Interconnection Process Enhancements 2021

Phase 2: Longer Term Enhancements
Final Proposal

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1 Introduction

This Phase 2 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

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

to the existing interconnection processes that can be applied to Cluster 14 following the completion of the phase I interconnection studies in September.

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 than last year's 10 year plan was based on, 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

[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

requests in April 2021, with 373 new interconnection requests being received in the ISO's Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[6] The 596 projects totaling 236,175 MW, 162,237 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. 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,[7] was posted to the ISO website on December 13, 2021. Additionally, the ISO has reviewed FERC's more recent Notice of Proposed Rulemaking ("FERC NOPR"),[8] and notes the ISO's current processes already incorporate many of the reforms set out in this NOPR. While the ISO anticipates participating in the comment process, ISO staff have made an effort to align some existing proposals with those included in the FERC NOPR in cases where there may be direct overlap.[9]

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

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

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.[10] The ISO proposes 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 Final Proposal is intended to present proposed solutions that focus on long-term process enhancements based on comments received from stakeholders from the July 26th Draft Final Proposal.

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 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

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

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 3.2).

There were two topics originally addressed in the 2021 IPE initiative moved to other more appropriate forums.

1. Coordination among the transmission planning process—and policy-driven transmission in particular—the interconnection process, and load serving entities' procurement processes. The ISO has concluded that this topic is more appropriately considered in the context of the ISO's transmission planning process where policy-driven transmission needs are coordinated with state input.
2. Consideration of a solicitation model for key location and constraints not addressed in portfolio development, where commercial interest is the primary driver. The ISO concluded this topic is more appropriate in a separate stakeholder process associated with the 2021-2022 Transmission Plan.

3.1 Transparency enhancements

- Background

  In the July 26th Draft Final Proposal the ISO proposed 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 requested comments on this section.

- Stakeholder Feedback

The ISO receive comments from 13 stakeholders. AES, CESA, Cal Advocates, CalWEA, EDF-R, Hanwha Q Cells USA Corp., MRP, SEIA, and Vistra support the ISO's proposal. REV does not oppose the ISO's proposal. EDF-R requests that the ISO rush publishing of this data so that cluster 15 project can be better informed.

AES, CESA, LSA also encourages the ISO to further consider and implement as soon as possible the creation of a heat map or other data visualization tools to help Interconnection Customers identify viable POIs prior to entering the queue. It is AES's belief that until the ISO provides more information on the best places to interconnect, the ISO will continue to experience overheated interconnection queues. As discussed at the August 1st stakeholder meeting, the ISO is going to wait for the FERC NOPR process to provide additional information before agreeing to produce a heat map.

CalCCA wants the ISO to publicize the PPA status and MW, rather than require entities to deduce whether a project has a PPA from its TPD allocation group. The ISO took the route, as suggested by the CPUC, because the ISO does not have the PPA status of the projects. The only time the ISO knows the PPA status of a project is if it needs to meet commercial viability criteria, or retention of deliverability. That pool of projects does not encompass all of the projects in the queue. It is the CPUC that tracks that information and has it readily available on its website. The ISO is not in a position to provide this information.

CESA requests that the ISO produce site exclusivity documentation and status; project milestones; construction status; and Affected System status. CESA further states that it believes that there may be alternative means to make this information available, which would support smart and rational decision-making by Interconnection Customers in entering, proceeding through, or withdrawing from the queue, thereby addressing the ISO's intent of better managing the overheated interconnection queue. They note that if the information is too commercially sensitive to provide at an individual level, CESA recommends that the ISO provide these data categories in an aggregate form, perhaps by transmission planning or local areas. CESA pointed to the Phase 1 Revised Straw Proposal, where the ISO provided helpful site exclusivity information for the ISO system as a whole in making the case for site exclusivity as a pre-requisite to enter Phase II studies, however that data was determined manually as a one-off process with the Participating TOs that took weeks to determine the information. In this process, the ISO is striving to provide data that it has easily accessible to market participants and can be consistently produced.

With respect to CESA's request for project milestone information, there are generally 36 milestones in a GIA, which the ISO currently monitors manually from the project quarterly status reports. The construction status is also monitored manually based on the status reports. Again, this is not data that is easily accessible for the reporting function being discussed. The Affected System information, while currently accessible in RIMS would be very voluminous to report out on, and to date, all affected system issues have been resolved to allow the project to synchronize to the grid, and therefore, the ISO sees no benefit in producing this information.

LSA continues to urge the ISO to clean up and update the data in the queue, at least for projects currently active. For example, projects in the active queue are listed with CODs that have already passed, the fuel data should be standardized by column, and POI substation and other names should be standardized. Each of LSA's suggestions have merit but are a challenge to implement. As an example, the ISO cannot change a project's COD unilaterally; the project must submit a modification request to change the COD. While the ISO contacts these projects on a regular basis requesting them to submit the MMA, to date the ISO has not exercised the breach of contract mechanism to require them to submit an MMA, but the ISO may move in that direction to enforce GIAs.

