Interconnection Process Enhancements 2021

Draft Final Proposal
Phase 1: Near Term Enhancements

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1 Introduction

The Interconnection Process Enhancements (IPE) Initiative is the ISO's ongoing commitment to improve its Generator Interconnection and Deliverability Allocation Procedures (GIDAP) and make process enhancements as resource interconnection needs evolve.

The 2021 IPE initiative is being conducted at a particularly critical inflection point in resource development in California, and in the ISO footprint in particular, as current circumstances have led to a confluence of issues that are needing consideration in the ISO's interconnection processes, related transmission and resource planning occurring at the ISO and state agencies, the procurement activities of load serving entities, and state policy development. Meeting the challenges facing timely, effective, reliable and economic resource and transmission development over the next decade and beyond will require enhancements and improved coordination across all fronts, and progress on each front must be considered in the context of improvements occurring in other parallel paths as well.

The impact of the drive towards higher levels of year over year resource development cannot be overstated. The ISO's 2021-2022 transmission planning currently underway is based on resource portfolios developed through CPUC processes that are more than double the previous plan's forecast for additions. The draft forecast requirements to be used in the 2022-2023 cycle indicate potentially a four-fold increase in new resource requirements over the forecast relied upon in the approved 2020-2021 plan[1]. At the same time, the CPUC authorized more midterm procurement in its June 24, 2021 decision that last year's 10 year plan was based on, and which was the largest single procurement authorization by the CPUC. Responding to these signals and previously approved authorizations, the resource development industry responded with a record-setting number of new interconnections requests in April, 2021, with 373 new interconnection requests being received in the ISO's Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[2] The 605 projects totaling 236,225 MW, 164,153 net MW at the Point of Interconnection (POI), currently in the queue exceeds mid-term requirements by an order of magnitude. This level of hyper competition actually creates distractions and commandeers precious planning, engineering and project management resources from the ISO and Participating TOs. Developing interconnection proposals for 10 to 15 times the volume of resources needed in that time frame, challenges the procurement activities being smoothly aligned

[1] Page 11, Day 2 Presentation, September 27-28, 2021 Stakeholder Meeting, *http://www.caiso.com/InitiativeDocuments/Day2Presentation-2021-2022TransmissionPlanningProcess-Sep27-28-2021.pdf*

[2] ISO Board of Governors July 7, 2021 Briefing on renewable and energy storage in the generator interconnection queue, http://www.caiso.com/Documents/Briefing-Renewables-Generator-Interconnection-Queue-Memo-July-2021.pdf

with transmission planning and state policy needs (including for resource diversity) when procurement responsibility is spread over more than 40 load serving entities.

The ISO's interconnection queue and transmission planning process (TPP) has to this point been very successful in meeting emerging needs and challenges as it evolved over the last ten to fifteen years. The ISO's current processes in fact already incorporate many of the reforms set out for discussion in the recent Advance Notice of Proposed Rulemaking released by the Federal Energy Regulatory Commission[3]. However, the volume of requirements, pace of development and intensity of competition clearly call for additional reforms to current processes designed around more measured pace of planning, procurement and resource development. A broader spectrum of reform considerations is needed than adjustments to any one process in isolation, and reforms and enhancements must be considered holistically. To aid the ISO in its own considerations, the ISO commissioned a review of other practices in the US, looking not only at other ISOs and RTOs but also other FERC-jurisdictional and non-jurisdictional organizations to explore other practices that may prove helpful. This review, conducted by Grid Strategies LLC[4], was posted to the ISO website on December 13, 2021.

Progress must be made on a number of fronts including the generation interconnection process; the 2021 IPE initiative is therefore focused on the interconnection process and enhancements specifically, and other tracks of process improvement will proceed through other efforts.

Accordingly, the 2021 IPE initiative will discuss and address interconnection-related issues the ISO and stakeholders have identified given current circumstances, and will seek to resolve concerns that have surfaced since the last IPE initiative in 2018.[5] The ISO seeks to consider potential changes to address the rapidly accelerating pace of new resources needing connection to the grid to meet system reliability needs and exponentially increasing levels of competition among developers resulting in excessive levels of new interconnection requests being received.

This Draft Final Proposal is intended to present proposed solutions that focus on near-term process enhancements based on comments received from stakeholders from the Revised Straw Proposal.

[3] Comments of the California Independent System Operator Corporation on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generation, Docket No. RM21-17-000: *http://www.caiso.com/Documents/Oct12-2021-Comments-AdvanceNoticeOfProposedRulemaking-BuildingTransmissionSystemoftheFuture-RM21-17.pdf*

[4] "Resolving Interconnection Queue Logjams - Lessons for CAISO from the US and Abroad" October 2021, Rob Gramlich, Michael Goggin, Jay Caspary, Jesse Schneider. http://www.caiso.com/InitiativeDocuments/ResolvingInterconnectionQueueLogjamsFinalReport.pdf

[5] For more information on the 2018 IPE initiative please refer to the initiative webpage at: California CAISO - Interconnection process enhancements (caiso.com).

2 2021 IPE Process Development

During the initial planning for the 2021 IPE initiative, the ISO identified certain issues to address related to the broader need for reforms, both in the short term and longer term, and also a number of relatively minor enhancements needed since the previous 2018 IPE initiative that also warranted attention.

This initiative will have two distinct, but simultaneously run, phases. Phase 1 will focus on near-term enhancements to the existing interconnection processes that the ISO can resolve for Cluster 14 and before the summer of 2022. Phase 2 will focus on resolving longer term modifications and broader reforms to align interconnection processes with procurement activities. The ISO will conduct both phases simultaneously with phase 1 targeting the ISO Board of Governors in May 2022, and phase 2 targeting November 2022.

During the Cluster 14 open window, the ISO received 373 interconnection requests, which resulted in the Supercluster Interconnection Procedures initiative that started on June 14, 2021[6]. The supercluster initiative focused specifically on addressing the immediate timing issues associated with the unprecedented number of interconnection applications to ensure parties were well informed of the timing impacts and that an effective plan could be put in place to deal with the situation. In the supercluster initiative, the ISO committed to continue to discuss topics that were not resolved in the time available within that initiative that could affect the Cluster 14 supercluster Phase II processes[7]. Topics that would impact Cluster 14 Phase II will be handled in the phase 1 portion of this initiative as described above. Another impact of the Cluster 14 supercluster is that the current GIDAP may need to be modified to be more adept at dealing with the current significant generation expansion and to better accommodate interconnecting significant amounts of new generation expeditiously to meet near-term reliability challenges. These potential changes will need more time to discuss and come to consensus with stakeholders and will be handled in the phase 2 portion of this initiative as described above.

The issues being addressed in this initiative fall into one of three categories; topics that would aid in moving resources more efficiently and effectively through the queue, topics that would aid in managing the overheated interconnection queue, and topics addressing other residual issues warranting attention at this time.

[6] For more information on the Supercluster Interconnection Procedures initiative please refer to the initiative webpage at: FinalProposal-SuperclusterInterconnectionProcedures.pdf (caiso.com)
[7] The supercluster initiative needed to produce a filing to FERC quickly to receive a FERC order in a time frame that would allowed Cluster 14 to move forward as expeditiously as possible under a revised schedule.

3 Moving resources through the interconnection queue more efficiently and potentially more quickly

3.1 Removing downsizing window and simplifying downsizing request requirements

- Background

  The January 25, 2022 Revised Straw Proposal, Section 3.1, maintained the ISO's original proposal to transition from an annual month-long open window for receiving downsizing requests and allow them to be submitted at any time. The downsizing requests would be held by the ISO for the next reassessment study where the impact of the upgrades associated with the downsized resource would be determined. The ISO also intends to simplify the downsizing request process where appropriate.

- Stakeholder Feedback

  The ISO received stakeholder comments from 16 stakeholders on this topic, of which ten support and six supported with comments.

  Avangrid and Middle River Power support the ISO's proposal but expressed concern regarding the impact to the current MMA review timeline. Additionally, PG&E supports but is also concerned with the potential increased volume of MMAs and suggests that all projects with assigned NUs be reviewed as part of the annual Reassessment.

  LSA/SEIA supports and recommended that downsizing requests be considered in an MMA process using the same criteria already stated in the BPM for Generator Management Section 6.2. Downsizing request not meeting these criteria would be processed in the annual Reassessment.

  RWE supports, but wanted confirmation that where an NU is still needed that an increase in allocation to other projects would still be considered material unless there is a cost cap to ensure no negative impacts to other projects.

