California ISO

2023 Interconnection Process Enhancements

Track 2 Revised Straw Proposal

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Executive Summary

The proposed changes in this Revised Straw Proposal address the unprecedented interconnection request volumes that are unsustainable in the ISO's current processes and seek to better enable rapid deployment of new generation for reliability, affordability, and decarbonization. Through robust stakeholder feedback, and considering the urgent need to bring historic amounts of new capacity online, the ISO proposes revisions to the Straw Proposal as part of a package of significant reforms that emphasize project viability and competition for resources identified in local and state resource planning efforts.

In this Revised Straw Proposal, the ISO has revised the following elements of the Straw Proposal, based on stakeholder comments and working group discussions:

- Refinements to the information provided to stakeholders to implement the zonal approach;
- An updated set of objective indicators for scoring criteria to address project readiness, including a load-serving entity (LSE) point allocation mechanism to incorporate LSE interest earlier in the process;
- Modifications to the auction administration;
- Description of the methodology for identifying and fulfilling 150% of each zone;
- Modifications to the Option B pathway;
- Proposed elimination of the Off-Peak and Operational Deliverability Assessments from the study process;
- Discussion of challenges regarding cost allocation of withdrawn projects under the one-time refundable withdrawal opportunity;
- Update to the viability criteria and a time-in-queue requirement for all projects in the queue;
- Introduction of an "implementation deposit" for queue management; and
- Update to the Phase Angle Measuring Units data

The proposed process aligns with the strategic direction established by a December 2022 Memorandum of Understanding between the ISO, California Public Utilities Commission (CPUC), and California Energy Commission (CEC), and is part of a broader effort to tighten linkages among resource and transmission planning activities, interconnection processes, and resource procurement.

To address the volume of interconnection requests the ISO received in Cluster 15, and will likely receive in future clusters, the ISO proposes the following framework.

- The ISO will make information available to stakeholders to enable the zonal approach, which encourages interconnections in transmission zones with available and approved transmission capacity. Prior to the interconnection request window opening, the ISO will provide accessible data regarding transmission constraints within zones, available transmission plan deliverability (TPD) by constraint, and identification of priority interconnection areas, as well as the interconnection heatmap, required in FERC Order No. 2023. Projects that seek to interconnect in zones that have no TPD available may only proceed as Option B projects, and thus the ISO proposes modifications to Option B to enable such projects to proceed.

- Interconnection requests will have to meet FERC Order No. 2023 requirements for site control, entry fees, and deposits, and are expected to submit documentation to enable their progression through the interconnection process.

- The ISO proposes to score interconnection requests based on a set of clear and verifiable criteria used to rank the projects for progression to the study process.

- If excess proposed capacity exists after applying the viability criteria, the ISO proposes to conduct a market-clearing, sealed-bid auction for the right to be prioritized and studied in a specific zone. Only projects that are deemed equal in viability rating and cause the total MW for a zone to cross the zone's capacity limit would participate in the auction. Under this proposal, successful projects will succeed to a single-phase study process, consistent with FERC Order No. 2023.

- Once studies are complete, the ISO acknowledges the need to modify the TPD allocation methodology as well as consider broader issues to bridge the gaps between the in-service dates of a Local Delivery Network Upgrade (LDNU) and a project's requested commercial online date.

To address the projects currently in the ISO's interconnection queue, the ISO proposes a number of changes to the contract and queue management process to provide projects an opportunity to either withdraw from the queue or advance to commercial operation.

- Consideration of a one-time opportunity to withdraw from the queue and receive any unused portion of the applicant's interconnection financial security postings and deposits, possibly over time.

- Extend to nine months the time to submit a Limited Operation Study (LOS) request before synchronization. This allows additional time for processing the request, drafting and issuing the study plan, and completing the study with the intent of providing interconnection customers additional time to evaluate the results and make decisions accordingly.

- Remove suspension rights for all projects that execute a future Large Generator Interconnection Agreement (LGIA).

- TPD transfer limitations to ensure viable projects proceed for legitimate purposes.

- Impose an unavoidable viability criteria and time-in-queue requirement for all projects in the queue.

- Modify requirements for asynchronous generators, project modification requests, shared network financial security postings, timing of modification results and timing of commencing network upgrades.

The process reforms described in greater detail in this Revised Straw Proposal are designed to accelerate progress toward execution of an interconnection agreement and commercial operations for the most viable and competitive projects in areas that align with local and state resource plans. The ISO looks forward to continuing to work with stakeholders to refine this proposal in the interest of deploying new resources to meet the grid’s evolving needs.

1. Introduction and Background

With this paper, the California Independent System Operator Corporation (ISO) provides its Revised Track 2 Straw Proposal for the 2023 Interconnection Process Enhancements (IPE) initiative. Given the rapid acceleration of clean energy development to meet reliability and policy needs and the unprecedented level of resource development activities reflected in interconnection requests to the ISO, this Track 2 Revised Straw Proposal explores concepts for significant and transformative improvements to the ISO's role in resource planning coordination, transmission planning, interconnection queuing and management, and power procurement.[1]

California's ambitious decarbonization goals and the large quantities of new clean resources required to meet them have caused the ISO to receive unprecedented numbers of interconnection requests from interested resource developers. Many of these requests are in areas that have not been prioritized in the state's resource planning. The ISO seeks to re-imagine the grid interconnection, prioritization, and coordination processes to ensure resource procurement and queuing are effectively oriented toward planned and existing transmission and interconnection capacity. These processes must also align with transmission development necessary for longer-term resource development.

The 2023 IPE initiative is part of a larger set of foundational framework improvements being coordinated among the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the ISO. The overall strategic direction is set forth in a joint Memorandum of Understanding (MOU)[2] signed by the three parties in December 2022.The ISO is now taking on additional reforms to the interconnection queuing process that will leverage the improved coordinated planning resulting from the MOU and help further break down barriers to efficient and timely resource development.

The expectations set out in the MOU are:

[1] The 2023 IPE initiative is utilizing two tracks. Track 1 focused on immediate adjustments to the Cluster 15 study schedule. The Track 1 tariff changes were approved by the ISO Board on May 18, and will soon be filed with the Federal Energy Regulatory Commission (FERC). Track 2 focuses on targeted modifications to the interconnection and queue management processes. The Track 2 modifications need to be in place when the Cluster 15 studies resume so they can be applied to those studies. It is currently anticipated that the processing for Cluster 15 interconnections requests will resume second quarter, 2024.

[2] The MOU (http://www.caiso.com/Documents/ISO-CEC-and-CPUC-Memorandum-of-Understanding-Dec-2022.pdf) is an updated version of a 2010 MOU between the parties.

- The CPUC will provide clear direction to its jurisdictional load serving entities (LSEs) to focus procurement in the key zones;
- Procurement will focus on the expected quantities enabled by the planned transmission development, as set forth in the ISO's transmission planning process (TPP);
- State agencies—including non-CPUC jurisdictional authorities—and LSEs' resource planning and procurement will continue to significantly inform the ISO's TPP.

This approach is necessary because of the long development timeframe of transmission resources relative to many energy supply resources: Procurement of new energy supply resources must consider the availability of transmission resources to ensure reliable delivery of the supply resources to the grid. Also, supply resources will be stranded if they are developed before this infrastructure is planned, approved, permitted, and constructed.

The ISO is implementing a more proactive approach to transmission planning and managing projects through the transmission and generation development processes. This approach is grounded in open access and the policy and reliability needs of the state to inform queuing and procurement and facilitate project development.

The ISO's strategic intent is for the revised interconnection procedures to prioritize interconnection requests aligned with priority zones where transmission capacity exists or is approved for development. This will help shape the interconnection queue as the resource development community responds with proposed projects in areas enabled by transmission development. Additionally, it will drive resource development with the operational characteristics and in geographic locations consistent with resource planning conducted by the CEC, CPUC, and other local regulatory authorities (LRAs) and the ISO's transmission planning, which is based on that resource planning.

This initiative will focus on the specific changes necessary for the ISO's cluster study and queue management processes to achieve these outcomes while maintaining open access to the transmission grid. With the significant increase in projects in the queue, the existing tools to move projects to commercial operation are insufficient. There are 188 gigawatts (GW) in the queue pre-Cluster 15, and 354 GW in Cluster 15 alone. The ISO needs a significantly reformed structure to advance viable projects and prevent stagnant projects from hindering the progress of viable projects in the queue.

The ISO also understands the need to ensure consistent treatment of all LSEs and offtakers—CPUC-jurisdictional and non-jurisdictional—within the ISO footprint on matters of generator interconnection and transmission planning, and seeks to ensure opportunities for non-CPUC jurisdictional entities to have their project needs considered in the TPP.[3]

This initiative proposes certain tariff amendments to enhance the process for studying and approving interconnection requests and developing additional tools for managing the queue. The ISO plans for these proposed tariff changes to go only to the Board of Governors, not to the Western Energy Imbalance Governing Body, because the changes apply to the ISO-controlled grid and the ISO is not proposing changes to real-time market rules.

This Revised Straw Proposal describes a number of new or modified elements to the ISO's interconnection process for additional stakeholder consideration. In Section 3, the ISO describes the stakeholder working group process and implications of FERC Order No. 2023 on the Revised Straw Proposal elements and the initiative. Section 4 includes descriptions of the details of the Revised Straw Proposal elements related to interconnection request intake, and Section 5 outlines a number of proposed changes to the ISO's contract and queue management practices. Sections 6 and 7 outline next steps for the initiative and approvals.

1.1. Working Group Process

Recognizing the potential implications of significant interconnection reform on the ISO's stakeholders, the ISO engaged stakeholders in an intensive working group process to inform development of the Revised Straw Proposal. The ISO and stakeholders also need to respond to FERC Order No. 2023, which the ISO views as the new baseline for its interconnection process. The FERC Order will necessitate additional changes to the ISO's interconnection process, impacting the scope of this initiative.

During stakeholder working group meetings in summer 2023, the ISO and stakeholders developed the following agreed-upon principles and problem statements to assist in aligning objectives and developing solutions. Problem statements addressed two categories of challenges with the interconnection process; interconnection request

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[3] The ISO recognizes the need to define the term "offtakers" in future iterations of this proposal. Currently, the ISO reviews power purchase agreements (PPAs) with entities without a resource adequacy obligation to verify the agreement requires Full Capacity Deliverability Status, and to ensure there are no corporate relationships between the contracting entities. The CAISO rejects agreements that it deems are designed to circumvent the CAISO's tariff and purpose of prioritizing TPD allocation by groups to ensure that projects are considered for an allocation in order of viability based on contracting status.

intake and queue management. Once the ISO and stakeholders established agreed-upon principles and problem statements, working group meetings focused on proposed concepts and solutions. Stakeholders engaged by providing informal survey responses, candid feedback, experience, expertise, and thoughtful proposals that aligned with the agreed-upon principles and problem statements. The ISO greatly appreciates the time and effort stakeholders spent to shape this Revised Straw Proposal and improve the ISO's interconnection process.

1.1.1. Principles

1. Prioritize interconnection in zones where transmission capacity exists or new transmission has been approved, while providing opportunities to identify and provide alternative points of interconnection or upgrades.
2. Ensure meaningful study results that take into account system capability, resource planning and procurement. Resource planning includes the CEC, CPUC, and other LRAs engaged in these activities.
3. Align interconnection and transmission plan deliverability processes with resource procurement functions.
4. Enhance the procedures, including contracting and queue management, for ensuring projects proceed to commercial operation and determine how to appropriately handle those that do not.
5. Enhance the ability of the interconnection process to support the procurement necessary to meet CPUC resource portfolios and CEC SB 100 portfolios, and portfolios established by non-CPUC jurisdictional LRAs.
6. Enhance public awareness and accessibility of data and information to support and enable the above principles.
7. All Parties share increased responsibility to improve the interconnection process.