LSA also proposes the ISO, to the extent possible, add all of the new information requested to the existing queue report and delete columns that are no longer needed – Interconnection Request Date, Application Status, Feasibility or Supplemental Review and Optional Study. The ISO's concern with deleting this information is that it is applicable for projects that are completed and withdrawn and the queue report is a report that was ordered by FERC for the ISO to publish monthly. The ISO intends to add items to the queue report where appropriate and only have additional reports if it makes sense to do so.

Vistra also requested the that the ISO update its existing Queue Report to include repowering requests, emergency fast track process, and Qualifying Facility Conversions. The Queue Report was specifically ordered by FERC to reflect the projects in the ISO's queue. The additional projects requested by Vistra are not part of the generator interconnection process and therefore do not belong in the queue report unless they do not meet the requirements of Section 25.1 of the ISO tariff. In that case, they would have to submit an interconnection request to make the changes identified, then they would enter the cluster process and be on the Queue Report.

- Final Proposal

The ISO proposes to implement the Draft Final Proposal and 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 ISO believes posting this data does not require a tariff change, and once the report forms are developed, the ISO will add them to the BPM including a description of the data fields.

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

- Background

In the July 26, 2022, IPE Phase 2 Draft Final Proposal, section 3.2, the ISO proposed eligibility criteria for a power purchase agreement (PPA) to be eligible to seek an allocation of TPD. Also addressed was the proposed eligibility criteria for PPAs with a non-LSE to seek an allocation of TPD. A summary of the proposals for these two items in the Draft Final Proposal were:

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. 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.
2. To allow TPD be allocated to Interconnection Customers with PPAs with non-LSEs. These PPAs will be subject to the 5-year minimum term requirement. 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. If the non-LSE procurement entity cannot demonstrate such a contract it must provide a deposit in-lieu of a contract. The deposit amount will be $10,000 per MW of allocated TPD, with a minimum deposit of $500,000.

- Stakeholder Feedback

1. TPD item 1 – the minimum required term for an eligible PPA.

Fourteen stakeholders provided specific input on the PPA eligibility criteria. The following are summaries of stakeholder comments.

	Minimum Term				
Entity (Name)	**No Min Term**	**1 Year**	**3 Years**	**5 Years**	**10 Years**
AReM		1			
California Community Choice Association					1
California Energy Storage Alliance			1		
CPUC - Public Advocates Office				1	
California Wind Energy Association				1	
Calpine		1			
Direct Energy		1			
EDF-Renewables					
Golden State Clean Energy			1		
Intersect Power		1			
Large-scale Solar Association/ LSA		1			
Middle River Power				1	
Six Cities/The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California				1	
Southern California Edison				1	
Vistra Corp.				1	
Sum of Comment Categories	**0**	**5**	**2**	**6**	**1**

- Stakeholder Comments Summarized

<u>Do Not Support a minimum term of more than one-year (5 commenters)</u>

AReM does not support any change to the requirement for a one-year PPA for new projects and state that the proposal is not needed and could result in unintended consequences.

Intersect Power stated “Contracting the RA attributes of a project does not mean the project is fully contracted” (which assumes the proposed term is only for the RA capacity). They contend that year ahead RA could come from greenfield projects and that assuming long-term contracts make a project more viable than short-term contracts is subjective. They state that the manner in which Interconnection Customers elect to structure their offtake contracts should not be dictated by the ISO and that the optimization of <u>contract tenor is a risk</u> management decision that should be left to the Interconnection Customer.

LSA opposes the ISO’s proposal for a minimum PPA term to qualify for TPD allocations that exceeds one year, stating the proposal fails to justify a five-year minimum PPA term, on the merits. Their comments focus on LSEs using short-term contracts (one month to a few years) relative to LSEs meeting short-term RA obligations. They state that revenue from RECs and energy can be relatively more significant, and those attributes can be contracted on a long-term basis to buttress short-term RA contracts and support project financeability and that long term contracts have greater risk in current environment of inflation and uncertainty. They recommend that if the ISO proceeds with the five-year minimum PPA requirement, the proposal should include an in-lieu deposit option where a project has secured a PPA of at least one year but less than an otherwise-applicable minimum term.

Calpine supports a minimum term of one year – in line with annual RA commitments. They state that upgrades to existing resources are smaller in size, frequently faster to market, less expensive than new builds and contracting for these upgrades takes many forms.

Direct Energy (NRG) would support a minimum one year term and that longer terms discriminate against legitimate projects with shorter term PPAs which do not require a long term PPA for financing. They state that the proposal would harm the ability of LSEs to meet their procurement needs.

<u>Supports a 3-year minimum (2 commenters)</u>

California Energy Storage Alliance urges for the ISO to return to the 3-year minimum contract term requirement, stating there are reasonable cases where short-term contracts are rational risk mitigation measures in the face of regulatory uncertainty about RA resource counting rules. They state the FERC NOPR 5-year minimum term as part of the commercial readiness demonstration has yet to receive comments, making the proposal potentially subject to change.