  Finally, SCE supports but has questions about how downsizing requests will be implemented going forward. Timing of NU reviews, PTO approval, charging of time, and effect on GIA tendering were all examples noted in their comments.

- ISO response to Stakeholder comments

  With respect to Avangrid and Middle River Power's concerns, the impact to the MMA Process is expected to be slight based on historical downsizing request data. A total of seven (7) downsizing request have been received and processed in the last five reassessment report periods (2017-2021), and two downsizing requests have been submitted for study in the 2022 Reassessment.

Specific to PG&E's concern, no downsizing requests have been submitted for projects in the PG&E area from 2017-2021, and one has been submitted for study in the 2022 Reassessment. Projects with NU(s) will generally need to be studied in the Reassessment to see if later clusters may be impacted.

To clarify LSA/SEIA and SCE's concerns, the requests will be implemented like all other MMAs using the existing process. Further, if an NU is still needed, the downsizing project maintains the cost responsibility.

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The ISO proposes to simplify the downsizing process, which currently encompasses six pages of Appendix DD. The ISO proposes to remove the downsizing application window, the unique downsizing deposit, and the downsizing agreement (Appendix HH), among other simplifications. Instead, the downsizing process will be modified to allow downsizing requests to be submitted at any time and be processed through an MMA-like process.[8] Once the downsizing request is received by the ISO the project would be deemed downsized to the requested capacity. Those projects that have no network upgrades would be approved through the MMA process and the GIA would be amended. If a project has one or more network upgrades, the project would be included in the annual reassessment to determine if the project's network upgrades are still required along with any potential cost allocation adjustments. Once the reassessment process is completed, then the downsizing MMA response would be received by the customer. Tariff rules that prevent interconnection customers from downsizing merely to reduce their cost allocations and non-refundable interconnection financial security before withdrawal will remain in place. The ISO believes the simplification of the downsizing process will enable interconnection customers to right-size their projects more easily and with less administrative burden for all parties.

3.2 Should Transmission Plan Deliverability (TPD) Allocation process revisions be considered?

- Background

In the January 25, 2022 Revised Straw Proposal, Section 3.2, the ISO proposed reducing the current seven allocation groups to three, including eliminating group three – proceeding without a PPA. Additionally, the ISO proposed simplifying the allocation retention requirements and further clarify the requirement related to a PPA requiring deliverability such that the PPA must be with an offtaker to fulfill its own RA obligation. In addition, the ISO proposed to revise the tariff to clarify that a PPA

[8] Appendix DD, Section 6.7.2.3 requires an MMA to be completed within 45 days unless the ISO notifies the Interconnection Customer and provides an estimated completion date and an explanation for the delay.

must be with an offtaker to fulfill its own RA obligation and the PPA must procure the deliverable capacity for a minimum of five years to be eligible for an allocation in allocation groups 1 and 2.

- Stakeholder Feedback

  21 stakeholders provided comments on this topic. The majority supported reducing the current seven allocation groups to three, but 14 stakeholders opposed the total elimination of allocation group 3.

  In general, those that oppose the elimination of allocation group 3 understood the ISO's concern with projects making the attestation of proceeding without a PPA and then using the allocation to obtain a PPA. They were generally open to modifying group 3 or creating a new group 4 that would allow projects to seek an allocation in order to facilitate both generation projects and procurement entities where projects are able to participate in the request for offer processes of offtakers already having obtained an allocation of TPD.

  The ISO considered a number of options for a new allocation group 4 that would result in the interconnection process being better aligned with procurement activities, transmission system capabilities and renewable generation portfolios developed for planning purposes. As a result, the ISO is proposing a new allocation group 4 intended to provide improved alignment by providing a pool of projects that are seeking a PPA to obtain an allocation of TPD, which would provide more certainty to LSE's seeking to contract with projects that are deliverable.

  Eight stakeholders opposed the requirement that for a PPA requiring deliverability to be eligible for an allocation the PPA must be with an offtaker to fulfill its own RA obligation.

  The ISO has considered the various reasons that stakeholders have provided and is willing to consider allocating TPD to projects contracting with offtakers that do not have an RA obligation of their own if documentation is provided demonstrating that the RA attributes of the project are contracted for with an entity that has an RA obligation to fulfill. This is to ensure that TPD capacity that was built at transmission ratepayer expense to provide sufficient transmission capacity for the RA requirements and CPUC policy is appropriately utilized.

  Three Stakeholders opposed the requirement that the PPA must procure the deliverable capacity for a minimum of five years to be eligible.

  The ISO understands the greatest concern with this component of its proposal is that there are projects that are currently in active negotiations for a PPA where the RA capacity component of the PPA may be for terms of less than five years. To avoid imposing the five year procurement term on these projects, the ISO proposes to transition into the five year term requirement as described in its proposal below.

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  The ISO continues to propose reducing the current seven allocation groups, folding group 4 projects into group 1, folding group 5 projects into group 2, and folding group 6 and 7 projects into group 3. The ISO further proposes to create a new group 4, eliminating the current group three proceeding without a PPA stipulation, and expanding on the current group 3 requirements. The table below and the notes that follow provide a summary of the four proposed allocation groups.

Proposed Allocation Groups

Allocation Group	Status of Project	Allocation Requirement	Can Build DNUs for Allocation?	Allocation Rank
1	Any project (active IR or achieved commercial operation)	Executed PPA requiring FCDS or interconnection customer is a LSE serving its own load	• FCDS & PCDS projects (see Note 1) • EO projects (see Note 2)	Allocated 1st
2	Any project (active IR or achieved commercial operation)	Shortlisted for PPA or actively negotiating a PPA	• FCDS & PCDS projects (see Note 1) • EO projects (see Note 2)	Allocated 2nd
3	Any project that achieved commercial operation	Commercial operation achieved	• FCDS & PCDS projects (see Note 1) • EO projects (see Note 2)	Allocated 3rd
4	Any Active project that meets the allocation Group 4 criteria	See proposed criteria below	For the 2022-2023 <u>allocation cycle</u> • FCDS & PCDS projects (see Note 1) • EO projects (see Note 2) Beginning with the 2023-2024 <u>allocation cycle</u> • FCDS & PCDS projects (see Note 1)	Allocated 4th

Note 1: FCDS & PCDS projects can fund the construction of DNUs assigned to them in their study reports to give them their current level of requested deliverability.

Note 2: EO projects can only utilize any remaining capacity from existing and yet to be constructed DNUs that is not assigned to a FCDS or PCDS project.[9]

Additional Criteria:

- Projects must have completed all studies to be eligible for all allocation groups.
- Energy Only Projects

  Projects with Energy Only Deliverability Status requesting deliverability, including Partial Capacity Deliverability Status projects that elected to convert any non-allocated portion of their project to Energy Only must be studied to ensure the project does not trigger a DNU to accommodate an allocation and must submit to the ISO a $60,000 study deposit for each Generating Facility seeking TP Deliverability.

- TPD will only be allocated up to the amount of deliverable MW capacity procured by the PPA.
- Explanation of Allocation Group 4

  Any project that does not have an allocation of TPD may apply for an allocation during the 2022-2023 TPD allocation cycle. Beginning with the 2023-2024 TPD allocation cycle only projects that are FCDS or PCDS will be eligible to seek an allocation through Group 4. No energy only projects will be eligible to seek an allocation through Group 4 after the 2022-2023 allocation cycle. As with all allocation groups, only projects that have completed all studies, including deliverability studies for ISP projects, qualify for Group 4. Restrictions similar to the restrictions for the current allocation Group 3 will be used for projects that seek an allocation through Group 4.

  Beginning with the 2023-2024 TPD allocation cycle and thereafter, an Interconnection Customer may apply for a TPD allocation in Group 4 at any time if its deliverability status at the time of the allocation affidavit due date is FCDS, or PCDS. If a Group 4 project receives TP Deliverability, it must accept the TP Deliverability allocation and forego parking that capacity, or withdraw. If a project seeking an allocation in Group 4 does not receive an allocation, it may park, if eligible, and apply under Group 4 a second time. A project would have the option to park after its Phase II study and not apply for Group 4 and come out of parking the next year and apply under Group 4. Once a project's parking opportunities have been exhausted and it is converted to energy only it is no longer eligible to seek an allocation under Group 4.

