting or land acquisition issues. The CAISO clarifies that it is asking for the interconnection customer to submit an MMA with the request for suspension stating the start and estimated end date so that the CAISO can realistically assess the impact to other projects, including those that are precursor network upgrades for other projects. The CAISO believes this is preferable to an assumption that all projects will suspend for the maximum amount of time (which would be the most likely to affect other customers). The MMA can also determine the tentative milestone dates to ensure that the PTO can schedule the network upgrades when they are needed. Where suspension time is still available, interconnection customers will be able to extend their original suspensions where the CAISO can determine that further suspension will not harm other interconnection customers.

The CAISO agrees with SCE that the suspension cannot go beyond the maximum time already allowed in the LGIA – three years. In addition, the CAISO supports SCE's suggestion that the interconnection customer must negotiate in good faith to expeditiously revise the milestone dates at the end of the suspension period.

The CAISO proposes the following revisions to this aspect of the straw proposal:

- Require the suspension request to be an MMA with the actual start date and tentative end date.
- Include a provision that the interconnection customer must negotiate in good faith to expeditiously revise the milestone dates at the end of the suspension period.

6.2 Affected Participating Transmission Owner

Background/Issue

Generating facilities interconnecting to the CAISO controlled grid may affect the transmission system of a PTO that is not the PTO at the POI. In these instances, the PTO being impacted is referred to as an affected PTO. The current GIDAP does not address how the interconnection customer's financial security postings, cost responsibility, and affected PTO repayment will be disbursed among the interconnecting and affected PTOs.

The CAISO currently documents the contractual rights and obligations of the CAISO, interconnection customer, interconnection PTO and affected PTO in two separate agreements. The CAISO enters into a *pro forma* small or large generator interconnection agreement with the interconnection customer and interconnecting PTO under which interconnection service is provided to the interconnection customer. The non *pro forma* affected participating transmission owner upgrade facilities agreement (UFA) among the CAISO, interconnection customer and affected PTO establishes the mitigation measures required on the affected PTO's electric system due to the interconnection of the interconnection customer's generating facility to the CAISO controlled grid.

Stakeholder Input

SCE supported providing developers greater cost certainty through the CAISO's proposal to modify the Tariff to allow a separate maximum cost responsibility for each PTO. The maximum cost responsibility for each PTO will be documented in the interconnection studies and the GIA or affected PTO upgrade facilities agreement as appropriate. SCE believes it would then be appropriate for interconnection customers to post interconnection financial security to each PTO separately.

SDG&E supported the CAISO's proposal to modify the Tariff to allow a separate maximum cost responsibility for each PTO, which will be documented in the interconnection studies and the GIA or affected PTO upgrade facilities agreement as appropriate. SDG&E supported the ICs making IFS postings with IFS instruments to each PTO separately, which would translate into the ICs receiving repayment for their contribution to the cost of network upgrades from each PTO separately. SDG&E supported the repayment amounts advanced for reliability network upgrades will be paid by each PTO up to a combined maximum of $60,000 per MW of generating capacity as specified in the GIA. SDG&E also believes that it is fair that the CAISO added proportionality to the total repayment of each PTO's RNU's.

CalWEA strongly recommended that CAISO reconsider its position regarding 4 (or more)-party GIAs. CalWEA stated that forcing the interconnection customer to sign and then maintain separate agreements with individual PTOs is inefficient because the overwhelming majority of the agreement provisions are the same among all GIAs and each time one of them needs to be modified, the modification must be separately negotiated with each PTO. CalWEA also believes there are obligations (the least of which is confidentiality) among the PTOs that cannot be managed in a separate GIA paradigm. CalWEA stated that, as a result, the PTOs try to obligate the interconnection customer to enforce inter-PTO obligations, something that ICs are in no position to make happen.

EDF-R agreed with CalWEA and added that the requirement for two agreements also negates the advantage to developers of siting projects in the large CAISO footprint and it imposes on developers the cost of CAISO reluctance to mandate consistent PTO procedures.

sPower strongly agreed that a single Generator Interconnection Agreement (GIA) is warranted and agreed with the comments of CalWEA and EDF-R. sPower believes there should be no need for the interconnection customer to negotiate two separate agreements with CAISO-area PTOs, especially since the CAISO has not imposed any standard template for GIA appendices.

SCE supported the CAISO not proposing to further discuss any potential for a four-party agreement with Affected PTOs. SCE believes that it is more appropriate, and more manageable, to have the continued use of separate agreements in order to properly identify the requisite terms and conditions among only the parties involved.

CAISO Response

The CAISO proposes to modify the tariff to describe separate network cost estimates for the interconnecting PTO and any affected PTO(s). These PTO cost estimates will sum to set a single maximum cost responsibility for the interconnection customer's entire project. This is a change from the draft straw proposal where the CAISO proposed a separate interconnection customer maximum cost responsibility for each of these PTOs. The cost estimates for each interconnecting and affected PTO(s) will be documented in the interconnection studies and the GIA or affected PTO facilities agreement as appropriate. The CAISO believes it is critical to maintain a single maximum cost responsibility for each project. This will allow the CAISO to entertain more efficient and lower overall network cost solutions without being constrained by individual interconnection customer maximum costs responsibilities across multiple PTOs. For example, if, through the study and/or reassessment processes, network upgrades identified by each PTO needed for a project change or better solutions are identified, the PTO costs will be allowed to float from one PTO to another within the limit of the interconnection customer's maximum cost responsibility for the project. However, in the case where overall network upgrade costs exceed the interconnection customer's maximum cost responsibility (due to project withdrawals or unanticipated system change), the PTOs whose costs increased such that after utilizing any available costs from any decrease in costs by another PTO, will assume financial responsibility for all dollars over the maximum cost responsibility for the project.

Example of Maximum Cost Responsibility Float

The interconnection customer will make their 1st and 2nd IFS posting to the interconnecting PTO and will make the third IFS posting to each PTO separately based on each PTO's network cost estimate. In addition, interconnection customers will be entitled to receive repayment for their contribution to the cost of network upgrades from each PTO separately. Repayment of amounts advanced for reliability network upgrades will be paid by each PTO up to a combined maximum of $60,000 per MW of generating capacity as specified in the GIA. Total repayment from both PTO's will be applied proportionately based on the amount paid to each PTO for its RNUs.

Sample Proportional Repayment Calculation

The following example assumes a 100 MW generating capacity and a $10,000,000 total cost of RNUs across all PTOs. In this scenario the total reimbursement for RNUs to the interconnection customer is $6,000,000 (100 MW × $60,000 per MW).

	RNU Cost	Proportion of Total Costs Assigned to PTO	100 MW Maximum Repayment
Interconnecting PTO	$ 7,000,000	70%	$ 4,200,000
Affected PTO	$ 3,000,000	30%	$ 1,800,000
Total	$ 10,000,000	100%	$ 6,000,000

The consistent desire of interconnection customers to negotiate a single agreement to document the rights and obligations of the interconnection customer, interconnecting PTO, affected PTO(s) and CAISO prompted the CAISO to reconsider its position requiring a separate GIA and UFA.

The CAISO is not convinced that the anticipated efficiencies of a single agreement will be realized since two agreements have coordinated terms and conditions and both the CAISO and the interconnection customers are parties to both which assists with the compatibility. The interconnection customer will always be in the middle as the PTO(s) are individually supporting the interconnection customer's interconnection project. The terms and conditions of the UFA are public as it is filed with the FERC. The GIA is public once it is effective. The terms and conditions of each agreement are available to interested individuals. Each PTO should be able to manage its electric system according to its policies. The CAISO is proposing to continue with the separate UFA / GIA structure. The CAISO is also considering submitting the UFA to the FERC, seeking to make it a CAISO *pro forma* agreement.

6.4 Performance and Diagnostic Minimum Requirements for Inverter based Generation

Background/Issue

The CAISO proposed modifications to the technical requirements for the interconnection of inverter based generation to the CAISO controlled grid. The CAISO proposed these new requirements to address incorrect and undesired tripping or cessation of inverter based generation which occurred during the routine high speed clearing of bulk electric transmission lines.

Stakeholder Input

The CAISO received comments from CalWEA, CESA, EDF-R, First Solar, LS Power, SCE, SDG&E, Six Cities, and sPower.

CalWEA generally supported the proposal to discontinue the use of momentary cessation with the understanding that the proposal would apply to new projects, and would apply to existing projects only if they repower or modify their inverters. CalWEA proposed that these requirements should be applicable to all projects, such as WDAT, and not just to projects connecting to the CAISO controlled grid. The CAISO agrees that this would improve system reliability and will recommend that the PTOs update their generation interconnection handbooks to reflect new approved requirements. CalWEA also proposed that the CAISO should work to resolve redundant reporting requirements to both CAISO and NERC/WECC.

EDF-R and sPower provided similar comments that stated that the CAISO's proposals are based on proposed NERC standards, and CAISO should wait until NERC establishes a standard before trying to implement any ride through requirements.

First Solar indicated that it will need to see specifics before providing detailed comments. Further, First Solar suggests that the ISO host a technical workshop once the specific requirements are identified.

SCE supported the CAISO proposal for addressing voltage and frequency ride-through requirements, including the requirement to continue to inject current during system fault conditions that are cleared within a prescribed time period (*i.e.*, cycles needed for system protection to clear faulted facilities). SCE agreed with the CAISO that tripping should be based on physical equipment limitations to protect the inverter itself, and not a generic NERC standard which is less stringent. SCE believes that minimum technical standards for return times following transient voltage deviations and post inverter trip return time are also appropriate to stabilize the grid following a disturbance and to not jeopardize the reliability of the network.

