California ISO

Interconnection Process Enhancements 2021

Phase 2: Longer Term Enhancements
Draft Final Proposal

July 26, 2022

Prepared by:
Robert Emmert
Deb Le Vine
Steve Rutty
Linda Wright

California Independent System Operator

Table of Contents

1 Introduction

This Phase 2 Draft Final Proposal is the next step in the 2021 Interconnection Process Enhancements (IPE) Initiative, one aspect of 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 was launched 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 need 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. While the accelerating pace of needed resource development called for examination of opportunities for process improvement, the timing of this initiative was also heavily influenced by the circumstances of the April 2021 Cluster 14 interconnection application window.

During the Cluster 14 open window, the ISO received 373 interconnection requests, creating an overload of industry resources which resulted in the Supercluster Interconnection Procedures initiative that started on June 14, 2021[1]. 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[2]. In addition to the issues related to the broader need for reforms, both in the short term and longer term, the ISO also identified a number of relatively minor enhancements needed since the previous 2018 IPE initiative that also warranted attention.

This led to the sequencing of the 2021 IPE initiative. Topics that would impact Cluster 14 Phase II were handled in the Phase 1 portion of this initiative. The Phase 1 package of changes, which was approved by the ISO Board on May 12, 2022, and submitted to FERC for approval on June 2, 2022,[3] accordingly focused on near-term enhancements to the existing interconnection processes that can be applied to Cluster 14 following the completion of the phase I interconnection studies in September.

---

[1] For more information on the Supercluster Interconnection Procedures initiative please refer to the initiative webpage at: [FinalProposal-SuperclusterInterconnectionProcedures.pdf (caiso.com)](FinalProposal-SuperclusterInterconnectionProcedures.pdf)

[2] 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] Phase 1 tariff amendment filing is available at http://www.caiso.com/Documents/Jun2-2022-TariffAmendment-InterconnectionProcessEnhancements-ER22-2018.pdf.

Another impact of the Cluster 14 supercluster was the recognition 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. Phase 2 focuses on resolving longer term modifications and broader reforms to align interconnection processes with procurement activities along with some additional issues that have arisen. It also addresses several residual issues that related to Phase 1 enhancements that were not fully resolved in the Phase 1 process. The ISO is targeting the ISO Board of Governors October 2022 meeting for approval of Phase 2.

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.

2 Background

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 plan approved by the ISO Board of Governors in March, 2022 was 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[4]. 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.[5] Responding to these signals and previously approved authorizations, the resource development industry submitted 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

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

[5] Cal. P.U.C., Dec. No. 21-06-035. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF

interconnection queue.[6] 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 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 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 ("FERC ANOPR")[7]. 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,[8] was posted to the ISO website on December 13, 2021. Additionally, the CAISO has reviewed FERC's more recent Notice of Proposed Rulemaking ("FERC NOPR").[9] While the CAISO anticipates participating in the comment process, CAISO staff have made an effort to align some existing proposals with those included in the FERC NOPR in cases where there may be direct

---

[6] 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

[7] 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*

[8] "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

[9] *Notice of Proposed Rulemaking: Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022).

overlap. The CAISO also seeks specific comments on this approach as indicated below.[10]

Progress must be made on a number of fronts including the generation interconnection process; the 2021 IPE initiative 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 was established to discuss and address interconnection-related issues the ISO and stakeholders have identified given current circumstances, and to resolve concerns that have surfaced since the last IPE initiative in 2018.[11] 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 Phase 2 Draft Final Proposal is intended to present proposed solutions that focus on long-term process enhancements based on comments received from stakeholders from the June 7th Revised Straw Proposal, including some additional issues that have arisen since the original issues list was developed.

3 Phase 2 topics focused on moving resources through the interconnection queue more efficiently and potentially more quickly

This section discusses a number of topics focused on moving resources through the interconnection queue more efficiently and more quickly. One area for opportunity in achieving those objectives has focused more specifically on achieving greater alignment between the interconnection process, procurement activity, and the ISO's transmission planning process that integrates state resource planning results. Because alignment efforts involve consideration not only of the interconnection process but also those related processes, opportunities in this regard need to be considered not only in the IPE 2021 effort but in refining other processes as well.

The ISO's transmission planning process includes a framework for developing policy-driven transmission associated with state (and federal, although that has not yet been relevant) policy needs and direction. However, that policy direction in the transmission planning process is not coordinated with interconnection requests seeking to utilize that

[10] This is *not* to say that the ISO may conduct a stakeholder initiative to comply with any final rule FERC issues. The ISO generally does not do so because it can only make tariff revisions consistent with the final rule, and no other.
[11] For more information on the 2018 IPE initiative please refer to the initiative webpage at: [California CAISO - Interconnection process enhancements (caiso.com)](https://www.caiso.com).

capacity as it is being developed, nor with the procurement activities of the large number of load serving entities now having procurement obligations. The ISO has proposed a number of measures relating to this overall objective in this initiative, including several measures approved in Phase 1 and continuing the discussion of others in this Phase 2 paper. The Phase 1 effort in this regard focused primarily on revisiting the deliverability allocation framework, and aspects of that have been carried over for further review in Phase 2. Phase 2 discussions also touch on the consideration of how policy-driven transmission should be made available for allocation (Section 3.4), and the potential role of solicitation models (Section 3.2).

Feedback from the stakeholder community to date generally supported various enhancements to current processes, but no structural changes that would disrupt the current interconnection queue process and prioritization within the queue. Beyond those already identified in the IPE 2021 process and in the ISO's transmission planning process, the ISO does not have further suggestions at this time on this broader topic of achieving greater alignment between the interconnection process, procurement activity, and the ISO's transmission planning process that integrates state resource planning results, but is interested in stakeholder feedback in this regard.

In the meantime, the ISO will continue to explore the various topics and proposals as set out below in the IPE initiative, as well as in other forums such as those relating to the transmission planning process.

3.1 Transparency enhancements

- Background

  In the June 7th Revised Straw proposal the ISO proposed to amend the tariff, where possible to allow certain data agreed to by stakeholders to be public information. The ISO requested specific comments from generator owners and interconnection customers on their willingness to share project-specific data publicly, and which requested data should be shared. The ISO already agreed to make PTO study area, TPD Allocation Group, and Resource IDs available.

- Stakeholder Feedback

  The ISO receive comments on various components of data transparency from 21 stakeholders. Most stakeholders support making as much data available as possible to improve transparency and allow utilization of the data by stakeholders for procurement, resource planning, and efficiency in decision-making and tracking projects.

AES, Clean Energy, LSA, and EDF-R support an interconnection heat map consistent with the FERC NOPR. In this instance, the ISO wants to wait and see the outcome of the FERC rulemaking before implementing an interconnection heat map.

Rev Renewables supports, and Golden State Clean Energy only supports, the TPD group and allocation being made public, whereas AES, BAMX, CESA, CalWEA, EDF-R, Hanwha Q Cells USA, SEIA, and CPUC believes the following should be made public:

- Suspension status
- Construction status, but we note that it might be hard to keep track of all phases of construction, so a simple yes/no or check mark that construction has started could be sufficient
- Parking status
- Phase level data: Generation and fuel type, and TPD Group and allocation should be made public
- Projects with TPD allocation should be more transparent and identifiable

Rev Renewables, BAMX, EDF-R, and CPUC supports making phase level data available but only generation and fuel type, MW, hybrid or co-located and MWH data for storage; but Rev Renewables is against making milestone dates, resource IDs, and TP Deliverability group and allocation public. Rev Renewables is also against making suspension status, construction status, parking status and TPD allocation group public information.

BAMX, CPUC, CalCCA, and LSA also proposed to make PPA execution and MW available whereas SEIA, AES, CalWEA, EDF-R, Hanwha Q Cells USA, Rev Renewables is against making PPA execution and MWs public because, as SEIA and EDF-R note, if the TPD allocation group is known, then the PPA status is in essence known. The CPUC notes that while PPA pricing is sensitive, the existence of a full or partial PPA for the project, the MWs under contract, and the expected online date of the MWs in contract is frequently publicly available when the contract is with an investor-owned utility or community choice aggregator and can be found on the CPUC website.

BAMX, Hanwha Q Cells USA, and CPUC also proposed to make Affected System status available and SEIA along with PG&E would like clarity on what is meant by Affected System status. CalWEA and Rev Renewable believes that Affected System status should remain confidential.

CESA would also like site control to be public data whereas LSA proposed that knowing just whether the project has provided an in-lieu deposit or not is sufficient. Rev Renewables considers site exclusivity confidential. EDF-R, CPUC and Rev

Renewables would also like the transmission planning study area and subarea information,

CPUC also requested that the CAISO should consider making a name and contact info for interconnection customers publicly available to enable better communication between developers and LSEs seeking to procure resources.

EDF-R requested that we restructure the fuel type by column to wind, solar, BESS rather than Fuel 1, Fuel 2 and Fuel 3. In addition they requested the ISO clean up the POI data.

Rev Renewables supports the project “formerly known as” name being public. The CPUC noted that alternative project names may be confidential due to business reasons, but allowing, but perhaps not requiring, project owners to voluntarily disclose former or alternative project names can only lead to easier resource planning and procurement.

LSA requested that the ISO explain the discrepancy between the May 24th paper and the May 31st meeting regarding its ability to provide the data whereas in this phase of the IPE initiative the ISO raised the issue of data that was confidential in the Revised Straw Proposal. The difference is twofold, after hearing the need from the participants and the uses of the information and seeing the direction FERC is going, the ISO reassessed its position and while it might take some time to produce the reports, as can be seen below, the ISO is taking a different stance on information it will publish on its website.

PG&E recommends that the CAISO consult with the Federal Energy Regulatory Commission on which data elements can be made public as requested by stakeholders, and which data elements should remain confidential. Some of the currently confidential data elements listed in the revised straw proposal may be used by energy market firms to influence or get ahead of market pricing information. PG&E recommends that any data that is or could be used to correctly identify the specific project and/or its location should remain confidential (i.e., “personally identifiable information”). PG&E requests clarification as to what is meant by the term “affected system status” and the context of that term be used. The ISO thanks PG&E for its recommendation and agrees the Critical Energy Infrastructure Information must remain confidential, the majority of the information being requested is not CEII and does not meet the confidentiality provisions of the CAISO Tariff.