[9] Summarizing Appendix DD, Section 8.9.2, only FCDS and PCDS projects may trigger the construction of Delivery Network Upgrades pursuant to Section 6.3.2. After the CAISO has allocated TP Deliverability to FCDS and PCDS projects, the CAISO will allocate any remaining TP Deliverability to Energy Only Interconnection Customers requesting Deliverability based on any remaining deliverability available.

Once a project applies under Group 4 it has two consecutive opportunities to seek an allocation. If after two allocation cycles an allocation group 4 project has either never received an allocation or has received an allocation, but has not been able to retain it, the project will be required to withdraw.

Once an Interconnection Customer seeks an allocation under Group 4 for a given project, that project will be subject to the Group 4 restrictions, regardless of whether the project receives an allocation or not. If a project seeks an allocation under Group 4 it may not request suspension under its GIA, delay providing its notice to proceed as specified in its GIA, or modify its Commercial Operation Date, except to accelerate its COD to a date earlier than the date established in its Interconnection Request when it requests TP Deliverability. However, where the Interconnection Customer has executed a power purchase agreement, consistent with Appendix DD Section 6.7.5, the Interconnection Customer may align the Commercial Operation Date for the deliverable MW capacity procured by the power purchase agreement. This change in milestones cannot impact the timing of shared Network Upgrades. Extensions due to Participating TO construction delays will extend these deadlines equally. Interconnection Customers that fail to proceed toward their Commercial Operation Date under these requirements and as specified in their GIA will be withdrawn.

ISO Comments on the Group 4 Proposal:

The ISO concluded that this option, where projects only have one year to get a PPA or be short listed, but are able to immediately reapply, is better than giving project two years to get a PPA or be shortlisted. It is possible, if not likely, that most projects will seek an allocation under Group 4, even with the associated limitations. Assuming this is true, the first cycle implementing group 4 will tie up most if not all of the TPD until some in that group are unable to retain their allocation after holding it for two years. If projects are given two years to get a PPA or be shortlisted, the next cluster group will be disadvantaged when they reach the point of being able to seek an allocation because all TPD will be allocated out in most if not all areas until the prior year's allocation cycle completes the two-year period before their retention affidavits are due. The next cluster would have to wait until the previous allocation cycle completes its two year opportunity for seeking a PPA or shortlist, waiting for the allocations that are not retained to become available, to have a realistic chance of getting an allocation for themselves. This would result in every other cluster only having one realistic opportunity to seek an allocation. Therefore, the proposed option is the most fair and equitable option.

- Revisions to the TPD retention process.

  For allocation groups 1 – 3, the ISO proposes to eliminate all TPD retention criteria except that those projects that received an allocation in group to 2 (as currently shortlisted or negotiating a PPA), must submit an executed PPA by the retention affidavit due date in the allocation/retention cycle following the year the allocation was received.[10]

Retention requirements for allocation Group 4

If a project receives an allocation on its first attempt, but does not obtain a PPA or is shortlisted, it will lose its allocation beginning with the next allocation cycle and may reapply for an allocation in that allocation cycle. Projects that obtain an allocation in its first attempt, but loses its allocation may only reapply one time. Projects that obtain an allocation in its second attempt, but loses its allocation are no longer eligible of an allocation.

- Ranking of Projects Within an Allocation Group

  The GIDAP BPM Section 6.2.9.4 defines the process where points are allotted to projects based on the project's maturity in areas such as their PPA, permitting and land acquisition. The points are used to rank the projects for determining the order that they are considered for allocating any available TPD. The ISO proposes that during the process of updating the BPM following the FERC approved tariff changes, the ISO will propose adjustments to the scoring process and weights within Section 6.2.9.4. The intent is to ensure that the more ready projects are considered for an allocation first and to provide more differentiation between projects to reduce the likelihood of ties.

- Clarifying the requirement related to a PPA requiring deliverability

  The intent of constructing delivery network upgrades and allocating deliverability is to allow the facility to participate in the Resource Adequacy program (RA). Although the tariff requires the PPA to require deliverability, it is ambiguous the deliverability required by a PPA is ultimately utilized by, or offered to, an entity with an RA obligation. The ISO proposes to revise the tariff to clarify that beginning with the 2022-23 TPD allocation cycle, a PPA must be with an offtaker to fulfill its own RA obligation. In other words, the PPAs of offtakers that do not have RA obligations will not be eligible for groups 1 or 2. Furthermore, beginning with the 2023-2024 TPD allocation cycle and thereafter, a PPA must procure the deliverable capacity for a minimum of five years to be eligible. The ISO is revising its proposal such that if a project has a PPA that is with an entity who does not have an RA obligation, but it can be demonstrated that the RA attributes of the project are under contract with an entity with a RA obligation for a term of five years or more, the project would be eligible for an allocation. The priority for allocating TPD to projects with such contracts will be after allocations are made to eligible projects whose PPAs are with an entity with an RA obligation. Financial incentives, the intent to sell capacity, or being shortlisted with an entity with an RA obligation are insufficient to meet this

[10] Appendix DD Section 8.9.3 (3): If the Generating Facility received TP Deliverability on the basis of negotiating or being shortlisted for a power purchase agreement, it must have executed the agreement by November 30 of the year it received TP Deliverability.

requirement. These are proposed to ensure that the TPD capacity built at transmission ratepayer expense to provide sufficient transmission capacity for the RA requirements and CPUC policy to be met is fully and effectively utilized to the greatest extent possible.

To avoid imposing the five year procurement term requirement for deliverable capacity on projects that are currently in active negotiations for a PPA that may be for terms of less than five years, the ISO proposes for the 2022-23 TPD allocation cycle to allow projects that are seeking an allocation under new allocation groups 1 and 2, and projects that are seeking to retain their allocations from the 2021-22 TPD allocation cycle to do so with contract terms of less than five years. Such projects will be allowed to continue using PPAs with less than five year terms as long as the project retains the PPA used to receive the allocation.

3.3 Should the ISO develop an emergency generation interconnection process?

- Background

Based on stakeholder comments requesting more details, in the Revised Straw Proposal[11], section 3.5, the ISO proposed the following specific details for the emergency generation process:

1. The ISO will accept emergency generation study requests only pursuant to:
    a. A specific emergency state mandate, and
    b. Only for interconnections and additions specifically ***designated by a state agency***, not including counties, municipalities, or CCAs.
2. The ISO also must agree the interconnection is warranted to potentially maintain reliability, and that the interconnection will mitigate reliability risks[12].
3. The interconnection customer will submit an emergency generation study request, a $50,000 study deposit, and all necessary technical information to assess the new generation.
4. Because the ISO anticipates these studies and interconnections will be rapid, the ISO does not propose to include any study timelines in the tariff.
5. The interconnection cannot negatively impact the cost or timing of any queued project unless the impacted project belongs to the same developer and the developer consents to the impact.
6. The interconnection cannot require network upgrades above $1 million or that cannot be constructed in fewer than six months.

[11] http://www.caiso.com/InitiativeDocuments/RevisedStrawProposal-InterconnectionProcessEnhancements2021.pdf
[12] The intent of (1) and (2) is to prevent anyone from abusing this process to interconnect generation outside of its specific purpose.

7. The installed generation will have interconnection service for no more than three years. For interconnection service beyond that period, the developer must obtain service through another tariff process, such as a new interconnection request.
8. During the three-year period, the generation will be ineligible for any deliverability except Interim Deliverability, consistent with Section 4.6 of the GIDAP.

The ISO believes the above proposal addresses stakeholder concerns regarding queue jumping, will only be used under an emergency authorization, and provides interim deliverability if available, but only for the duration of the emergency order.

- Stakeholder Feedback

The ISO received stakeholder comments from 15 stakeholders on the topic of developing an emergency generation interconnection process of which eight stakeholders supported the proposal.

In prior comments Middle River Power supported the ISO developing an emergency interconnection process, however upon further consideration, Middle River Power stated their strong preference would be for California to develop and implement a rational, regular procurement process that would completely obviate the urgent, but avoidable, need to periodically deploy new generation on an emergency basis when system conditions tighten after years of procurement inaction.

CALWEA and Upstream oppose the ISO's proposal to develop an emergency interconnection process, and Vistra opposes the proposal with caveats. CALWEA opposes this queue-jumping exercise and rather than creating this non-transparent process that favors Participating TOs, the ISO should accelerate interconnection of ready projects already in the queue. Upstream strongly opposes a new accelerated interconnection process that is non-transparent and continues to incentivize "last minute" procurement that ultimately harms the ratepayer via higher costs. Vistra frowns upon a situation where state agency can cherry pick resources to jump the queue and concerned that such an emergency process will be counterproductive as it will likely stall the interconnection of other resources identified through intermediate-term processes like the IRP. However, Vistra does believe any further emergency actions should be included in tariff provisions that defined this emergency fast track option and processes to enhance equity, efficiency and transparency.