Parties agreed that in addition, the reforms must:

- Continue to ensure open access and avoid unduly discriminatory or preferential treatment, and
- Result in a process that is manageable, meaningful, and sustainable to the ISO and stakeholders.

1.1.2. Problem Statements: Interconnection Request Intake

1. Unsustainable increases in interconnection requests have overwhelmed Generator Interconnection and Deliverability Allocation Procedures.
2. Increases in interconnection requests have overwhelmed critical planning and engineering resources across the industry.
3. The Generator Interconnection and Deliverability Allocation Procedures, as currently designed, simply cannot efficiently accommodate the increased amount of interconnection requests.

4. Study results lose accuracy, meaning and utility when the level of cluster interconnection request capacity is multiple times the existing or planned transmission capacity for an area.
5. Lack of accurate, actionable information on the location and amounts of available interconnection and deliverability capacity prior to opening the interconnection request windows results in increased numbers of interconnection requests.
6. Although the issue of project viability is a widely discussed industry topic, it is not well defined and not currently considered for interconnection request acceptance criteria in the Generator Interconnection and Deliverability Allocation Procedures.
7. Stakeholders need to define which viability criteria are appropriate for a new interconnection request, the point in the process viability is tested and determine if process revisions are needed.
8. Technology solutions to enhance interconnection request intake, validation and study process may exist and should be explored for opportunities to increase process efficiencies and reduce time and staff requirements.
9. Timelines for design and construction of interconnection customer required upgrades continue to increase, negatively impacting achievable commercial online dates (CODs).

1.1.3 Problem Statements: Queue Management

1. Following the study process, a number of projects in the interconnection queue do not proceed to commercial operations as expected (e.g., delay executing a GIA, meet contract milestones) and remain in the queue without indication of their intent to proceed to contracting or construction.
2. The current processes for managing the queue present certain challenges for projects proceeding to commercial operation (e.g., modifications, limited operation study, commercial viability criteria) and challenges for the ISO's enforcement of projects that are not.
3. There is a lack of common understanding of what it means for a project to maintain 'viability' as it moves through the stages to achieve commercial operation.

1.2. FERC Order No. 2023 [Updated]

On July 27, 2023, the Federal Energy Regulatory Commission (FERC) Issued Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements.[4]

[4] The order was subsequently published in the Federal Register on September 6, 2023.

Because FERC compliance is a prescriptive process for the ISO, the ISO does not open compliance filings to stakeholder feedback. Nevertheless, because Order No. 2023 compliance and IPE Track 2 will substantially revise the CAISO's GIDAP, stakeholders should know that the ISO intends to comply with the order as fully and quickly as possible, with a compliance filing in early April 2024.[5] The vast majority of the ISO's resulting tariff revisions under Order No. 2023 will mirror FERC's revisions to its own *pro forma* procedures.

The ISO encourages stakeholders to focus comments and feedback in future workshops and working group meetings on issues distinct to the IPE initiative. Proposed Order No. 2023 reforms are therefore considered beyond the scope of this initiative. At a high level, these reforms include:

- Interconnection request requirements
- Information availability and heatmap
- Entry fees and deposits for queue entry
- Site control requirements as defined in FERC Order No. 2023
- Study process timelines
- Financial posting requirements and withdrawal penalties
- Affected system processes
- Consideration of grid-enhancing technologies
- Consideration of planned storage operation

Based on its initial read, the ISO does not foresee Order No. 2023 compliance having a significant impact on Clusters 14 or earlier; however, as a transitional measure, all interconnection customers without site control or executed GIAs may be required to have them sooner than the GIDAP currently contemplates. The ISO will communicate any new timelines and requirements for projects in clusters 14 and prior as early as possible to give stakeholders time to prepare.

Because the ISO must comply with Order No. 2023 and implement the proposals in this paper before commencing the Cluster 15 interconnection study, the ISO will maintain high volume in the queue in 2024. As such, the ISO does not expect to open an interconnection request window in 2024. The tariff requirements for such a cluster would be in flux, and additional queue volume would compound the challenges described below.

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5 FERC extended the compliance filing requirement from December 2023 to April 2024.

2. Interconnection Request Intake

2.1. The Zonal Approach: Data Accessibility [Updated]

Background

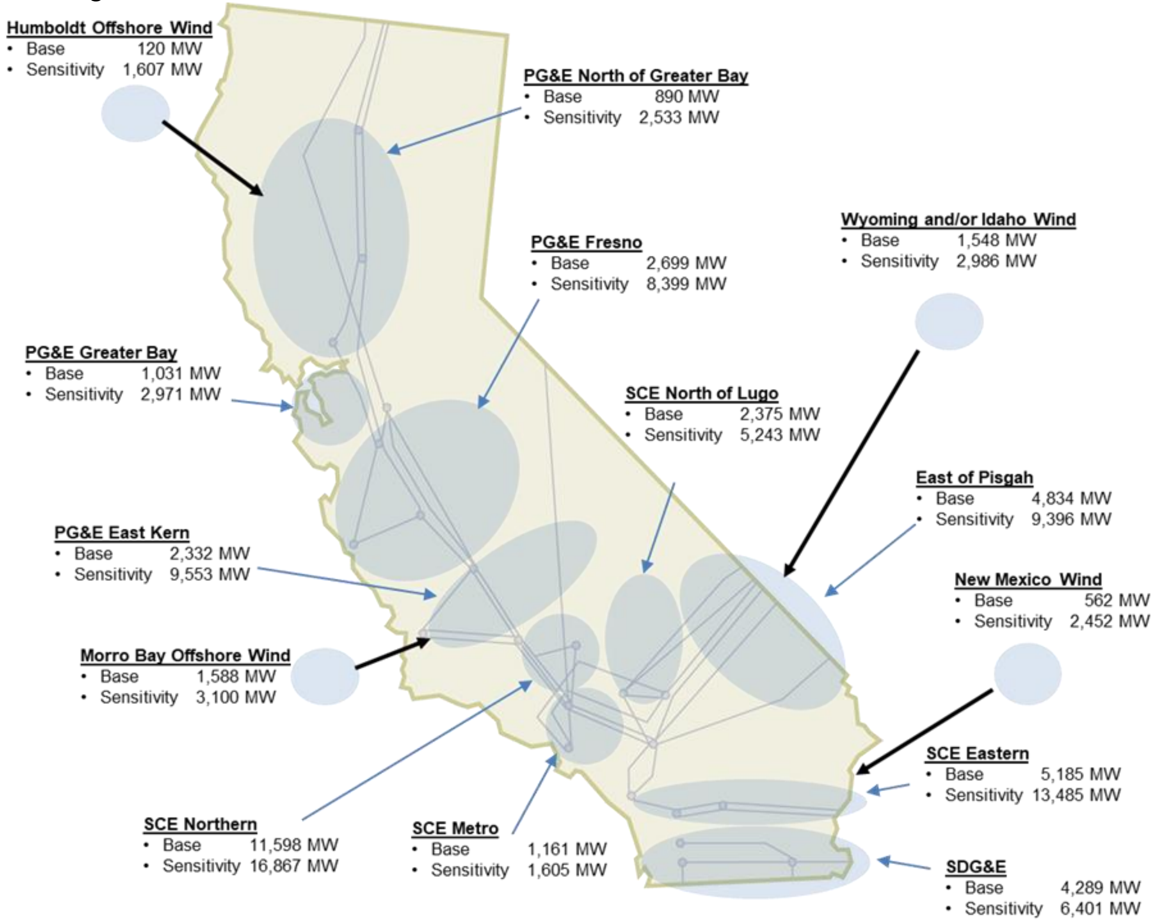
As noted in the first principle, a central tenet of the ISO's reform is the zonal approach: the prioritization of projects that seek to utilize available capacity and are in zones where there are planned capacity additions approved in the ISO transmission planning process as established in state and local regulatory authority resource planning portfolios. Along with this approach, the ISO understands the importance of maintaining open access and providing a path for projects that seek to interconnect where no transmission exists or has been approved.

The ISO relies in particular on the CPUC for its lead role in developing resource forecasts for the 10-year planning horizon, with both the ISO and CEC providing input to the CPUC for those resource forecasts. The ISO also relies on the CEC for its lead role in forecasting customer load requirements. The MOU signed by the three parties in December 2022 reaffirms our respective roles and commitment to ensure we are working in concert with one another. As such, the MOU also sets the overall strategic direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement so the three entities are synchronized in integrating new resources promptly.

The ISO's 2022-2023 Transmission Plan took a zonal approach to planning for the resources in the portfolio provided by the CPUC for this planning cycle, setting the foundation for the alignment of procurement and interconnection process enhancements, as envisioned in the MOU. Figure 1 identifies the transmission zones and the installed capacity of resources in the base and sensitivity portfolios provided by the CPUC for the 2022-2023 transmission planning process (TPP).[6] The transmission zones illustrated below are also aligned with the transmission interconnection areas used in the generation interconnection process.

[6] Figure 3.4-1 on page 63 of the ISO's Board Approved 2022-2023 Transmission Plan. http://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf

Figure 1. Transmission Zones and installed capacity of resources for the 2022-2023 Transmission Planning Process.



The CPUC has mapped the portfolios it generates with input from the CEC and the ISO to the substations[7] within each of the transmission areas or zones identifying the installed capacity and technology of the resources in the portfolios.

Table 1 lists the interconnection planning areas that the resources have been mapped to, based on the CPUC's busbar mapping effort. The table lists the transmission area/zone, substation, technology and capacity in the workbooks provided by the CPUC for the mapping of the resources.

[7] The resource-to-busbar mapping process is documented in the CPUC report entitled Methodology for Resource-to-Busbar Mapping & Assumptions for the Annual TPP with further refinements as described in the CPUC staff report entitled Modeling Assumptions for the 2022-2023 Transmission Planning Process. https://files.cpuc.ca.gov/energy/modeling/Busbar%20Mapping%20Methodology%20for%20the%20TPP_V2021_12_21.pdf
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF

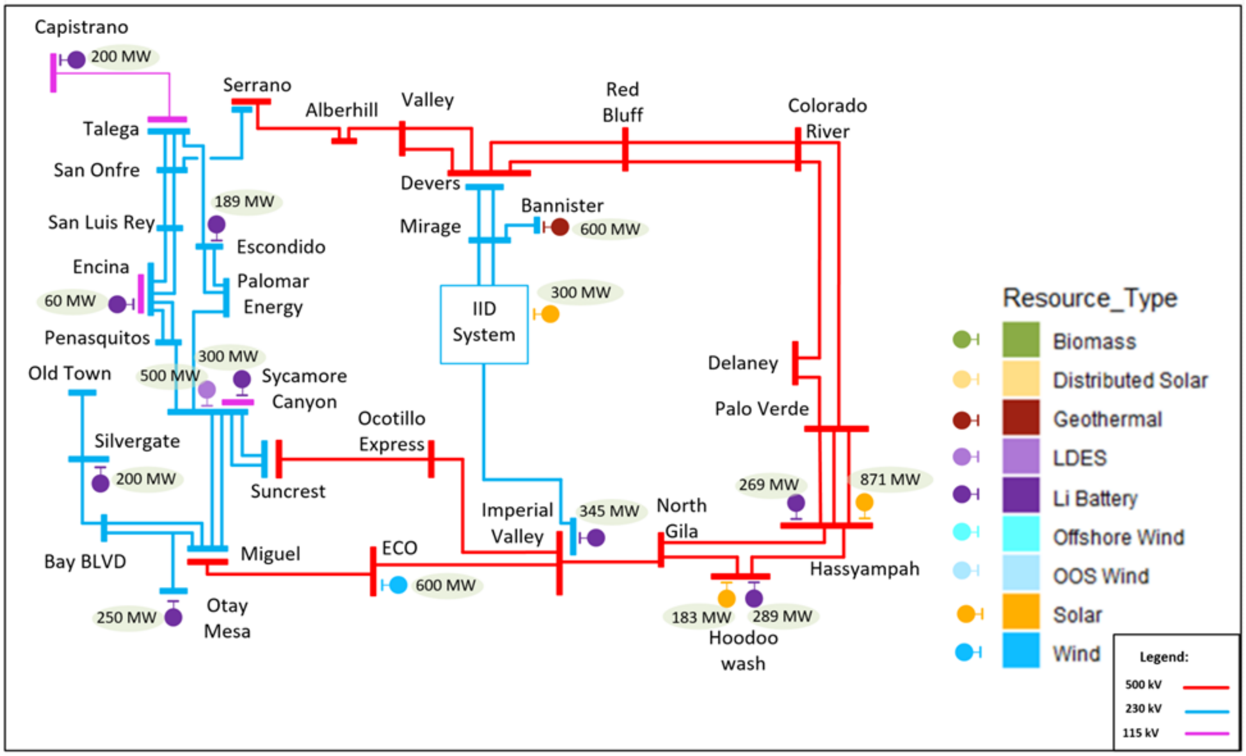
Table 1. Interconnection Planning Areas based on CPUC busbar mapping effort.[8]