Golden State Clean Energy stated that a 3-year minimum term requirement would be reasonable given it is only needed to support the resource adequacy program, which is a short-term compliance regime of no more than 3 years. They do not agree with the assertion that new greenfield projects or project expansions require a contract of at least ten years. Their experience has shown that using a portfolio approach to contracting, including layering in short-term contracts, contracts for RECs and contracts for RA, renders a project viable for obtaining financing. They state that the focus on a long-term contract is outdated and should not be a threshold for how deliverability is allocated and retained and that setting a minimum term requirement for contracts to receive and retain TPD needlessly interferes with commercial negotiations and financing strategies.

<u>Supports (7 commenters)</u>

California Community Choice Association supported 10-year minimum and agree that 5-year is a reasonable compromise. Their members' experience is no entity has procured capacity from new greenfield projects or an expansion of an existing project for less than ten years and the proposal is consistent with CPUC's 2019 and 2021 procurement orders.

California Public Utilities Commission - Public Advocates Office supports a term of five or more years. They state that the term aligns with the ISO Tariff where Interconnection Customer investment in network upgrades is reimbursement over a five-year period.

California Wind Energy Association, Middle River Power, Six Cities, Southern California Edison and Vistra Corp generally support the Draft Final Proposal.

- **ISO Response to Stakeholder Comments**

The ISO maintains that it is imperative to require a minimum term for PPAs that align with LSE procurement practices and the requirements of the CPUC, which accounts for the majority of the LSE procurement requirements. The ISO must ensure that the TPD allocation process ensures the most viable and ready projects have an opportunity for an allocation before less viable and ready projects, and to ensure entities are seeking allocations in good faith, especially as the availability of deliverability decreases. The majority of new capacity procurement falls under mandates of the CPUC,[11] which require LSEs to enter into agreements with new resources for terms of at least ten years in duration. Six Cities, a group of non-CPUC jurisdictional LSEs supports the ISO's proposed term of five year. No LSE has stated that they procure capacity from new greenfield projects or an expansion of an existing project for less than ten years.

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. The ISO continues to maintain that the viability and readiness of projects with PPAs of terms less than five years are of a lesser readiness than those with PPAs with terms of five or more years. Any exceptions are rare. Moreover, providing allocations to less viable and ready projects on an equal footing as those with long term PPAs puts LSEs at a greater risk of not receiving an allocation. A condition that would hinder the ability of LSEs to bring new capacity online to meet their mandated timelines for new capacity and would put reliability of the ISO system at greater risk.

While comments for the FERC interconnection NOPR are not yet due, the 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:

[11] 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; 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

> "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*."[12]

This demonstrates that many transmission providers have already instituted PPA term requirements, and FERC agrees that a PPA for a minimum term 5 or more years demonstrates commercial readiness.

The ISO believes the merits of a five year PPA term are fully justified and the option proposed by LSA to include an in-lieu deposit alternative for projects that have secured a PPA of at least one year but less than an the required five year term is imprudent.

- Final Proposal for PPA eligibility remains unchanged from the proposal in the Draft Final Proposal.

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.

Clarifications

- 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.
- A number of sequential PPAs with a specific project where the sum of the terms of the individual contracts meets the minimum requirement would qualify.
- The PPA requirements for the 2022-2023 allocation cycle will be the same as for the 2021-2022 allocation cycle.
- The PPA requirements for the retention of an allocation received prior to the 2023-2024 TPD allocation cycle, for projects requesting a COD extension and

[12] *Notice of Proposed Rulemaking: Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022) at P 129.

projects required to demonstrate Commercial Viability will be the same requirements that were in place when a project received its allocation of TPD.

2. **TPD item 2 – the ISO proposed requirements to allow TPD be allocated to Interconnection Customers with PPAs with non-LSEs.**

Thirteen stakeholders provided input on eligibility criteria for PPAs with non-LSEs. The following is a summary of stakeholder comments.

Entity (Name)	Supports	Comments for Different Approach	Comments on Deposit Amount
AEE and AEBG	1		
California Community Choice Association	1	Does to not support giving a non-LSE procuring entity extra time to secure a contract with an LSE with a RA compliance obligation.	
California Energy Storage Alliance	1		
CPUC - Public Advocates Office	1		
California Wind Energy Association	1		
Direct Energy,	1		
EDF-Renewables	1		Requests logic and empirical justification
Hanwha Q Cells USA	1		
Large-scale Solar Association/ LSA	1		Proposes a $5K/MW, w/$250K minimum and $1 million cap
Middle River Power, LLC	1		
Solar Energy Industries Association/SEIA	1		Deposit amount Needs to be adequately justified
Six Cities/The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California	1	RA sale term should be 5 yrs, same as PPA term	
Vistra Corp.	1	Allow long-term RA contracts between counterparties, regardless of affiliation	
Sum of Comment Categories	13	3	3

ISO Response to Stakeholder Comments

The ISO believes that the extra time provided to the non-LSE offtaker to obtain a contract to sell the RA capacity to an LSE with an RA obligation is appropriate because this process is an additional step in the procurement process for a non-LSE. Projects working towards PPAs with LSEs with RA obligations and with non-LSEs offtakers should be on the same timeline for executing their PPAs in time to submit seeking allocation affidavits by the affidavit due date. The requirement for the non-LSE to complete the sale of the RA capacity could take time, particularly with projects that have longer lead-times to COD.