EDF Renewables, PG&E, and SCE did not oppose or support the ISO's proposal to develop and emergency interconnection process, but provided relevant comments and requests for clarifications.

Stakeholders, regardless of providing support or not, requested clarification on the following:

1. Clarify if the $1 million cost threshold includes both NU and distribution upgrades?
2. How eligible projects are determined and made transparent? Will the existing queue be utilized? How to ensure PTO projects and third party projects equal access? Can upgrades be built in time (considering required outages)? Screening process? Would modification request where storage is added to existing generation qualify (When would they be available for TPD?)
3. How impacts on queued generation is determined? What metrics will be used to confirm this? Engineering judgement or something like the electrical independence test? If engineering judgement is used, how will the ISO ensure that this process is uniform across PTOs and study areas?
4. Clarify that the interconnection service should be limited to the emergency period, as established by the order or authorization from a state agency, yet no more than 3 years. How is this enforced – will the generator be disconnected promptly, or will the GIA have a firm termination date?
5. How deliverability will be prioritized between existing queued projects and emergency projects?
6. Required study agreement, IR and technical package, validation, studies, study report, results meetings, letter agreement or GIA, filing with FERC, and all associated timelines?
7. Where will the parameters of the emergency process reside (GIDAP and/or BPM)?
8. How does the ISO intend to prevent this new process from being flooded with new requests?

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The ISO agrees with Vistra and is proposing language similar to the defined principles outlined in the proposal be included in the tariff. With respect to the stakeholders requested clarifications, the ISO offers the following:

1. The $1 million cost cap is intended for Network Upgrades only. Distribution upgrades are not under the purview of the CAISO tariff and do not have a cap.

2. The ISO is not the procurement entity for these emergency generators, a state agency is. The ISO is merely prosing to codify the process to study and connect the generating facilities determined by the state to meet the emergency need.

3. Similar to the MMA process today both an engineering and business assessment are done to determine if there are impacts to other queued customers.

4. As stated in requirement 7 of the proposal, the interconnection service is only for three years. This will be documents in their generator interconnection agreement ("GIA") as a termination of the emergency interconnection unless the interconnection customer uses another tariff method to obtain interconnection to the ISO controlled grid.

5. The emergency generator is only eligible for Interim Deliverability and the prioritization will be commensurate with existing practice for Interim Deliverability.

6. The process for study and GIA will be similar to what was done in 2021. The study and GIA execution will be on an expedited process. With the proposed language in the tariff, the pro forma GIAs will be used and a FERC filing will not be required.

7. As required by the Federal Power Act, the tariff will establish the requirements and additional detail regarding implementation and process will be in the BPM.

8. Again, the ISO is not the procurement agency for the emergency generator, the state is and it will be up to the state to determine what projects they believe are viable, warrant study and a GIA.

The ISO is not proposing to change the Revised Straw Proposal[13], and proposes to put in the tariff the following requirements for the emergency generation process:

1. The ISO will accept emergency generation study requests only pursuant to:
   (i) A specific emergency state mandate, and
   (ii) Only for interconnections and additions specifically ***designated by a state agency***, not including counties, municipalities, or CCAs.
2. The ISO also must agree the interconnection is warranted to potentially maintain reliability, and that the interconnection will mitigate reliability risks[14].
3. The interconnection customer will submit an emergency generation study request, a $50,000 study deposit, and all necessary technical information to assess the new generation.
4. Because the ISO anticipates these studies and interconnections will be rapid, the ISO does not propose to include any study timelines in the tariff.

[13] http://www.caiso.com/InitiativeDocuments/RevisedStrawProposal-InterconnectionProcessEnhancements2021.pdf

[14] The intent of (1) and (2) is to prevent anyone from abusing this process to interconnect generation outside of its specific purpose.

5. The interconnection cannot negatively impact the cost or timing of any queued project unless the impacted project belongs to the same developer and the developer consents to the impact.
6. The interconnection cannot require network upgrades above $1 million or that cannot be constructed in fewer than six months.
7. The installed generation will have interconnection service for no more than three years. For interconnection service beyond that period, the developer must obtain service through another tariff process, such as a new interconnection request.
8. During the three-year period, the generation will be ineligible for any deliverability except Interim Deliverability, consistent with Section 4.6 of the GIDAP.

4 Managing the overheated queue

4.1 Should site exclusivity be required to progress into the Phase II study process?

- Background

In the January 25, 2022 Revised Straw Proposal, Section 4.2, the ISO proposed to require site exclusivity (SE) to move into the Phase II study process, beginning with Cluster 14. For the final draft proposal the ISO is expanding this topic to include the deposit in lieu of site exclusivity (SE deposit) amount and level of deposit to be at risk from the topic 4.1 of the Revised Straw Proposal – "Should higher fees, deposits, or other criteria be required for submitting an IR". Previously, the ISO proposed (1) to increase the site exclusivity deposit requirements to $250k for small generators and $500k for large generators; and (2) if a project withdraws after the interconnection request is deemed complete, 50% of the site exclusivity deposit becomes nonrefundable. The proposal related to modifications to the IR study deposit in 4.1 of the Revised Straw Proposal will continue to be addressed within the scope of Phase 2: Long-Term Enhancements.

- Stakeholder Feedback

<u>Comments received on the site exclusivity deposit and refundability:</u>

Seven stakeholders, Six Cities, SCE, Balanced Rock Power, PG&E, Middle River Power, RWE Renewables and LSA/SEIA support the ISO's proposal as is. RWE Renewables states there needs to be an alternative when site is on federal/state/tribal lands.

Five stakeholders support the ISO proposal to increase the site exclusivity deposit but with modifications to the refundability provisions. Upstream recommends refundability of site exclusivity be 50% nonrefundable 30 days after scoping meeting. REV Renewables suggest 50% refundability be tied to the completion of the scoping meetings and would like clear definition of site exclusivity and also suggest non-refundable site exclusivity deposits be used for additional studies needed for impacted projects. CalWEA recommends refundability of site exclusivity be 50% nonrefundable 30 days after Phase 1 results meeting. Strata Clean Energy recommends aligning refundability provisions of the site exclusivity deposit with the study deposits. Next Era opposes loss of site exclusivity deposit if forced to withdraw prior to Phase II studies.

<u>Comments received on the site exclusivity requirements for entering into Phase II studies.</u>

Twenty one stakeholders commented, eleven in support, four in opposition, and six not specifically stating their support or opposition. Seventeen made comments related to specific components of the proposal.

The majority of commenters' primarily comments were related to when the requirement for site exclusivity starts. As a result, the ISO has proposed a transitionary process. The ISO proposes that Cluster 14 would not be required to demonstrate site exclusivity to proceed into the Phase II study, but Cluster 14 projects utilizing a site exclusivity deposit after making their initial IFS posting would not be eligible to receive a refund of their deposit if they withdrew without having demonstrated site exclusivity.

Five stakeholders provided comments specific to the site exclusivity requirements for public/BLM lands, and Bureau of Ocean Energy Management (BOEM) leases and California State Water requirements. The ISO has made specific proposals based on the input from Stakeholders in these areas.

- Draft Final Proposal

For Cluster 14 IRs:

(1) For Cluster 14, on a one-time basis, an IR may proceed into the Phase II studies using a Deposit in lieu of Site Exclusivity, but the entire amount of its site exclusivity deposit is non-refundable if it withdraws after having made it initial IFS posting.
(2) If an IC demonstrates site exclusivity for a Cluster 14 IR at any time while the project is active, the IC will receive a full refund of its site exclusivity deposit.

For Cluster 15 IRs and beyond:

(1) Beginning with Cluster 15 and beyond, increase the Deposit in lieu of Site Exclusivity requirements to $250k for small generators (20 MW and below) and $500k for large generators (greater than 20 MW).