				22-23 TPP 38 MMT Proposed Base Case Final Mapped Amount		
Transmisison Area	**Substation**	**Voltage**	**Resource Type**	**FCDS (MW)**	**EODS (MW)**	**Total (MW)**
PG&E Fresno Study Area	Alpaugh	115	Biomass/Biogas	3	-	3
SCE Northern Area	Antelope	230	Distributed Solar	3	-	3
SCE Northern Area	Antelope	230	Li_Battery	439	-	439
SCE Northern Area	Antelope	230	Solar	450	497	947
PG&E East Kern Study Area	Arco	230	Li_Battery	76	-	76
PG&E East Kern Study Area	Arco	230	Solar	125	28	153
SDG&E Study Area	Bannister	230	Geothermal	600	-	600
SCE Metro Study Area	Barre	230	Li_Battery	10	-	10
East of Pisgah Study Area	Beatty(VEA system	138	Geothermal	440	-	440
PG&E North of Greater Bay Study Area	Bellota	115	Biomass/Biogas	4	-	4
PG&E North of Greater Bay Study Area	Bellota	115	Li_Battery	132	-	132
SCE Northern Area	Big Creek Hydro Fa	230	Biomass/Biogas	6	-	6

The ISO’s 2022-2023 Transmission Plan provided a single-line diagram for each of the transmission zones indicating the capacity and technology type where the resources in the portfolio were mapped to the electrical grid in the zone. Figure 2, below, is an example of the resource mapping in the San Diego transmission zone from the 2022-2023 Transmission Plan.[9]

[8] https://files.cpuc.ca.gov/energy/modeling/BusbarMapping_Dashboard_38MMT_V2022_02_08_v2.xlsx
[9] Figure 3.5-15 on page 96 of the ISO’s Board Approved 2022-2023 Transmission Plan. http://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf

Figure 2. Example of resource mapping in the San Diego transmission zone.



In the ISO's annual transmission plan, the ISO assesses the reliability of the transmission system to meet the forecasted load requirements and ability to deliver resources to load for the resources identified in the CPUC portfolios. If needs are identified in the base resource portfolio, the ISO assesses alternatives to determine the transmission mitigation solution to be recommended to the ISO's Board of Governors for approval in the transmission plan. In determining the best solution for the base case needs, the ISO also considers the sensitivity portfolios.

In addition to information in the transmission plan, the ISO provides data on the capability within the transmission zones in the ISO's Transmission Capability Estimates for the CPUC's Resource Planning Process[10] and for the ISO's annual Transmission Plan Deliverability Allocation Report.[11] Within the workbook for the transmission capability estimates for identified constraints in each of the transmission zones/areas, the available Transmission Plan Deliverability (TPD) is identified associated with the constraint along with the area deliverability network upgrade (ADNU) that would be

[10] https://www.caiso.com/Documents/White-Paper-2023-Transmission-Capability-Estimates-for-use-in-the-CPUCs-Resrouce-Planning-Process.pdf
[11] https://mpp.caiso.com/tp/Documents/2023%20TPD%20Allocation%20Report.pdf (on Market Participant Portal)

needed to increase the TPD. For each ADNU, the estimated increase in TPD and the estimated cost and duration to construct the ADNU is provided. Some constraints may overlap more than one of the transmission zones. Table 2 illustrates the constraints in the San Diego transmission zone, as an example.

Table 2. Constraints in the San Diego Transmission Zone[12]

Transmission capability estimates for use in the CPUC's IRP process - Revised 6/28/2023						
Transmission Constraint	Affected Resource Locations	Condition Under Which Constraint is Binding (On-peak and/or Off-peak)	Estimated FCDS Capability Based on On-peak Study Resource Output (MW)**		ADNU & Cost Estimate ($million)	
			Transmission Plan Capability***	Incremental due to ADNU	ADNU (Time to Construct)	Cost (2022$)
SDG&E Interconnection Area Constraints						
Capistrano-San Onofre 230 kV constraint	SDGE local area	On-peak	1,500	920	Capistrano-San Onofre 230 kV upgrade (60 months)	$58
Chicarita 138 kV constraint	Baja, Imperial, SDGE local area	On-peak	224	700	Chicarita 138 kV Upgrades (48 months)	$100
El Cajon 69 kV constraint	SDGE local area	On-peak	406	547	El Cajon 69 kV Upgrade (48 months)	$15
Internal San Diego Area constraint	Baja, Imperial, SDGE local area	On-Peak, Off-Peak	1,001	2,757	Internal San Diego Area reconductors (48 months)	$107
Miguel 69 kV constraint	SDGE local area	On-peak	231	431	Miguel 69 kV upgrades (48 months)	$671
Encina - San Luis Rey 230 kV constraint	Baja, Imperial, Arizona, SDGE local area	On-Peak, Off-Peak	1,922	4,660	New Encina - San Luis Rey 230 kV line (120 months)	$84
East of Miguel constraint	Baja, Imperial, Arizona, Riverside East	On-Peak, Off-Peak	1,035	1,286	New Imperial Valley - Serrano 500 kV line (188 months)	$2,713
San Luis Rey-San Onofre 230 kV line constraint	Baja, Imperial, Arizona, SDGE local area	On-Peak, Off-Peak	2,018	4,254	New San Luis Rey-San Onofre 230 kV line (120 months)	$107
Ocean Ranch 69 kV constraint	SDGE local area	On-peak	274	692	Ocean Ranch 69 kV upgrade (48 months)	$28
Otay Mesa 230 kV constraint	Imperial, SDGE local area	On-peak	1,425	2,189	Otay Mesa 230 kV upgrade (60 months)	$80
Silvergate - Bay Blvd 230 kV constraint	Baja, Imperial, SDGE local area	On-Peak, Off-Peak	663	4,887	Silvergate - Bay Blvd 230 kV 3-ohm Series Reactor (36 months)	$30
Silvergate-Old Town 230 kV constraint	Baja, Imperial, SDGE local area	On-peak	1,221	2,522	Silvergate-Old Town 230 kV Upgrades (60 months)	$283
Talega 230 kV constraint	SDGE local area	On-peak	1,205	2,201	Talega 230 kV Upgrades (60 months)	$211
Trabuco-Capistrano 138 kV constraint	SDGE local area	On-peak	501	556	Trabuco-Capistrano 138 kV upgrade (48 months)	$103

Below, Figure 3 and Table 3 from the 2023 Transmission Plan Deliverability Report[13] illustrate the transmission system area for one constraint within the San Diego transmission zone. Table 3 also includes the requested TPD, allocated TPD, and remaining TPD for one of the transmission constraints in the transmission zone. The report indicated that TPD is allocated to the TPD candidates after first preserving capacity for the 2,148 MW prior commitment that is not yet operational, and that there is no available TPD for the eligible candidates.

[12] http://www.caiso.com/Documents/Transmission-Capability-Estimates-for-use-in-the-CPUCs-Integrated-Resource-Planning-Process.xlsx

[13] Figure 4.1 and Table 4.2 on page 22 of the 2023 Transmission Plan Deliverability Allocation Report. https://mpp.caiso.com/tp/Documents/2023%20TPD%20Allocation%20Report.pdf

Figure 3. Map of transmission system area for one constraint within the San Diego transmission zone

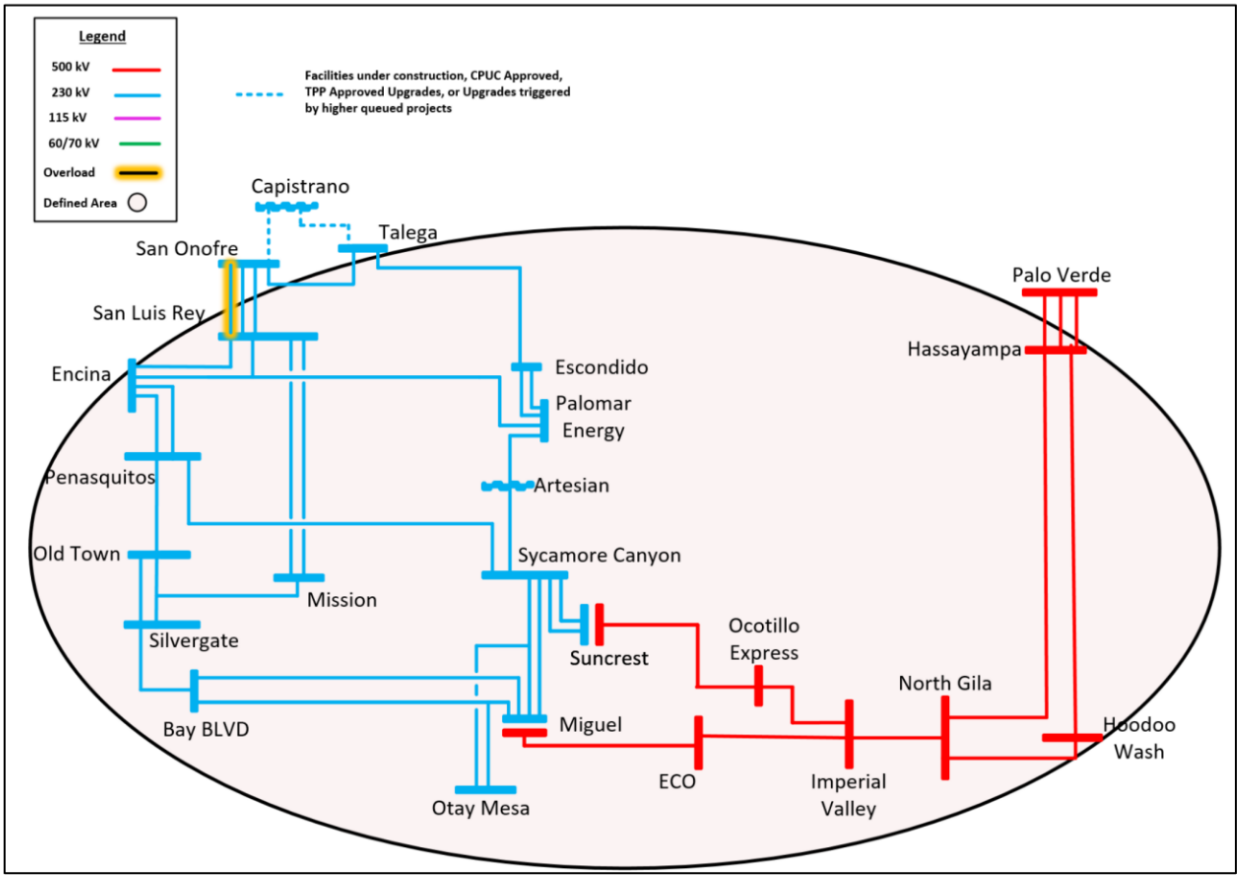


Table 3. Available TPD for one constraint within the San Diego transmission zone

Non-Operational Prior Commitment (MW)	2148
Eligible TPD Candidate (MW)	2747
TPD Allocated (MW)	0
Remaining TPD available (MW)	0

The PTOs provide additional information on interconnection requirements in their respective Transmission Interconnection Handbooks.[14] This includes information on specific POIs that cannot accommodate further interconnections. The ISO suggests that stakeholders review the information noted above when assessing potential points of interconnect they are considering. Whenever possible, the ISO will reference or document this guidance to ICs prior to the interconnection request window.