SDG&E agreed that these obligations need to be on a “moving forward” basis and only apply to existing resources if projects repower or modify their inverters. SDG&E supported the CAISO’s proposal to no longer permit momentary cessations for new inverter based generation during momentary drops in the system AC voltage. SDG&E believes that if inverters give priority to reactive current (during transient low voltage conditions), then this would remedy the issue of inadvertent generator tripping by supporting the system. SDG&E fully supported the CAISO’s proposals regarding: Momentary low voltage, momentary high voltage, return times following transient voltage deviations, phase lock loop synchronization issues, post inverter trip return time and diagnostic equipment. SDG&E believes that the sum of these approaches and recommendations will go a long way in preserving the reliability of our high voltage transmission system.

CAISO Response

In response to CalWEA’s comment that CAISO should work to resolve redundant reporting requirements between CAISO and WECC/NERC, the CAISO notes that it previously requested NERC to share data submitted in response to previous alerts / advisories.. NERC responded that it cannot share data submitted to it with Balancing Authorities or other outside entities.

In response to EDF-R, and sPower’s feedback, the CAISO is working closely with NERC and is an active participant in the NERC task force that is developing a guideline for inverter based generation (note: a copy is now available for public comment). NERC is not currently active in developing a new national standard for inverter based generation. The CAISO ride through proposal is based on recently issued recommendations identified in a NERC alert (advisories) issued to registered inverter based generating units, and not on any “proposed” NERC Standards. The applicable NERC Advisory can be found at: https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf

In response to First Solar, the CAISO will prepare specific requirements as the next step in this stakeholder process. The CAISO will consider the request to host a technical workshop once specific requirements are identified. In response to First Solar’s comment pertaining to dynamic model requirements, the CAISO intends to enforce modeling requirements in the interconnection study process. Non-compliant dynamic model settings will be rejected as invalid. Non-compliant performance observed in simulation will be noted in the study report and will need to be mitigated by the interconnecting customer.

The CAISO fully concurs with stakeholder input that it is now appropriate to provide detailed information on the proposed ride through requirements. The following is the CAISO’s initial proposal to update the technical requirements summarized in Appendix H of the generator interconnection agreement:[5]

[5] This language represents an initial draft for policy discussion purposes. The CAISO will stakeholder its draft tariff language at the conclusion of the policy development. As always, the CAISO reserves the right to modify its final tariff language up to its submission with FERC, so long as that language is completely consistent with the final policy approved by the CAISO Board.

Appendix H

INTERCONNECTION REQUIREMENTS FOR AN ASYNCHRONOUS GENERATING FACILITY

Appendix H sets forth interconnection requirements specific to all Asynchronous Generating Facilities. Existing individual generating units of an Asynchronous Generating Facility that are, or have been, interconnected to the CAISO Controlled Grid at the same location are exempt from the requirements of this Appendix H for the remaining life of the existing generating unit. Generating units that are replaced, however, shall meet the requirements of this Appendix H.

A. Technical Requirements Applicable to Asynchronous Generating Facilities

i. Low Voltage Ride-Through (LVRT) Capability

An Asynchronous Generating Facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

1. An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, having a duration equal to the lesser of the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum normal clearing time associated with any three-phase fault location that reduces the voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

2. An Asynchronous Generating Facility shall remain online for any voltage disturbance caused by a single-phase fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, with delayed clearing, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum backup clearing time associated with a single point of failure (protection or breaker failure) for any single-phase fault location that reduces any phase-to-ground or phase-to-phase voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

3. Remaining on-line shall be defined as continuous connection between the Point of Interconnection and the Asynchronous Generating Facility's units, without any mechanical isolation. ~~Asynchronous Generating Facilities may cease to inject current into the transmission grid during a fault.~~ For transient low voltage conditions, the Asynchronous Generating Facility's units will inject reactive current. The level of this reactive current shall be directionally proportional to the decrease in Per Unit voltage at the inverter AC terminals. The inverter shall produce full rating reactive current when the AC voltage at the inverter terminals drops to a level of 0.50 PU. The Asynchronous Generating Facility's units may cease to inject current into the transmission grid for transient high voltage conditions above 1.20 PU. The Asynchronous Generating Facility should continue to absorb reactive current for transient voltages between 1.10 and 1.20 PU.

Upon the cessation of transient voltage conditions and the return of the grid to normal operating voltage (0.90 < V < 1.10 PU), the Asynchronous Generating Facility's units shall automatically connect to the grid within a maximum of 0.10 seconds (if momentary cessation was used for transient high voltage), and transition to normal active (real power) current injection. The Asynchronous Generating Facility's units shall ramp up to inject active (real power) current with a minimum ramp rate – from no output to full output - of at least 100%/second. A ramp rate of 200% / second is preferred. The entire time to complete the transition shall be one second or less.

Inverter protective functions should use a filtered, fundamental frequency voltage input for overvoltage protection to avoid spurious tripping on transient high voltages.

4. An Asynchronous Generating Facility unit trip is defined as the opening of the unit's AC circuit breaker or otherwise electrical isolation of the unit from the grid. Following the unit trip, the unit will make at least one attempt to resynchronize and connect back to the grid. The time delay to accomplish this will be adjustable to between 2 and 5 minutes. The default time shall be 2 ½ minutes.

5. The Asynchronous Generating Facility is not required to remain on line during multi-phased faults exceeding the duration described in Section A.i.1 of this Appendix H or single-phase faults exceeding the duration described in Section A.i.2 of this Appendix H.

6. The requirements of this Section A.i of this Appendix H do not apply to faults that occur between the Asynchronous Generating Facility's terminals and the high side of the step-up transformer to the high-voltage transmission system.

7. Asynchronous Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

8. Asynchronous Generating Facilities may meet the requirements of this Section A.i of this Appendix H through the performance of the generating units or by installing additional equipment within the Asynchronous Generating Facility, or by a combination of generating unit performance and additional equipment.

9. The provisions of this Section A.i of this Appendix H apply only if the voltage at the Point of Interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds, excluding any sub-cycle transient deviations.

10. Asynchronous Generating Facility units shall not trip or cease to inject current for loss of the Phase Lock Loop (PLL). As a minimum, the Asynchronous Generating Facility's unit controls may lock the PLL to the last synchronized point and continue to inject current into the grid at that last calculated phase until the PLL can regain synchronism upon voltage recovery (e.g. the transmission system fault clears). The reactive current injection may be limited to protect the inverter.

11. Inverter restoration following transient voltage conditions must not be impeded by plant level controllers. If the Asynchronous Generating Facility uses a plant level controller, it must be coordinated to allow the individual inverters to rapidly respond following transient voltage recovery, before resuming overall control of the individual plant inverters.

~~The requirements of this Section A.i in this Appendix H shall not apply to any Asynchronous Generating Facility that can demonstrate to the CAISO a binding commitment, as of July 3, 2010, to purchase inverters for thirty (30) percent or more of the Generating Facility's maximum Generating Facility Capacity that are incapable of complying with the requirements of this~~

~~Section A.i in this Appendix H. The Interconnection Customer must include a statement from the inverter manufacturer confirming the inability to comply with this requirement in addition to any information requested by the CAISO to determine the applicability of this exemption.~~[6]

ii. Frequency Disturbance Ride-Through Capability

An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the ~~WECC Under Frequency Load Shedding Relay Application Guide or successor requirements as they may be amended from time to time.~~ NERC Standard PRC-024, Western Variance.

iii. Power Factor Design Criteria (Reactive Power)

An Asynchronous Generating Facility not studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer ~~Point of Interconnection~~ as defined in this LGIA in order to maintain a specified voltage schedule, if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability. An Asynchronous Generating Facility studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA in order to maintain a specified voltage schedule. The power factor range standards set forth in this section can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and CAISO. The Interconnection Customer shall not disable power factor equipment while the Asynchronous Generating Facility is in operation. Asynchronous Generating Facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Phase II Interconnection Study shows this to be required for system safety or reliability.

iv. Supervisory Control and Data Acquisition (SCADA) Capability

An Asynchronous Generating Facility shall provide SCADA capability to transmit data and receive instructions from the Participating TO and CAISO to protect system reliability. The Participating TO and CAISO and the Asynchronous Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed Asynchronous Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability.

v. Power System Stabilizers (PSS)

Power system stabilizers are not required for Asynchronous Generating Facilities.

vi. Diagnostic Equipment

An Asynchronous Generating Facility shall monitor and record the following data in real time:

<u>Plant Level</u>

[6] New policy aside, the CAISO may remove this paragraph as anachronistic. The CAISO will move this language into the BPM for those generators for which this applied.

(1) Plant three phase voltage, current and power factor
(2) Status of ancillary reactive devices
(3) Status of all plant circuit breakers
(4) Status of plant controller
(5) Plant control set points
(6) Status of main plant transformer no load taps
(7) Status of main plant transformer tap changer (if applicable)
(8) Protective relay trips (relay target data)

Inverter Level Data
(1) High and low frequency ride through events
(2) High and low voltage ride through events
(3) Momentary cessation for transient high voltage events
(4) Reactive current injection for transient low voltage events
(5) Phase Lock Loop (PLL) status
(6) Inverter status
(7) AC and DC current
(8) AC and DC voltage

The data shall be time synchronized to a one millisecond level of resolution. The Asynchronous Generating Facility shall store this data for a minimum of 30 calendar days. The Asynchronous Generating Facility, upon request from the CAISO or the PTO, shall make this data available within 10 calendar days of the request.

The Asynchronous Generating Facility shall install and maintain a PMU (Phase angle Measuring Unit) at the service entrance to the facility. The PMU shall have a resolution of at least 30 samples per second. The Asynchronous Generating Facility, upon request from the CAISO or the PTO, shall make this data available within 10 calendar days.