AES suggested that the ISO review PJM’s public interconnection queue as a helpful model for what the ISO should emulate. The ISO reviewed the PJM public queue and notes that the only different between the public ISO Queue Report and the PJM report is MW in service if less than the project total MW. Otherwise the ISO public

Queue Report has all of PJM's data and more, including study process, queue date, TPD requested, and location by county.

EDF-R believes the data should be transparent, and by transparent data we mean data that is accurate, available to the interconnection customers, and accessible to the average stakeholder. This specifically means (1) clear definitions on what the data represents, (2) clear naming conventions that allow the data to be mapped and related to other CAISO data, and (3) formatted in a manner that allows analysis of the data. EDF-R encourages CAISO integrate new data into the existing interconnection queue report or another report delivered from RIMS where possible.

LSA, PG&E, Rev Renewables and the CPUC believe that Interconnection Customers should be allowed to disclose their own project information, directly (which LSA believes that they are allowed to do today) or in CAISO documents. The ISO agrees, but has not seen any interconnection customer publish the information being requested in this initiative. SDG&E supports making data public that better informs developers and leads to more realistic projects being submitted in the interconnection queue. AES, SEIA commented that data transparency should not be left optional, it should be consistently applied across all projects whereas Rev Renewables believe making data public should be optional.

GSCE requested that the ISO assess the benefits to be gained from each piece of data the ISO makes public and any proposal should be grounded in that benefit versus based on a few stakeholders support and other do not. Moreover, the ISO needs to be cognoscente of the commercial sensitivities of project data. GSCE is generally unsure how most of the requested data could provide benefits such as informing future interconnection requests.

- Draft Final Proposal

The ISO proposes to make the following project information public to stakeholders, likely through RIMS – PUB similar to the existing Queue Report:

  - PTO study area and sub-area by cluster;
  - TPD allocation group and percentage allocation (or MW amount allocated) for the project. From this information stakeholders could deduce whether a project has a PPA;
  - Resource ID(s);
  - Status of suspension and parking (yes/no);
  - Phase data: Generation and fuel type, MW, hybrid or co-located, synchronization date and COMX or COD date.

The remaining data items requested were not strongly supported by the responding stakeholders. However, if the Interconnection Customers would like the ISO to put together a list of developers to be posted on the ISO website, that is possible. At this time, the ISO believes posting this data does not require a tariff change, and once the reports are developed, the ISO will add them to the BPM including a description of the data fields. The ISO may, however, add tariff language to expressly require the ISO to continue to post the new information.

3.2 Revisiting the criteria for PPAs to be eligible for a Transmission Plan Deliverability (TPD) allocation

- Background

  In the June 7, 2022, IPE Phase 2 Revised Straw Proposal, section 3.4, the ISO reintroduced the Phase 1 TPD eligibility criteria of a power purchase agreement (PPA) to merit the highest level of priority ranking in the TPD allocation process. Having an executed PPA, being shortlisted for a PPA, or actively negotiating a PPA have been the foundational criteria for demonstrating project readiness and eligibility to qualify for obtaining TPD, with the level of assurance of a PPA determining the priority for allocating TPD. The clarifications proposed in the Revised Straw Proposal include:

  1. 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.
  2. If a project has a PPA that is with an entity that does not have an RA obligation, but it can demonstrate 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 requirement.

- Stakeholder Feedback

  The following is a summary of stakeholder comments based on the stakeholder comment template for the phase 2 - Revised Straw Proposal.

  1. Stakeholder Feedback on PPA eligibility:
     a. Should the allocation of TPD require a PPA that procures the project's RA capacity for some minimum term?
     b. If yes, what should that minimum term be and what is the basis for that?

     Twelve stakeholder answered these questions.

	Minimum Term				
Entity (Name)	**No Min Term**	**1 Year**	**3 Years**	**5 Years**	**10 Years**
ACP-California			1		
Avangrid Renewables	1				
California Community Choice Association					1
California Energy Storage Alliance	1				
California Public Utilities Commission Energy Division				1	
California Wind Energy Association			1		
Golden State Clean Energy		1			
Large-scale Solar Association/ LSA	1				
San Diego Gas & Electric				1	
Solar Energy Industries Association/SEIA	0.5 [1]		0.5 [1]		
Six Cities/The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California				1	
Southern California Edison					1
Sum of Comment Categories	**3.5**	**1**	**2.5**	**3**	**2**
		8.5 Agree to some Min Term [2]			

[1] SEIA does not believe CAISO should require any minimum term, but would support 3 years

[2] **Weighted average of suggested Min Term = 5.1 years**

- ISO Discussion of Stakeholder Comments

Based on a request for clarification by CalCCA, the ISO clarifies that the requirement that RA capacity be procured for a minimum term is intended for all projects to either obtain or retain deliverability in all allocation groups (except group C, which has no such requirements). The minimum term would be required for all projects seeking an allocation in group A, for all shortlisted projects seeking an allocation in group B, group B projects seeking to retain their allocation, and for group D projects seeking to retain their allocation through either the shortlist for a PPA or the executed PPA.

The ISO clarifies that the intent of using a minimum contract term is to ensure projects most ready to move forward and most likely to deliver benefits to ratepayers are the projects that will have the highest priority in the allocation process. All of the procurement entities that commented suggested a minimum term of five to ten years. In comments and discussions with procurement entities, no entity has stated that they procure capacity from new greenfield projects or an expansion of an existing project for less than ten years. The ISO has seen no evidence that a short term RA contract (less than five years) provides sufficient demonstration of revenue for a greenfield project to be financeable.

The ISO believes that many of the arguments for short-term contracts are only valid related to existing resources that are already online and competing to obtain short term RA contracts. Allocation group D was designed for projects that do not have long-term contracts to seek an allocation of TPD. The vast majority of RA capacity is under the jurisdiction of the CPUC and the capacity procurement requirements of jurisdictional LSEs require contracts for a minimum term of ten years. All of this leads the ISO to believe that longer term contracts are a significant benchmark of a project's viability for proceeding to commercial operation.

Providing TPD allocations to projects with short-term contracts would result in projects that are still seeking a long term PPA to get a higher priority in group A. Allocation group A is for projects that have completed their contracting and are moving on to construction. Projects that still need some form of additional contracting are not on par with group A projects and thus warrant lower prioritization.

The CPUC asked the ISO to consider allowing sequential PPAs or a sequential combination of PPAs and PPA short-listings or negotiations that sum up to a time longer than the minimum term requirement to qualify a project for inclusion in the appropriate deliverability allocation groups. The ISO agrees that a number of sequential PPAs for a specific project where the sum of the terms of the individual contracts meets the minimum requirement would qualify.

LSA argues that PPA contract length is beyond the purview of the CAISO. However, longer term contracts have always been the measure of project viability. It has only recently become apparent that the historical TPD allocation criteria needs to be bolstered to ensure the most ready projects have first priority for an allocation. With more developers submitting questionable documentation to claim eligibility in higher groups, the ISO believes that more detailed qualifications are necessary to differentiate among the ISO's many projects in queue. Doing so will help to ensure that new project capacity goes into operation at a pace necessary to meet the levels needed to ensure resource sufficiency in the near and long term horizons, an issue front and center for the ISO.

LSA lists a number of uncertainties and increasing risks associated with proposing and negotiating pricing for their projects. These are challenges that developers and procurement LSEs must address to meet the required ten or more year contract terms required by the CPUC, as well as expectations for long term contracts by non-CPUC jurisdictional entities.

The ISO agrees with SDG&E's comments that it is imperative to maintain a minimum term for PPAs to be eligible for a TPD allocation to ensure entities are seeking allocations in good faith, especially as deliverability becomes scarce. Nearly all procurement obligations for new capacity mandated by the CPUC require LSEs with an RA obligation to enter into agreements with new resources for terms of at least ten years in duration. Banks and financiers likewise require long-term commitments to finance projects. Providing equal access to deliverability to contracts with a materially shorter-term requirement, or no term requirements at all, creates additional hurdles and undue burdens for CPUC-regulated entities' efforts to procure capacity for long-term grid reliability.

Six Cities, a group of non-CPUC jurisdictional LSEs supports the CAISO's proposed term of five year and points out that not all deliverability network upgrades are based on the CPUC Integrated Resource Planning process. Some deliverability upgrades in the ISO TPP support the needs of non-CPUC jurisdictional LSEs and the ISO needs to ensure these upgrades are used effectively for the purpose of delivering the capacity of RA resources to the LSE ratepayers that fund these upgrades. The ISO believes a longer term contract supports the use of the TPD as soon and fully as possible by allocating TPD to projects that are positioned to come online as soon as possible. Giving the highest TPD allocation priority to projects that have long term contracts in place, facilitating their expeditious progression into construction, accomplishes that.

SCE, as an LSE responsible for the ongoing safe and reliable operation of its transmission system and the load is serves, states that a longer-term component of a PPA is a desirable feature because it provides greater stability to an LSE to meet its RA obligation, reducing the need to more frequently negotiate new energy contracts. SCE supports a minimum PPA term of ten years to receive an allocation of TPD since this duration would provide greater RA stability and would be consistent with the CPUC's 2019 and 2021 procurement orders which require virtually all new capacity to be procured through 2026 to be under contract for a minimum of ten years. While agreeing with this, the ISO believes that a middle ground compromise of a five-year minimum contract term requirement will accomplish the goal of giving priority to the most ready projects to facilitate binging the greatest amount of new capacity into operation as quickly as possible.