In summary, for each major constraint limiting TPD capacity in a zone, the following information is available: the constraint, the limit imposed by the constraint, the cost and timeline associated with mitigating the constraint, the amount of TPD capacity that has already been allocated, and the capacity remaining and available for future allocation (if any).

Stakeholder Feedback

Throughout working group discussions, stakeholders have emphasized the importance of (1) data transparency and accessibility to inform developers on where transmission capacity would be located, the costs of interconnection, and the timing of interconnection and (2) an alternative self-funding path to enable projects to interconnect outside of the priority zones.

Stakeholders were generally supportive of the zonal approach in the proposal. Most stakeholders requested more clarification and definition of zones and boundaries, and the determination of where available capacity within the zones is available.

The following is a summary of the comments provided on the Straw Proposal and working group sessions:

Some parties, such as CalWEA, Intersect Power, SB Energy, and Strata Clean Energy expressed concerns with the zonal approach. Intersect power stated “The zonal approach has several unnecessary complications including, but not limited to:
(i) necessity to accurately define the zones geographically/electrically, (ii) determination of the base zonal capacities (which are inherently dynamic and heavily influenced by processes such as the TPP), (iii) rationalization and establishment of an arbitrary zonal capacity buffer (e.g., 150% of available or planned capacity), and (iv) necessity for

[14] Pacific Gas & Electric. Transmission Interconnection Handbook, Section G2
Southern California Edison. The Interconnection Handbook (Rev 12)
San Diego Gas & Electric Company. Generation Interconnection Handbook. 24 April 2023.

bespoke Option B pathways." SB Energy added concern that the zonal approach had "the potential to drive-up resource adequacy costs due to limited supply."

Many stakeholders voiced concern that the information CAISO has committed to provide to comply with FERC Order 2023 will not be available with sufficient time before the refresh period for Cluster 15.

AES submitted a proposal for an Annual Report containing:

- POIs in each zone,
- existing and planned deliverable capacity in each zone,
- map and status of current queue in each zone,
- line diagram identifying substations in each zone, identified constraints for each substation,
- the MW ability for each substation to be expanded, and
- transparent price range per MW for interconnection in each TPP zone with a price cap.

The AES proposal was supported by nearly all stakeholders. AES recommended that the ISO publicize this information at least 6 months, but ideally 12 months, prior to the queue opening.

AES, Intersect Power, LSA, and New Leaf Energy requested confirmation of whether projects are inside or outside of a zone with available capacity.

ACP suggested an expansion of the definition of a zone to include an area where "transmission capacity is expected to be approved in the next TPP based on the busbar mapping from the CPUC's resource portfolios."

CalWEA, Intersect Power, and LSA asked to which clusters will TPP capacity additions applied and how much TPD will remain available after prior clusters.

Calpine requested in comments that the ISO hold a workshop to review the information being provided and how it will be used to determine the zones and capacity values. Many other stakeholders supported this approach in working group meetings.

CalCCA and Sonoma Clean Power Authority asked the following questions:

- Is available capacity equivalent to available transmission plan deliverability (TPD) or does it include all unused capacity (which may include projects in the queue that already secured TPD)?
- Will projects be counted using their maximum capacity (Pmax) at the interconnection or using a methodology consistent with the generator interconnection and deliverability allocation process?

- Are “zones” equivalent to the TPD constraint zones or the broader “transmission areas” depicted in Figure 1 in the straw proposal?

The CPUC asked in what timeline/interconnection window the ISO will include deliverability for transmission upgrades expected to be placed into service in 10 years.

Vistra asked the ISO to clarify whether any of the information available will be provided by year, especially for points that may have interim capacity availability at a given point in time. Vistra also asked the ISO to develop a heatmap with available interconnection service capacity, available full capacity deliverability transmission capacity, and available Energy Only deliverability status.

Vistra and Terra-Gen asked how CAISO will provide the interconnection feasibility information for the POI outside transmission zones on its controlled grid.

PARS asked how the ISO plans to identify the impacts of a large approved transmission upgrade on multiple zones.

CalWEA reiterated support for its “Proposal to Effectively Address the Queue Overload While Preserving Open Access, Competition, and Resource Diversity” as presented at the July 11, 2023 working group meeting.

BAMx, Six Cities, and NCPA support the zonal approach proposal, but would like more information on the coordination. NCPA stated “the mere inclusion of non-CPUC-jurisdictional LSE resource plans into the TPP is not sufficient to ensure that the projects those LSEs need will actually be built. A more detailed plan to manage those projects in the study process is still needed.”

CalCCA requested that the ISO provide regularly updated information about existing projects in the queue that do not require any network upgrades, as the CAISO did in its May 22, 2023 presentation, to assist LSEs in project evaluation.

Pre-Queue Entry Information Framework was presented by Clearway Energy Group and supported by AES, Avantus, CalWEA, Clearway Energy Group, GridBright, GridWell Consulting, REV Renewables, Terra-Gen, and Vistra Corp. The proposal suggested that the following information be made available at least 9 months prior to the open queue window:

- Interconnection Feasibility at POIs identified in the CPUC portfolio
- Deliverability data at a granular level
- Cost guidance, estimates for RNUs
- Schedule guidance, timelines for RNUs

Discussion of Stakeholder Comments and Questions

Within the straw proposal, the ISO indicated that it was aligning the approaches of the transmission interconnection areas utilized in the annual transmission planning process and the interconnection process. The ISO uses the CPUC portfolios mapped to substations within the transmission interconnection areas and identifies transmission projects for approval in the annual transmission planning process to deliver the portfolio resources to loads. The same transmission interconnection areas are utilized in the generator interconnection areas. The ISO has developed transmission capability estimates, primarily from the generator interconnection cluster studies. The transmission capability estimates are also used by the CPUC in its portfolio development for available capacity within areas and cost of transmission upgrades to go beyond the capability of the existing and approved transmission grid. The transmission capability estimates provide constraints in the transmission interconnection areas that represent sub-zones for the areas of available transmission capacity available for the specific points of interconnections identified behind each of these constraints. The information provided on the interconnection areas, TPD allocated to queue resources and constraints will be used to determine locations with available capacity.

The CPUC and ISO have committed to working together to determine opportunities to align the timing of interconnection processes with the IRP planning and procurement process. The ISO views this coordination and alignment, in addition to coordination and alignment with the CEC and LRAs, as a critical and foundational element of the IPE initiative.

SB Energy indicated concern that the zonal approach had “the potential to drive-up resource adequacy costs due to limited supply.” The intent of the MOU between the CPUC, CEC and the ISO is to enable proactive planning of the transmission system to integrate the resources at the location identified in the CPUC portfolio with this information to be used by interconnection customers to determine where available transmission capacity is available for interconnection of resources.

A significant number of stakeholder comments relate to identifying where additional capacity is available within the zones and how transmission capability estimates are utilized to determine the available capacities within the zones and at specific points of interconnection. The ISO recognizes that the interconnection area and transmission capability information resides within many documents in different locations on the ISO website. The ISO will consolidate information for each of the interconnection areas into a single document for ease of reference. The documentation will include additional information such as the substations within each of the interconnection areas and the points of interconnection that were studied in development of the transmission constraint.

The ISO will not be able to provide the capacity for each substation to be expanded; however, information specific to substation POIs will become available with the heatmaps to be developed. In addition, the ISO is not able to provide a price range per MW for interconnection in each TPP with a price cap as this is dependent upon the location within the zone, capacity and which constraint(s) point of interconnection is behind. With regard to providing the information annually and within 6 to 12 months of the interconnection window opening, due to the timing of when information becomes available from the various study processes (i.e., annual transmission planning process, cluster studies, TPD Allocation) development of an annual report provided 6 to 12 months ahead of the cluster window opening would result in out of date or stale data. The ISO will update and provide notification when the data is available from the various processes. The ISO also will coordinate the process schedule so the most recent data is used in the current studies.

Regarding ACP's comment about including where transmission capacity is expected to be approved, the capability limits are based upon the information available at the time of studies. The ISO cannot speculate on what transmission might be approved in future transmission planning cycles. As indicated above, the ISO will review study schedules to ensure that the latest information is included in the subsequent study (i.e., approved transmission projects from latest transmission planning process included in the TPD allocation and cluster studies). This will include when large transmission projects are approved, such as the Southern reinforcement projects in the 2022-2023 Transmission Plan, to accommodate the resources within multiple interconnection areas in the portfolio. In the next cycle of studies such as the cluster study and TPD allocation studies where the approved upgrades are included, the available transmission capability and transmission constraints will be updated accordingly.

Calpine suggested, and many stakeholders supported, the ISO providing a workshop to go over the data that will be available and how this data can be used to determine where available capacity is available. The ISO agrees and has scheduled a stakeholder session on December 18 for this.

With respect to CalCCA and SCPA comments, the available capacity reflects the TPD that would be available after consideration of the TPD that has been allocated to projects within the queue. This is done using the methodology consistent with the generator interconnection and deliverability allocation process. The interconnection area in Figure 1 identifies where the ISO is planning for based on the CPUC portfolios mapped by resource type and to the specific substation identified in its busbar mapping process. The acknowledged constraints identify sub-zones within the interconnection area. The ISO will provide a list of POIs that are behind the constraints.

The most recent approved transmission are included in the cluster studies, where the transmission capability estimates have been developed, and the TPD allocation studies at the time of the studies and do not provide yearly availability of capacity. The ISO will expand the information provided in the TPD allocation studies to more clearly identify what transmission projects the TPD is dependent upon being in-service.

The ISO has initiated the process of developing the heatmap and the associated information identified by FERC in Order No. 2023. Per the order, the heatmap is to be available after the first Cluster Study and Restudy that the order applies to. The ISO is targeting to have the heatmap or a portion of it including the specific data by substation available in Q2 of 2024, reflecting the Cluster 14 – Phase II study results and the 2024 TPD allocation base case.

Regarding comments from Vistra and Terra-Gen on interconnection feasibility outside of transmission zones, the transmission current capability limits are based upon constraints identified in the latest Phase I study and provide significant capabilities on the system; however, there may be areas where the studies have not identified constraints or available capacity. The heatmap will provide information for all substation points of interconnection.

The ISO does not view the CalWEA ”Proposal to Effectively Address the Queue Overload While Preserving Open Access, Competition, and Resource Diversity” as presented at the July 11, 2023 working group to be in alignment with the principles and problem statements identified during early stakeholder working group meetings. The first several recommendations of the presentation (e.g. “no artificial limit on the number, size, or location of submitted interconnection applications,” and “all projects entering a queue cluster should be eligible for a scoping meeting”) run counter to the first two working group principles.[15] The subsequent recommendations assume studies will be completed in two phases. As the ISO describes below, this is no longer feasible under FERC Order No. 2023 requirements.

[15] Working group principles: 1) Prioritize interconnection in zones where transmission capacity exists or new transmission has been approved, while providing opportunities to identify and provide alternative points of interconnection or upgrades. 2) Ensure meaningful study results that take into account system capability, resource planning and procurement. Resource planning includes the CEC, CPUC, and other LRAs engaged in these activities.