7. Interconnection Financial Security and Cost Responsibility

7.1 Maximum Cost Responsibility for Network Upgrades and Potential Network Upgrades

Background/Issue

Currently the “maximum cost responsibility” is established from the Phase I and Phase II study reports. The combined costs for all network upgrades in the Phase I and Phase II study reports are compared and the lower of the cost for all network upgrades between the two reports sets the maximum cost responsibility for network upgrades for the project. However, an Interconnection Customer’s “current cost responsibility” is used to calculate the required Interconnection Financial Security (IFS). This latter figure can change as the result of customers withdrawing from the queue. The CAISO is aware that the reassessment related cost responsibility changes and the increased appearance of contingent (fka potential) network upgrade costs in project’s study reports has created understandable confusion around how the maximum cost responsibility plays out in practice. The CAISO also has observed that there is confusion regarding when a provided figure relates to the maximum cost responsibility or the current cost responsibility. The CAISO is hoping that the addition of new cost responsibility and exposure definitions will provide more clarity on how potential network upgrades from prior clusters where GIAs have and have not been executed affect cost responsibility.

Stakeholder Input

CalWEA and First Solar supported the CAISO's proposal. First Solar stated a concern that power purchase agreements may include an interconnection cost cap that requires the seller to pay for any costs in excess of the cap and requests that stakeholders be allowed to discuss the proposal in more detail before settling on a final proposal.

PG&E, SDG&E, and SCE generally supported the proposal and all agreed that potential network upgrades should be included in the maximum cost responsibility. In addition, they urged the CAISO to keep in its proposal the requirement that potential network upgrades should be included in the maximum cost responsibility in the Phase I and Phase II study reports rather than raising the maximum cost responsibility later when an earlier queued project withdraws prior to executing a GIA.

PG&E, SCE and SDG&E are concerned that execution of a GIA does not guarantee that a project will progress towards completion in a timely manner. They requested that the trigger for the removal of potential network upgrades not be the execution of the GIA, but rather some other trigger point, such as receipt of final financial postings and written authorization to proceed from the Interconnection Customer.

SCE's position is that a 100% share of certain shared RNUs which SCE labels as "plan of service" RNUs in the interconnection studies, should be included in the potential network upgrades costs for each interconnection customer participating in the upgrade, for purposes of determining each of the sharing interconnection customer's maximum cost responsibility. SCE stated that the backstop financing risk associated with the potential re-allocation of costs associated with a plan of service RNU must be placed upon those remaining interconnection customers that absent the sharing of the RNU, would otherwise be required to construct the RNU. They continued, stating that if PTOs are not allowed to re-allocate any remaining plan of service RNUs and would be required to backstop finance facilities that provide no network benefits that the PTO may no longer agree to allow ICs to share plan of service RNUs.

EDF-R and sPower both stated they believe that the ISO should clarify in the Phase II study and GIA the maximum cost responsibility without the potential network upgrades. They also agreed with the initial CAISO proposal that the headroom between maximum cost responsibility and current cost responsibility not be used to create headroom for non-potential network upgrades. Both parties stated that when more than one PNU is assigned to a project that each PNU's cost is dealt with on an individual basis and not be allowed to create headroom for a different PNU if the one PNU is removed from the Maximum Cost Responsibilities (MCR). In other words the removal of one PNU should not create headroom for another PNU the same way that a PNU cannot create headroom for another assigned upgrade whenever a reallocation of costs is performed in a reassessment study.

CAISO Response

In response to PG&E, SCE and SDG&E's concern that execution of a GIA does not guarantee that a project will progress towards completion and request that the trigger for the removal of potential network upgrades not be the execution of the GIA, but rather some other trigger point, such as receipt of final financial postings and written authorization to proceed from the Interconnection Customer, the CAISO understands the PTO's concern; however, the CAISO has not identified a better solution and is looking for additional stakeholder input.

In response to SCE's position that a 100% share of plan of service RNUs in the interconnection studies should be included in the potential network upgrades; the CAISO agrees and notes this is the current practice and should continue.

In response to EDF-R and sPower's feedback that the headroom between maximum cost responsibility and current cost responsibility should not be used to create headroom for non-potential network upgrades, the CAISO agrees and notes that this is the intent of the proposal. The CAISO also notes that it likely will refer to these upgrades as "contingent upgrades" consistent with Order No. 845.

First Solar raised a concern that the impact of contingent network upgrades raising the maximum cost responsibility late in the process could put a power purchase agreement at risk. The CAISO believes that having contingent network upgrade's impact reflected at the beginning of the study process mitigates First Solar's concern related to unanticipated changes to the maximum cost exposure after the interconnection customer submits a proposal into an RFO as they seek to obtain a power purchase agreement.

<u>The CAISO proposal</u>

The CAISO has reconsidered its original proposal and determined that the proposed definitions in the straw proposal did not fully meet the original objectives, specifically the treatment of contingent network upgrades. The CAISO has decided to revisit with stakeholders the framework for overall cost responsibility in this paper and will propose final definitions in the next IPE paper:

1. An interconnection customer is assigned the cost of reliability network upgrades (RNUs) and local deliverability network upgrades (LDNUs) identified in their Phase I and Phase II study reports.
2. These RNUs and LDNUs include two components:
    a. Direct RNUs and LDNUs - Network Upgrades originally identified in the interconnection customers Phase I or Phase II study reports.
    b. Contingent RNUs and LDNUs – Network Upgrades that are required by a project for its selected level of service whose cost responsibility is assigned to one or more prior-queued projects where at the time that a study report is completed

none of those prior queued projects have executed a Generator Interconnection Agreement, including Stand Alone Network Upgrades (SANUs).

3. The interconnection customer maximum cost exposure includes two components:
    a. The lower subtotal for both RNUs and LDNUs originally assigned to the interconnection customer in the final Phase I or the final Phase II interconnection study reports (Currently known as the Maximum Cost Responsibility).
    b. The full cost of any contingent RNUs and LDNUs.
4. The interconnection customer maximum cost exposure can change over time during the annual reassessment study:
    a. The maximum cost responsibility originally assigned to the interconnection customer is subject to adjustment based on the results of the annual reassessment and the criteria for changes to the maximum cost responsibility in the reassessment process provisions in Appendix DD. However, this cost can never be more that the amount determined in 3.a. above plus the full cost of any former contingent upgrade now assigned to this project. More specifically, if a contingent upgrade becomes a direct upgrade, the full cost for that Network Upgrade will be included in the project's maximum cost responsibility and the maximum cost responsibility may increase (see expanded discussion below).
    b. Costs for contingent facilities can change if these upgrades are memorialized in an executed GIA, are determined to be no longer needed, or become a direct RNU or LDNU (see expanded discussion below).
5. The interconnection customer only posts IFS for direct RNUs and LDNUs (currently known as 'current cost responsibility') and will not post IFS for the cost of Contingent Network Upgrades. However, if the interconnection customer wishes to achieve commercial operation, they may have to post and fund any remaining contingent RNUs and LDNUs needed for the projects selected level of service.

<u>Expanded discussion from (4a & 4b) above</u>

The CAISO is considering providing tariff and or BPM language clarifying that if a prior cluster project executes a GIA that contains a Network Upgrade that is identified as a Contingent Network Upgrade in a later cluster project's study report, then the Contingent Network Upgrade is removed from the maximum cost exposure of that later cluster project unless the $60,000/MW RNU reimbursement cap becomes an issue for the later-queued cluster (as discussed in Section 7.7 of this revised straw proposal). Conversely, a Network Upgrade stops being contingent and becomes a direct LDNU or RNU when all prior cluster projects assigned a cost responsibility allocation for that contingent Network Upgrade withdraw without having executed a GIA. This will result in:

1) The costs for the Network Upgrade to be included in the project's current cost responsibility for Network Upgrades in the proportionate amount that the Network Upgrade is allocated to each project within that cluster that is now responsible for funding the upgrade. In other words, the cost of the Network Upgrade(s) is allocated to each project in the cluster that "inherits" the responsibility for the upgrade in the same manner

the cost for any Network Upgrade is allocated to projects sharing a Network Upgrade in the cluster study process.

2) The full cost for that Network Upgrade will be included in the project's maximum cost responsibility and the maximum cost responsibility may increase.

A contingent network upgrade will not serve to provide headroom for increasing cost allocations of Network Upgrades that are part of a project's maximum cost responsibility, nor can a Contingent Network Upgrade be used to create headroom for another contingent network upgrade when more than one are assigned to a project.

The full cost (100%) of each contingent network upgrade will be included in a project's maximum cost exposure. With the PTO protected from having to backstop the cost of a contingent network upgrade prior to a project that has the upgrade in its current cost responsibility signing a GIA, there is no need for any projects to post more than its cost allocation for a network upgrade established in its current cost responsibility. Projects will not be required to post towards a contingent network upgrade until such time that the contingent network upgrade ceases to be a contingent network upgrade and the cost of the contingent network upgrade becomes part of the projects current cost responsibility.

7.3 Eliminate Conditions for Partial IFS Recovery upon Withdrawal

<u>Background/Issue</u>

Pursuant to Section 11.4 of Appendix DD to the CAISO tariff, an interconnection customer can withdraw its interconnection request and recoup a partial amount of the interconnection financial security posted if it meets certain criteria. The CAISO currently requires a project to meet conditions for partial recovery of the interconnection financial security of network upgrades. Once proof is submitted by an interconnection customer and approved by the CAISO, the CAISO can refund the network upgrades financial security posting to the project. There are different calculations depending on the timing of the project withdrawal, but often the interconnection financial security amount refunded is fifty percent of the amount posted. Non-refundable funds are disbursed first to PTOs to help pay for network upgrades that the withdrawing projects have a cost responsibility for and are still needed by other projects, up to the withdrawing projects obligation; and if funds are still available to the PTO's to decrease the cost of the Transmission Revenue Requirement, which is paid by ratepayers.