(2) If an IR is withdrawn on or before thirty (30) calendar days following the Scoping Meeting, the CAISO shall refund to the Interconnection Customer the entire amount of its site exclusivity deposit.
(3) If an IR is withdrawn more than thirty (30) calendar days following the Scoping Meeting without having provided a demonstration of site exclusivity, 50% of the site exclusivity deposit is non-refundable.
(4) If an IC demonstrates site exclusivity for an IR at any time while the project is active, the IC will receive a full refund of its site exclusivity deposit.
(5) Site exclusivity will be required to move into the Phase II study process and the site exclusivity documents will be due 10 business days prior to the initial IFS posting due date for each project.
(6) If the site exclusivity requirement is not met, the IR is withdrawn and 50 percent of the ICs site exclusivity deposit is non-refundable.

The ISO proposes that any non-refundable site exclusivity deposits will be used to offset the cost of the reassessment studies. Each year's non-refundable site exclusivity deposits will be used to offset a portion of the cost to each IC that incurs costs from the ensuing reassessment study on a prorated basis, up to its full cost for the reassessment. If the non-refundable site exclusivity deposit amount for any given year exceeds the total cost of that year's reassessment, the surplus will be distributed in accordance with ISO Tariff Appendix DD Section 7.6 – Application of Non-Refundable Amounts.

The ISO's current Appendix A definition of "Site Exclusivity" provides how interconnection customers can demonstrate site exclusivity on public land; however, this language is specific to BLM applications, which had been the predominant use-case. Because the ISO will begin to see offshore wind applications as well, the ISO proposes to remove case-specific language in the tariff. The ISO believes this is prudent because it has little experience with offshore wind applications, public land licensing processes can change, and flexible tariff language would align the ISO tariff with other ISO/RTO tariffs. The ISO would instead include a broad provision that the interconnection customer must demonstrate it holds a duly executed written contract or option to purchase, acquire an easement, a license or a leasehold interest in the real property for which new interconnection is sought; or that the interconnection customer has filed applications for required permits to site on federal or state property. The ISO would also specify in the tariff that it will include current, known requirements for certain use cases in the business practice manual. This approach will provide the ISO and interconnection customers with flexibility to meet public land requirements without the risk of needing to change the tariff frequently to match public land requirements.

ISO Tariff Appendix DD Section 3.5.1 (iii):

The demonstration of Site Exclusivity, at a minimum, must be through the Commercial Operation Date of the new Generating Facility or increase in capacity of the existing Generating Facility.

5 Other Issues

5.1 Expanded errors and omissions process to provide criteria and options when changes to network upgrade requirements occur after Financial Security (IFS) postings have been made

- Background

In the January 25, 2022 Revised Straw Proposal, section 5.3, the ISO proposed that any cost responsibility increases associated with an error or omission discovered after a project makes its second IFS posting should be the responsibility of the party that made the error or omission. Specifically, the MCR and MCE cannot be increased due to an error or omission discovered after the second IFS posting due date has passed.

The ISO further proposed that when an error or omission is discovered after a project has made either its first or second IFS posting that increases the aggregate of all costs for the project to interconnect, regardless of whether the cost is refundable, or pushes back its earliest achievable ISD or the in service date for any DNUs required by the project to achieve its requested deliverability status, the project would be given the option to either accept and move forward with the changes or withdraw and receive a full refund for its IFS and a refund of any unused study deposit. The ISO proposed a cost increase threshold of ten (10) percent and a minimum of a 12 month delay in the earliest achievable ISD.

- Stakeholder Feedback

The ISO received 16 comments from stakeholders on this topic, of which 15 stakeholders supported the ISO's proposal.

SCE disagrees with the CAISO's proposed cost increase threshold of 5% and a minimum of a 12-month delay in the earliest achievable ISD. If the CAISO insists on placing the cost responsibility on the PTO for a substantial error or omission after the IFS posting have been made, then at a minimum, the definition and terms in GIDAP Section 6.8.1 should remain the same other than revising "COD based on the results of the final Phase II Study." The project's ISD and COD should be based on the date that is adjusted after the Phase II Results Meeting and reflected GIDAP Section 13.2.1. The ISD and COD is adjusted based on when the GIA is tendered, either thirty (30) CDs from the Phase II Results Meeting or May 1, after TPD Allocation Study results are issued and affidavits received. In most cases, the ISD and COD is based on tendering the draft GIA by May 1 if the IC does not park or withdraw its project from the queue based on their TPD Allocation Study results.

- The ISO has adjusted its proposal to some extent based on SCE's comment above.

If a project parks or executes a GIA and then subsequently invokes Article 5.16 – Suspension, the IC's project should not be eligible for one hundred percent of its IFS posting for Network Upgrades. The IC can either accept the error or omission impact to cost and/or schedule to its project or withdraw its IR or terminate its GIA without receiving one hundred percent of its Network Upgrade IFS posting.

- The ISO does not agree that projects situated as described above are any less harmed than other situated projects. The ISO proposes that these projects would qualify for the refunds proposed here.

If the consensus is to support issuing a full IFS refund due to a termination of a PPA, then the party terminating the PPA must be the Buyer or Off-taker (e.g., SCE), not the IC. With respect to documentation, a notarized letter on company letterhead signed by an Off-takers' or Buyers authorized representative stipulating that they terminated the PPA because of the IC being unable to meet its performance obligations pursuant to the terms and conditions in the PPA specifically due to the schedule impact associated with the error or omission.

The ISO used some of SCE's suggested language, along with that of other stakeholders to develop the proposal for termination of a PPA as a criterion for a refund of the IFS posting.

- Draft Final Proposal

The ISO proposes that any cost responsibility increases associated with an error or omission on the part of the Participating TO that is discovered after a project's due date for its second IFS posting would be the responsibility of the Participating TO. The MCR and MCE cannot be increased due to an error or omission discovered after the second IFS posting due date has passed. Any changes or modifications to the project by the interconnection customer that increase the cost responsibility for the project would be the responsibility of the interconnection customer.

The ISO further proposes that when an error or omission on the part of the Participating TO is discovered after an active project's[15] due date for either its first or

[15] This means that only after a project has completed its required interconnection financial security posting and the due date for the posting has passed, would a project be considered for eligibility for a refund.

second IFS posting that meets any of the conditions below, the project may be eligible for a refunded its IFS and any unused study deposit.

a. The aggregate of all costs for the project to interconnect increases, regardless of whether the cost is refundable.
b. The project's earliest achievable ISD or the in service date for any DNU required by the project to achieve its requested deliverability status is pushed back.
c. A PPA that the project has executed is adversely impacted, resulting in the termination of the PPA.

Changes or modifications to the project by the interconnection customer would not be a cause for the interconnection customer to receive this proposed refund.

If a project meets one of the three criteria above, the project would have to meet the relevant threshold criteria provided below. If it does, the project would be given the option to either accept and move forward with the changes or withdraw and receive a full refund of its IFS and a refund of any unused study deposit.

For the threshold criteria the ISO proposes to modify the definition of a substantial error or omission from Appendix DD Section 6.8.1 in a manner similar to the following.

A substantial error or omission shall mean an error or omission that results in one or more of the following:

(i) understatement of the Interconnection Customer's total cost responsibility for Network Upgrades and Participating TO Interconnection Facilities by more than five (5) percent or one million dollars ($1,000,000), whichever is greater; or
(ii) results in a delay to the schedule by which the Interconnection Customer can achieve Commercial Operation by more than one year, based on most recent COD as documented in the final Phase II Interconnection Study report, the latest reassessment study report, or the GIA, as applicable; or
(iii) the Interconnection Customer has a PPA that was terminated due to the impacts of the error or omission. The termination of the PPA shall be documented by a notarized letter on company letterhead signed by an authorized representative of the off-taker or buyer. The letter must stipulate the party who initiated the termination and that the grounds for terminating the PPA was solely due to the IC being unable to meet its performance obligations pursuant to the terms and conditions in the PPA

specifically due to the impacts of the error or omission, or because of financial penalties imposed on the seller solely due to the impacts of the error or omission.

5.2 Clarify definition of Reliability Network Upgrade (RNU)

- Background

  The January 25, 2022 Revised Straw Proposal maintained the ISO's proposal to clarify its existing policy that a RAS is always considered an RNU, regardless of the study that identified the need for the RNU.

- Stakeholder Feedback

  The ISO received 10 comments from stakeholders, five in support and five opposing the ISO's proposal. LSA/SEIA commented and EDP Renewables N.A., and RWE agreed that it is unreasonable to treat an upgrade as a DNU for cost allocation, but as an RNU for cost reimbursement. If the upgrade is identified in the reliability study, the cost should be an RNU allocated to the entire cluster, making the cost reimbursement limit application consistent. If the upgrade is identified in the deliverability study, it should be a DNU with the cost allocated only to projects seeking deliverability with DNU cost reimbursement policies applied.