The ISO will engage with non-CPUC jurisdictional entities regarding its approved resource plans to be included in the ISO's annual transmission planning process. And he ISO will consider these issues within the scoring criteria for prioritization to the study process.

The ISO updated information about existing projects in the queue that do not require any network upgrades on December 5, 2023. It will continue to provide updates as warranted.

Information on the interconnection network upgrades at the POI of resources in the queue that Clearway identified is currently only available within the individual Cluster Study reports (Appendix A). The ISO proposes to make the individual Cluster reports public on the ISO market participant portal with confidential information, as indicated in Sections 3.6 and 15.1 of Appendix DD of the CAISO's tariff, to be redacted. The ISO seeks feedback from stakeholders on what information, if any, should be redacted. The heatmap information also will provide transmission availability at the more granular level to the POI that Clearway has requested.

Proposal

A central tenet of this initiative is the prioritization of projects in areas with available transmission capacity for progression into the study process. This proposal reflects the first principle established by the working group to "Prioritize interconnection in areas where transmission capacity exists or new transmission has been approved, while providing opportunities to identify and provide alternative points of interconnection or upgrades." Projects or interconnection requests outside the zones will still have the option to self-fund network upgrades through a modified "Option B" process, as explained below. The ISO understands that access to information is critical for the zonal approach, and will provide stakeholders with information on the available transmission capacity within the transmission zones prior to the interconnection request window.

Accessible information

Much of the information necessary to understand where transmission capacity exists or has bene approved is currently available through a number of independent documents and workbooks. The ISO will consolidate the information for each of the interconnection areas into one document so that is easier to use to assess the available interconnection capability at points of interconnection. This currently available information includes:

- Single line diagrams of the interconnection area with the CPUC portfolio resources identified at the substations that the CPUC has mapped the resources to in its busbar mapping process;

- Transmission constraints that have been identified within each interconnection area, with the available TPD, the ADNU identified to increase beyond the current TPD along with the estimated cost and time to construct the identified ADNU; and
- Single line diagrams that identify the points of interconnections that were studied and that are behind each of the identified constraints.

In addition to the currently available information listed above, the ISO will provide:

- Listing of substations that are within each of the identified transmission interconnection areas;
- For each transmission constraint, the points of interconnection where resources in the queue were located in the studies behind the constraints.

As indicated, the resources identified within the CPUC portfolios mapped to the substations within the transmission interconnection areas are assessed in the annual transmission planning process. This is done to determine the capability of the existing transmission system and identify transmission projects for approval to address the constraints identified to deliver the capacity and types of resources to load at the locations identified in the CPUC portfolios. The transmission constraints in the Transmission Capabilities Estimates are used by the CPUC in the development of its portfolios. While the ISO is planning the transmission up to the resource identified in the CPUC portfolio in each of the interconnection areas, the specific constraints provide the capability of sub-zones within the interconnection area. A particular interconnection point may be identified behind more than one constraint, as some of the constraints are either nested within or overlap other constraints. The capability of a POI for resource interconnection needs to consider all of the constraints that it would be behind. The ISO will utilize the transmission constraint information along with the allocated TPD to determine available transmission capability for future clusters to be studied, as set out below.

Updated Queue Reports

The ISO updated the information within the Queue Report in Q2 of 2023 to include additional information for each project in the active queue, including:

- Which projects have TPD allocated to them as FCDS, PCDS (with percentages), or are Energy Only.

- The interconnection area where the queue project is located. The interconnection areas that are in the queue report do not reflect the current interconnection areas identified in Figure 1.

The ISO proposes to identify in the queue report where FCDS has been allocated and where FCDS has been requested and not yet allocated to each interconnection customer. The ISO will also update in RIMS the area information based on the current interconnection areas.

Interconnection Heatmap

FERC Order No. 2023 requires development of a heatmap, along with specific associated information, 30 days after the Cluster Study that No. Order 2023 applies to (i.e. Cluster 15), and 30 days after the restudy of that cluster study. The ISO is in the process of developing requirements for the heatmap and associated information and is working so the heatmap can be provided based on the Cluster 14 Phase II base cases as well as the 2024 Reassessment base cases; however, this will not be available 30 days after the Cluster 14 Phase II reports are issued. The ISO is targeting for the heatmap information to be available within Q2 of 2024. The heatmap will provide information at the POI level of available capacity based upon the generation that was included in the latest cluster study and after the restudy. In addition to providing the heatmap based upon the latest cluster study and restudy, the ISO proposes to provide the heatmap information after the annual TPD allocation study. Additional information will be provided to generators assessing potential points of interconnection by virtue of having the heatmap information of available capabilities based on the resources that were studied in the latest Cluster Study/Restudy, as well as the available capacity after the TPD has been allocated.

Interconnection Area Reports

The ISO currently makes the Interconnection Area Reports from each Cluster Study publicly available on the ISO's market participant portal. This provides details of the Cluster Study and the associated network upgrades that have been identified. The Interconnection Area reports do not include the specific interconnection network upgrades required to interconnect the generator at the specified POI.

The ISO proposes to post the individual interconnection reports on the ISO market participant portal in Appendix A of interconnection reports. They will be in redacted form removing confidential information. Appendix DD of the ISO tariff in Section 3.6 states: "Except in the case of an Affiliate, the list will not disclose the identity of the Interconnection Customer until the Interconnection Customer executes a GIA or requests that the applicable Participating TO(s) and the CAISO file an unexecuted GIA with FERC." At a minimum, this information will be redacted, unless an LGIA has been executed, and will assess if any additional information in the reports should be considered confidential. This will provide generators information on available interconnection capability and potential interconnection requirements at points of interconnection being considered.

Non-CPUC jurisdictional LSE Resource Plans

In addition to the portfolios received by the CPUC for the annual transmission planning process, the ISO will coordinate with the LRAs and non-CPUC jurisdictional entities to determine their approved resources in their individual IRPs to include in the transmission planning analysis. As part of the 2024-2025 transmission planning process the ISO will request the non-CPUC jurisdictional entities to provide their current approved resource plans as input into the development of the study plan that the ISO will engage stakeholders on in February.

2.2. Interconnection Request Requirements and Review [Updated]

Throughout this initiative and working group process, the ISO and stakeholders have explored new or elevated requirements (financial and non-financial) for a complete interconnection request as a means to require a greater level of project readiness before study. In addition, stakeholders considered mechanisms to incorporate LSE input on priority projects, scoring criteria, and higher fees and deposits.

The detailed proposals below seek to comply with new FERC requirements, address stakeholder concerns and proposals, and gather information necessary to evaluate project readiness and inform prioritization of projects that advance to the study phase. The ISO proposes the following requirements and procedural steps during the interconnection request intake and review window:

1. Site control requirements consistent with FERC Order No. 2023, applied to Cluster 15.
2. Entry fees and study deposits consistent with FERC Order No. 2023.

As discussed below, the ISO no longer proposes to require interconnection customers to submit sealed bids for the potential zonal auction with interconnection requests.

Upon submittal of an interconnection request, the ISO proposes to apply scoring criteria to advance the most "ready" projects into the study process for each zone. If the scoring criteria does not sufficiently reduce the capacity to be studied in each zone, the ISO proposes a sealed-bid auction. The ISO explains each component, below.

2.2.1. Site Control [Updated]

FERC Order No. 2023 increases the site control requirement to 90% upon submission of an interconnection request; therefore, the IPE process will no longer consider changes to the current site exclusivity requirement. The ISO will comply with the site control requirements established in Order No. 2023. Cluster 15 interconnection customers will need to provide site control documentation by the end of the request validation process, or they will not be included in the cluster 15 study.

2.2.2. Entry fees and deposits

Likewise, Order No. 2023 imposes several new entry fees and study deposits. Stakeholders have suggested that the ISO reconsider current levels of entry fees and study deposits, but the ISO does not propose such changes at this point.

2.3. Interconnection Request Limitations [Updated]

To ensure that no developer can overwhelm the processing of interconnection requests during a cluster window process, or try to capture an inappropriate share of the available transmission capacity, the ISO Straw Proposal recommended limiting the number of requests that a developer may submit in any given cluster application window to 25% of the available transmission MW capacity across the ISO footprint for that cluster.

The ISO has received significant opposition to this proposal, primarily from the development community, and has been asked to provide clarity on the rationale for such a limitation. In previous clusters, and in several instances, the ISO has received over 20 interconnection requests from individual companies (Figure 4). As discussed during working group meetings, the ISO's initial intent was twofold; to align the number of interconnection requests with the resource portfolios, and to ensure competition before and after the study process.

Parent Companies	IRs Submitted
27	1
9	2
18	3-5
10	6-10
7	11-20
3	21-35

Figure 4. Interconnection Request numbers by parent company (Cluster 14)

The ISO's goal is to balance access to the queue with reasonableness, and ensure the ability to process and score future interconnection requests in a timely manner, consistent with the Order No. 2023 timeline.

While the original mechanism proposed presents some implementation challenges, the ISO will continue to explore various mechanisms to achieve a total interconnection request capacity limit and/or a cap on the total number of requests per parent company if it does not move forward with the capacity cap. The ISO continues to believe that some limitation is necessary to maintain manageable levels of interconnection requests, beyond Order No. 2023 site control requirements.

Proposal

The ISO proposes to prevent excessive numbers of interconnection requests from any one parent company. This limit will reflect the total amount of system need in a given year, based on the year-ahead target from the resource planning portfolios used in the TPP process. The ISO proposes to limit interconnection request capacity to 25% of the total available transmission capacity for a particular cluster. This limit is scalable to the total available transmission capacity for a cluster, ensures consistency and alignment with planning and procurement efforts.

2.4. Scoring Criteria for Prioritization to the Study Process [Updated]

Background

In the Discussion Document, the ISO raised the possibility of instituting a scoring process based on criteria that would rank interconnection requests on their readiness. The scoring process would be the first and potentially final process for determining the projects that would be studied in each of the transmission zones. If the scoring process does not result in enough diversity in project scores to produce a project ranking that clearly determines the projects that would be studied in each transmission zone, a second mechanism would be needed.

The ISO also sought feedback in the Straw Proposal on how best to incorporate LSE interest earlier in the process. Doing so would help satisfy the MOU goal of aligning resource and transmission planning with procurement and interconnection.

Stakeholder Feedback

Many stakeholders supported the use of simple, objective scoring criteria consistent with the project development process to evaluate readiness of interconnection requests vying to progress to the study. A number of stakeholders submitted proposals to assess project readiness. Multiple stakeholders noted that some of the suggested scoring criteria appeared to be duplicative. Specifically, the majority of stakeholders strongly opposed the use of PPAs or permitting milestones as criteria to advance to the study process, noting that these are more appropriate milestones to evaluate much later in the project development process.

Avantus and Leeward Renewables commented that the criteria may be too generic and not sufficiently granular to avoid ties. Rev Renewables expressed general concern that the overall scoring process may not be successful; and New Leaf commented that the scoring is too restrictive. EDF-Renewables, GridStor, and Upstream favored a gating process that scales requirements as projects proceed further into the study process in lieu of scoring criteria. Vistra advocated for moving the process in the direction of a “first ready, first served” cluster process. Sonoma Clean Power’s proposal to use a remaining import capability (RIC) type mechanism for scoring based upon LSE interest was also favored by California Community Choice Association.

In recent working group discussions, a growing number of generation developers reiterated a recommendation to move toward a stage-gating approach to evaluating project readiness, with increased financial deposits to be used as initial requirements to submit an interconnection request.

Discussion of Stakeholder Comments and Questions

The ISO understands that some development companies are more comfortable with financial requirements at this stage in the process, particularly without assurance that interconnection costs or timelines will be known prior to the interconnection request window. However, as noted above in the discussion of the zonal approach, the ISO is committed to providing as much information as possible in as accessible format as possible to stakeholders to maximize awareness with the queue and the transmission sub-zones. While the ISO will consider increased financial deposits associated with interconnection requests as this initiative moves forward, these types of requirements may not be the optimal measure of project readiness.