The ISO believes it is likely that contracting for the RA capacity from a project with a non-LSE long term PPA will resemble the contracting with existing generators versus new greenfield projects, which are often shorter term contracts in the one to three year range. It would not be appropriate to put a potential barrier on this contracting process by requiring a five year agreement, which could result in RA capacity failing to obtain an agreement and be left unused.

The deposit in-lieu of an RA contract amount was designed to create a sufficient incentive for the non-LSE to perform on the requirement to enter into an agreement with an LSE with an RA obligation as quickly as possible to help to ensure the RA capacity is utilized to support system reliability. The $500,000 minimum amount is needed to accomplish this for smaller projects. It is important not to establish a maximum amount, or cap, as an incentive against large amounts of TPD being tied up in projects that seek to essentially “buy” TPD capacity, which could result in significant amounts of TPD being unused for a significant period of time and unavailable to projects that could use it sooner. Furthermore, offtakers with RA obligations do not have to ability to buy TPD in a similar manner.

The ISO does not support allowing long-term RA contracts between counterparties, regardless of affiliation. The ISO is concerned about the risk that Interconnection Customers 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.[13] The ISO has rejected and will continue to reject such PPAs and others it views as shams or workarounds to obtain deliverability.

- Final Proposal for PPAs with a non-LSE remains unchanged from the proposal in the Draft Final Proposal.

The ISO proposes to allow TPD be allocated to Interconnection Customers 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

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

requirements depending on which group the Interconnection Customer 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 TPD. If the project receives an allocation, the deposit will be due within 30 days of the ISO notifying the Interconnection Customer 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 Interconnection Customer 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 Interconnection Customer 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,

[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.

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).

Clarification

Notwithstanding the requirements described above, all of the PPA requirements listed in Section 3.2, TPD item 1 – the minimum required term for an eligible PPA, apply to PPAs with non-LSEs. The qualifying PPA with non-LSE procurement entities must require deliverability for the portion of the project procured.

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 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.

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

[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.

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 July 26th Draft Final Proposal the ISO significantly revised its proposal on this topic based on stakeholder feedback and also that on June 16, 2022 FERC issued a Notice of Proposed Rulemaking (NOPR) on 'Improvements to Generator Interconnection Procedures and Agreements'. The revised proposal attempted to integrate a number of FERC's proposals while maintaining key aspects of the ISO cluster study process. Some of the notable proposed changes included revising the allocation of study costs, setting study deposit amounts that are based on project MW size, requiring demonstration of commercial readiness or in lieu deposits, and imposing withdrawal penalties that increase as the Interconnection Customer moves through the study process. The ISO requested stakeholders provide feedback on whether the ISO should wait for the FERC NOPR process to be completed, or if the ISO should move forward with its own revised proposal as detailed in the July 26th final draft proposal, making the changes applicable for cluster 15.

- Stakeholder feedback

There are 4 stakeholders that fully support the ISO proposal. The CPUC Cal Advocates supports these revisions, stating they are consistent with the FERC NOPR reforms and with these changes the ISO should be able to effectively manage the overheated queue by raising the bar for entry into the interconnection process. NRG supports the flexible approach outlined which allows different options to show commercial viability and increased deposits for larger contracts. SCE supports the ISO integrating several of FERC's Generator Interconnection NOPR proposals – 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 Interconnection Customer moves through the study process – while maintaining key aspects of the ISO cluster study process. SCE states the ISO should clarify if commercial readiness must be tied to a site or could only be used for one active interconnection request. SCE does not see a need to wait until the final FERC determination to proceed with the ISO proposed tariff revisions as it will benefit Interconnection Customers, ISO, and PTOs to focus resources on fewer projects that are ready to proceed. PG&E is supportive of ISO's revisions to the proposal to align it with FERC's recently issued Notice of Proposed Rulemaking on interconnection issues. Even though FERC's action is a proposal at this time and not a final order, aligning with the direction FERC seems to be going is reasonable. Aligning with FERC's proposal, even though what eventually may be adopted could be somewhat different, makes sense as it will reduce impacts of making changes in the future to the interconnection request requirements.