In the straw proposal, the CAISO proposed to eliminate the conditions for partial recovery of interconnection financial security upon withdrawal of interconnection request or termination of GIA as detailed in section 11.4.1 of Appendix DD. Virtually all interconnection customers are able to meet a criterion, and the CAISO believes that by removing this requirement, it will eliminate the administrative effort of searching for documents that prove a project meets the requirement (which virtually all eligible interconnection customer can eventually produce), and this also will avoid further delays in the refund process of the interconnection financial security. The CAISO also believes that by posting interconnection financial security an interconnection customer has already made a considerable effort in developing the project. The CAISO's intent is to make the withdrawal process easier for these interconnection customers. The refundable portion amount will remain the same; however, all projects, will qualify for partial recovery of the Interconnection Financial Security.

Stakeholder Input

CalWEA supported the CAISO's proposal to eliminate the conditions for partial recovery of interconnection financial security for Network Upgrades.

SCE requested the CAISO consider a change in the current non-refundable amounts disbursement process which includes the proposal that a transmission-build entity be eligible for recovery of 100% of incurred costs of a transmission facility or network upgrade approved by the CAISO which is subsequently cancelled by the CAISO or deemed to no longer be needed. Six Cities disagreed with SCE and stated that FERC's standard policy for non-incentive projects is to require 50-50 sharing of abandonment costs between shareholders and ratepayers. Six Cities also stated that this is a matter of FERC policy, and including provisions in the CAISO tariff that purport to provide 100% cost recovery in the event of abandonment is not appropriate.

CAISO Response

In response to SCE's comment to include full cost recovery for costs incurred on a transmission facility or network upgrade approved by the CAISO, which is subsequently cancelled or deemed to no longer be needed, the CAISO believes that this issue is too complex to insert into the 2018 IPE initiative at the revised straw proposal stage. The issue warrants a more complete stakeholder discussion process than the 2018 IPE would allow at this point.

The CAISO will move forward with the proposal to eliminate conditions for partial IFS recovery upon withdrawal without additional modifications.

7.5 Shared SANU and SANU Posting Criteria Issues

Background/Issue

The CAISO tariff defines a SANU as Network Upgrades or tasks (e.g., telecommunications, environmental, or property work) that an interconnection customer may construct without affecting day-to-day operations of the CAISO controlled grid or affected systems during their construction. The PTO, the CAISO, and the interconnection customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Large Generator Interconnection Agreement.

The CAISO tariff allows a SANU to be built by an interconnection customer when the CAISO and the PTO agree that it qualifies as a SANU and agree to allow the interconnection customer to build the SANU. The CAISO GIDAP BPM currently requires that 100% of the cost responsibility for the network upgrade must be assigned to the interconnection customer as indicated in the study reports to qualify as a SANU. The CAISO has received requests to remove the 100% cost responsibility requirement to an individual interconnection customer and allow two or more interconnection customers to share the cost responsibility for a SANU. In addition, stakeholders have requested that CAISO allow two or more interconnection customers to share the construction responsibility for a SANU as well.

This issue closely aligns with the FERC Order No. 845 item A.2 on the interconnection customer's option to build stand alone network upgrades.

Stakeholder Input

All stakeholders agreed with the CAISO's proposal to clarify the GIDAP BPM to address the issue that a SANU can be shared by more than one interconnection customer, and to allow the PTOs to make this determination on a case by case basis. The CAISO will remove the requirement in the BPM that each interconnection customer seeking to self-build a SANU be assigned 100% of the cost.

However, EDF-R and sPower stated there is no rationale for treating SANUs different from other shared Network Upgrades and the CAISO proposal would allow the current piecemeal practices to remain and worsen them by allowing PTOs to treat SANUs differently.

EDF-R and sPower also stated that PTOs should not be allowed to set their own security-posting policies and that while PTOs are entitled to have legitimate costs covered, that principle does not require more than 100% cost coverage in security postings. GIAs can easily be modified to provide for cost-responsibility and security-posting increases if projects sharing a SANU withdraw.

PG&E supported the proposal associated with interconnection customers sharing the responsibility of building a SANU as long as each PTO has the freedom to establish its own criteria for SANU cost allocation.

SCE pointed to the GIDAP BPM requirement that any project assigned a SANU must post for 100% of the associated costs and should remain intact. SCE went on to state that if multiple interconnection customers share a SANU, they each should continue to be required to post 100% of the costs. Changing the current CAISO policy to allow each project assigned a SANU to post less than 100% of the costs would unreasonably transfer financial risk to the PTO if projects with a shared SANU withdraw, but the SANU is still needed.

CAISO Response

In response to EDF-R and sPower's comment that there is no rationale for treating SANUs different from other shared Network Upgrades, the CAISO contends that SANUs do have distinct differences from most RNUs. The typical RNU is more highly impacted by project size and potentially the number of projects needing the particular RNU. When a non-stand alone RNU is designed for multiple projects and later some of those projects withdraw it is likely the RNU can be scaled back or eliminated due to reduction in project capacity. However, with a SANU, which is typically a new switching station, no matter how many projects need the upgrade initially or later when the SANU is identified by later clustered projects who intend to utilize the SANU, if all but one project withdraw the SANU continues to be needed for that one project. The cost of a new switching stations is often significant, as EDF-R and sPower stated, which opens the door for gaming where one project initiates the need for a SANU and a later cluster project also needs the SANU. This is a frequent occurrence and without some cost responsibility by the later cluster project the first project could withdraw, putting the full cost responsibility on the PTO and the later cluster project gets the SANU at zero cost to them. It is possible that in this scenario the amount of nonrefundable IFS funds the initial project loses is less than the cost the SANU would impose on the later cluster project who ultimately benefits from the construction of the SANU.

In response to EDF-R and sPower's comment that PTOs should not be allowed to set their own security-posting policies and that PTOs should not require more than 100% cost coverage in security postings, the CAISO agrees that IFS postings should not be greater than the cost allocation established in the Phase I and Phase II study reports; however, the CAISO continues to believe that all projects associated with a SANU should have 100% of the cost included in their MCR in the same manner that Contingent Network Upgrades are proposed to be covered in the MCR in topic 7.1.

In response to PG&E's support being contingent on each PTO having the freedom to establish its own criteria for SANU cost allocation the CAISO disagrees. The CAISO believes the cost allocation methodology needs to be consistent across all PTOs. The CAISO will solicit stakeholder feedback on this issue so that the PTOs can demonstrate what would justify different cost allocation practices, and so developers can comment on their preference.

In response to SCE's reference to the GIDAP BPM requirement that any project assigned a SANU must post for 100% of the associated costs and should remain intact, the CAISO clarifies, the BPM only states "To qualify as a Stand Alone Network Upgrade the Interconnection Customer must be assigned 100% of the cost responsibility for the Network Upgrade as indicated in the study reports." This is the BPM language the CAISO proposes to remove from the BPM to allow multiple projects to partner together in building a SANU. The CAISO's proposal is to only require a project's posting to be based on a 100% cost allocation when the project is truly the only project needing the SANU.

SCE commented that if multiple interconnection customers share a SANU, they each should continue to be required to post 100% of the costs. SCE is concerned that changing the current CAISO policy to allow each project assigned a SANU to post less than 100% of the costs would unreasonably transfer financial risk to the PTO if projects with a shared SANU withdraw, but the SANU is still needed. As previously stated, the CAISO does not agree that multiple projects should each be required to post 100% of the costs of the SANU. The CAISO believes PTOs should be adequately protected by requiring that all projects associated with a SANU have 100% of the cost included in their MCR in the same manner that Contingent NUs are proposed to be covered in the MCR in topic 7.1. Including the full cost for the SANU in the MCR of each project that needs the SANU protects the PTO when projects with a shared SANU withdraw, but the SANU is still needed. Requiring each project to post based on a 100% cost allocation for the SANU is not needed.

The CAISO proposes to clarify the GIDAP BPM by removing the requirement in the BPM that each interconnection customer seeking to self-build a SANU be assigned 100% of the cost of the SANU. This will remove the barrier to multiple generators partnering to build a SANU and provide for the PTOs to make a determination on a case-by-case basis whether an interconnection customer proposed arrangement for multiple interconnection customers to jointly build a SANU should be allowed.

The CAISO further proposes that when multiple projects need a common SANU and are within a cluster that initially identified the need for a SANU then the IFS postings should reflect the cost allocations established in the Phase I and Phase II study reports. Additionally, all projects needing the same SANU, regardless of what cluster they are in, should have 100% of the cost included in their MCR in the same manner that Contingent Network Upgrades are proposed to be covered in the MCR in topic 7.1.

The CAISO's FERC Order No. 845 compliance filing is due on or before November 5, 2018. The CAISO proposes to make the BPM change stated above and will include the option for the PTOs to make a determination on a case by case basis whether an interconnection customer proposed arrangement for multiple interconnection customers to jointly build a SANU should be allowed in its compliance filing to FERC. The posting and MCR requirements proposed here will continue to be handled in the 2018 IPE initiative.

7.7 Reliability Network Upgrade Reimbursement Cap

Background/Issue

Section 14.3.2.1 of the GIDAP provides that PTOs will reimburse an interconnection customer's cost responsibility for RNUs only up to $60,000 per MW of the interconnection customer's generating capacity, as specified in its GIA.[7] This policy was designed to ensure that ratepayers only incur costs for RNUs commensurate with the benefits they receive from the new generator. The repayment limit of $60,000 per MW for RNUs assigned to a project was determined to result in full cash repayment for RNUs for the vast majority of projects, and provides an incentive for interconnection customers to avoid siting projects in locations where the costs of RNUs needed to support the interconnections would be inappropriately high.