Avantus sought clarification on whether expansion of an operational facility applies to phased projects that intend to share facilities where the earlier stages are not yet operational (in study or in construction). The ISO intends to award points to expansion of projects that are operational, rather than to projects that are potential expansions of other projects in the development process. Ascribing points to a project that expands upon another project that is not yet operational would add significant ambiguity to the validation process. Additionally, MN8 asked for more detail on how the expansion of an operational facility would function as an indicator of readiness. The ISO understands that there may be several development advantages and cost savings associated with this type of expansion, including reduced permitting requirements, reduced costs, and the potential ability to avoid requiring a new position at a substation.

In both written comments and during working group meetings, stakeholders such as GridStor, Golden State Clean Energy, and others expressed a desire to clarify the difference between—and ultimately recommended that the ISO combine—the categories of “LSE interest” and “commercial viability” as both categories sought to evaluate the likelihood of a project proceeding to PPA execution and commercial operations. The ISO appreciates the efforts of LSEs, led by Southern California Edison, to develop a mechanism for LSEs to allocate points in the scoring process to desirable projects.

Feedback strongly favored removing any points associated with a PPA from the scoring criteria, as stakeholders felt that commercial milestones (e.g., shortlisting, term sheets, and PPAs) were more relevant indicators of progress after interconnection studies. The ISO agrees and proposes to remove those commercial milestones and permitting indicators from the scoring criteria.

LSA asked whether the scoring is applicable to Energy Only capacity projects, or projects inside or outside transmission zones. LSE and New Leaf asked the ISO to clarify any difference between “load pockets” and Local Capacity Areas in the proposals. The distinction is where the CPUC identifies significant retirements that trigger new transmission. The portfolios distinguish between resources that have FCDS capability vs. Energy Only capability. One option is for the ISO to only study Energy Only projects that are awarded points by an LSE.

GridStor proposal included several levels of scoring resources located in Local Capacity Resource (LCR) area, such as:

- Where current CPUC Preferred System Plan assumes resource retirements in LCR area;
- Where local RA deficiencies identified in LCR area or sub-area;
- Where LSE or Central Procurement Entity has documented procurement challenges in LCR area;
- Provides local RA within an LCR area on a 1:1 replacement basis;
- Provides local RA within an LCR area on a less than a 1:1 replacement basis

The ISO believes that GridStor's proposal for scoring in LCR areas does not address the ability to charge new storage resources in an LCR area without the addition of resources to charge them or new transmission to support their charging requirements. It also duplicates LSE procurement based on RA and LCR needs. The proposal will focus on readily available information on a demonstrated need for additional capacity in that local area and the issue of sufficient capacity being available in the LCR area to charge any proposed new energy storage facilities without needed additional transmission, as outlined in the annual local capacity technical study.

Gridstor also proposed several indicators of system need matching procurement, however stakeholder comment and discussion indicated that this category of scoring criteria was both unnecessary and difficult to validate. The alignment with portfolios and procurement direction from the CPUC and other LRAs should be inherent in the zonal approach and the LSE interest portions of the scoring criteria. As a result, the ISO does not propose use of these criteria.

Proposal

The ISO proposes to continue to move forward with scoring criteria as a key mechanism to ensure that the most ready projects advance to the study process, and has significantly revised the proposal based on stakeholder feedback and working group discussions. The ISO does not propose a threshold minimum score that projects must meet, but rather intends to advance the highest-scoring projects to the study process regardless of numeric scores. The revised criteria, described below, still require stakeholder feedback and discussion regarding the appropriate level of granularity and opportunities to easily validate scores.

The ISO proposes requiring interconnection customers to submit documentation supporting their score, as well as a self-assessment score sheet with their interconnection request(s) to minimize time required for the ISO to score and validate a large batch of requests in a narrow window.

LSE Interest

In the Straw Proposal, the ISO encouraged more discussion and stakeholder feedback on opportunities to incorporate LSE procurement activities[16] earlier in the interconnection process with the goal of facilitating the zonal approach and appropriately sequencing implementation of these practices for a more efficient process.

The ISO proposes moving forward with a simplified version of a proposal that SCE developed with a group of LSEs (CPUC-jurisdictional and non-jurisdictional) to create a three-step system to assess LSE interest as part of the scoring process:

1. The ISO calculates total LSE capacity allocation.

In this process, the ISO would determine how much capacity (MW) can be allocated across the CAISO footprint, based on available and planned transmission capacity. SCE proposed that 35% of the total TPD capacity be eligible to receive points in order to ensure that LSEs are selective in point allocation. The ISO agrees that there should be some reduction of eligible capacity to receive points, but is open to stakeholder feedback about what the appropriate reduction should be.

Example:
Assume total TPD capacity across CAISO footprint is 45,000 MW.
Total LSE Capacity Allocation = TPD Capacity x LSE Weighting Factor
= 45,000 x 0.35
= 15,750 MW (to be shared by all LSEs)

2. The ISO calculates individual LSE capacity allocation.

In this step, the ISO would determine how much capacity (MW) the CAISO can award to each individual LSE based on its load share[17].

[16] Activities could take a number of forms, including results from LSE requests for information or offers, project screening, bilateral discussions, and narrowing the list of projects to those of interest within their procurement processes.
[17] Load share based on the California Energy Commission's energy demand peak load forecasts for LSEs published in their annual Integrated Energy Policy Report.

Example:
LSE 1 Load Share = 30%
LSE1 Capacity Allocation = Total LSE Capacity Allocation x LSE Load Share
= 15,750 MW x 0.30 = 4,725 MW
LSE 1 is eligible to allocate 4,725 MW of project capacity

3. LSE allocates points to selected projects submitted in the cluster window for new applications

Each LSE determines how they want to allocate their points to selected applications.

Assumptions:
LSE 1 Load Share = 30%
LSE 1 Capacity Allocation = 4,725 MW (provided by CAISO in Step 2)
LSE 1 Scenario 1 = Two 300 MW Projects (P1 and P2)
Full Support of P1 and P2
Capacity allocation needed to fully support P1 and P2 = Total capacity in each Application x Number of Applications = 300 MW x 2 = 600 MW (LSE 1 has 4,125 MW capacity allocation remaining)
P1 and P2 receive the full points available to a project in the scoring criteria (because 100% of the capacity of each project was selected by an LSE)

LSE 1 Scenario 2 = One 1,000 MW project (Project 3) and LSE 1 has partial interest of 500 MW of the project (50% of project capacity was selected by LSE 1)
Partial Support for Project P3
Capacity allocation needed to support P3 = Partial Interest MW Interest = 500 MW (LSE 1 has 3,625 MW capacity allocation remaining)
Partial Capacity Interest / Full Project Capacity x Max. Points in Off Taker interest Category
P3 points = 500/1000 = 50% of the points available to a project in the scoring criteria (because 50% of the capacity of P3 was selected by LSE 1)

If P3 does not receive any additional interest from other LSEs to increase its score, the interconnection customer would have the option to be scored based on 50% of the points available to a project in the scoring criteria or to downsize to 500 MW and receive the full points available to a project in the scoring criteria. (There are intermediate downsize options where P3 could downsize to 750 MW and receive 750/1000 = 75% of the points available to a project in the scoring criteria.)

The ISO acknowledges the complexity and the additional process time it would require to implement this proposal, but finds it worth exploring. The ISO would initially propose that after the interconnection request window closes, the information required by the LSEs to evaluate the projects would be made available to them on a confidential basis. The LSEs would be given some amount of time to evaluate the projects and provide the ISO with their elections, possibly 30 calendar days. Further stakeholder and internal discussion will define the optimal timing.

Non CPUC-jurisdictional LSEs

With any scoring process, the ISO proposes to automatically include any project that a non-CPUC jurisdictional LSE demonstrates is a preferred resource in its resource plan that has been approved by its Local Regulatory Authority (or where no approval is required). These projects will be included in the group of projects comprising the 150% available capacity that move forward to the study process. Interconnection requests for projects that have been recently approved by a non-CPUC jurisdictional LSE's Local Regulatory Authority may not be far enough along in the development process to qualify for scoring beyond the capacity allocated by the LSE to the project. It is possible such a project is important to the LSE and delaying the project could be detrimental to the LSE. Since the project would already have progressed through the LSEs procurement process, it should be able to move forward and be studied.

Project Viability

The ISO considered criteria suggested by stakeholders and selected criteria the ISO believes are appropriate early in the interconnection process. The ISO also preferred those criteria easily validated with interconnection requests during the cluster request window. To assist in the ISO's validation process, the ISO will require interconnection customers to provide both a self-assessment and proof of each scoring criterion below.

Some commercial and permitting criteria like PPAs or permitting success may be improbable to expect before the study process, and difficult to validate for ISO staff. The ISO no longer proposes inclusion of these criteria in the scoring process.

The ISO proposes four indicators of project viability, with the entire category comprising 30% of the overall scoring weight.

- Demonstration of business partnerships for future supply of major equipment prior to COD
- Submittal of an Engineering Design Plan
- Expansion of an existing facility

- Expansion of an existing facility where the existing Gen-Tie already has sufficient surplus capability to accommodate the additional resource

The ISO invites stakeholder feedback on these specific proposed criteria. In particular, the ISO is concerned that the first two criteria (demonstration of business partnerships and submittal of engineering design plan) are very achievable for interconnection customers, and may be unnecessary to include for points if each interconnection customer can provide them. However, our goal is to increase criteria to provide a more granular assessment of project viability.

System Need

The ISO proposes two additional indicators of system need, which together would make up 30% of the overall scoring weight:

- Ability to provide Local Resource Adequacy in an LCRA with an ISO-demonstrated need for additional capacity in that local area.
- Long lead-time resources: Meets the requirements of the current CPUC resource portfolio where the TPP has approved transmission projects to provide necessary transmission requirements. This includes resource types that are considered for central procurement under Assembly Bill 1373 (2023), or as specifically identified by the CPUC in the portfolio provided to the ISO for use in the transmission planning process.

The ISO requests additional stakeholder comments on the revised scoring criteria regarding the reasonableness of interconnection customers to provide information at the interconnection request application stage, how to make the scoring rubric (and range of potential points) more granular while retaining objectivity, and the expected ease of validating scores within the interconnection request window.

The table below provides the ISO's current proposal. The total score is to demonstrate the concept, where in this example a project qualifies for each scoring criterion. The ISO proposes to use weighted scoring, multiplying the total points value by the weight to calculate the total score for each category.

Indicators of Readiness	Points	Weight (%)	Weighted Points	Validation
LSE Interest (Numeric value)				
□ Preferred resource in non-CPUC jurisdictional resource plan that has been approved by Local Regulatory Authority	Automatically advances			
□ Points based on the percentage of capacity allocated by LSEs to the project (e.g. a 500 MW project receiving 500 MW capacity allocation would earn 100 points for this category. A 500 MW project receiving 250 MW capacity allocation would earn 50 points for this category.)	100	40%	**40**	LSE communication
Project Viability (check all that apply)				
□ Demonstration of business partnerships for future supply of major equipment prior to COD	15	30%	**30**	Affidavit of Master Services Agreement or Purchase Order[18]
□ Engineering Design Plan[19]	15			Engineering design plan submitted to ISO with IR
□ Expansion of an existing facility	30			IC submits information indicating that new IR uses same or directly adjacent site from existing facility
□ Expansion of an existing facility where the existing Gen-Tie already has sufficient surplus capability to accommodate the additional resource	40			IC submits information indicating that new IR uses same or directly adjacent site from existing facility
System Need (check all that apply)				
□ Ability to provide Local Resource Adequacy (RA) in an LCRA[20] with an ISO demonstrated need for additional capacity in that local area	40	30%	**30**	
Long Lead-time Resources[21] □ Meets the requirements of the current CPUC resource portfolio where the TPP has approved transmission projects to provide necessary transmission requirements	60			
Total		100%	**100**	
Distribution Factor	Value	Tie-Breaker		
□ Value used as tie-breaker (lowest DFAX selected first)				Interconnection request

Distribution Factors

The ISO will use each project's distribution factor (DFAX)[22] as a tie-breaker when the selection process is near the 150% threshold and two or more projects are tied and less capacity is needed to reach 150% than the sum of the tied project's capacity. DFAX is a measure of the impact of injections of energy from a generator at a particular location which could result in required network changes on the grid. The lower the DFAX, the lower the impact to the grid. The projects will be selected in order of the lowest DFAX with the selection process ending with the project that caused the 150% threshold to be exceeded, regardless of the size of the last project selected and the amount by which 150% is exceeded. If project ties still exist after the use of projects' DFAX then the auction process will be used to break the ties.