- Discussion of Other Relevant PPA Term Information

  TPD capacity on the ISO system is designed to the level dictated by the CPUC Integrated Resource Planning process to meet the requirements of the RA program and to develop the public policy-driven transmission solutions needed to enable the grid infrastructure to support local, state, and federal directives. These transmission upgrades are paid for by ratepayers through the Transmission Access Charges of the Participating TOs. The amount of TPD available to allocate to interconnection projects is limited to the amounts and locations of TPD capacity needed to meet the IRP resource portfolios the CPUC provides to the ISO. The ISO believes the further clarifications of the eligibility criteria of a PPA are necessary to ensure system-supplied transmission capacity is allocated on a basis that prioritizes projects that are most ready to proceed, and can demonstrate a clear and timely path for providing resource adequacy capacity.

The 2021 CPUC procurement order for 11,500 MW of additional net qualifying capacity by June 1, 2026[12] requires; *"All contracts for resources, including imports, used to satisfy the requirements of this procurement order shall have a minimum duration of ten years."* The 2019 CPUC procurement order for 3,300 MW of incremental resources by August 1, 2023,[13] requires; *"For any procurement of resources that are new after the date of this decision, load serving entities with procurement obligations under Ordering Paragraph 3 of this decision shall enter into contracts of at least ten years in length…"* While some portion of the combined total of 14,800 MW has already been awarded a PPA and received an allocation of TPD, these CPUC orders set the requirement for virtually all new capacity to be procured through 2026 to be under contract for a minimum of ten years. This suggests that the eligibility criteria for a project with a PPA, or a project shortlisted or in active negotiations for a PPA, should procure the project's RA capacity for a minimum term ten of years to receive an allocation of TPD.

The FERC NOPR proposes to include a commercial readiness framework that includes the establishment of the defined terms "Commercial Readiness Demonstration." One criterion of that framework is

- "Executed contract (as opposed to term sheet), binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale is not less than five years."

This suggests that the eligibility criteria for a project with a PPA, or a project shortlisted or in active negotiations for a PPA, should procure the project's RA capacity for a minimum term 5 of years to receive an allocation of TPD.

- Draft Final Proposal for PPA eligibility

Beginning with the 2023-2024 TPD allocation cycle, any tariff deliverability requirement for a PPA will require a term of five or more years. In other words, the minimum term will apply to allocation groups A and B, including the retention requirements for group B, and the retention requirements for group D. Projects that received an allocation prior to the 2023-2024 TPD allocation cycle will not be subject to the new minimum term requirements at this time.

[12] Decision 21-06-035: Decision Requiring Procurement To Address Mid-Term Reliability (2023-2026), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF#page=50&zoom=100,96,703
[13] Decision 19-11-016: Decision Requiring Electric System Reliability Procurement For 2021-2023, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

2. Stakeholder Feedback on Eligibility for Non-LSE PPAs:

   a. Should a PPA that is with an entity that does not have an RA obligation be eligible for an allocation if the procuring entity demonstrates that it has a contract to sell the RA capacity procured to a load servicing entity that has an RA obligation?

   b. If yes, should the procuring entity be given extra time after the project receives an allocation to secure a contract with a load serving entity with an RA obligation?

   c. If yes, what length of extra time should be provided and what is the basis for that?

   Fourteen stakeholder answered these questions.

	Oppose/Support		Suggested Extra Time					
Entity (Name)	**Opposes TPD to non-LSEs**	**Supports TPD to non-LSEs**	**No Extra Time**	**1 Extra Year**	**2 Extra Years**	**Other Extra Time**	**Use Group B for No LSE Contract**	**Other Proposal**
ACP-California		1		1				
Amazon Energy		1				1 [1]		
Avangrid Renewables		1		1				
California Community Choice Association		1	1					
California Energy Storage Alliance		1			1			
California Public Utilities Commission Energy Division		1	1				1	
California Wind Energy Association		1		1				
EDF-Renewables		1				1 [2]		
Golden State Clean Energy		1				1 [3]		
Large-scale Solar Association/ LSA		1		1				
Pacific Gas & Electric		1						1 [4]
Solar Energy Industries Association/SEIA		1		0.5 [5]	0.5 [5]			
Six Cities/The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California		1	1					
Southern California Edison	1							
Sum of Comment Categories	**1**	**13**	**3**	**4.5**	**1.5**	**3**	**1**	**0**
				9 Support some extra time				

[1] Not be required to have an arrangement in place until the final LSE supply plans are due for the year the project is to reach COD

[2] Supports "minor delays"

[3] Defers to non-LSE offtakers for amount of time

[4] Require entities seeking an allocation of TPD meet certain qualifications e.g. 3rd IFS posting, site control, etc.

[5] SEIA supports 1 to 2 years of extra time

- ISO Discussion of Stakeholder Comments

All stakeholders except SCE supported allowing TPD allocations to non-LSEs. With strong support for allowing allocations to non-LSEs, the remaining question is should a procuring non-LSE be given additional time beyond the allocation affidavit deadline to demonstrate having a contract to sell the RA capacity to an LSE with a RA obligation, and if so, how long?

California Community Choice Association, the CPUC and Six cities suggested no additional time should be provided. The CPUC further suggested the status of the RA sale contract should be consistent with the PPA status allocation requirements for each allocation group. For example, if a project is in negotiations for such a contract, it should be required to apply for an allocation in group B.

Six commenters suggested additional time be allowed. EDF suggested a minor amount of additional time. Avangrid, CESA, CalWEA, LSA, and SEIA suggested one to two years of additional time.

Amazon suggested non-LSEs should not be required to have an arrangement in place until the final LSE supply plans are due for the year the project is to reach its commercial operation date (Golden State deferred to non-LSE offtakers' views of what is necessary to make these commercial arrangements.)

PG&E suggested that entities seeking an allocation of TPD be required to meet certain qualifications prior to receiving an allocation. One example would be to require a third financial security posting.

- Draft Final Proposal for PPAs with a non-LSE

  The ISO proposes to allow TPD be allocated to ICs with PPAs with non-LSEs. These PPAs will be subject to the 5-year minimum term requirements described above. Non-LSE PPAs will also be subject to the following requirements depending on which group the IC seeks to qualify for:

  - Seeking an allocation in group A
    - The non-LSE procurement entity must demonstrate at the time the seeking affidavit is due that it has a contract to sell the RA capacity to an LSE with a RA obligation for a term of at least one year.[14]
    - If the non-LSE procurement entity cannot demonstrate that it has a contract to sell the RA capacity to an LSE with a RA obligation for a term on at least one year, it must provide a deposit in-lieu of such a contract. The deposit would only be required if the project obtains an allocation of

[14] The contracts must provide sufficient MW procurement and match technology; however, they do not have to be 1:1. For example, a non-LSE could execute PPAs with six 200 MW projects. If the non-LSE then had a contract with an LSE to supply 1,000 MW of RA, five of the non-LSE's six projects could immediately qualify for group A, and the other could qualify for group B.

TPD. If the project receives an allocation, the deposit will be due within 30 days of the ISO notifying the IC that the project has received an allocation. The deposit amount will be $10,000 per MW of allocated TPD, with a minimum deposit of $500,000.

- Seeking an allocation in group B
  - Consistent with all projects receiving an allocation in group B, the IC must demonstrate by the next allocation retention affidavit due date that it has executed a PPA with a non-LSE offtaker that requires deliverability for a term or five or more years. Furthermore, the offtaker must demonstrate a contract to sell the RA capacity to an LSE with a RA obligation for a term of at least one year, and if unable to do so, must provide a deposit in-lieu of such a contract. The deposit would be required by the retention affidavit due date. The deposit amount will be $10,000 per MW of allocated TPD, with a minimum deposit of $500,000.
- Retaining an allocation in group D
  - Consistent with all projects receiving an allocation in group D, the IC must demonstrate by the next allocation retention affidavit due date that it has executed a PPA or is shortlisted or actively negotiating a PPA with a non-LSE offtaker that requires deliverability for a term or five or more years. In the allocation retention cycle that a project demonstrates an executed PPA with a non-LSE, the offtaker must demonstrate a contract to sell the RA capacity to an LSE with a RA obligation for a term of at least one year, and if unable to do so, must provide a deposit in-lieu of such a contract. The deposit would be required by the retention affidavit due date. The deposit amount will be $10,000 per MW of allocated TPD, with a minimum deposit of $500,000.

Deposits in-lieu of RA contracts will be held by the ISO and refunded to the entity providing the deposit after a demonstration of a contract to sell the RA capacity to an LSE with a RA obligation for a term on at least one year, or after the project achieves its COD. If the project withdraws without meeting these requirement,[15] the entire deposit will be non-refundable and will be processed with non-refundable interconnection financial security, as described in Appendix DD, Section 7.6 (to offset still-needed upgrades or transmission revenue requirements).

The ISO believes its proposal represents a workable paradigm for developers to execute PPAs with non-LSEs and obtain deliverability. The ISO's proposal provides

[15] Unless the project withdraws due to an error or omission that allows the project to receive a full refund of its interconnection financial security posting.

off-takers with the opportunity to market the energy they have procured, while still protecting ratepayers from financing delivery network upgrades without receiving the benefit of their bargain. The ISO's proposal also recognizes that non-LSE procurement is new and could provide a viable path for different customer classes to receive the various benefits new projects provide. The ISO's deposit requirements align with FERC's NOPR and help ensure that only committed, viable projects can retain deliverability, thereby minimizing churn in the queue.

At the same time, the ISO is concerned about the risk that ICs may offer illegitimate or sham PPAs to qualify for deliverability and then seek a legitimate PPA. The ISO clarifies that it views PPAs with affiliates (marketing houses, holding companies, etc.) as an attempt to circumvent tariff requirements.[16] The ISO has rejected and will continue to reject such PPAs and others it views as shams or workarounds to obtain deliverability.

4 Phase 2 topics on managing the overheated queue

4.1 Should higher fees, deposits, or other criteria be required for submitting an IR?

- Background

In the September 30, 2021 preliminary issue paper, section 4.1, the ISO sought stakeholder input on whether the bar for entry into the interconnection process should be raised to discourage numerous and perhaps excessive interconnection request submissions by a single developer, such as requiring higher fees or deposits for submitting an interconnection request, or imposing other requirements. Stakeholders were generally supportive for higher fees or imposing other requirements. Site exclusivity deposit requirements were addressed in Phase 1, and are not being revisited in Phase 2.