The CAISO has found that the $60,000 per MW maximum reimbursement amount for an RNU for funds advanced for network upgrades has the potential to be circumvented in instances where earlier-queued projects withdraw from the queue but the upgrades are still needed. To demonstrate this potential issue, consider the following example; Assume a 100 MW project in Cluster 8 with an executed GIA has a required RNU whose cost exceeds the $60,000 per MW limit. Also assume a Cluster 10 project, also 100 MW, requires the same RNU as the Cluster 8 project to interconnect. If the Cluster 8 project that triggered the RNU withdraws, the PTO must fund the construction costs of the RNU for the Cluster 10 project.[8] In this example the PTO is responsible for funding the entire cost of the RNU, including the portion over $60,000 per MW, and will include the entire cost of the RNU into its Transmission Revenue Requirement and ratepayers will ultimately have to pay for the entire cost of the RNU.

The CAISO is revising its original proposal provided in the straw proposal. The $60,000 per MW reimbursement cap for RNUs is to ensure that ratepayers only incur costs for RNUs commensurate with the benefits they receive from the new generator. This is a principle that

[7] Reimbursement beyond the cost cap would come in the form of Merchant Transmission Congestion Revenue Rights.

[8] *See* Section 14.2.2 of Appendix DD to the CAISO tariff.

overrides any cost protection principles for interconnection customers and PTOs. The goal of this proposal is to provide a process that is transparent to participants in the GIDAP to help them deal with the inherent uncertainties that the concept of contingent upgrades present, while protecting ratepayers from excessive RNU costs. The proposal continues to seek to ensure that when a PTO becomes responsible for funding an RNU that exceeds the cap because a project signs a GIA and then withdraws, there is a mechanism to require the project that ultimately benefits from the RNU to pay the cost component over the cap related to the specifics of their project. Without this mechanism, the PTO would fund the full amount of the RNU and place those costs in its rate base, which would then burden ratepayers with costs the policy was designed to exclude.

In the straw proposal the CAISO proposed that if a project withdraws after executing a GIA whose RNU costs exceed the $60,000 per MW RNU cost cap, the cost responsibility for the amount exceeding the $60,000 per MW RNU cost cap will fall to the later cluster projects needing the RNUs, in the fashion of a contingent Network Upgrade, but not be reimbursable. These costs will thus be included as contingent upgrades in the interconnection customers' study reports.

Stakeholder Input

The ORA, PG&E, SCE, SDG&E and the Six Cities fully agreed with the proposal.

EDF-R, First Solar and sPower suggested that if a later-queued project becomes responsible for funding a RNU previously assigned to a withdrawn project, then the MW capacity of that project should be used to recalculate the amount of the reimbursable portion of the RNU.

First Solar requested clarification as to the equities of this proposal to the later queued interconnection customer. The uncertainty associated with withdrawals may change or eliminate required reliability network upgrades, and there is not sufficient justification to move these costs to the next cluster.

EDF-R and sPower stated that a generation project with an executed GIA would typically have made its second security posting. Thus, the PTO would already be entitled to retain security postings equal to ~30% of the upgrade cost, which would likely far exceed the non-refundable portion.

CAISO Response

In response to EDF-R, First Solar and sPower's suggestion that if a later-queued project becomes responsible for funding the RNU, then the MW capacity of that projects should be used to recalculate the amount of the reimbursable portion of the RNU, the CAISO agrees. The determination of the cost cap should be developed on a project by project basis. The determination of the amount of a later-queued project's RNU cost related to the RNU cap should be determined on the basis of it capacity amount and total RNU costs plus the cost of any RNUs it inherits from a withdrawing project, regardless of how the RNU cost cap may have impacted the project that withdrew.

First Solar stated that withdrawals may change or eliminate required reliability network upgrades, and there is not sufficient justification to move these costs to the next cluster. The CAISO agrees that the reassessment could determine that the RNU is no longer needed or it is downsized, to the benefit of the remaining active projects. While it is understandable that project developers may be concerned with the additional uncertainty this proposal imposes, the $60,000 per MW reimbursement cap for RNUs was designed and accepted by FERC as just and reasonable to ensure that ratepayers only incur costs for RNUs commensurate with the benefits they receive from the new generator. The CAISO's proposal is solely intended to ensure that the policy is not circumvented.

EDF-R and sPower comment that a generation project with an executed GIA would typically have made its second security posting. Thus, according to them, the PTO would already be entitled to retain security postings equal to ~30% of the upgrade cost, which would likely far exceed the non-refundable portion. The CAISO believes that the premise that the PTO is allowed to retain the full second posting amount if false. Topic 7.3 proposes to eliminate the conditions for partial recovery of interconnection financial security upon withdrawal such that all projects who have made their initial or second postings withdraw will be entitled to a potential refund, typically 50% of their second posting[9]. Furthermore, the GIDAP tariff provides for a process for the application of non-refundable amounts from IFS postings to be disbursed to the applicable PTO as a contribution in aid of construction of the still-needed network upgrade and be reflected as a reduction in the cost of this Network Upgrade for purposes of reallocating the cost responsibility for this Network Upgrade[10]. This will be to the benefit of any later-queued project that has the RNU as a Contingent Network Upgrade. However, while the amount provided to the PTO will be used to reduce the RNU costs there is no guarantee that any amount that is provided to the PTO in this manner would be sufficient to cover a significant portion of the RNU's total cost.

In the CAISO's development of the details of the various scenarios to describe how the proposal would operate it became apparent that the final determination of the cost that exceeds the $60,000 per MW RNU cost cap should not be performed against the earlier project(s) that initiated any precursor RNU, signed a GIA, and then withdrew. Rather, the determination of the cost that exceeds the $60,000 per MW RNU cost cap should be performed against the first cluster project(s) that actually go into commercial operation and utilize the precursor RNU. An example of a scenario where ratepayers might not be protected is where a 100 MW project "A" initially triggers RNUs that have a total cost of $8,000,000, but is only eligible to be reimbursed for $6,000,000 ($60,000 × 100 MW). Project "A" executes a GIA and then withdraws. Project "B" is a 20 MW project in the next cluster and needs the same RNUs and has the same $8,000,000 in total RNU costs. The PTO constructs all needed RNUs for the 20 MW project "B," funding the construction costs based on the GIA that project "A" executed, and project "B" then goes into operation. Project "B" is only eligible to be reimbursed for $1,200,000 ($60,000 × 20 MW). Basing the non-refundable amount of the IFS posting on the project "A" would not protect ratepayers, it would actually harm ratepayers.

There are also scenarios where the later projects could be harmed. A 20 MW project "A" initially

[9] Tariff Appendix DD Section 11.4.1 – Conditions for Partial Recovery of Interconnection Financial Security Upon Withdrawal of Interconnection Request or Termination of GIA

[10] Tariff Appendix DD Section 7.6 – Application of Non-Refundable Amounts

triggers RNUs that have a total cost of $8,000,000, but is only eligible to be reimbursed for $1,200,000 ($60,000 × 20 MW). Project “A” executes a GIA and then withdraws. Project “B” is a 135 MW project in the next cluster and needs the same RNUs and has the same $8,000,000 in total RNU costs. The PTO constructs all needed RNUs for the 135 MW project “B,” funding the construction costs based on the GIA that project “A” executed, and project “B” then goes into operation. Project “B” is eligible to be reimbursed for all $8,000,000 ($60,000 × 135 = $8,100,000). Basing the non-refundable amount of the IFS posting on the project “A” would harm project “B”. While this scenario could be easily dealt with, it demonstrates that the determination of the amount of the RNU’s costs that exceeds the $60,000 per MW RNU cost cap needs to be based on the project that actually goes into operation.

The CAISO developed the following three options and requests that stakeholders provide comments on these options, state their preferred option and explain their reasons for preferring that option.

Option 1

One option to protect ratepayers and interconnection customers is to have any project with a precursor RNU determined to be needed in the project’s Phase I study report to have 100% of that precursor RNU’s cost included in their Maximum Cost Responsibility (MCR). If there are more than one projects that needs the same precursor RNU then each project will have 100% of that precursor RNU’s cost included in their MCR. The full amount of the precursor RNU cost is needed in each project’s MCR to ensure that the generation project(s) that are actually constructed and utilize the designated precursor RNU are the projects that have the $60,000 per MW RNU cost cap tested against. The 100% of the precursor RNU’s cost in a project’s MCR will ensure that there is sufficient headroom in the MCR to accommodate the situation where any given project is the only project that ultimately needs the RNU. Any amount less than a 100% cost allocation in each project’s MCR would put ratepayers at risk of funding some portion of the amount over the $60,000 per MW RNU cost cap. This option fully protects ratepayers and provides information to the Interconnection Customer of its potential cost exposure in the Phase I study report – the earliest of the three options.

Option 2

A second option is to document any precursor RNU’s that are included in a GIA executed by a previous project (*e.g.* project “A”) required by a later cluster project (*e.g.* project “B”) in its Phase I and Phase II study reports, and track the continuing need for the precursor RNU in the reassessment studies. This follows the CAISO’s current process. If the end result is that project “A” withdraws and project “B” goes into operation with the precursor RNU’s still needed and funded and constructed by the PTO for project “B” then any potential non-reimbursable IFS posting would be calculated based on project “B’s” MW capacity and the total RNU costs of all RNUs needed for project “B,” including the precursor RNU that was funded by the PTO. Any amount that exceeds the $60,000 per MW RNU cost cap for RNUs would not be reimbursed to project “B”. There is a risk in this option that project “B’s” total postings for both RNUs and DNUs is less than the non-refundable amount calculated for project “B” because project “B” did not post for the precursor RNU, and Project “B” will need to provide additional funds to cover the shortfall. This option fully protects ratepayers, but does not fully provide information on the amount of an interconnection customer's IFS posting at risk of being non-refundable until late in the process.