  SDG&E noted that if a RAS needed for deliverability is not implemented, congestion management cannot be used in lieu of the RAS. Congestion management could be used instead of a RAS for reliability without affecting local and system resource adequacy which is consistent with the way the ISO treats non-RAS upgrades as part of the interconnection process.

  Finally, Vistra does not support and recommends the ISO include a process step to confirm the RAS is intended to substitute a need for a RNU before identifying as a RNU is needed.

- ISO response to Stakeholder comments

  In response to LSA/SEIA, EDP Renewables N.A., and RWE's concerns the IRs responsible for each RAS are grouped together pursuant to GIDAP Appendix DD section 6.1.3. The cost responsibility for the RAS as an RNU is allocated to the corresponding electrical group. To clarify SDG&E's comments, congestion management cannot be utilized, that is why an RNU is identified as needed. Further, to Vistra's comment, the RAS is the needed RNU.

- Draft Final Proposal

  The only RNUs the ISO's deliverability studies may identify are RASs. This is not to say that the RAS is required for deliverability. It means that the assumptions the

ISO uses in the deliverability studies are different than the initial reliability studies. Rather than requiring the Participating TOs to re-run the reliability studies based on the outcome of the deliverability studies, RASs are RNUs are merely included as deliverability study results. If a RAS is determined to be needed in any study, the RAS is required for all projects in the study area, including EO projects. Unlike a DNU, a RAS may be required for a project to synchronize to the grid and a limited operations study is needed to determination if the project can synchronize prior to the RAS being in service.

Because there has been confusion on this issue, the ISO proposes to clarify its existing policy that a RAS is always considered an RNU, regardless of the study that identified the need for the RNU. Because RASs are RNUs, they are included, and will continue to be included, in the RNU reimbursement calculation.

5.3 Transferring Participating Transmission Owner (TO) Wholesale Distribution Access Tariff (WDAT) Projects into ISO Queue

- Background

  The ISO's January 25, 2022 Revised Straw Proposal section 5.5 retained its proposal to move forward with developing tariff language allowing the ISO to accept interconnection request transfers from the a participating TO's WDAT queue to the ISO queue.

- Stakeholder Feedback

  The ISO received stakeholder comments from 11 stakeholders on this proposal, six in support and five support with additional comments. Hydrostor Inc., LSA/SEIA, and RWE all support with the additional request for information regarding substation/line operational control be make public for facilities over 50 kV on the PG&E and SDG&E systems that are under PTO control , and facilities that are under 200 kV on the SCE system that are under CAISO control. This information would be helpful in avoiding this issue in the first place. PG&E commented that they will work on reciprocal tariff changes to PG&E's WDT to receive transfers from the CAISO. SDG&E requested the definition of "transferring."

- ISO response to Stakeholder comments

  To address Hydrostor Inc., LSA/SEIA, PG&E and RWE's comments the ISO will work with the PTOs to see if this information can be made public. Additionally, to clarify SDG&E's request for the definition of "transferring," the ISO notes when a project submitted to a PTO during a cluster window is found to have requested a transmission level POI, the project will be accepted by the ISO into its queue for study in the same cluster. This will be documented in the tariff language for the initiative.

- Draft Final Proposal

  The ISO proposes to move forward with developing tariff language for allowing the ISO to accept interconnection request transfers from the Participating TO's WDAT queue to the ISO queue. The ISO will work with the Participating TO's to develop any criteria necessary to ensure that the transfer occurs within an appropriate window of time. Once the ISO has amended its tariff, the Participating TOs could revise their WDATs to include reciprocal language about receiving IRs initially submitted to the ISO. Each Participating TO have a unique window for accepting WDAT IRs. The ISO proposes to work directly with the Participating TOs to develop the specific criteria for this process that accommodates the various differences between the Participating TOs and put forth a more detailed proposal in the next IPE paper.

5.4 Changing Sites and POIs during IR Validation

- Background

  In the January 25, 2022 Revised Straw Proposal, section 5.6, the ISO kept its proposal that the timing of the process for changing POIs remain consistent with current ISO practice that the interconnection customer must confirm its POI within five business days of the project's scoping meeting and any change in POI will be limited to within the same transmission study area as the POI originally requested in its Interconnection Request. If an interconnection customer requests a change of its POI consistent with this criteria, it may change its site as well. Site changes will only be permitted in conjunction with a permissible change in POI.

- Stakeholder Feedback

  The ISO received 14 comments on this initiative, six in support and eight in support with comments. Avangrid Renewables, CalWEA Hydrostor Inc., LSA/SEIA, RWE, and Upstream all requested the definition of "Same Transmission Area" and "Transmission Study Area" with a publicly available map clearly showing the boundaries made available. Avangrid further requested information regarding the treatment of an IR with multiple POIs vs multiple IRs with different POIs for a single project submitted by the same developer. LSA/SEIA also requested that it is clearly stated that site changes are allowed later via the MMA request process as long as the POI (substation and voltage level) stays the same.

  PG&E requested that a limit of two alternative POIs be allowed for discussion during the scoping meeting. Additionally, PG&E requests that the proposal includes language making it clear that PTO and ISO staff cannot provide technical advice on the design of the IC's project.

SDG&E proposes additional communications between the PTO and IC regarding POI availability in advance of the scoping meetings allowing the IC to change the POI and update the technical data accordingly. Providing bay availability within one (1) bus or line away from the IC's proposed POI represent reasonable effort from the PTO and is consistent with the GIDAP BPM.

- ISO response to Stakeholder comments

To clarify for stakeholders, the ISO will work with the PTOs to see if definition of "Same Transmission Area" and "Transmission Study Area" with a publicly available map clearly showing the boundaries made available. Further, to clarify Avangrid's comment requesting information regarding the treatment of an IR with multiple POIs vs multiple IRs with different POIs for a single project submitted by the same developer the ISO notes the second paragraph of Tariff Appendix DD 3.1 already addresses this issue: *"The Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. The Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage level shall be treated as two Interconnection Requests."*

Further, in response to LSA/SEIA's request for clarification, the ISO clarifies this initiative only addresses changes in site/POI during the IR validation process. The ability to request a site change later via the MMA process is unchanged.

Specific to PG&E's request, the ISO notes Paragraph 4 of the GIDAP BPM addresses the extent of POI discussions at the scoping meeting: "*Should the proposed Point of Interconnection be determined to be infeasible, the Interconnection Customer may explore alternative Points of Interconnection. The Interconnection Request requires the Interconnection Customer provide the address or location, including the county, of the proposed new Generating Facility site and the Interconnection Customer may explore alternative Points of Interconnection near the site proposed in the Interconnection Request, for example, within the same county, one transmission line, or one switchyard from the original."* Additionally, it is correct that PTO and ISO staff cannot provide technical advice on the design of an IC's project, this is outside the scope of this initiative.

Finally, in response to SDG&E's proposal, the ISO clarifies that advance communications may not be feasible in all cases due to varying number of IR submissions received for a PTO region.

- Draft Final Proposal

  The ISO proposes the timing of the process for changing POIs remain consistent with current ISO practice that the interconnection customer must confirm its POI within five business days of the project's scoping meeting and any change in POI will be limited to within the same transmission study area[16] as the POI originally requested in its Interconnection Request. If an interconnection customer requests a change of its POI consistent with this criteria, it may change its site as well. Site changes will only be permitted in conjunction with a permissible change in POI.

5.5 Should parked projects be allowed to submit MMAs while parked?

- Background

  The January 25th Revised Straw Proposal evolved the issue of submitting a MMA while the project was parked. While the Interconnection Customers want the ability to submit MMAs while parked and Participating TOs and other transmission owners support the ISO's proposal to not allow parked projects to submit MMAs while parked, the ISO proposed to allow only fuel-type, technology type (e.g. wind to storage, solar to storage, solar to wind, etc.) and POI changes be allowed while the project is parked, but the Interconnection Customer must make the second IFS posting when submitting the MMA.

- Stakeholder Feedback

  The ISO received comments from 10 stakeholders on this issue. Aypa, EDF-Renewables, RWE, Upstream and SCE supports the ISO's proposal as currently written. SDG&E supports the ISO's proposal but notes that there are inconsistencies in the tariff and BPM as to when the POI can change. CalWEA supports the proposal but recommends allowing downsizing while parked. Middle River Power urges the ISO to expand the list to change inverters.