In the December 6, 2021 Issue Paper and Straw Proposal, section 4.1 the ISO proposed that for the first two interconnection request submitted by a parent company/entity in an annual cluster window, the study deposit would be $250K per request, for interconnection requests 3-5 the study deposit would be $500K per request, and for any more than 5 interconnection requests, the study deposit would be $1M per request. The same percentages would be at risk as currently defined in the tariff.

In the June 7, 2022 Revised Straw Proposal, section 4.1 the ISO modified its proposal by requiring the same study deposit per project per parent company/entity,

[16] The exception being between LSEs with RA requirements and their generation affiliates (such as the IOUs).

with a similar per project deposit as compared to the average cost per project as originally proposed, and was based on the total number of projects submitted in a cluster window as shown in the following table.

Number of interconnection requests submitted per parent company	Study deposit per interconnection request
1-2	$250,000
3-4	$375,000
5-7	$500,000
8-10	$650,000
11 or more	$800,000

The ISO also proposed the following study deposit refund criteria:

If an interconnection request is withdrawn for any reason, the study deposit is:

- Refundable minus costs until the interconnection request is determined complete.
- 20% non-refundable once the interconnection request is determined complete up until 30 calendar days following the scoping meeting.
- 50% non-refundable after 30 days following the scoping meeting and up to 30 days following the Phase I study results.
- 100% non-refundable after 30 days following the Phase I study results.
- 100% refundable minus costs upon reaching commercial operation.

- Stakeholder feedback

Five stakeholders support the ISO proposal. The Bay Area Municipal Transmission Group (BAMx) supports the tiered deposit approach so as to not disadvantage small developers that submit one or two IRs and do not contribute to the problem. California Community Choice Association (CalCCA) supports the ISO proposal to increase study deposits to encourage a more reasonable number of IRs. San Diego Gas & Electric (SDGE) supports the ISO's proposal. The Six Cities support the CAISO's proposal to adopt a revised deposit structure that is tiered according to the number of interconnection requests that are submitted. The Six Cities also support tightening the refundability criteria for study deposits as outlined in the Revised Straw Proposal. Southern California Edison (SCE) supports the tiered fee approach of the study deposit per interconnection request, ranging from $250,000 to $800,000, dependent on the number of interconnection requests submitted per parent company. In recognition of the substantial time and effort devoted to validating an IR and preparing for and conducting scoping meetings, SCE also supports the CAISO's proposal that a portion of the study deposit should be immediately at risk after the IR has been deemed complete.

Twelve stakeholders do not support the ISO proposal. ACP-California supports higher fees but opposes study deposits based on how many IRs a parent company has submitted and suggests a different approach with study deposits based on $/MW as a good middle ground. AES Clean Energy also support adoption of higher fees but is strongly opposed to study deposit amounts based on number of projects submitted by a parent company. California Energy Storage Alliance (CESA) strongly opposes the ISO proposal to establish a tiered fee approach based on parent company and runs the risk of not being deemed just and reasonable and not being unduly discriminatory by FERC. CESA does see potential in the ISO's proposal to increase the non-refundable portion of deposits based on the stage of the interconnection process which is in line with the FERC NOPR to subject interconnection customers to additional study deposits, continued commercial readiness demonstrations, and penalties for leaving the queue at different stages to ensure that ready projects can proceed through the queue in a timely manner. California Wind Energy (CalWEA) suggests that the first tier should be 1 to 5 IRs, and supports higher deposits if more than 5 IRs are submitted by the same parent company. CalWEA opposes any non-refundability of unused study deposits if withdrawn within 30 days from the scoping meeting. EDF-Renewables (EDF-R) opposes the first refund threshold where the study deposit is 20% non-refundable once the IR is determined complete up until 30 calendar days following the scoping meeting. EDF-R believes if the ISO proceeds with the 20% threshold, the ISO should include with it tariff language that requires the provision of basic information on feasibility at scoping meetings and in the written meeting notes. Data should include: a summary of the area's history including historical queue drop out information (which indicates that Points of Interconnection is not viable), Transmission Plan Deliverability availability, congestion, and the magnitude of upgrades needed to accommodate new supply. Golden State Clean Energy (GSCE) requests the ISO conduct further analysis to understand why projects withdraw and suggest it may be other factors that are more directly connected to the failure rate, such as lack of site exclusivity. GSCE thinks there is room for additional policy changes that strengthen the site exclusivity and also that the ISO should get in front of FERC's recent generator interconnection NOPR and require site exclusivity from future IRs. Hanwha Q Cells USA (HQC) believes the tiered approach to application costs unfairly penalizes larger developer, and believes that a cost structure based on project size is a better alternative. Large-scale Solar Association (LSA) strongly opposes the ISO proposal as it fails to address the root cause of developers submitting multiple IRs due to lack of readily available information on transmission constraints/deliverability availability, the proposed fees exceed study costs and are arbitrary, unjust and unreasonable, and the proposed retention and forfeit revisions are not justified. Pacific Gas & Electric (PG&E) states the particular approach the CAISO has laid out may not be sufficient due to potential gaming by "parent" companies setting up separate LLCs to skirt around the rules. PG&E believes CAISO may need to look at other methods of containing the number of IRs submitted, such as developing a refined set of criteria for submitting what is deemed a "quality" application to help weed out speculative projects that are not adequately advanced in development. One criterion that could be strengthened is site control / site exclusivity / site accessibility. REV Renewables (REV) in general supports higher fees, deposits and criteria to limit IRs, but strongly opposes the ISO's proposal for higher deposits based on total number of IRs as discriminatory to large developers. REV suggests that, in line with the FERC NOPR on generator interconnections, the ISO could increase project viability with transparently developed criteria such as technical documents, site control and increasing deposits at risk. REV also suggests that the study deposits be fully refundable (minus costs) within 30 days after the scoping meeting because this is the first opportunity the developer has to discuss the project with the ISO/PTO. Solar Energy Industries Association (SEIA) believes the ISO proposal to increase study deposit amounts depending on the number of interconnection requests submitted per parent company will be difficult to enforce and could disadvantage larger developers. SEIA supports a study deposit framework like that employed in MISO, SPP, and PJM that increases according to the size of the interconnection request. SEIA also supports putting more of the deposit at risk earlier in the interconnection process, noting that this provides a firm but fair disincentive for both small and large developers. As in the MISO, SPP, and PJM construct, CAISO could also employ additional financial and/or readiness milestones throughout the interconnection process that are non-refundable if the interconnecting customers withdraws with few exceptions. California Public Utilities Commission- Energy Division (CPUC) staff does not oppose higher fees or other criteria be required for submitting an interconnection request; however, increasing fees, as noted by the proposal itself, may not achieve the result of reducing interconnection requests per parent company. Also, although the queue appears overheated now, under the recently requested CPUC transmission study under high electrification 30 MMT high electrification sensitivity, the CPUC expects there to be a need for 83 GW of new resources by 2035. Having a steep increase in costs for interconnection requests above a fixed number per entity may just incentivize the creation of LLCs and increase costs to customers without actually addressing how to efficiently and effectively manage interconnection requests. Also, unfortunately a fixed number may become stale as the magnitude of the need for resources fluctuates [and composition of the developer market modifies.]

- Draft Final Proposal

  Considering stakeholder feedback and the fact that on June 16, 2022 FERC issued a Notice of Proposed Rulemaking (NOPR) on 'Improvements to Generator Interconnection Procedures and Agreements' after the ISO posted its most recent straw proposal, the ISO has significantly revised its proposal on this topic to integrate a number of FERC's proposals while maintaining key aspects of the ISO cluster study process. Some of the notable proposed changes include revised allocation of study costs, study deposits that are based on project MW size, required demonstration of commercial readiness or in lieu deposits, and withdrawal penalties that increase as the IC moves through the study process.

  The ISO would like stakeholder feedback on whether the ISO should wait for the FERC process to be completed, or if the ISO should move forward with its own revised proposal as detailed below that incorporates a number of FERCs proposals. If the ISO puts on hold a revised proposal, it may face a repeat of Cluster 14, requiring cluster 15 to undergo a three-year study process with no open application window in 2024. However, if the ISO does move forward with a revised proposal, there is a high likelihood that additional revisions will need to be made once FERC issues its final rulemaking. FERC has yet to issue a final rule in the proceeding, and it is unclear to what extent regional differences will be permitted. Modifying the deposit requirements for cluster 15 with the NOPR ongoing would likely result in different study deposit rules for clusters 14 and prior, cluster 15, and clusters 16 and beyond. The ISO also seeks comment, especially from developers, on whether *any* change to study deposit requirements will mitigate the number of interconnection requests developers plan to submit to cluster 15. The ISO recognizes that with increased procurement and no interconnection requests in 2022, another large cluster may be unavoidable.

  Similar to the FERC NOPR on Interconnections, the CAISO proposes the following that will apply to Cluster 15 and subsequent clusters:

Allocation of Study Costs

The CAISO proposes to change how study costs are allocated as follows:

- 90% pro-rata based on requested MW,
- 10% per-capita based on number of IRs received in cluster.

Study Deposit

Study deposits will be based on project MW size. In a variation from FERC's proposal of a separate study deposit for each study, the CAISO proposes to require only one study deposit that will cover both the Phase I (System Impact) and Phase II (Facilities) studies, as well any reassessment studies. However, since the CAISO will only require one study deposit, the CAISO's study deposit will be twice the amount that FERC proposed for each cluster study phase.

Study deposit required to be included with the interconnection request will be as follows:

- Projects < 80MWs = $70K + $2K/MW (Max would be $230K)
- Projects 80MW to < 200MW = $300K
- Projects 200MW and greater = $500K

<u>Commercial Readiness</u>

Similar to FERC's NOPR proposal, the ISO will require projects to meet increasing commercial readiness requirements to enter the Phase I (System Impact) and then continue into the Phase II (Facilities) studies.