Option 3

A third option, using the same project "A" and "B" as above, at the point that project "A" withdraws increase project "B's" MCR by the cost project "B" would be allocated for the precursor RNU. The MCR would be increased based on the cost allocation of the precursor RNU that project "B" must now become responsible for. If more than one project in project "B's" cluster "inherit" the RNU, then each project's MCR would increase by the cost of the RNU allocation to each project. Each project would not take on a 100% cost responsibility for the RNU as is proposed in Option 1. This could result in the MCR increasing above the minimum of the Phase I and Phase II cost responsibility. Furthermore, if project "B" was not allocated 100% of the cost of the precursor RNU, its MCR could continue to increase if projects sharing in the precursor RNU's cost withdraw and the precursor RNU is still needed. This option fully protects the ratepayers, but adds uncertainty to interconnection customers. Option 3 provides information to the interconnection customer on its MCR later than Option 1, but sooner than Option 2 and does not require the full 100% cost responsibility if the precursor RNU is shared with other projects.

8. Interconnection Request

8.4 Project Name Publication

Background/Issue

The CAISO's public interconnection queue currently provides a variety of project information by queue number (*e.g.,* POI area, PTO, capacity, GIA status). It does not list project names or developer names. In the straw proposal, the CAISO proposed to modify the current confidentiality requirements for project names so that in the future they will be publicly available through the interconnection queue report accessible on the CAISO's public website and sought input on publishing developer/Interconnection Customer names as well.

Stakeholder Input

CalWEA indicates that this information is commercially sensitive and recommend publication only upon approval from the Interconnection Customer or upon the filing of the executed GIA with FERC.

EDF-RE and SPower indicate no objection to publication of project names but oppose publication of interconnection customer names.

First Solar supports publication of project names and suggested that project names not be established until later in the interconnection process.

CAISO Response

The CAISO maintains its proposal to publish project names as part of the interconnection queue report. The CAISO believes that providing project names will provide more transparency to interconnection customers, PTOs, and LSEs. Based on stakeholder input, the CAISO is not proposing to publish developer/ interconnection customer names.

In response to the First Solar suggestion that project names not be established until later in the interconnection process, this would constitute a significant change in the interconnection process and associated systems that is beyond the scope of this initiative but may be considered at a later time.

9. Modifications

9.1 Timing of Fuel Type Changes

Background/Issue

Because the CAISO provides a fairly open-ended ability to modify projects, current tariff provisions do not provide detailed limitations on the timing or types of technology and fuel type changes that an interconnection customer may request. Interconnection customers may request changes to the technology and fuel type of projects between the Phase I and Phase II process, and after the Phase II results. Moreover, the CAISO does not review a project's time-in-queue or commercial viability status for technology/fuel type changes. Commercial viability reviews are only performed for extensions of commercial operation date beyond the 7/10 year threshold.

Due to increased overall system reliability associated with transmission upgrades and topology changes, if the CAISO retains its current evaluation framework, the CAISO anticipates approving more technology and fuel change requests later in the project development cycle. Interconnection customers have reported that observing the highest-queued projects receive approval for changes in technology after being in the queue for over 10 years seems unfair.

In the 2018 IPE Straw Proposal the CAISO proposed to create an absolute prohibition on technology changes that change the project fuel type for interconnection customers that have (or are requesting) a commercial operation date beyond the 7/10 year threshold anticipated by the CAISO tariff. The proposal also outlined that fairly and effectively implementing a moratorium requires the following attributes:

- Interconnection customers with projects that have not yet declared commercial operation may request technology to the best available (e.g., a change to the number, type, or manufacturer for project inverters) provided the change does not alter the technology fuel type;
- The moratorium must apply to both requests to change technology as well as requests for additive technology; and
- Interconnection customers requesting technology changes, regardless of time in queue, will need to demonstrate that they are able to construct the project with the proposed new technology/fuel configuration within the 7/10 year threshold.

Additionally, the CAISO also proposed to change the MMA process to evaluate CVC for every MMA requested by a project where the project milestones are beyond the 7/10 year threshold. For example, a 50 MW solar PV interconnection request that has been in the queue for 11 years would be required to reconfirm it meets CVC in the event it wants to alter its gen-tie route, add project phasing, or change its project site.

Stakeholder Input

CalWEA, EDF-R, PG&E, SCE, SDG&E, and sPower all generally supported the CAISO's proposal.

CalWEA expressed concern applying this policy to projects who are beyond the 7/10 year threshold for reasons beyond their own control, and requests the CAISO provide an exception in this circumstance.

EDF-R and sPower caveated their support with a request that the CAISO continue to allow additive fuel type changes after the 7/10 year threshold, citing that such an allowance could only increase the project value and viability.

PG&E and SDG&E supported changing the MMA process to evaluate CVC for every MMA requested by a project where the project milestones are beyond the 7/10 year threshold.

CAISO Response

The CAISO appreciates CalWEA's concerns regarding applying this policy to projects who are beyond the 7/10 year threshold for reasons beyond their own control. The CAISO confirms that the PTO delay process currently in place protects projects from the outcome CalWEA describes. To the extent there are changes to the scope of, or schedule for, planned network upgrades or PTO interconnection facilities, and such changes are not attributable to the interconnection customer's inaction (*e.g.*, failure to pay invoices or failure to submit specifications), the PTO delay process provides projects with day-for-day schedule slippage for their COD milestone and does not trigger a commercial viability evaluation.

The CAISO appreciates EDF-R and sPower's suggestion that additive fuel type changes should be exempt from the fuel change prohibition. The CAISO cannot agree to a policy where additive fuel type changes are unrestricted because the concession creates a policy loophole that renders the policy basically unenforceable. To demonstrate this potential loophole consider the following example; A customer with 100 MW gas plant could request to add 100 MW solar PV and to develop the project components in distinct phases with the solar project declaring commercial operation several years in advance of the gas portion. After the solar phase is online, the interconnection customer could then enter the annual downsizing process and eliminate the gas phase of the project. This project would have then effectively swapped its technology.

The CAISO proposes to move forward with the fuel type prohibition as summarized above (including the proposal to check commercial viability for every MMA requested by a project where the project milestones are beyond the 7/10 year threshold) with one modification: the CAISO proposes that projects beyond the 7/10 year threshold be allowed *de minimus* additive fuel type changes. Additive fuel type changes will be capped at the same MW amounts allowed by the CAISO's de minimis reductions in generating facility capacity policy: no more than the greater of five percent (5%) of its MW capacity or 10 MW, but by no more than twenty-five percent (25%) of the MW capacity as specified in the GIA. For example:

Project GIA MW	the greater of		Not More than 25%	Maximum allowable additive fuel type change
	5%	10 MW		
10 MW	.5 MW	10 MW	2.5 MW	2.5 MW
20 MW	1 MW	10 MW	5 MW	5 MW
100 MW	5 MW	10 MW	25 MW	10 MW
500 MW	25 MW	10 MW	125 MW	25 MW

This limit closes the loophole described above. A customer with 100 MW gas plant could request to add 10 MW solar PV and to develop the project components in distinct phases with the solar project declaring commercial operation several years in advance of the gas portion. After the solar phase is online, the customer could still enter the annual downsizing process and eliminate the gas phase of the project, but the policy circumvention ultimately achieved is, by its definition, minimal.

The CAISO plans to take this proposal to the September 2018 board meeting for approval.

9.2 Commercial Viability – PPA Path Clarification

Due to the nature and relationship of CVC and the TPD allocation process, the CAISO has decided to include this topic in 2018 IPE and combine this topic with topics 4.1, 4.2, 4.3, and 4.5. This combined topic will seek to enhance the GIDAP in a manner that addresses all five issues under one topic to be addressed in Section 4.1.

10. Additional Comments

Section 10 consists of issues that were finalized in the Straw Proposal. These are either topics going to the July Board of Governors meeting or topics that are not being included in this initiative but stakeholder comments were submitted.

10.1 Clarify New Resource Interconnection Requirements (Section 6.3)

<u>Background/Issue</u>

Existing and operational generating units under grandfathered PPAs can convert to participating generator status under Section 25 of the CAISO Tariff. These prospective participating generators are required to execute agreements with the CAISO for generator interconnection and market participation, and also complete the New Resource Implementation process (NRI).

CAISO proposed modifications to Section 25 of the CAISO Tariff to clarify the need to complete the NRI process for existing and operational generating units converting to participating generator status. This Tariff modification does not add any new requirements, but highlights the requirement of completing the NRI process for existing generating units.

Stakeholder Input

CalWEA, First Solar, EDF-R, SCE, Six Cities, and PG&E had no comments on this proposal. SDG&E agreed with the CAISO proposal on this issue.

CAISO Response

Considering the general support, the CAISO will be taking this topic to the July Board of Governors meeting as proposed.

10.2 Affected System Options (Section 6.5)

Stakeholder Input

The CAISO received comments from First Solar on Affected System Options that, as noted in the straw proposal, the CAISO is not including as part of this initiative. First Solar suggested additional coordination between the CAISO and affected system operators. First Solar suggested that a limit be placed on the maximum forfeiture amount in order to mitigate the financial risk associated with a project withdrawal associated with the inability to resolve affected system issues.