There are 5 stakeholders that do not support any provisions of the ISO proposal. EDF Renewables strongly opposes moving forward with this proposal as it is not mature and not appropriate for the ISO unique interconnection and deliverability procedures. EDF is also advocating for a transparent stakeholder discussion of any FERC order compliance proposals before it goes to the ISO Board for approval. LSA states ISO proposals go far beyond providing criteria for “submitting and IR” to encompass Interconnection Study cost allocation, new readiness criteria for entering both Phase I and Phase II Studies, and Study Deposit retention far beyond completion of Interconnection Studies. LSA states the proposed cost-allocation and study deposits bear no relationship to ISO costs, the commercial readiness criteria are vague and inconsistent with ISO-area PPA contracting practices, and the study deposit refund proposals are unjust and unreasonable. Hanwha Q Cells believes the ISO must delay the start of C15 or the rollout of IPE Phase 2 to allow additional debate on the FERC NOPR, and believes that having the option of providing a financial deposit in lieu of commercial readiness is essential. Also, until a developer receives a system impact study, meeting the commercial readiness criteria is not feasible. Intersect Power opposes the proposals for: (1) revised cost allocation and Study Deposit structures that do not reflect ISO costs, (2) Study Deposit amounts that far exceed ISO costs, (3) Commercial Readiness criteria, which are vague at this time and inconsistent with ISO-area contracting practices, and (4) Study Deposit retention for years after study completion. Vistra recommends deferring action on the allocation of study cost and study deposit proposals and opposes the commercial readiness proposals.

There are 9 stakeholders that support some but not all of the provisions of the ISO proposal.

Allocation of study costs – CalWEA supports the proposed study cost allocation. REV Renewables supports the proposed cost allocation of study costs. California CCA states the ISO should allocate study fees in a way that reflects the drivers for the costs incurred by the study. If the ISO incurs more costs for studying larger MW projects than it does for studying smaller MW project, then the ISO’s proposal to allocate costs primarily based on requested MW is reasonable. If the costs are the same to study a larger project and a smaller project, then the ISO should revisit its proposal and provide this feedback to the FERC in response to the NOPR such that the ISO’s allocation of study fees can align with the way different projects impact the costs of the study. AES Clean Energy does not oppose the 90/10 study cost allocation proposal. However, it was unclear from the proposal when any unspent study deposits would be refunded to customers, it would be unjust and unreasonable to retain the deposit once all study activities have been completed.

Study costs based on project MW size – SEIA supports implementing elements of the FERC NOPR, like study deposits, recognizing that these enhancements will likely comply with any FERC interconnection rulemaking. Middle River Power supports the ISO Proposal with regards to fees and deposits. CalWEA supports the study deposit structure and urges the ISO to move forward without waiting until FERC NOPR process is completed. REV Renewables supports the proposed study deposit revisions that will create an additional financial liability on the Interconnection Customer thus creating an incentive to submit viable projects. Six Cities are not categorically opposed to the ISO's proposed revisions to study fees and deposit structures proposed by the ISO, however it may be that the ISO footprint requires a different approach or alternative weighting, as compared with the FERC NOPR. CESA supports the adoption of a combined study deposit as proposed as reasonable and aligns with the thresholds in the NOPR. Golden State Clean Energy supports the proposal to base study deposits on a megawatt amount rather than the number of interconnection requests. This makes ISO's proposal directionally consistent with the NOPR while increasing study deposit amounts to create better incentives for projects entering the queue. The proposed increase in study deposits warrants a reexamination of the use of funds in excess of actual study costs given the study deposit is now also being used as a deterrent to projects entering the queue rather than increasing to cover study costs. AES Clean Energy supports the new study deposit structure being based on project size and finds the proposed fee structure in line with study deposit requirements in MISO and PJM.

Commercial Readiness – SEIA opposes the commercial readiness requirements and the ISO should delay implementation until FERC issues final rulemaking. Middle River Power states it is not realistic to require parties to furnish a binding, executed term sheet before moving into Phase I studies and that there is no guarantee that the studies, let alone the upgrades required will be completed on time so developers will be unwilling to take on the risk associated with a binding schedule. CalWEA believes the commercial readiness deposit to enter Phase II studies is too high and recommends reducing it to 2.5 times study deposit. REV Renewables strongly opposes the commercial readiness proposal. CESA opposes the commercial readiness requirements proposal and notes it is problematic because it provides no way for projects to meet this requirement through a merchant development strategy. CESA states the structure for commercial readiness requirements, if maintained, would represent excessively high amounts of capital at risk that would deter market participation. CESA requests that the ISO clarify whether the study deposits must be provided in cash or could be provided via other means. Golden State Clean Energy supports some form of commercial readiness demonstration and increased fees to submit an interconnection request, but the eligibility criteria should be expanded to more accurately reflect readiness early in project development. Readiness demonstrations should be expanded and include site exclusivity, permitting, procurement of major equipment, or an early financial commitment to interconnection facilities to support multiple projects. AES Clean Energy opposes the commercial readiness requirements as currently outlined in the DFP

Withdrawal Penalties – SEIA supports implementing elements of the FERC NOPR, like withdrawal penalties recognizing that these enhancements will likely comply with any FERC interconnection rulemaking, however the ISO should be incentivizing earlier withdrawals with no penalties prior to entering Phase I studies. CalWEA recommends reducing the maximum withdrawal penalty to 1.5 times the study deposit. REV opposes the proposed withdrawal penalties that are tied to commercial readiness criteria. CESA is opposed to the adoption of withdrawal penalties, which are unnecessary given the withdrawal penalties already in place associated with the initial financial security (IFS) posted after Phase I and Phase II studies. AES Clean Energy opposes the withdrawal penalties proposal as written in the draft final proposal. AES believes that the withdrawal penalty framework should be revised to incentivize early withdrawal and increase as projects move through the process.