Demonstration of commercial readiness or a deposit in lieu of commercial readiness for the generator to enter the Phase I cluster study will be required with the interconnection request.

Either of the following options are acceptable commercial readiness demonstration to enter the Phase I cluster study:

- Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale is not less than five years.
- Reasonable evidence that the project has been selected in a resource plan or resource solicitation process by or for an LSE, is being developed by an LSE, or is being developed for purposes of a sale to a commercial, industrial, or other large end-use customer.

Demonstration of commercial readiness for the generator to enter the Phase II cluster study or a deposit in lieu of commercial readiness will be required at least ten (10) business days prior to the initial financial security posting is required. (Similar to the timing for demonstration of site exclusivity which is pending approval at FERC)

Either of the following may serve as commercial readiness demonstration options to enter the Phase II cluster study, and must be provided with the executed facilities study agreement:

- Executed contract (as opposed to term sheet), binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale is not less than five years.
- Reasonable evidence that the project has been selected in a resource plan or resource solicitation process by or for a load serving entity, is being developed by an LSE, or is being developed for purposes of a sale to a commercial, industrial, or other large end-use customer.

A commercial readiness deposit can be made in lieu of meeting the commercial readiness requirements and are as follows:

- The same study deposit to enter the Phase I Studies
- 3.5 times the study deposit to enter the Phase II Studies

These deposits would be *in addition* to any required study and site exclusivity deposit requirements.

Site Exclusivity

The CAISO recently filed proposed modifications to site exclusivity requirements with FERC as part of the IPE 2021 phase 1 stakeholder initiative. Under that proposal the CAISO will require either a demonstration of site exclusivity, or a deposit in lieu of site exclusivity in the amount of $250K for projects 20 MW and below, and $500K for projects greater than 20 MW. To enter the Phase II study, a demonstration of site exclusivity will be required with no option to provide a deposit in lieu of site exclusivity. The ISO anticipates FERC's decision before September 1, 2022. The ISO notes that this is a variation from the FERC NOPR that requires Site Control and only allows an in-lieu deposit in special cases = $10K/MW subject to a floor of $500K and ceiling of $2M. As such, developers should recognize the ISO will likely need to revise its new requirements to align with any final rule FERC issues.

Withdrawal Penalties

The CAISO will assess withdrawal penalties to ICs that chose to withdraw at any point in the interconnection study process or do not otherwise reach commercial operation unless:

1) The IC withdraws after receiving the Phase II ~~most recent~~ cluster study or reassessment reports and the costs assigned to the IC have increase 25% compared to ~~previous~~ the Phase I cluster study report; or
2) Current tariff provisions that allow a project to withdraw without penalty due to a substantial error or omission. ~~the IC withdraws after receiving the individual~~

~~facilities study report and the costs assigned to the IC have increased by more than 100% compared to costs identified in the cluster study report~~[17]

Withdrawal penalties will increase as the IC moves through the study process and will also increase if a commercial readiness and/or a site exclusivity deposit has been provided in lieu of demonstration of commercial readiness and/or site exclusivity. The CAISO proposes withdrawal penalties that are somewhat based on FERC's NOPR proposal with modifications. The CAISO proposes to base withdrawal penalties on the study or site exclusivity deposits provided and not actual studies costs so that IC's know exactly what is at risk when they enter the cluster study process.

Withdrawal penalties if Commercial Readiness Demonstration is provided:

- Zero (0) times the study deposit if withdrawn after the IR is deemed complete until 30 days following the scoping meeting.
- 0.5 times the study deposit if withdrawn after 30 calendar days following the scoping meeting up to 30 days following the Phase I study results meeting.
- 1 times the study deposit if withdrawn after 30 days following the Phase I study results meeting.

(As per the FERC NOPR these penalties will be used to offset study costs)

Withdrawal penalties if a deposit is provided in lieu of Commercial Readiness Demonstration:

- 0.2 times the study deposit if withdrawn after the IR is deemed complete until 30 days following the scoping meeting. This is not included as part of the FERC NOPR, but may help limit the number of applications submitted in the cluster application window.
- 1 times the study deposit amount if withdrawn after 30 calendar days following the scoping meeting up to 30 days following the Phase I study results meeting.
- 2.5 times the study deposit after 30 days following the Phase I study results meeting.

(As per the FERC NOPR these penalties will be used to offset study costs)

Withdrawal penalties if a deposit is provided in lieu of Site Exclusivity (currently filed with FERC):

[17] The FERC NOPR has two other exceptions that would be difficult for the ISO to assess because the CAISO provides network upgrade cost caps and the PTOs reimburses the IC for network upgrades: 1) the withdrawal does not delay the timing of other proposed generation facilities in the same cluster; and 2) the withdrawal does not increase the cost of network upgrades for other proposed generating facilities in the same cluster.

- 50% of the site exclusivity deposit after 30 calendar days following the scoping meeting up until the Phase II studies.
- Site Exclusivity must be demonstrated prior to Phase II studies.

Withdrawal penalties associated with financial security

The FERC NOPR proposes to impose a withdrawal penalty equal to nine times the study costs if the customer withdraws before achieving commercial operation and after executing the LGIA or filing an unexecuted LGIA. The ISO does not propose to adopt this penalty, and instead plans to maintain the current non-refundability provisions associated with the postings of financial security.

The current CAISO Tariff requires Financial Security to be posted following the Phase I studies and adjusted after the Phase II studies and at the start of construction as described below:

Typically 15% of the assigned estimated costs for network upgrades is posted (initial financial security posting) by the IC to the applicable PTO as financial security following the Phase I studies and prior to beginning the Phase II studies. Following the Phase II studies the financial security is increase to 30% (second financial security posting) of assigned costs for network upgrades and increased to 100% at the start of construction.

If the Interconnection Customer withdraws at any time between the initial posting and the deadline for the second posting of the Interconnection Financial then the applicable Participating TO(s) shall liquidate the Interconnection Financial Security for the applicable Network Upgrades and reimburse the Interconnection Customer the lesser of: (a) the Interconnection Financial Security plus (any other provided security plus any separately provided capital) less (all costs and expenses incurred or irrevocably committed to finance Pre-Construction Activities for Network Upgrades on behalf of the Interconnection Customer); or (b) the Interconnection Financial Security plus (any other provided security plus any separately provided capital) minus the lesser of fifty (50) percent of the value of the posted Interconnection Financial Security for Network Upgrades or $10,000 per requested and approved, pre-downsized megawatt of the Generating Facility Capacity.

If the Interconnection Customer withdraws at any time after the second posting of the interconnection financial security and before the commencement of construction activities for such network upgrades, then the applicable Participating TO(s) will liquidate the interconnection financial security for the applicable network upgrades and reimburse the interconnection customer the lesser of: (a) the interconnection financial security plus (any other provided security plus any separately provided capital) less (all costs and expenses incurred or irrevocably committed to finance pre-construction activities for network upgrades on behalf of the interconnection customer) and less (any posting reduction due to the interconnection customer's election to self-build stand-alone network upgrades); or (b) the interconnection financial security plus (any other provided security plus any separately provided capital) minus the lesser of fifty (50) percent of the value of the posted interconnection financial security for network upgrades or $20,000 per requested and approved, pre-downsized megawatt of the generating facility capacity.

5 Phase 2 topics - Other Issues

5.1 Should the ISO re-consider an alternative cost allocation treatment for network upgrades to local (below 200 KV) systems where the associated generation benefits more than, or other than, the customers within the service area of the Participating TO owning the facilities?

- Background

The ISO tariff requires Participating TOs to reimburse interconnection customers whose generators are interconnecting to their systems for the costs of reliability and local delivery network upgrades necessary for the interconnection. The Participating TOs then include those network upgrade reimbursement costs in their FERC-approved transmission rate bases, requiring ratepayers to pay those costs through either the local or regional transmission access charges (TAC). Network upgrades for 200 kV systems and above are considered regional, and upgrades below 200 kV are considered local. The regional TAC is a "postage stamp rate" based on the aggregated transmission revenue requirements (TRR) of all Participating TOs for all regional facilities on the ISO system. In contrast, the local TAC is PTO-specific, charged only to customers within the service area of the Participating TO owning the facilities. There is ongoing concern that the current practice for local upgrades could unduly impact local ratepayers who are not the sole beneficiaries of the upgrades, but who solely bear their costs.

The ISO addressed this issue with stakeholders and filed a narrowly focused proposal to FERC in 2017. FERC ultimately found that the ISO failed to support its proposal as just and reasonable and not unduly discriminatory and rejected the ISO's filing without prejudice, which allows the ISO to refile a proposal.[18]

In the December 6, 2021 Issue Paper and Straw Proposal, section 5.1, the ISO proposed that the addition of the capital costs for low voltage (<200kV) network upgrades driven by generation interconnections to the LTRR of a Participating TO will not cause the aggregate of the net investment for all low voltage network

[18] FERC filing ER17-432: https://elibrary.ferc.gov/eLibrary/filedownload?fileid=01EE09AD-66E2-5005-8110-C31FAFC91712

upgrades driven by generation interconnections included in the LTRR to exceed fifteen (15) percent of the aggregate of the net investment for all low voltage transmission facilities of that Participating TO reflected in their LTRR in effect at the time of the in-service date of the network upgrade. Any costs for low voltage network upgrades in excess of the 15 percent threshold will be financed by interconnection customers without cash reimbursement.

In the June 7, 2022 Revised Straw Proposal, section 5.1, the ISO did not propose any changes to the December 6, 2021 straw proposal, however the ISO did provide additional data and responses to stakeholder initial concerns.

- Stakeholder Feedback

One stakeholder supports the ISO proposal. Valley Electric Association (VEA) supports the CAISO's proposal because it is a significant improvement from the circumstances today, in which Valley's members are wholly exposed to all of the costs of low-voltage interconnections (subject to overall cost caps imposed by the CAISO Tariff). However, even with a 15% cap, Valley's retail electric members would still have exposure to significant costs of network upgrades associated with generator interconnections which do not materially benefit Valley or its members. VEA is supporting the CAISO's 15% proposal as a regulatory solution to try to bridge parties' positions toward a more workable policy.