The ISO proposes to apply the following scoring criteria on a points system to select projects that can fulfill 150% of the available and/or planned transmission capacity in each zone. Stakeholder feedback suggested a range between 150-300% of available TPD in each zone to enhance competition. In addition to the limit on the number of requests that a developer may submit in any given cluster application window, the ISO still proposes selection of 150% of available or planned capacity per zone as appropriate.

As discussed below, the ISO proposes to study 150% of the available and/or planned transmission capacity in each zone.

2.5. Prioritization of Projects for the Study Process [Updated]

The ISO will review and score Interconnection Request information to identify projects most ready to proceed into the study process. This scoring process is described in Section 2.4. The Straw Proposal suggested studying 150% of the available and planned transmission capacity in each zone as a means to right-size the number of studies with

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[18] The ISO seeks feedback on other validation mechanisms to demonstrate a business relationship, and specifically, whether there are additional agreements that might indicate progress toward the specific IR project.
[19] The ISO would appreciate input from stakeholders about what elements of an engineering design plan are appropriate to require at this phase of the process.
[20] This includes a requirement that sufficient capacity is available in the LCRA to charge any proposed new energy storage facilities without needed additional transmission as outlined in the annual local capacity technical study.
[21] Resource types that are being considered under Assembly Bill 1373 as long lead-time resources, considered for central procurement, or as specifically identified by the CPUC in the portfolio provided to the ISO for use in the transmission planning process.
[22] Distribution Factor (DFAX): Percentage of a particular generation unit's incremental increase in output that flows on a particular transmission line or transformer when the displaced generation is spread proportionally, across all dispatched resources in the Control Area.

the necessary development to achieve resource planning portfolios. Such scaling will ensure more meaningful study results to interconnection customers as they move through a compressed, single phase study process.

Stakeholders from the developer/interconnection customer perspective expressed strong concerns around the 150% capacity limitation, noting that this cap would “arbitrarily” reduce the number of projects that can compete and flagged the potential for the cap to drive-up resource adequacy costs due to limited supply. The ISO understands these concerns, but notes that the rationale for selecting 150% is to ensure continued competition and supply. The ISO intends to create fair and reasonable limits on the amount of new generation it can study on a timely basis. Without addressing the initial problem of excessive volume in the queue, other reforms are moot.

The ISO will apply the scoring criteria to select projects that can fulfill 150% of the available and planned transmission capacity in each zone. However, if the scoring process does not sufficiently reduce the number of viable projects in a transmission zone, the ISO proposes to conduct an auction.

2.5.1. Fulfillment of 150% of available and planned transmission capacity [New]

In order to fulfill each of the zones/interconnection areas described above in Section 2.1, the ISO proposes to analyze individual transmission zones with sub-zonal constraints. In the interest of transparency, the ISO will use the same information described and provided to stakeholders prior to the interconnection process, as described in Section 2.1.

In the study process for each zone, the ISO will add projects to various substations within each zone until network upgrades are triggered. In zones/interconnection areas/sub-zones with nested constraints, the sub-zone with the constraint will be filled up until it triggers an upgrade, and at that point the sub-zone will be ‘frozen,’ limiting any additional interconnections in that area. Other projects seeking to interconnect in that area will be eligible to interconnect in the broader zone until 150% of the capacity is reached.

2.5.2. Zonal Auctions [Updated]

Background

The ISO initially raised the concept of an auction to reduce the number of interconnection requests to a more manageable level in the discussion paper, posted in May 2023, and discussed the concept during stakeholder workshops and working group meetings.

The Straw Proposal paper further refined an auction design with the following key attributes:

- A market-clearing, sealed-bid auction for the right to be studied in a specific zone;
- Each zone would be studied at 150% of the available and planned capacity for each zone;
- Auctions conducted only if there is excess proposed capacity after applying viability scoring criteria, and only projects that are deemed equal in viability rating and cause the total MW for a zone to cross the capacity limit for a zone will participate in the auction;
- Interconnection Customers would submit bids on a dollars per MW basis as part of their initial interconnection request.
- Interconnection Customers would only submit at-risk financial security if they win the auction and proceed to be studied.
- Interconnection Customers that reach commercial operation will be refunded their at-risk auction financial security;
- Interconnection Customers that withdraw (or are deemed withdrawn) would partially lose its at-risk financial security depending on the timing of the withdrawal; and,
- Use of non-refundable auction funds will offset and support still-needed network upgrades.

Stakeholder Feedback

A few stakeholders support the zonal auction proposal while a majority oppose or suggest modifications.

Ormat Technologies, Inc., Sonoma Clean Power Authority, SCE, and the Shell Companies support the proposed auction and viability scoring approach proposal. SCE suggests further refinements, including measures to help participants beyond well-financed developers. The Shell Companies suggest exploring financial consequences associated with withdrawal.

ACP, Rev Renewables, and SCE all commented that the proposed approach to auction revenues is reasonable.

The CPUC (Energy Division) favors the development of refined criteria for viably to help minimize the reliance on an auction but support the use of an auction as an as-needed backup mechanism. California Community Choice Association, CESA, EDP Renewables, Leeward Renewable Energy, LSA, and NextEra Energy Resources all favor a robust and granular viability scoring criteria to minimize or eliminate the need and use of an auction. NextEra Energy Resources, Strata Clean Energy, California Community Choice Association, ENGIE NA, and SEIA add that any projects that meet a minimum commercial readiness score should be studied, and a project with a zero commercial viability score should not be studied.

AES states bidding is not an appropriate mechanism to compare projects against one another, and Avantus Clean Energy, CPUC-PAO, CalWEA, Clearway, Leeward Renewable Energy, MN8 Energy, Northern California Power Agency, SEIA, Terra-Gen, LLC, and Upstream state that an auction advantages large well capitalized entities, thus enabling the highest bidders and not necessarily the most ready projects to be studied.

AES believes the proposed auction mechanism causes discriminatory treatment since projects as auction projects are subject to a different at-risk financial security than higher viability projects that are not auctioned.

As an alternative to conducting an auction as a tie-breaker, AES, CalWEA, CESA, ENGIE NA, GridStor, Intersect Power, Leeward Renewable Energy, LSA, and Upstream propose the 150% MW study cap for a zone should be a flexible, rather than hard cap. Suggestions include accepting all ties for project that cross the 150% margin to be studied or study each of these projects on a pro rata MW basis to stay within the 150% margin. GridStor suggests developing a tiebreaker that adds the greatest diversity to the cluster based on some calculation of divergence of criteria scores.

Avantus suggests the ISO consider a queue application cap similar to MISO instead of financial commitments.

If an auction is ultimately utilized as a tiebreaker, ACP, Clearway, EDP Renewables, ENGIE NA, Independent Energy Producers Association, Leeward Renewable Energy, and LSA all suggest that auction bid submittals should only be later in the process after the higher-scoring projects accepted for study, and the “tied” projects subject to the auction are identified.

CalWEA commented that given the vague, arbitrary, and imprecise nature of the scoring criteria, it would only be fair to include projects across a range of viability scores in the auction, not just those with the same score.

GridStor suggest that Auction bids should be fully refundable in the event of penalty free withdrawals triggered by FERC 2023 criteria or study errors or omissions that result in a timeline of greater than 12 months. Also penalty free withdrawals if results of the study indicate a timeline interconnection completion of more than 3 years.

Middle River Power states that having auction security at risk until completion of a project may serve to increase the incentive for projects to remain in the queue after they become non-viable.

California Community Choice Association, EDF Renewables, NCPA all comment that the auction proposal will result in increased costs due to financing costs associated with auction postings.

Upstream comments that the zonal auction concept would incentivize developers with large public or private land holdings that don't require on-going option payments to submit extremely large projects that force each zone into the zonal auction.

Six Cities requests clarification on whether development/procurement by non-CPUC jurisdictional LSE's will be required to participate in the scoring/auction.

Terra-Gen, LLC requests a review of the auction proposal by an economic consultant that specializes in auction design would be helpful.

Discussion of Stakeholder Comments and Questions

The ISO agrees with stakeholders that favor a robust and granular viability scoring system to determine which projects are most ready to be studied and encourages stakeholders to continue to work with the ISO to develop this system. However, if stakeholders and the ISO are unable to agree on a viability scoring system, then the ISO believes an auction will be needed as a backup mechanism to limit the number of projects accepted to be studied.

The ISO does not agree with stakeholders that suggest projects with a zero viability score should not be studied. The ISO believes that any project that meets FERC's Order No. 2023 minimum requirements to be studied, including having 90% site control, should be allowed to submit an application into the ISO interconnection process and participate in the ISO viability scoring system and auction process as appropriate. The

ISO also is concerned that the scoring system itself will incentivize developers to score as high as possible, mitigating the effectiveness of the criteria as a mechanism to limit queue volumes to manageable levels.

The ISO agrees that for projects that are required to participate in an auction, large well capitalized entities may have an advantage over lesser capitalized entities. However, the ISO disagrees this is a poor outcome. Generation development requires significant capitalization, and developers will be able to allocate their auction funds to their most viable projects. Auction allocations thus provide a proxy for viability. The ISO believes this is a reasonable outcome and preferable to a high application deposit to limit interconnection requests. The ISO does not agree that the auction as proposed disadvantages more ready projects from the opportunity to be studied as the auction will only be applied to projects with equal viability scores.

The ISO recognizes that the proposed auction mechanism will subject some projects to different at-risk financial security requirements. The ISO does not believe this result is unduly discriminatory: All interconnection customers will have equal opportunity to site their projects and develop them sufficiently to avoid auctions, and all interconnection customers can elect to forego a project that triggers an auction.[23] Nevertheless, the ISO agrees to monitor the success of auction projects compared to non-auctioned projects in queue to ensure auction requirements are not an unreasonable barrier to commercial operation.

The ISO agrees with stakeholders that the requested MW in a transmission zone may be ‘lumpy’ and most likely will not land exactly on the 150% MW study cap. The ISO’s revised proposal will clarify that projects that submit the highest bids and are either within or the first project that crosses the 150% MW transmission zone capacity will be accepted to be studied *in their entirety* for that transmission zone. The ISO does not agree that all projects that are equal in viability scoring should automatically be studied, even on a *pro rata* basis, as this may not have the desired effect to limit the number of projects to be studied to a reasonable amount.

In response to the suggestion that a scoring tiebreaker should be developed that adds the greatest diversity to the cluster based on some calculation of divergence of criteria scores, the ISO is open to considering any timely proposal with significant community stakeholder vetting and support. In the revised draft proposal for scoring criteria in

[23] The ISO clarifies that if a sufficient number of projects elect to forego the auction, the remaining tied projects would simply be studied without an auction.

Section 2.4, the ISO has proposed to utilize a distribution factor (DFAX) as a tie-breaker that may further limit the need for an auction as a tie-breaker.