Site Exclusivity – Middle River Power believes site control should be demonstrated before moving into the study process.

- Final Proposal

Based on stakeholder input, it is apparent that reaching consensus on any proposal for this topic in time for approval of the ISO Board at their scheduled October meeting, which would be necessary to have any proposal apply to Cluster 15, is not feasible. The ISO has decided not to move forward with a final proposal on this topic within IPE Phase 2. The ISO will refocus its efforts on this topic by participating within the framework of the FERC NOPR on ‘Improvements to Generator Interconnection Procedures and Agreements’[16].

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

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.[17]

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 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.

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

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.

In the July 26th Draft Final proposal, the ISO refined its latest proposal with two additional enhancements. The first enhancement was for the ISO to maintain up-to-date data on the ISO 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 second enhancement was 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 enhancements would provide customers with as much transparency as possible while protecting the customer from the risk of merchant-financing low-voltage upgrades where unexpected.

- Stakeholder Feedback

There are 4 stakeholders that support or do not oppose the proposal. The CPUC Cal Advocates supports this proposal, which intends to protect local transmission ratepayers from funding excessively expensive interconnection-related local voltage network upgrades. According to them, this change also moves the ISO closer to a participant funding model used by other regional planning organizations, in which Interconnection Customers pay a fair portion of the cost of required network upgrades to reflect a fair allocation of benefits between the Interconnection Customer and ratepayers. Valley Electric Association (VEA) supports the proposal as a reasonable balancing if the interests involved, and for VEA, it is a significant improvement from the circumstances today. SCE does not oppose the ISO proposal.

There are 7 stakeholders that oppose the ISO's proposal. SEIA believes that the ISO proposal will discourage future resource development on local systems, which could have deleterious effect on California clean energy goals. EDF-R views the proposal as similar proposal rejected at FERC before and believes it is unjust and unreasonable to impose different and discriminatory refundability rules in different ISO area locations. Middle River Power (MRP) states that the impetus for this issue is a reasonable concern that Valley Electric Association (VEA) customers should not incur undue costs related to lower-voltage interconnection of generators that are connecting in the VEA area not for the primary purpose of serving load there but instead to serve load in the ISO. That said, however, MRP is not yet persuaded that the way to address that legitimate concern is to limit generators' cash reimbursement recovery of network upgrade costs. CalWEA opposes requiring Interconnection Customers 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. LSA continues to believe that the ISO's proposal is not just and reasonable and that the assertion that this proposal would apply to "any PTO" in a "non-discriminatory" fashion is simply not true. LSA also states the proposal would likely have the impact of preventing most future generation development on the VEA system, since the cap is so low that a single project could easily absorb the entire $3.5 million below it. If that is the intent, the ISO should simply say so. LSA is disappointed that ISO did not explain in any detail its reasons for rejecting the SEIA "Net Importer/Net Exporter" proposals, or any of LSA's alternative suggestions. These alternatives included, for example, addressing FERC's problems with the earlier proposal by allocating "excess" LV-TRR costs to other PTO LV-TRRs based on LSE contracting of projects in the VEA area, which would provide the direct connection to beneficiaries required by FERC. LSA is also requesting clarification on the calculation of the cap and the PTO-provided figures, specifically whether the calculation would include LV costs associated only with completed projects, projects under construction or with executed GIAs, or forecasts based on study results for additional projects or clusters. If the ISO proceeds with this framework, it should not apply to project already in the queue as well as projects moving to a higher voltage POI due to application of the cap should qualify for "lower of" Phase I/Phase II cost-cap protection and projects that do not receive full Network Upgrade reimbursement due to the 15% limit should be entitled to additional reimbursements if the target dollar amount increases. REV Renewables states the High and Low voltage transmission in California is configured in a loop arrangement in most locations. Therefore, any network upgrades that get built on the low voltage transmission side provide overall reliability and other benefits to the bulk high voltage transmission as well, similar to upgrades that get built on high voltage transmission. Separating the cost allocation on high and low voltage would not only be cumbersome but would also go against the fundamentals that are in place today. AES Clean Energy opposes this proposal. However, if the ISO adopts this proposal, then they should grandfather all resources currently in queue from this 15% cap and make this policy effective starting with Cluster 15 projects so that developers can better manage the risk of developing projects on lines below 200 KV. While AES appreciates the ISO's proposal to allow project to withdrawal without penalty if the 15% cap is reached, this still will not make developers whole to the investments already made to develop the project.