Five stakeholders do not support the ISO proposal. ACP-California (ACP) is concerned that the ISO proposal may inhibit generation that interconnects to the VEA area, by making generation above a certain level in this region more expensive to LSEs than generation in other regions. ACP requests additional insight and discussion on why CAISO has not further considered the alternative options that VEA had put forth at the time of the original IPE Issue Paper and Straw Proposal. AES Clean Energy (AES) opposes this proposal. Rather than requiring generators to fund upgrades once the 15% cap is reached, the CAISO should explore revising its cost allocation to spread any remaining costs to the regional rate base. The current proposal could incentives more developers to only locate on the higher voltage lines to avoid having to fund network upgrades. However, higher voltage network upgrades are more expensive than upgrades needed on lower voltage lines, and thus ratepayers may be charged more to interconnect these projects than they would have if the project had interconnected at the lower voltage and the upgrade costs were share with both the local and regional rate base. California Wind Energy Association (CalWEA) opposes requiring ICs to finance network upgrade costs exceeding the funding cap. The cost should be borne by all parties that benefit from accessing the generation enabled by the transmission upgrades. Large-scale Solar Association (LSA) agrees something should be done, but continues to believe that the ISO's proposal is not just and reasonable as it would impose different and discriminatory refundability rules in different ISO area locations and would have the impact of preventing most future generation development on the VEA system. LSA is disappointed that the ISO did not consider any of LSA's alternative suggestions such as addressing FERC's problems with the earlier [GIDNUCR] proposal by allocating "excess" LV-TRR costs to other PTO LV-TRRs based on LSE contracting of projects in the VEA area. If the ISO moves forward with its proposal, LSA recommends that it should only apply to future queued projects and projects moving to a higher-voltage POI due to application of the cap should still qualify for "lower of" Phase I/Phase II study cost cap protection. Solar Energy Industries Association (SEIA) opposes the CAISO proposal to allocate network upgrade costs to local systems above the proposed threshold to developers as it will create additional uncertainty for developers that will directly impact project economics. If the ISO decides to proceed with this proposal, SEIA requests that a cost cap be implemented to provide developers with cost certainty. SEIA believes that FERC should adopt a methodology that encourages developer certainty for any cost allocation of upgrade costs, such as a cost cap. SEIA believes there are alternative options that can reduce the risk to developers. CAISO can classify local systems as net importers or net exporters and base cost allocation for network upgrades on that classification. More specifically, SEIA believes such a classification system could justify socializing network upgrade costs regionally. A demonstration that a local system is a net exporter of power means the benefits are realized more regionally, and the costs should therefore be shared regionally. Network upgrades to local systems identified as net importers would be reimbursed by local ratepayers since local ratepayers will be benefitting. SEIA believes that such a proposal would align costs with the beneficiaries in a just and reasonable and not unduly discriminatory manner.

Six stakeholders neither support nor oppose the ISO Proposal but provided relevant comments. Bay Area Municipal Transmission Group (BAMx) reserves its opinion on the CAISO's proposal on this issue until PG&E-specific data is available. Hanwha Q Cells USA (HQC) is generally supportive of a methodology that employs a cost cap for network upgrades. HQC believes that a cost cap enables developers to make prudent and sound financial decisions. HQC looks forward to reviewing the ISO's detailed proposal. Norther CA Power Agency (NCPA) supports the allocation methodology of costs to those that receive the benefits. We request PG&E provide data showing available investment before the 15 percent cap is reached. NCPA further supports LV facilities to be competitively bid, which can also reduce the overall cost to ratepayers. San Diego Gas & Electric (SDG&E) supports CAISO's efforts to ensure that local ratepayers are protected from the cost impact of low voltage (below 200 kV) generation interconnection-driven network upgrades that benefit all customers in the CAISO' system. SDG&E also agrees with the CAISO that if the current cost allocation structure remains unchanged it might lead to inequitable cost allocation in the future. SDG&E is concerned with the 15% limit selected by the CAISO and would appreciate if the CAISO could provide more data that explains why a 15% limit is just and reasonable compared to a 30% limit or a 10% limit. It is unclear in the current proposal that only 15% of generation interconnection-driven network upgrade costs only benefit local ratepayers. SDG&E believes that the CAISO should try to find a clear correlation between a selected limit and the benefits received by local ratepayers. SDG&E is also concerned that CAISO's proposal does not address the fact that generation interconnection-driven network upgrades benefit all ratepayers irrespective of their location. This essentially means that all ratepayers should share the cost of generation-driven network upgrades that are part of the CAISO-controlled grid. The current proposal as it stands, might not be consistent with FERC's cost causation principles and might lead generators to avoiding cost-efficient and feasible point of interconnections for more expensive high-voltage interconnection points. Six Cities do not oppose the CAISO proposal to cap the investment associated with new low voltage network upgrades at 15% of each Participating TO's low voltage transmission revenue requirement ("TRR") and to require interconnection customers to fund, without reimbursement, all network upgrade costs in excess of this threshold, subject to resolution of the following questions and comments: First, the Six Cities request that the CAISO provide information regarding the applicable threshold for PG&E. Second, how is the amount of investment in low voltage network upgrades for each PTO being determined? Third, how will the 15% threshold be applied on a going forward basis, as the value of the plant-in-service associated with the low voltage TRR and low voltage network upgrades depreciates? If the applicable threshold is reached in one year, such that interconnection customers are required to fund low voltage network upgrades, and then falls below the 15% threshold in a subsequent year, will interconnection customers become eligible for reimbursement until the 15% threshold is again reached? Fourth, how will the 15% threshold apply for Participating TOs that do not have low voltage transmission facilities at this time, but could develop low voltage facilities or network upgrades in the future? Finally, the Six Cities request that the CAISO confirm that, notwithstanding that there will be no reimbursement of network upgrade costs in excess of the proposed threshold, that there will likewise be no restriction on the ability of interconnection customer-funded network upgrades to be part of the CAISO controlled grid and available for the use of CAISO transmission customers on an unrestricted basis just like any other assets that are under the CAISO's operational control. Southern California Edison states they do not oppose the ISO proposal.

- Draft Final Proposal

The ISO does not propose to revise or change its proposal substantially; however, the ISO agrees that it should provide constant transparency on where each PTO is in relation to the 15% threshold so developers can understand how costs will fall. The ISO proposes to maintain up-to-date data on the CAISO website on where each PTO's share of interconnection-related low-voltage costs are, and where the ISO projects them to be in the near-term based on queued projects that have executed GIAs. The ISO also proposes to allow interconnection customers to withdraw at minimum cost—consistent with the IPE Phase I tariff revisions for substantial errors and omissions—if it submits an interconnection request where the PTO would have reimbursed the costs of a low-voltage upgrade, but that changes for the customer while in queue (due to the PTO going over the 15% threshold while the customer is in queue, regardless of whether this was projected). These two proposals provide customers with as much transparency as possible while protecting the customer from the risk of merchant-financing low-voltage upgrades where unexpected.

The ISO continues to disagree with stakeholder opposition that would shift costs to the regional TAC. Stakeholder suggestions are not materially different than the ISO's rejected proposal in 2017, and fail to distinguish between the benefits of the network upgrades themselves and the benefits of the generation that triggered them. As FERC reiterated in 2017, "The Commission has found that network upgrades represent improvements to the integrated transmission system and that these benefits to the transmission system are considered independent from any benefits customers may receive as a result of generation that interconnects to the system."[19] As such, proposals that look to the procurement of the generating capacity or the benefits the generation provides are inconsistent with FERC cost allocation precedent. The ISO also believes that examining whether each PTO "imports or exports" is antithetical to the purpose of an integrated grid and ISO/RTO.

The ISO agrees that its proposal may create hurdles to low-voltage interconnections once a PTO has crossed the 15% threshold; however, the ISO believes this result is not imprudent, and should—rightfully—incentivize larger interconnections to the high-voltage grid. The ISO also notes that nothing prevents developers from recouping network upgrade costs through power purchase agreements and ongoing energy sales, a common practice outside of California.

The ISO recognizes that 15% is an arbitrary figure—an unavoidable result for this structure—but that does not mean it is not just and reasonable. As FERC has stated, "It is well established that there can be more than one just and reasonable rate."[20] The ISO based this figure on the tariff's existing LCRIF provisions, and believe it represents a reasonable share of low-voltage network

[19] *California Independent System Operator Corp.,* 160 FERC ¶ 61,047 at P 34 (2017).
[20] *Midwest Indep. Transmission Sys. Operator, Inc.*, 127 FERC ¶ 61,109, at P 20 (2009).

upgrades resulting from generator interconnections. The ISO disagrees with comments arguing it creates unduly discriminatory cost allocation rules. To the contrary, these rules would apply to each PTO equally. The fact that the rules would produce different results for groups of ratepayers based on past and future expenditures is not unduly discriminatory. Few cost allocation rules do otherwise. Moreover, failing to do so would leave ratepayers such as those in VEA paying costs of low-voltage network upgrades disproportionate to their benefits, inconsistent with the Federal Power Act and FERC cost allocation precedent.

As requested by a number of stakeholders, PG&E has provided an estimate of their available low voltage network facilities investment before the 15% cap is reached and is included in the following table:

PTO	(A) Estimated investment for all low voltage network facilities	(B) Estimated investment for low voltage network upgrades driven by generation interconnections	Percentage = B/A	Estimated available investment before the proposed 15% cap is reached
PG&E	$9,645,808,250	$347,586,176*	3.6%	$1,099,285,061
SCE	$387,761,394	$3,532,187	0.9%	$54,632,022
SDGE	$3,387,000,000	$264,480,000	7.8%	$243,570,000
VEA	$23,049,376	$0	0%	$3,457,406

* PG&E's (B) estimate includes all network upgrades driven by generation for all voltage levels. Therefore, the estimated available investment for low voltage network facilities before the proposed 15% cap is reached is conservative.