  PG&E and Vistra disagrees with the proposal pointing out that any changes required by the Interconnection customer can be made once the project comes out of parking. However, if the ISO does allow parked projects to submit an MMA, PG&E agrees the second financial security posting should be submitted with the MMA.

- Draft Final Proposal

  Based on the feedback, the ISO proposes to expand the parked MMA proposed to allow downsizing in addition to fuel-type, technology type (e.g. wind to storage, solar

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16 Study areas change infrequently, but are established annually in the ISO's transmission planning process. *See, e.g.* the ISO's proposed TPP study plan for 2020-21 at p. 9, available at http://www.caiso.com/Documents/FinalStudyPlan_2020-2021TPP_Revised.pdf.

to storage, solar to wind, etc.) and POI changes, but the Interconnection Customer must make the second IFS posting when submitting the MMA. The ISO does not believe that inverter changes need to be added because they can be done once the project exits parking and will likely change several times over the construction period due to changes in technology and availability.

6 Other Stakeholder Suggested Proposals

6.1 Adding due dates for curing deficiencies in Appendix B, to avoid delays in starting Phase II studies

- Background

The January 25, 2022 Revised Straw Proposal, section 6.1, maintained the ISO proposal to add a deadline for the validation of Appendix B's, where all Appendix B's and any associated technical data must be deemed valid by 70 calendar days after the date of the Phase I study report. Those not valid would be withdrawn with five business days to cure.

- Stakeholder Feedback

The ISO received 12 comments from stakeholders on this topic, five in support, four in support with comments, and two in opposition with comment. CalWEA agrees with the ISO proposal, but asked that Appendix B be reviewed to remove unnecessary data requirements. Hydrostor Inc. supports greater clarity on timelines as long as it is presented in a transparent manner to all parties.

RWE, SDG&E would support if all parties have the same amount of time. A minimum amount of cure time also needs to be maintained, technical deficiencies can be more complex to evaluate. Vistra supports with concern that the due date for curing be reasonable with input from stakeholders as to what that date might be. LSA/SEIA, EDP Renewables N.A. and Middle River Power oppose but could support by tying the validation period to the results meeting rather than the issuance of the Phase I report.

- ISO response to Stakeholder comments

In response to CalWEA's request that Appendix B be reviewed to remove unnecessary data requirements, the ISO notes it would be helpful for CalWEA to provide details as to what they deem unnecessary. The form is provided by FERC. The ISO can review the form and see if any modifications can be made based on CalWEA's input.

To provide clarity on timelines based on Hydrostor Inc. comments, the determination of a deadline for Appendix B validation is part of our transparent IPE stakeholder process, will be added to the Tariff Appendix DD, GIDAP BPM, GIDAP Customer Guidelines document, and included in scoping meeting minutes, Phase I Results meeting minutes, and also addressed at the Resource Interconnection Fair.

Finally, in response to the other commenter's requests for clarification, the ISO notes this initiative provides a minimum of 35 CD for a project to have its Appendix B validated. Adding a validation date based on the results meeting for each project is not only an administrative burden, but also has the potential to overburden technical resources at both the ISO and the PTO due to the timeline to complete results meetings within 30 CD from the issuance of the Phase I study results.

- Draft Final Proposal

Appendix DD Section 7 states "Within ten (10) Business Days following the Phase I Interconnection Study Results Meeting, the Interconnection Customer shall submit to the ISO the completed form of Appendix B". The ISO proposes to add a deadline for the validation of Appendix B's, where all Appendix B's and any associated technical data must be deemed valid by 70 calendar days after the date of the Phase I study report. Those not valid would be withdrawn with five business days to cure.

6.2 Modification to Commercial Viability Criteria

- Background

The January 25th Revised Straw Proposal proposed that the commercial viability criteria should be assessed only if the Interconnection Customer submits the modification request to delay beyond the seven years and not when the Participating TO triggers a delay. With respect to the definition of delay, it should be based on the party that caused the delay. A few examples:

- If the Participating TO cannot get the equipment needed for the project until after the originally anticipated date and it will delay the In-Service Date, then it is a Participating TO delay.
- If the IC does not meet a document submittal deadline to the Participating TO, then it is an IC delay.

- Stakeholder Feedback

The ISO received stakeholder comments from 11 stakeholders on the proposal to only assess commercial viability criteria if the Interconnection Customer submits the modification request to delay beyond the seven years and not when the Participating TO triggers a delay. Aypa Power, CESA, EDP Renewables N.A., LSA/SEIA, Middle River Power, PG&E, RWE, and Vistra Corp. support this proposal. Additionally, consistent with this proposal, LSA/SEIA request that CVC only apply if Interconnection Customer submits a modification request to move past the seven year deadline, and not if the project is delayed past the seven year deadline because of Participating TO delays which is consistent with the ISO's proposal. They note this would help ensure that infeasible projects do not stay in the queue longer than necessary and take up TP Deliverability. Further, LSA/SEIA clarifies that this proposal is not intended to blame the Participating TO for delays that may have taken place before the GIA was executed.

CalWEA and Hydrostor support this proposal with suggests for improvement. CalWEA notes the proposal does not resolve concerns regarding project interconnection before all RNUs are in service. Particularly, they explain the timing of the Limited Operation Study (LOS), which occurs 5 months before the ISD, does not provide enough time for project development. They explain that a mechanism should be in place for developers to understand whether a project can interconnect within two years and a non-binding LOS should evaluate if the projects with executed GIAs can interconnect as requested by relying on market operation instead of reliability upgrades. Hydrostor echoes CalWEA's concern that there is not enough time for project development with the current LOS study timeline and reevaluating this timeline would be helpful for projects seeking to assist in meeting the state's Mid-Term Reliability needs. As the ISO stated in the January 25th Revised Straw Proposal, a 24 month LOS, is not practical as discussed in the December 6th Issue Paper and Straw Proposal. At two years prior to synchronization, the assumptions would be that all transmission is built, unless there is a known delay, and all projects are coming online therefore no information could be garnered from that type of a study and it would take resources away from other valuable work.

SCE express that developers must continue to comply with the commercial viability criteria if the 7 year timeframe is breached. The ISO agrees and that is already a requirement in the existing tariff.

- Draft Final Proposal

  The ISO proposes to retain its existing proposal for commercial viability criteria, it should be assessed only if the Interconnection Customer submits the modification request to delay beyond the seven years and not when the Participating TO triggers a delay. With respect to the definition of delay, it should be based on the party that caused the delay. A few examples:

  - If the Participating TO cannot get the equipment needed for the project until after the originally anticipated date and it will delay the In-Service Date, then it is a Participating TO delay.
  - If the Interconnection Customer does not meet a document submittal deadline to the Participating TO, then it is an Interconnection Customer delay.

6.3 Expanding Deliverability Transfer Opportunities

- Background

  The January 25th Revised Straw Proposal proposed ISO tariff language that expands ability to transfer deliverability to projects at the same substation and same voltage is the same level at which deliverability is allocated to the Interconnection Customers. The ISO proposes to revise Section 8.9.9 of Appendix DD and the definition of Point of Interconnection to be at the substation and voltage level versus at a specific point in the substation. This will allow greater opportunity for projects to transfer deliverability.

- Stakeholder Feedback

  A total of 12 stakeholders provided comments on this topic, Aypa, CalWEA, EDF-Renewables, Hydrostor Inc, LSA/SEIA, Middle River Power, PG&E, Rev Renewables, RWE, and Upstream all support the topic. Golden State Clean Energy supports the issues but wants to ensure that a Generating Facility can still transfer deliverability among its Generating Units.

  Vistra believes there should be more flexibility to transfer deliverability to projects that can show commercial readiness such that projects that are less viable could give up their deliverability allocation to more viable projects to better support timely exit of commercially ready assets. Vistra recommends the ISO develop a commercial readiness requirement and that be an explicit test that must be met to allow for deliverability transfers.

- Draft Final Proposal

  The ISO agrees with Golden State Clean Energy and did not intend to limit the existing authority to transfer deliverability and has made that change to the proposal. The ISO disagrees with Vistra, an additional commercial readiness requirement is not warranted in this instance. What the ISO has seen so far is a project moving deliverability to allow the project to be more viable and the ISO has even seen a project move deliverability to another project and then withdraw. These are the outcomes the ISO would like to achieve by expanding this opportunity.