CAISO Response

The CAISO agrees that this issue may warrant examination; however, because FERC is still considering Affected System issues in Docket Nos. EL18-26 and AD18-8, the CAISO believes that it is prudent to wait for FERC to act before making modifications to its existing process.

10.3 Data Modeling Requirements (Section 6.6)

Stakeholder Input

The Six Cities urged the CAISO, in formulating these new data reporting requirements for modeling data from Participating Generators, to work with resources to ensure that generators have adequate time to respond to any requests from the CAISO for modeling data and to ensure that the scope of and process for submittal requirements are clearly documented and communicated. Six Cities stated they believe if there are resources that are not currently subject to the applicable reporting requirements as a result of compliance obligations, then the CAISO may need to consider an implementation plan to the extent that the reporting requirements necessitate testing or verification activities that generators may not have recently undertaken.

CAISO Response

The CAISO has already submitted PRR 1067 into the BPM change management process at: https://bpmcm.caiso.com/Pages/default.aspx The PRR provides, explicit data requirements for the generating unit and the complexity diminishes based on the size and point of interconnection of the generating unit. The first set of generators will need to provide data by May 31, 2019, thus CAISO believes there is ample time to submit the data and testing if required.

10.4 ITCC for Non-Cash Reimbursement Network Upgrade Costs (Section 7.2)

Stakeholder Input

CalWEA commented that the justification offered at the last stakeholder call for SCE continuing to collect ITCC for non-cash reimbursable network upgrade costs was the requirement by the CAISO tariff. CalWEA is unable to find such a requirement in the CAISO tariff and would like to ask CAISO to identify that part of its tariff that distinguishes between cash reimbursable and non-cash reimbursable network upgrade costs when it comes to collection of ITCC.

CAISO Response

The CAISO clarifies that ITCC is not addressed in the CAISO tariff.

10.5 Clarification on Posting Requirements for PTOs (Section 7.6)

Background/Issue

Interconnection customers currently post interconnection financial security (IFS) to PTOs for the construction of their network upgrades and interconnection facilities. Currently, there is no distinction in the tariff for projects where the interconnection customer itself is also the PTO. PG&E proposed that PTOs should not have to post financial security to themselves when they develop new generation projects interconnecting to their own areas. PG&E has noted that the PTOs have already successfully petitioned FERC for case-by-case waivers on this issue, which FERC has granted.

Stakeholder Input

sPower, First Solar, EDF-R, and CalWEA generally support the proposal.

CAISO Response

Stakeholders generally agree with the CAISO proposal to exempt the PTOs from posting financial security to themselves when they develop new generation projects interconnecting to their own areas in conjunction with a tariff mechanism requiring a PTO that withdraws an interconnection project after the initial and subsequent posting due dates to provide appropriate non-refundable funds to the CAISO in accordance with the tariff requirement. The CAISO will be taking this topic to the July Board of Governors meeting as proposed with the clarification that the PTO must be developing the project in their own service area.

10.6 Reimbursement for Network Upgrades (Section 7.8)

Stakeholder Input

SDG&E commented that although Reimbursement of Network Upgrades was not selected as a topic for the CAISO's 2018 IPE, SDG&E wanted to clarify their original position. SDG&E was not supportive of the CAISO including the reimbursement of network upgrades topic in 2018 IPE because, as the CAISO mentioned, it is such a big paradigm shift that would require a separate setting and huge modifications to the tariff that could not be covered in 2018 IPE. SDG&E, however, believes that this is a topic worth studying and considering in a separate process that has a larger timeline, since this topic likely requires much more time than provided in IPE.

CAISO Response

The ISO thanks SDG&E for this clarification and suggests that they propose this issue through the stakeholder catalog process.

10.7 Impact of Modifications on Initial Financial Security Posting (Section 7.9)

Background/Issue

Between the end of the Phase I study and the due date for the Initial Interconnection Financial Security (IFS) postings, the CAISO has found that due to changes in the CAISO queue, such as project withdrawals or other system changes, there may be network upgrades or PTO interconnection facilities that may no longer be needed. If an upgrade or interconnection facilities are known to be no longer needed after the completion of the Phase I studies, then that will be reflected in the Phase II studies and no changes are made to the Phase I study report. The CAISO believes that if engineering judgement can definitively determine that a required upgrade in an interconnection customer's Phase I study report is no longer needed due to the withdrawal or changes to earlier queued projects or other system changes, and that determination is made in advance of the initial IFS posting due date, the interconnection customer should not be required to post IFS for that upgrade. This determination would be a collaborative effort between the PTO and the ISO and both parties would need to be in agreement that these facilities and upgrades can be removed.

The CAISO proposed in the straw proposal to change the requirement that a project may only qualify for an adjustment in the initial interconnection financial security if they have modified the project, such as a reduction in electrical output of the facility or changed deliverability status.

Stakeholder Input

CalWEA, EDF-R, First Solar, and SPower fully supported this proposal. EDF-R and SPower both commented that the proposal is a matter of common sense. First Solar stated they appreciate the CAISO identifying this improvement based on its experience from Cluster 10.

SCE, SDG&E, and PG&E supported this proposal and agree that the term "engineering judgment" has been a controversial point between the developers and the PTOs. SCE, SDG&E,

and PG&E are all concerned they will need to provide justification in support of their engineering judgement for not removing upgrades or facilities.

CAISO Response

The CAISO agrees with SCE, SDG&E, and PG&E that the term "engineering judgment" can be contentious and that any removal of upgrades or facilities should only be removed if both parties can agree with certainty that they are no longer needed. In addition, the CAISO agrees that the PTOs should not be required to provide justification for their engineering judgement methodology and will address this in the new tariff language developed for this proposal.

Stakeholders support the CAISO proposal. The CAISO will be taking this topic to the July Board of Governors meeting as proposed with the clarification that the CAISO and PTO must agree that the upgrade or facilities are no longer needed.

10.8 Study Agreement (Section 8.1)

Background/Issue

The CAISO proposes to incorporate Appendix 3 of Appendix DD, the generation interconnection study process agreement (GISPA), into the interconnection request so that it is executed when the interconnection customer submits an interconnection request. To achieve this efficiency, the interconnection request form would be changed slightly to incorporate the documentation required by the GISPA.

The CAISO proposes to establish the following requirements for interconnection customers to agree to the study agreement terms and conditions within the interconnection request: (1) The interconnection request will be expanded to include the modified GISPA; and (2) interconnection requests can only be submitted by an authorized signatory of the interconnection customer.

Stakeholder Input

CalWEA generally supported the proposed clarifications and clean-up of the GIP Study Agreement (GIPSA) language. However, CalWEA requested that the Interconnection Customer be allowed at least 5 business days (preferably 10 calendar days) to complete the GIPSA with the final POI and size for the project. As they have stated previously, the scoping meeting is one of the most important components in the generation interconnection process. The information gathered at the scoping meeting allows all parties, and particularly the interconnection customer, to make significant improvements in the details of the interconnection application (or withdraw the application) for the benefit of all parties involved including the ratepayers.

First Solar & SDGE supported this proposal.

CESA, EDF-R, Able Grid, LS Power, SCE, Six Cities and SPower provided no comments on this aspect of the propsoal.

CAISO Response

In response to CalWEA's question about adjusting the time allowed for project modifications following the scoping meeting from 3 to 5 days; the CAISO believes this requirement needs to remain at 3 days. This timeline was previously 5 days and through a prior process was shortened to 3 days due to the timing of the study process and a need to ensure the process continues moving forward.

The interconnection customer will still have the opportunity to confirm the POI within 3 business days following the scoping meeting and that does not impact the execution of the study agreement. The CAISO also proposes to clarify Section 3.5 of Appendix DD to ensure that developers understand that they must submit the $150,000 interconnection study deposit within the interconnection request window. Absent the deposit, the CAISO does not have funds to process and validate the interconnection request. As such, the CAISO intends to clarify that the lack of an interconnection study deposit is not a deficiency that can be cured by May 31. Interconnection requests that lack a deposit by the close of the window will be rejected without opportunity to cure. The CAISO notes that this clarification is not true for Site Exclusivity Deposits. Often interconnection customers submit site exclusivity documentation that is deemed insufficient. Interconnection customers will continue to have the opportunity to cure this deficiency with either further documentation or submitting a $250,000 deposit within the cure window.

Stakeholders support the CAISO proposal. The CAISO will be taking this topic to the July Board of Governors meeting as proposed with the clarification regarding study deposit requirements versus site exclusivity deposits.

10.9 FERC Order 827 (Section 8.6)

Stakeholder Input

CalWEA indicated in comments to the straw proposal that on topic 8.6, CAISO should establish study processes that determines projects compliance with FERC Order 827 under normal operating voltage (typically from 0.95 to 1.05 PU) at the POI and not contingency based operating voltages such as 0.9 PU. Projects should be allowed to reduce their MW output to meet FERC Order 827 requirements under contingency based operating voltages such as 0.9 PU.

CAISO Response

As stated in the issue paper, the methodology of evaluating reactive power capability in the generation interconnection studies will be discussed in the BPM change management process. The CAISO will address this feedback in that process.

10.10 PPA Transparency (Section 9.3)

Background/Issue

The CAISO requires interconnection customers demonstrating CVC with a PPA to provide a copy of the PPA so the CAISO can verify that the project and the PPA match. This requirement ensures accurate project-to-PPA data relationships and a robust and transparent commercial viability process. In order for interconnection customers with PPAs to modify the project's COD, the PPA must have the following in common with the proposed generating facility in the GIA:

- the point of interconnection;
- MW capacity (allowing differences in utility defined project size before transformation and line losses);
- fuel type and technology; and
- site location

The CAISO proposes no changes to this process, but intends to move the requirement from the BPM to the tariff for greater transparency.