5.2 Policy for ISO as an Affected System – how is the base case determined and how are the required upgrades paid for?

- Background

In the last decade, there have been virtually no instances where a generator's interconnection to a neighboring balancing authority area would affect the reliability of the ISO grid. In interconnection terms, the ISO is almost never an "affected system." However, recently the ISO has received a few notices from neighboring BAAs that a proposed interconnection may affect the ISO, and therefore warrants study. The ISO developed a study process and agreement for such studies in the

Contract Management Enhancement initiative. However, that initiative deferred the question to IPE of how any network upgrades required to mitigate reliability impacts would be reimbursed.[21] The ISO also needs to determine what base cases would be used for affected system studies.

In the June 7, 2022 Phase 2 Revised Straw Proposal, section 5.2, the ISO proposed the base case assumptions for the ISO as an affected system study to be based on previously queued projects as of the affected system study agreement execution date. The ISO also proposed to use its existing policy for RNU reimbursement for RNUs resulting from an affected system study. Under FERC Order No. 2003, the ISO must provide some form of remuneration for the financing of network upgrades, either in the form of cash reimbursement or transmission rights, which would be Merchant Transmission CRRs for the ISO. The ISO believes providing cash reimbursement is preferable for several reasons:

- It is the ISO's existing policy, and is therefore easy to understand and implement for the ISO and Participating TOs.
- The creation, allocation, and tracking of Merchant Transmission CRRs is complex, presenting a burden that would outweigh the few network upgrades the ISO may ever have to construct as an affected system. Stakeholders should remember that, to date, the ISO has never had to construct network upgrades as an affected system.
- Cash reimbursement from the Participating TO recognizes that although the generator may be elsewhere, the network upgrades themselves are in the Participating TO's service territory, and therefore benefit its ratepayers. FERC explained the drawbacks of non-reimbursement policies at length in its recent ANOPR, indicating a preference for cash reimbursement (or transmission owner financing) in the future.
- Reciprocity agreements or providing reciprocal treatment based on the neighboring BAA's own policy fails to recognize that most neighboring BAAs are not FERC jurisdictional and can operate in completely different paradigms than the ISO. Moreover, most of these affected systems do not only fail to provide cash reimbursement when they are the affected system; they do not provide cash reimbursement to their own interconnection customers as well. Like the affected systems, the ISO merely proposes to apply its own policy for RNU reimbursement consistently.

[21] Consistent with FERC policy, as an affected system the ISO would only be able to address reliability impacts on the ISO system; not deliverability or common loop flow.

    - Tracking and providing different reimbursement rules depending on the offtaker erroneously focuses on the beneficiaries of the generator; not the network upgrades themselves.

- Stakeholder Feedback

  The ISO received comments from eight stakeholders on the ISO's proposal outlined above. No stakeholder opposed the ISO's proposal that the base case assumptions for the study to be based on the previously queued projects as of the affected system study agreement execution date.

  Six stakeholders, ACP, AES, CalWEA, LSA, SEIA, and Six Cities, support the ISO's proposal to use its existing policy for RNU reimbursement for RNUs resulting from an affected system study. LSA and Six Cities also urges the ISO to seek reciprocal arrangements with other jurisdictions. Six Cities asked if the ISO would consider evaluating the value and appropriateness of tracking and reporting the costs of upgrades on the ISO controlled system triggered by affected systems.

  PG&E opposed the RNU reimbursement proposal and instead agrees with the cost allocation proposal regarding Affected Systems in the Contract Management "COMA" Enhancements Initiative Draft Final issued September 30, 2021. This paper proposed that Participating TO's would not reimburse external interconnection customers for network upgrades, consistent with neighboring utilities' practices Draft

- Draft Final Proposal

  There is no change to the ISO proposal that the base case assumptions for the study to be based on previously queued projects as of the affected system study agreement execution date.

  The ISO also believes that its proposal to use its existing policy to reimburse the costs for network upgrades on the ISO grid when the ISO is an affected system is just and reasonable and does not plan on making any changes. The ISO believes network upgrades, regardless of their cause, benefit the local ratepayers, and therefore should be included in the relevant transmission revenue requirement, similar to any other upgrade. The ISO believes this is consistent with general FERC policy, as set forth in Order No. 2003 and FERC's recent ANOPR on transmission planning and interconnections. The ISO believes that neighboring utilities' practices are not determinative. The ISO also notes that neighboring utilities in general do not reimburse developers in cash for network upgrades triggered by internal interconnections either. In other words, neighboring utilities are not discriminating against affected system upgrades; they are simply applying their own policy consistently for all network upgrades, regardless of cause, just as the ISO proposes to do here. The ISO's proposed policy also ensures network upgrades are right-sized to mitigate the specific impact, and removes any incentive to use affected system mitigation to replace or defer other upgrades for the utility's benefit and at the developer's expense. The ISO also continues to believe its five-year repayment term is appropriate. The interest costs of longer terms would be significant.

5.3 While the tariff currently allows a project to achieve its COD within seven (7) years if a project cannot prove that it is actually moving forward to permitting and construction, should the ISO have the ability to terminate the GIA earlier than the seven year period?

- Background

The June 7th Revised Straw Proposal discussed five specific questions the ISO requested to be answered to determine in the December 6th Issue Paper. Based on stakeholder feedback, the ISO proposed that Energy-Only projects should not be allowed to stay in the queue forever. The ISO agreed and proposed that the ISO would be more assertive in implementing BPM for Generator Management, Section 6.5.2.1 which states that "projects requesting to remain in the queue" beyond the applicable limit "clearly demonstrate that: "(1) engineering/permitting/construction will take longer than that; (2) the delay is beyond the IC's control; and (3) the requested COD is achievable in light of any engineering, permitting and/or construction impediments." The ISO also supported CalWEA's proposal that if the Energy-Only project contribute to the short circuit duty on the grid then the project should be terminated if the project does not agree to mitigate the short circuit duty issue.

The ISO also proposed that Interconnection Customers should be reporting the status of their projects and if the customer does not respond, then the ISO should invoke the default clause in the GIA, Section 17 in the LGIA and Article 7.6 of the SGIA.

- Stakeholder Feedback

The ISO received comments from 14 stakeholders for feedback on the following:

1) While the tariff currently allows a project to achieve its COD within seven (7) years if a project cannot prove that it is actually moving forward to permitting and construction, should the ISO have the ability to terminate the GIA earlier than the seven year period.

AES supports the CAISO's efforts to enforce the existing language in its tariff to manage queued projects. AES noted that projects that can demonstrate progress- e.g., have site control, have started construction, etc. should still be allowed to remain in queue, even if the 7-year mark has passed. Similarly, LSA proposed and continues to support the use of the BPM for Generator Management, Section 6.5.2.1

which states that “projects requesting to remain in the queue” beyond the applicable limit “clearly demonstrate that:” (1) engineering/permitting/construction will take longer than that; (2) the delay is beyond the IC’s control; and (3) “the requested COD is achievable in light of any engineering, permitting and/or construction impediments.”

ACP-California supports the proposal that if Energy-Only projects contribute to short circuit duty and are not moving forward, they should be removed from the queue. HQC does not believe any project should be allowed to indefinitely stay in the queue.

2) If a project does not reply to queries for information, should there be a time limit as to when the project must reply before a default of the GIA is declared? Currently, the ISO generally does not invoke the default clause if the project does not reply to inquiries, should the ISO invoke this clause for this reason?

ACP, CESA, CalWEA, EDF-R, GSCE, HQC, LSA, PG&E, SDG&E, Six Cities, SCE support CAISO’s proposal to enforce project status reporting requirements. CESA and GSCE requests clarification on the applicability of the proposal since, as they understood it, this is not intended to impact projects requesting to remain in the queue beyond the applicable limit if they clearly demonstrate that engineering, permitting, or construction will take longer than that and are actively advancing projects, per the Business Practice Manual for Generator Management, Section 6.5.2.1. CESA and GSCE are correct, the ISO would just be more aggressive in enforcing the tariff and BPM language it already has. Similarly, LSA commented that consistent with discussions between GridBright and the CAISO, projects should be allowed to remain in queue if they comply with the BPM provisions and agree to fund their share of any short circuit duty (SCD) mitigation needed, i.e., not terminate these projects for SCD reasons alone. The ISO agrees and mitigation is always an option to cure a breach of the GIA.

Avangrid Renewables interprets the Straw Proposal as applying no new milestones or changes to the GIA requirements for FCDS or PCDS customers. Instead, the CAISO is notifying interconnection customers that it will use its authority to enforce requirements regarding status updates and progress toward meeting milestones. Avangrid Renewables does not object to this proposal, but as described in response to question 13, but would ask the CAISO to approach this enforcement on a case-by-case basis that respects differences between truly “stalled” projects and projects that have faced unexpected and uncontrollable delays. The ISO completely agrees. The issues a project is having need to be handled on a case-by-case basis and the existing language allows that.

3) If a project needs a MMA (e.g., because it has missed a major milestone or its’ COD) but will not initiate the process, how long should the ISO wait before invoking

the default clause? CPUC staff supports the CAISO's ability to terminate the generator interconnection agreement (GIA) earlier than seven years if the project is not proving it is moving forward with permitting and construction;

CESA, CalWEA, EDF-R, HQC, LSA, PG&E, SDG&E, Six Cities, SCE and NCPA support CAISO's proposal to enforce the default clause GIA Section 17.1.1 when appropriate, taking into account the project specific issues and circumstances.

SCE commented that regarding the situation when a project needs an MMA (e.g., because it has missed a major milestone or its COD) but will not initiate the process, the Interconnection Customer should be given ten (10) business days to acknowledge that a major milestone has been missed or that a COD MMA extension request is required before the PTO in coordination with the CAISO, or visa-versa, issue a notice of default. The ISO does not disagree with SCE. In a number of cases the Interconnection Customer acknowledges that a COD MMA is required and promises the ISO will have it shortly, but never delivers. In this instance the breach section of the GIAs would be used to either get the COD MMA to cure the breach or terminate the GIA consistent with its terms. In either circumstance the ISO would use the existing procedures established with the Participating TOs to terminate the GIA.