There are 3 stakeholders that neither support nor oppose but are asking for further clarifications. The Six Cities note that their prior comments included several questions that were not addressed in the Draft Final Proposal, including:

- How is the amount of investment in low voltage network upgrades for each Participating TO being determined? Are these amounts self-reported? How are the proposed amounts validated? Is the basis for the reported investment included in any FERC-filed financial reports? The Six Cities note the ISO's commitment to post relevant amounts on its website. (See Draft Final Proposal at 32.)
  - 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?
- 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?
  - The Six Cities request that the ISO confirm, 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 ISO controlled grid and available for the use of ISO transmission customers just like any other assets that are under the ISO's operational control. The Six Cities request the ISO to provide in its Final Proposal additional information on how it will implement this proposal.

PG&E requests the ISO clarify in any final proposal that the proposed 15% cap on reimbursement for low-voltage network upgrades is not in-lieu of and replacing the current respective PTO structures for NU reimbursements, including which type of network upgrades are eligible for reimbursement and at what rate. PG&E recommends ISO add language making clear that Interconnection Customers are still responsible for certain types of NUs (e.g., area deliverability network upgrades (ADNUs)) irrespective if a PTO has reached the 15% reimbursement threshold and that the proposal is not proposing to require PTOs to reimburse Interconnection Customers for all NUs until it has reached the 15% threshold. SDG&E supports ISO'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 ISO's system. SDG&E also agrees with the ISO that if the current cost allocation structure remains unchanged it might lead to inequitable cost allocation in the future. Under ISO's current proposal, generation interconnection-driven network upgrades will be limited at 15% of the low voltage transmission revenue requirement (LTRR) of a Participating TO. SDG&E is concerned with the 15% limit selected by the ISO and would appreciate if the ISO 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. At a minimum, SDG&E believes that the ISO should try to find a clear correlation between a selected limit and the benefits received by local ratepayers. Furthermore, although SDG&E believes the ISO is taking a step in the right direction to protect local ratepayers, SDG&E is also concerned that ISO'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 ISO-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.

- 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 ISO 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 prior to when the customer executes the GIA (due to the PTO going over the 15% threshold prior to the customer executing the GIA, 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."[18] 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."[19] The ISO based this figure on the tariff's existing LCRIF provisions, and believe it represents a reasonable share of low-voltage network 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

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

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.

In response to stakeholder questions, the ISO includes the following clarifications:

- Each PTO determines the share of low voltage network upgrades driven by interconnections by tracking what triggered the upgrades (*e.g.,* an interconnection study, transmission planning, load growth). The PTO will self-report them to the ISO, and the ISO tariff will require each PTO to report them accurately. The ISO is unaware of any FERC reporting requirement or rate case element that requires this specific breakdown.
- Once an Interconnection Customer has executed a GIA, its reimbursement eligibility will not change regardless of any change to the PTO's share of interconnection-driven upgrades due to other interconnection costs (up or down). This will provide the Interconnection Customer a firm cutoff to understand its reimbursement eligibility before proceeding toward a GIA and third posting. Although this may create some float for the transmission owner to manage project to project, the ISO believes this firm, simple rule outweighs the benefits of reimbursement provisions that could change for every customer right up until commercial operation.
- The ISO and each PTO will evaluate the Interconnection Customer's reimbursement eligibility when it tenders its GIA. If the parties agree to extend the negotiation period beyond the 120 days recommended by the tariff, the PTO should update the precise reimbursement eligibility before execution. The PTO's share at the time of the GIA tendering should be based on its current transmission revenue requirement plus any costs for network upgrades by Interconnection Customers that have executed GIAs. Likewise, because reimbursement will not be finalized until a customer has executed a GIA, the PTO should exclude costs from queued projects that have not executed GIAs.
- The 15% threshold will apply to all PTOs, regardless of their current share of interconnection-driven upgrades or if they even have low-voltage facilities at this time. This will protect potential future PTOs that may be concerned over rate shock and current PTOs considering expanding their system. A universal rule for all PTOs also ensures the rule is non-discriminatory.
- All network upgrade costs that do not receive cash reimbursement will be owned by the PTO and considered part of the ISO controlled grid. The Interconnection

Customer will not have any special or unique rights for those upgrades. The ISO will treat non-reimbursable upgrades under this rule just as it treats non-reimbursable upgrades under the Reliability Network Upgrade cap, meaning the Interconnection Customer would receive Merchant Transmission CRRs if additional capacity creates them according to existing Merchant Transmission CRR rules.

- The ISO's proposed rule is iterative on existing cost allocation and reimbursement rules. The ISO does not propose to change how any network upgrades are classified or triggered. Nor does the ISO's proposed rule impact cost cap classifications or rules. As stated above, stakeholders should use the Reliability Network Upgrade reimbursement cap as an analogy for how this rule will work in concert with other cost allocation rules.
- The ISO proposes to make this rule effective in 2023 for all queued customers that have not executed GIAs when the rule goes into effect. Because the ISO intends for this rule to protect ratepayers against costs for which they do not commensurately benefit, the ISO does not believe a drawn-out transition period is appropriate. If an individual Interconnection Customer believes this requirement should not apply to them, the parties may negotiate a non-conforming GIA for FERC approval, or file the GIA unexecuted.