Stakeholder Input

CalWEA and SDGE supported the proposal to move the demonstration requirements for commercial viability from the BPM to the tariff.

CAISO Response

Stakeholders support the CAISO proposal. The CAISO will be taking this topic to the July Board of Governors meeting as proposed.

10.11 Increase Repowering and Serial Re-Study Deposit (Section 9.4)

Background/Issue

With the increase in repowering and serial re-studies, the current $10,000 deposit is insufficient for covering the study costs. Based on experience, the CAISO proposes to increase the study deposit for repowering and restudy of serial projects to $50,000.

The CAISO received four comments on the straw proposal. Three comments supported the CAISO straw proposal and one comment opposed the straw proposal.

Stakeholder Input

CESA supported the CAISO's efforts to ensure that the re-study deposit covers the CAISO's costs. CESA only added that since the re-study efforts will be underway for any repowering requests as well as for requests to keep repowered facilities online after the original generation facility retires, the CAISO should consider all the various pathways a repowered facility can remain online. For example, as noted in our comments on Issue 5.2 above, CESA recommended options to pursue potential mitigation measures if certain criteria in the reliability assessment are not met. Overall, CESA recommended that the CAISO consider all the pathways to allow repowered facilities to take advantage of less intensive, less costly material modification study processes rather than having these facilities be pushed into the full cluster study process.

SDG&E and PG&E supported the CAISO's proposal to revise all references from $10,000 to $50,000 in sections 25.1.2 of the tariff, Appendix U Sections 6.4, 7.6, 8.5, 10.1 and 12.2.4. By increasing the deposit past the average cost of the study, the CAISO ensures that billing and payment, between the PTOs and the CAISO, can typically be done without requesting additional funds from the interconnection customer.

CalWEA and sPower opposed the proposal to increase the Repowering Study Deposit to $50K. CalWEA and sPower believes this proposal is inconsistent with the method used to establish cluster-study Study Deposits, where the new figure was set at the median study cost; that prior methodology would establish the Repowering Study Deposit at $25K and not $50K. In addition, sPower commented that the number of repowering applications is fairly small, and the CAISO certainly has adequate tools to recover actual study costs from generators. Moreover, sPower noted it has experienced significant delays for refunds of unused study-deposit amounts – more than a year, in some cases – so increases above this level should not be considered until the CAISO and PTOs improve their refund processes.[11]

<u>CAISO Response</u>

The CAISO has responded to CESA's comments in Section 5.2 above. With respect to CalWEA and sPower's comment that a median should be used, the current methodology was developed when the CAISO went from the serial study process to the cluster study process and is not appropriate here. In the instance of serial restudies and repowering studies, the number is increasing, and while not close to the number is a cluster study, the CAISO and PTO should not put its ratepayers in a position to cover costs where work has been done but the deposit is insufficient to pay for the services and the customer goes bankrupt or just goes away without paying the difference between the deposit and actual cost of the study. The CAISO agrees with sPower that refunds should not be delayed. For most types of optional studies, the tariff already provides:

> The Participating TO(s) shall invoice the CAISO for any assessment work within seventy-five (75) calendar days of completion of the assessment, and, within thirty (30) days thereafter, the CAISO shall issue an invoice or refund to the Interconnection Customer, as applicable, based upon such submitted Participating TO invoices and the CAISO's own costs for the assessment.[12]

To ensure that this requirement is consistent for all studies, the CAISO will add similar language for studies where such deadlines are not express.

Stakeholders support the CAISO proposal. The CAISO will be taking this topic to the July Board of Governors meeting as propose.

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[11] While not an issue in IPE, the CAISO completely understands the interconnection customers frustration with the time it takes to receive refunds. The CAISO has revised the tariff to require the PTOs to provide the invoice within 75 days of completion of the study process or MMA and added CAISO staff to process the refunds so that they can be done quicker. There is a backlog, but we are working as quickly as possible to refund and invoice all projects as soon as possible. Since July 2017 we have processes 365 refunds.

[12] *See, e.g.*, Section 6.7.2.3 of Appendix DD (for modification requests).

10.12 Clarify Measure for Modifications After COD (Section 9.5)

Background/Issue

Interconnection customers frequently struggle to understand the test to determine whether a modification will be approved. Specifically, this confusion may depend on whether the project is in the interconnection process or has already achieved commercial operation. The GIA confounds this issue in Article 5.19 by stating that approval of all modifications will be based on the Material Modification in accordance with the GIDAP which in essence determines the approval of the modification based on whether it impacts the scope, schedule or budget of a project in the queue. During the interconnection process modifications are generally approved unless they are material, as explained in Section 9.1 above. On the other hand, existing, online generating units may request modifications to their generating facility if the total MW capability of the generating facility and its electrical characteristics do not change in accordance with Section 25 of the CAISO tariff. Both requirements are intended to prevent changes that will affect reliability and other projects studied or connected to the grid.

The CAISO received three comments all supporting the straw proposal.

Stakeholder Input

CalWEA, SDG&E and PG&E supported CAISO's proposal to clarify in the LGIA and SGIA that modifications requested prior to COD will be approved based on the material modification assessment in the GIDAP, and modifications requested after COD will be approved based on the criteria in Section 25 of the CAISO tariff, and to enable downsizing generation projects after COD. In addition, SDG&E supported the ability to downsize generation projects after COD.

CAISO Response

Stakeholders support the CAISO proposal. The CAISO will be taking this topic to the July Board of Governors meeting as proposed.

10.13 Short Circuit Duty Contribution Criteria for Repower Projects (Section 9.6)

Background/Issue

The criteria used to test whether there is a substantial change in short circuit duty contribution due to a repower project request is more stringent than that used for a material modification request.

The short circuit duty test for repower projects requires that the repowered project must produce the same or less short circuit duty as compared with the original generating unit. This framework is also used to evaluate post-COD modification requests. A small increase of short circuit duty would fail the test, even if the system still has a high breaker capacity margin.

For modification requests for projects active in the interconnection queue, the CAISO will consider changes to project equipment and transformers to be non-material if the new equipment is substantially similar and does not cause significant electrical changes, including changes to short circuit duty or reactive support. Evaluating changes to short circuit duty follows the general principle of no adverse impact to later queued generation project and the PTO. If the requested change causes only a small increase of short circuit duty, the modification could be considered non-material if the increase causes no breaker capacity concerns.

In the straw proposal, the CAISO proposes to apply the following criteria in short circuit duty tests for both repower and modification requests.

Increase of the short circuit duty at network breakers that require upgrades in the generation interconnection study is less than the amount that would be flagged by the Participating TO as meaningful contribution; and

The total short circuit duty from the repowered Generating Unit and all the active generation projects in the queue at network breakers that do not require upgrades in the generation interconnection study does not exceed the breaker capacity.

The CAISO is bringing this topic to the July Board of Governors Meeting.

Stakeholder Input

CalWEA, CESA, SCE, SDG&E and PG&E commented on this topic. All stakeholder comments supported CAISO's proposal. CalWEA requested that the PTOs be required to pre-specify "the [SCD] amount that would be flagged by the Participating TO" for the purpose of determining whether the increase of the short circuit duty at network breakers will be considered an adverse impact.

CAISO Response

The SCD threshold as the meaningful contribution varies depending on the situation. Therefore, pre-specifying the amount would adversely impact approval of the requests since a conservative number has to be used.

Stakeholders generally support the CAISO proposal. The CAISO will be taking this topic through the BPM change management process at the conclusion of the IPE initiative.

10.14 Storage Issues – Other

Stakeholder Input

CESA observed that in the Straw Proposal the only energy storage-specific issue that was included in the scope of the 2018 IPE Initiative is Issue 5.2. CESA commented in the issue paper that two other energy-storage-specific issues should be considered by the CAISO in this initiative, revising Resource Adequacy (RA) deliverability rules for distributed generation to enable distributed energy resource aggregations (DERA) for RA capacity value; and deliverability for Effective Flexible Capacity (EFC) using a deliverability assessment that focuses on Net Qualifying Capacity (NQC), as the CAISO works to finalize potential, new product designs and flexible deliverability assessments for Flexible RA in Phase 2 of the Flexible RA Capacity and Must-Offer Obligation (FRACMOO) Initiative.

CAISO Response

As the CAISO has previously stated, issues on resource adequacy are not included in the interconnection process enhancements initiative because they are not part of the interconnection process and are already underway in a separate stakeholder initiative – ESDER and Flexible RA.

10.15 EFC/NQC Separation - Other

Stakeholder Input

LS Power commented that CAISO should include EFC/NQC separation under 2018 IPE. LS Power supported establishment of an EFC, independent of NQC, which is a Peak deliverability product.

CAISO Response

The CAISO notes that issues related topic NQC/EFC are already underway in a separate stakeholder initiative – FRACMOO2 and therefore not included in this initiative.

11. Final Proposals

The following topics are considered final and the CAISO plans to seek approval at the September 2018 Board of Governors meeting:

- Transmission Plan Deliverability Allocation
- Balance Sheet Financing
- Participating in the Annual Deliverability Allocation
- Change in Deliverability Status to Energy Only
- Energy Only Projects’ Ability to Re-enter the Queue for Full Capacity
- Options to Transfer Deliverability
- Replacing Entire Existing Generator Facilities with Storage
- Suspension Notice
- Affected Participating Transmission Owner
- Maximum Cost Responsibility for NUs and potential NUs
- Financial Security Postings and Non-refundable Amounts
- Shared SANU and SANU Posting Criteria Issues
- Reliability Network Upgrade Reimbursement Cap
- Project Name Publication
- Timing of Technology Changes
- Commercial Viability – PPA Path Clarification