4) If the project is not moving to permitting, procurement, and construction of the interconnection facilities or generating facility, should the ISO do anything other than requiring the project to meet the GIA milestones? Stakeholders may offer other suggestions about moving stalled projects through the queue to completion or withdrawal.

GSCE request additional information on CAISO's proposed change in enforcement of BPM for Generator Management Section 6.5.2.1.

5) Any other stakeholder suggestions about moving stalled projects through the queue to completion or withdrawal are welcome.

The CPUC encourages the CAISO to identify ways to make queue terminations a more transparent process, and/or a process possibly supported by an independent verification process. The ISO believes the existing tariff and FERC rules for termination provide the transparency that the CPUC seeks.

ACP requests ISO continue to hold discussions on how to best ensure that transmission owners are meeting their obligations under the GIAs and are moving required upgrades forward as expeditiously as possible to support new resource interconnections and deliverability status. The ISO believes the quarterly transmission forums that have been implemented this year and will continue solves the majority of this concern. However, it will still be up to the Interconnection Customer to work with the Participating TO to ensure the two entities understand the status of their upgrades. ACP also requests further discussion on standards that might be able to be used to help hold Transmission Owners accountable for timely completion of upgrades under GIAs. The standards are the terms and conditions of the executed GIA and it's up to all parties to the agreement to ensure that the milestones are being met.

The CPUC strongly encourages the CAISO to make public summary information about how many projects are potentially at risk to be terminated (i.e., designate in the public queue report when a project is put on notice), and designate when the GIA has been terminated by the CAISO (and which requirement triggered the termination). The Interconnection Customer still has the ability to cure the breach and then a cure period to implement the mitigation. Posting this data could be misleading as the Interconnection Customer may easily cure the breach and be in good standing expeditiously.

While it is reasonable for the CAISO to require Interconnection Customers to respond to requests for project status updates as per milestones set in the GIA, Avangrid Renewables would not support any new rule changes or amendments that impose a higher or faster burden on projects toward achieving COD. They note that multiple years between receipt of a GIA and COD can be consumed by CAISO and Participating TO processing and upgrades. Beyond these factors, unexpected permitting, supply chain, or offtake changes can create disruptions which compromise a project's ability to achieve COD within seven years, despite developer's best efforts to keep a project moving forward. The CAISO should provide individual consideration and attention to the circumstances of each project rather than imposing any new automatic termination triggers. The ISO is not proposing to add any new rules or amendments to the GIA, it is merely trying to transparently implement the terms and conditions that already exist and as discussed previously, the ISO completely agrees that each project needs to be evaluated on a case-by-case basis.

PG&E suggests the CAISO consider if projects should not be able to "park" or be suspended to help manage the queue and resources. Either of these options would require a full stakeholder initiative and tariff change, including changing FERC pro forma language for suspensions, and the ISO does not think that drastic a step needs to be taken at this time.

CPUC staff suggests that the CAISO might explore whether there are any small incentives that can be offered to motivate Interconnection Customers to remove themselves from the queue rather than wait the full 7 years for queue expiration. Given the vast quantities of resources needed to ensure reliability, it may be worthwhile for ratepayers to encourage Interconnection Customers to not block more viable projects just because they have an ability to do so. The ISO has tried these types of incentives in now three interconnection process enhancement initiatives and, absent paying projects to get out of the queue which has been suggested, the initiatives have gotten some movement in that direction.

- Draft Final Proposal

The ISO does not propose to change the solutions proposed in the Revised Straw Proposal for this issue. The only clarification would be that the ISO would only use the BPM for Generator Management, Section 6.5.2.1, or Section 17 of the LGIA and Article 7.6 of the SGIA where appropriate, taking into account the project specific issues and circumstances.

6 Phase 2 topics - Other Stakeholder Suggested Proposals

6.1 Examining the issue of when a developer issues a notice to proceed to the PTO, requesting the PTO/ISO should start planning for all upgrades that are required for a project to attain FCDS, including the upgrades that get triggered by a group of projects

- Background

In the June 7th Revised Straw Proposal, the ISO proposed to continue the Transmission Forum stakeholder meetings on a quarterly basis to allow each of the Participating TOs to give a presentation on the status of their transmission upgrade projects. Two have already been held this year on January 21, 2022 and April 26, 2022,[22] which were well received, and the next one is scheduled for July 29th.

With respect to the ISO ensuring the Participating TOs immediately commence each of the 147+ projects once the notice to proceed is received by the Participating TOs, the ISO determined it was best to allow the Interconnection Customer and the Participating TOs to work on a solution together. With this many projects in flight, it is not practical to require the Participating TOs to start every project's network upgrades when the GIA is executed or the notice to proceed is received by the Participating TO. The network upgrades need to be sequenced to meet each project's COD and ensure the work force is available for construction. The ISO encourages the Interconnection Customers to work closely with the Participating TO to ensure that both the generation and transmission projects are on track to meet the GIA milestone dates.

- Stakeholder Feedback

[22] California ISO - User groups and recurring meetings (caiso.com)

The ISO received stakeholder comments from nine (9) stakeholders.

LSA, AES Clean Energy and REV Renewables disagree with the ISO's proposal and favor the ISO providing oversight to ensure the Participating TOs actually proceed after receiving an Interconnection Customers notice to proceed, at a timing/pace to meet the milestones in the GIA. Their concern is that often times Participating TOs wait until enough projects execute GIAs and issue notice to proceed to start planning for shared network upgrades that are required to interconnect and/or deliver all projects. This leads to uncertainty for the projects that are ready to proceed and hence providing a plan and timeline to the Interconnection Customers that are ready would be helpful. While the *actual construction* may not start right away, it is just and reasonable for the Participating TO to provide a plan for the upgrades and not defer the project until some date unknown by the Interconnection Customer. Some Interconnection Customers believe the ISO has greater ability to influence the Participating TOs and supports the ISO exploring additional tools and mechanisms at the ISO's disposal to keep Participating TOs on track to meet construction milestones. While the ISO appreciates that customers believe we have a greater ability to influence the Participating TOs, the milestones in the GIA are set-up to require the Interconnection Customer and the Participating TO to work together to ensure that the project is on track. The ISO believes the Interconnection Customer and the Participating TO need to establish a relationship that addresses the forward progress of the project. In addition, the recently formulated Transmission Forums which the ISO intends to continue, will assist in this transparency.

ACP-California continues to support increased transparency into how Participating TOs prioritize the development, permitting and construction of upgrade projects. However, ACP-California understands that the specific request for Participating TOs to immediately begin planning all upgrades required for a project to achieve FCDS as soon as the developer issues a notice to proceed is not feasible, given the large number of projects and limited resources. ACP-California and EDF-R support additional, public discussions on how Participating TOs are prioritizing upgrades to ensure reliability and needed deliverability increases are achieved. EDF-R requested that more transparency be provided as to, whether upgrades get higher priority based on: (1) First-come, first served or original in-service date; (2) how many projects or how much capacity is depending on them; (3) whether they are RNUs (needed for interconnection) vs. DNUs (needed for deliverability). EDF-R noted the Jan 21, 2022 CAISO response only provided brief feedback from one Participating TO on the sequencing of projects. In addition, EDF-R requested that the ISO clarify that there is no strict limit on the nature of Transmission Development Forum questions asked on the call, provided the question is about a transmission project being reviewed in the forum. The purpose of the forums is to create a single forum to track the status of transmission network upgrade projects that affect generators and all other transmission projects approved in the ISO's transmission planning process not to discuss project cost information or priority management of the Participating TOs. Those conversations are best had directly with the Participating TO.

CESA maintains that how work plans for network upgrades are prioritized and initiated merit deeper discussion in a new IPE Initiative tackling more fundamental reforms. CESA and EDF-R believe the ISO should consider that it is feasible to start planning for project network upgrades when the GIA is executed or when the notice to proceed is received. Doing so would provide a plan and timeline to the Interconnection Customer, which would provide vital information that is not currently made available. Key information regarding these upgrades would include prioritization, if any, to upgrades coming out of study processes such as the TPP, as well as considerations to the cost of the shared upgrade. Given the FERC NOPR, the ISO has no appetite at this time to start another IPE initiative. The ISO believes we should conclude this initiative and then see what improvements should be made to the generator interconnection process are determined by the Commission.

PG&E, Six Cities and SCE supports the enhancement, which proposes that Interconnection Customers work with the Participating TOs on timing of network upgrades. SCE notes that network upgrades need to be planned in a particular order to meet CODs while also taking into consideration work force and outage availability. A particular example of this is a RAS/CRAS upgrade, which requires significant coordination between multiple teams of skilled personnel across a region. Diverting those resources to start on newly triggered projects could jeopardize the timely completion of existing in-flight work. Regarding updates on the status of transmission projects, SCE would refer developers to the quarterly Transmission Development Forum.

- Draft Final Proposal

The ISO will continue to hold the Transmission Development Forum allowing each of the Participating TOs to give a presentation on the status of their transmission upgrade projects which has been well received. As previously proposed, the ISO encourages the Interconnection Customers to work closely with the Participating TO to ensure that both the generation and transmission projects are on track to meet the GIA milestone dates.

7 Stakeholder engagement

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

IPE Phase 2	
Date	**Event**
07/26/22	Publish draft final proposal
08/02/22	Stakeholder conference call on draft final proposal
08/16/22	Stakeholder comments due on revised draft final proposal
09/13/22	Publish final proposal and draft tariff language
09/20/22	Stakeholder conference call on final proposal and draft tariff language
10/04/22	Stakeholder comments due on final proposal and draft tariff language
October 26-27 2022	Board of Governors Meeting

The ISO will hold a stakeholder meeting on August 2, 2022 to review the Phase 2 Draft Final Proposal. Stakeholders are encouraged to submit comments on this Revised Straw Proposal through the ISO's commenting tool using the link on the initiative webpage by close of business on August 16, 2022.