  The ISO proposes to revise Section 8.9.9 of Appendix DD and the definition of Point of Interconnection as follows:

  > 8.9.9 Deliverability Transfers Deliverability may not be assigned or otherwise transferred except as expressly provided by the CAISO Tariff. An Interconnection Customer may reallocate its Generating Facility's Deliverability among its own Generating Units or Resource IDs at the Generating Facility, <u>or to other projects at the same substation at the same voltage level.</u> The Generating Units must be located at the same Point of Interconnection. The Generating Facility's aggregate

output as evaluated in the Deliverability Assessment cannot increase as the result of any transfer, but may decrease based on the assignee's characteristics and capacity. The CAISO will inform the Interconnection Customer of each Generating Unit's Deliverability Status and associated capacity as the result of any transfer. The results will be based on the current Deliverability Assessment methodology.

An Interconnection Customer may request to reallocate its Deliverability among its Generating Units or to other Projects at the same substation and voltage level as their Project pursuant to Section 6.7.2.2 of this GIDAP, Article 5.19 of the LGIA, and Article 3.4.5 of the SGIA, as applicable. A repowering Interconnection Customer may transfer Deliverability as part of the repowering process pursuant to Section 25.1.2 of the CAISO Tariff. An Interconnection Customer expanding its capacity behind-the-meter pursuant to Section 4.2.1.2 also may transfer Deliverability as part of that process, or subsequently under the other processes in this Section.

The ISO proposes to revise Appendix A definition as follows:

Point of Interconnection The point, as set forth in Appendix A to the Large Generator Interconnection Agreement or Attachment 3 to the Small Generator Interconnection Agreement, where the Interconnection Facilities connect to the CAISO Controlled Grid. ~~For Generating Facilities connected to the Distribution System, t~~The Point of Interconnection is the substation at which the Generating Facility connects to the CAISO Controlled Grid. For an EIM Participating Resource or non-participating resource, the Point of Interconnection is the point at which the EIM Participating Resource or non-participating resource connects to an EIM Entity's transmission facilities.

6.4 Requirement that any IR that proposes to utilize a third party owned gen-tie must provide documentation as part of their IR that demonstrates that the gen-tie owner has agreed to the project using its gen-tie

- Background

In the January 25, 2022 Revised Straw Proposal, Section 6.9, the ISO proposed that an IR submittal would require a letter of intent between the non-PTO owned or third party gen-tie or substation and the project seeking to share the gen-tie or substation. The proposal further required an executed gen-tie sharing agreement to proceed into the Phase II studies.

- Stakeholder Feedback

The ISO received comments from 11 stakeholders on this topic, of which eight supported the ISO's proposal. RWE, would support the proposal if the agreement would not be required until the GIA is executed. Both EDP and LSA/SEIA oppose the proposal and LSA/SEIA noted that the CAISO nor any PTOs have presented any evidence that this is a problem.

- ISO response to Stakeholder comments

  In response to RWE's comment, the ISO does not agree because waiting until after the Phase II studies are completed can introduce too much uncertainty in the Phase II study results. Further, in response to LSA/SEIA's comments, the does not agree because waiting until after the Phase II studies are completed can introduce too much uncertainty in the Phase II study results.

- Draft Final Proposal

  For Cluster 14:

  The ISO proposes for Cluster 14, that a letter of intent between the non-PTO owned or third party gen-tie or substation and the project seeking to share the gen-tie or substation will be required to enter into the Cluster 14 Phase II study. The letter of intent must document the intent of the parties to negotiate the terms of the sharing agreement. The proposal is to further require an executed gen-tie sharing agreement following the Phase II studies. The executed agreement would be due at the time the second IFS posting is due.

  For Cluster 15 and beyond:

  The ISO proposes that starting with Cluster 15, the IR submittal will require a letter of intent between the non-PTO owned or third party gen-tie or substation and the project seeking to share the gen-tie or substation. The letter of intent must document the intent of the parties to negotiate the terms of the sharing agreement. The proposal is to further require an executed gen-tie sharing agreement to proceed into the Phase II studies. The executed agreement would be due at the time the initial IFS posting is due.

  For a request for project modification:

  If a gen-tie sharing arrangement is requested in conjunction with a request for project modification, the ISO would require an executed gen-tie sharing agreement to proceed with the MMA. The proposal related to MMAs is to be implemented upon FERC approval of the IPE tariff changes.

The ISO does not propose to include tariff requirements for the terms and conditions in the letter of intent or the subsequent gen-tie sharing agreement. If at a future date it is determined that requirements are needed, the ISO would propose such requirements in a modification to the GIDAP BPM.

6.5 Recommendation that after the IR validation, the ISO should be consistent in using RIMS for all documents, details, etc. related to projects

- Background

  The January 25th Revised Straw Proposal was that all communication handled now exclusively via email, including deliverability allocation results, financial security posting requests, and MMA documentation (requests, data files and results), repowering and Limited Operation Study documents (request, study plan and study report) should be provided on RIMS in addition to being communicated via email and other written correspondence.

- Stakeholder Feedback

  The ISO received comments from 14 stakeholders which all supported the proposal. Aypa Power, CalWEA, EDF-Renewables, EDP Renewables N.A., Golden State Clean Energy, Hydrostor Inc., LSA/SEIA, Middle River Power, Rev Renewables, SDG&E, Upstream, and Vistra support the ISO proposal with no changes.

  RWE supports the proposal but wants the project to be automatically added to the RIMS account when new, the interconnection customer should not need to add them manually. SCE also supports the ISO proposal and wants the ISO to grant SCE personnel access to all documents and files (IR, Phase I/II Studies, Meeting Minutes, Appendix B Submittals, Reassessments, MMAs, TPD Allocation Study results and affidavits, etc.,) to a project proposing to interconnect to a neighboring PTO (e.g, GridLiance West or Valley Electric Association) when SCE is the Affected Participating TO. Documents posted to RIMS should also include Notice to Operate in Parallel Letters to the Interconnection Customer and ISO System Operator/NRI.

- Draft Final Proposal

  Affected Systems already have access to the projects that affect them in RIMS, so SCE should already have this capability. With respect to RWE's request to automatically add a project to RIMS, the ISO has no way to know when a developer is going to submit a project nor does the ISO know the data, including electrical characteristics. So there is no way for the ISO to automatically add a project to RIMS.

  The ISO proposes to retain the existing proposal first stated in the Issue Paper and Straw Proposal to include in the RIMS documents deliverability allocation results, financial security posting requests, and MMA documentation (requests, data files and results), repowering and Limited Operation Study documents (request, study plan and study report), and other final communication among the parties.

7 Stakeholder engagement

The schedule for stakeholder engagement is provided below. The ISO will present its proposal for phase 1 to the Board of Governors in May 2022, and phase 2 will presented to the Board of Governors in November 2022.

Date	Event
09/30/21	Publish preliminary issue paper
10/08/21	Stakeholder suggestions due
10/19/21	Stakeholder workshop on preliminary issue paper
10/28/21	Stakeholder comments due on preliminary issue paper and workshop
12/06/21	Publish issue paper/straw proposal
12/13/21	Stakeholder conference call on issue paper/straw proposal
01/03/22	Stakeholder comments due on issue paper/straw proposal
01/25/22	Publish revised straw proposal
02/01/22	Stakeholder conference call on revised straw proposal
02/15/22	Stakeholder comments due on revised straw proposal
Phase 1	
03/17/22	Publish draft final proposal
03/24/22	Stakeholder conference call on draft final proposal
03/31/22	Stakeholder comments due on draft final proposal
04/11/22	Publish draft tariff language
04/21/22	Publish final proposal
04/25/22	Stakeholder comments due on draft tariff language
04/28/22	Stakeholder conference call on final proposal
05/05/22	Stakeholder comments due on final proposal
May 2022	Board of Governors Meeting
Phase 2	
06/07/22	Publish draft final proposal
06/14/22	Stakeholder conference call on draft final proposal
06/28/22	Stakeholder comments due on draft final proposal
07/26/22	Publish draft tariff language and final proposal
08/09/22	Stakeholder comments due on draft tariff language
08/16/22	Stakeholder conference call on final proposal
08/30/22	Stakeholder comments due on final proposal
November 2022	Board of Governors Meeting

The ISO will hold a stakeholder meeting on March 24, 2022 to review the Draft Final Proposal – Phase 1: Near-Term Enhancements. Stakeholders are encouraged to submit comments on this Draft Final Proposal through the ISO's commenting tool using the link on the initiative webpage by close of business on March 31, 2022.