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.[20] 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

[20] 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.

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.
- 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.

- 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 July 26 Draft Final Proposal proposed that the ISO does not 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. The ISO requested comments on this section.

- Stakeholder Feedback

The ISO received comments from 11 stakeholders for feedback on the following:

CESA, CalWEA, EDF-R, LSA, MRP, PG&E, SEIA, Six Cities, and SCE support the ISO's proposal as a reasonable approach to exercise and enforce the ISO's existing authorities and procedures in order to manage the queue.

Cal Advocates views the ISO's proposal to be more modest than originally proposed and urges the ISO take the additional step of requiring Interconnection Customers to report on an annual basis, the detailed status of its project(s), demonstrate specific issues with engineering, permitting, or construction and, if the Interconnection Customer does not respond, then the ISO could invoke the default clause in the Generation Interconnection Agreement (GIA), Section 17 in the Large Generation Interconnection Agreement (LGIA) and Article 7.6 of the Small Generation Interconnection Agreement (SGIA). The ISO actually requires all projects to provide quarterly reports on the status of their project and to the extent the Interconnection Customer does not respond, the ISO would invoke the default section of the GIAs.

Calpine does not support unilateral termination prior to 7 years. The ISO would not unilaterally terminate an agreement. The project would need to demonstrate that it is not following the terms and conditions of the GIA and if not then the ISO would send a notice of breach to the Interconnection Customer that gives them an opportunity to cure the breach. If the breach is not cured, then the ISO would file at FERC for termination of the GIA. The Interconnection Customers can protest that filing at FERC if they still disagree with the ISO's actions after having ample opportunity to cure the breach.

- Final Proposal

The ISO does not propose to change the solutions proposed in the Draft Final Proposal for this issue.

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 July 26th Draft Final 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. As previously proposed, the ISO encourages the Interconnection Customers to work closely with the Participating TO to ensure that both the generation and transmission portions of the projects are on track to meet the GIA milestone dates.

- Stakeholder Feedback

  The ISO received stakeholder comments from three (3) stakeholders, none of which support the ISO proposal.

  CESA, REV have found that the Transmission Development Forum is ill-suited for the purpose of discussing project-specific questions. CESA recommends that this issue be taken up in the new TPP Enhancements Initiative. Having such a proposal in place will inform procurement and project development activities, as well as ensure accountability on the construction of network upgrades.

  LSA objects to the ISO's removing the item about Interconnection Customers Notices to Proceed from the scope of this initiative. ISO's characterization of this issue has been mischaracterized from the start. Developers are not asking for the Participating TO to start working on "every project's network upgrades when the GIA is executed or the [NTP] is received by the [PTO]." Instead, the Participating TO should be required to begin work on all upgrades in time for the project to achieve its COD and deliverability status. Work on the longest lead-time upgrades should begin first, followed by work on shorter lead-time upgrades, so the Participating TO can fulfill its commitments under the GIA. If developers could just "work closely with the Participating TO" to resolve this problem, it would already be resolved. Instead, Participating TOs frequently delay work on needed upgrades after the Notice to Proceed ("NTP") is provided, delaying project progress toward the milestone dates the Participating TO has committed to in the GIA. LSA asks what is the purpose of an Interconnection Customer "Notice to Proceed" (often accompanied by a third (non-refundable) posting) if the Participating TO does not, in fact, actually proceed? Why should Interconnection Customers make a unilateral commitment when the Participating TO is not doing the same? We again ask the ISO to respond to these questions.

  As the ISO stated in the July 26 Draft Final Proposal and August 1st stakeholder call, while the ISO appreciates that customers believe the ISO has 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 consistent with the terms and conditions of the GIA.

REV believes 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. If needed, Participating TO could require the first project that issues NTP to post security for the entire network upgrade and not just the cost allocated to this project, so a Participating TO has coverage for the financial obligations to build these upgrades. As more projects start executing GIAs and issuing NTPs these projects could reimburse their portion of cost obligation to the first project.

- Final Proposal

  The ISO will continue to hold the Transmission Development Forum allowing each of the Participating TOs to give a presentation on the high level status of the transmission upgrade projects which has been well received. As previously proposed and consistent with the terms and conditions in the GIA, the ISO encourages the Interconnection Customers to work closely with the Participating TOs to ensure that both the generation and transmission projects required to interconnect their generating facilities 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**
09/13/22	Publish final proposal
09/20/22	Stakeholder conference call on final proposal
10/04/22	Stakeholder comments due on final proposal
October 26-27 2022	Board of Governors Meeting

The ISO will hold a stakeholder meeting on Sept 20, 2022 to review the Phase 2 Final Proposal. Stakeholders are encouraged to submit comments on this Final Proposal through the ISO’s commenting tool using the link on the initiative webpage by close of business on October 4, 2022. The ISO also will publish draft tariff language and hold a conference call to discuss the draft tariff language well before the Board of Governors meeting.