The ISO does not agree with applying a first-come, first-served application cap to limit interconnection requests in a cluster window because the first applications received may not be the most ready projects. This would also put the ISO in a difficult position if there were any technology glitches during the application process that led to a dispute.

The ISO agrees with stakeholders that suggested auction bid submittals should only come later in the process after the higher-scoring projects are accepted for study, and the "tied" projects subject to the auction are identified. The revised draft proposal has been revised accordingly.

In response to the comment that "given the vague, arbitrary, and imprecise nature of the scoring criteria, it would only be fair to include projects across a range of viability scores in the auction, not just those with the same score", the ISO is open to revisit this if stakeholders continue to believe the viability scoring system is not granular enough to be fair and therefore the auction should be applied more widely.

In response to the suggestion that auction bids should be fully refundable under certain circumstances such as FERC Order No. 2023 criteria or study errors or omission, the ISO agrees, and will apply similar refund opportunities to the auction posted financial security that are afforded to other posted financial securities under the GIDAP, as revised by FERC Order No. 2023.

In response to concerns that having auction security at risk until completion of a project may serve to increase the incentive for projects to remain in the queue after they become non-viable, the ISO believes the added and enhanced queue management proposals in this paper to keep projects accountable for moving forward address this concern.

The ISO agrees with stakeholders, and acknowledged in the straw proposal, that the auction proposal will result in increased costs due to financing costs associated with auction postings. The ISO continues to believe this will have a minimal impact on a projects total development cost and that the benefits of this proposal—reducing queue volumes to enable more timely study processes—outweigh that cost.

The ISO believes the concern that the zonal auction concept would incentivize developers with large public or private land holdings that don't require ongoing option payments to submit extremely large projects that force each zone into the zonal auction is speculative, however if this does become reality in the future, the ISO could address it in a later IPE process.

In response to the requests for clarification on whether development/procurement by non-CPUC jurisdictional LSEs will be required to participate in the scoring/auction, the proposal states that any project that can be sufficiently documented that it is a non-CPUC-jurisdictional LSE preferred resource that has been approved by its Local Regulatory Authority does not have to go through the scoring/auction process to be studied. Any project that does not meet this criteria would be subject to the scoring/auction process.

Proposal

Auction Design

The ISO understands that the novelty of this concept raises a number of questions for stakeholders, and has attempted to address them below in the revised proposal. The ISO continues to believe the auction may be essential to achieve manageable queue volumes and preserve the competition of viable projects in each zone.

As discussed above, the scoring criteria would be the first and potentially final process for determining the projects that would be studied in each of the transmission zones. However, if the scoring system does not result in enough diversity in project scores to produce a project ranking that clearly determines the projects that would be studied in each transmission zone, a second mechanism would be needed. The ISO also proposes to use a points-based project viability scoring system that utilizes a distribution factor (DFAX) as a tie-breaker to determine which projects are most ready to move forward to be studied. The ISO also proposes to study 150% of the available and planned transmission capacity for each transmission zone, where this capacity is determined to be available as described in section 2.5 above.

As a second tiebreaking mechanism, the ISO proposes to conduct a market-clearing, sealed-bid auction for the right to be studied in a specific zone. The auction dollars at risk would be based on a clearing price set by the marginal bid. All interconnection customers that are required to participate in a transmission zone auction would have the same $/MW rate applied to their specific capacity where the auction clears.

The ISO will conduct auctions only for projects that are deemed equal in viability rating and cause the total MW for a zone to cross the 150% MW capacity limit for a zone. Projects with high viability scores that do not cause the total MW for a zone to cross the capacity limit will be studied and not required to participate in an auction. Projects with lower viability scores that exceed the MW capacity for a zone will not participate in the auction and will not be studied.

In response to stakeholder comments, the ISO proposes to request bids for the auction after the scoring system process, rather than requiring bids to be provided with an interconnection request. After the ISO completes the viability scoring process described in section 2.4 above, the ISO will notify only those projects that are deemed equal in viability rating and cause the total MW for a zone to cross the 150% MW capacity limit in a transmission zone. Those interconnection customers would be requested to submit an auction bid on a dollars per MW basis. If sufficient interconnection customers forego participating in the auction in a zone, the remaining interconnection customers would simply “win” the auction and not be required to post auction funds.

Based on stakeholder feedback concerning the potential and likely lumpiness in requested MW capacity and the 150% MW cap, the ISO clarifies that projects that submit the highest bids and are either within or the first project that crosses the 150% MW transmission zone capacity will be accepted to be studied *in their entirety* for that transmission zone. These interconnection customers must post financial security equal to the auction clearing price (the lower of the winning bids) prior to being studied.

If a project reaches commercial operation, its auction financial security would be refunded to the interconnection customer. If it withdraws from queue (or is deemed withdrawn), it would partially lose its auction financial security, depending on timing of the withdrawal, similar to the ISO’s current financial security requirements or Order No. 2023’s withdrawal penalty structure.

Example:

- Assume there is 266 MW of available transmission capacity in a zone, and thus 400 MW capacity deemed reasonable to study
- Seven 100 MW projects apply in this zone
    - Projects A and B have a viability score of 70
    - Projects C, D, and E have a viability score of 60
    - Project F and G have a viability score of 50
- Projects A and B are selected to be studied since they have the highest viability score, and therefore do not need to compete in the auction,
- Only projects C, D and E will be considered in the auction because their projects cross 400 MW. The two projects with the highest auction bids will win the auction, be studied, and must post the clearing price (the lower of the two winning bids) prior to being studied.
- Projects F and G will not be considered in the auction and will not be studied.

Use of Auction Revenues

The ISO proposes that non-refundable auction funds resulting from project withdrawals offset and support still-needed network upgrades, lowering costs for ratepayers. Projects that successfully compete in an auction and reach commercial operation will be refunded their auction-posted security. Even if setting aside the value of the posted auction security for several years may slightly increase a project's development cost, the ISO believes the benefits of this proposal outweigh that cost. The ISO notes that auction security can take any of the forms currently allowed for interconnection financial security, allowing developers to elect the most financially efficient form for their needs.

Like financial security, the ISO proposes that any liquidated auction funds go to the applicable PTO to fund still-needed network upgrades. Any amounts that exceed the costs of still-needed network upgrades will be applied to offset Regional Transmission Revenue Requirements, as recovered through the CAISO's Transmission Access Charge, and to offset Local Transmission Revenue Requirements. The PTO would only liquidate and use auction security if the customer withdraws. If the project instead reaches commercial operation, the interconnection customer will be entitled to a release of the posted auction financial security.

The ISO does not propose that auction financial security be instantly 100 percent non-refundable. Like interconnection financial security, the refundability would decrease as the customer progresses in queue. The proposed forfeiture amounts are intentionally set to be significant to further discourage interconnection customers from submitting less viable projects. The ISO proposes the following refundability percentages:

Withdrawal Timeline (Timeline is consistent with FERC Order 2023)	**Amount to be refunded to the Interconnection Customer**	**Amount to be dispersed to the applicable Participating TO**
If Interconnection customer withdraws or is deemed withdrawn during the Cluster Study or after receipt of a Cluster Study Report, but prior to commencement of the Cluster Restudy or Interconnection Facilities Study	85%	15%
If Interconnection customer withdraws or is deemed withdrawn during the Cluster Restudy or after receipt of any applicable restudy reports issued, but prior to commencement of the Interconnection Facilities Study	70%	30%
If Interconnection customer withdraws or is deemed withdrawn during the Interconnection Facilities Study, after receipt of the Interconnection Facilities Study Report issued, or after receipt of the draft GIA but before Interconnection customer has executed an GIA or has requested that its GIA be filed unexecuted	50%	50%
If Interconnection customer has executed an GIA or has requested that its GIA be filed unexecuted	0%	100%

Acceptable Interconnection Financial Security Instruments

The auction funds posted by an interconnection customer may be any combination of the following types of financial security instruments provided in favor of the applicable Participating TO(s):

a. an irrevocable and unconditional letter of credit issued by a bank or financial institution that has a credit rating of A or better by Standard and Poor’s or A2 or better by Moody’s;

b. an irrevocable and unconditional surety bond issued by an insurance company that has a credit rating of A or better by Standard and Poor’s or A2 or better by Moody’s;

c. an unconditional and irrevocable guaranty issued by a company that has a credit rating of A or better by Standard and Poor's or A2 or better by Moody's;

d. a cash deposit standing to the credit of the applicable Participating TO(s) in an interest-bearing escrow account maintained at a bank or financial institution that is reasonably acceptable to the applicable Participating TO(s);

e. a certificate of deposit in the name of the applicable Participating TO(s) issued by a bank or financial institution that has a credit rating of A or better by Standard and Poor's or A2 or better by Moody's; or

f. a payment bond certificate in the name of the applicable Participating TO(s) issued by a bank or financial institution that has a credit rating of A or better by Standard and Poor's or A2 or better by Moody's.

If at any time the guarantor of the auction fund financial security fails to maintain the credit rating required above, the Interconnection customer shall provide to the applicable Participating TO(s) replacement Interconnection Financial Security meeting the requirements within five (5) Business Days of the change in credit rating.

2.5.3. Modifications to the Merchant-Financing "Option B" Process

Background

As discussed above, the zonal approach is foundational to this straw proposal, so the ISO proposes to prioritize the study process to focus on interconnection requests that seek to interconnect in areas that have available transmission capacity, including planned capacity that will be available for allocation in the TPD allocation process. However, stakeholders emphasized the importance of retaining and providing opportunities to identify and provide alternative points of interconnection or upgrades.

Projects that seek to interconnect and meet the conditions required for the zonal studies where transmission capacity exists are eligible to proceed as Option A projects. Projects that seek to interconnect in zones that have no TPD available may only proceed as Option B projects.[24] The ISO will not provide any opportunity for these projects to convert to Option A later in queue.

Stakeholder Feedback

[24] The exceptions to this are projects that meet the criteria for non-CPUC jurisdictional LSEs.

ACP, AES, CalCCA, CESA, Clearway, EDF, Golden State Clean Energy, Rev, SEIA, Terra-Gen, and Vistra state that Option B projects should be allowed in the interconnection priority zones and any projects that did not score high enough to be studied should be allowed to elect to move forward as an Option B project. SEIA added as long as they meet the minimum score threshold applied to Option B.

EDF, LSA, Rev, Sonoma Clean Power Authority, Terra-Gen, and Vistra suggested that if the TPP determines an ADNU is needed that an Option B project is funding, then projects should be released from their obligation to fund the ADNU.

LSA, esVolta, New Leaf Energy, and Terra-Gen asked that the ISO provide estimates of revenues from the Congestion Revenue Rights (CRRs) related to any required ADNUs so potential Option B sponsors can better understand the net costs of the upgrades. Additionally, Avantus suggested that reimbursement of the cost for an Option B ADNU should be an option if the sponsors for an ADNU are able to demonstrate benefits to the system, e.g., deliverability for future projects in that area or reliability improvements.

LSA, esVolta, New Leaf Energy propose the following modifications:
- Projects in transmission zones should be allowed to elect Option B if they do not receive a TPD allocation.
- Upon withdrawal of a project with shared cost responsibility for an Option B ADNU, any interconnection financial security posted for the ADNU by the withdrawing project should go to other projects sharing the upgrade.
- Posted security should be transferred elsewhere if the PTO is not building the Option B upgrade, e.g., to another entity established by Option B projects to facilitate upgrade construction or another entity hired by Option B projects to build the upgrade
- Option B projects sharing an ADNU should be allowed to negotiate alternative funding, including but not limited to mutually established earlier postings or other financial protections of each other.

CalCCA suggests limiting Option B projects within transmission zones using the same scoring criteria used for Option A projects.

esVolta suggests that ICs be allowed to switch from Option B to Option A at the time of receipt of the Cluster Study Report.

CalWEA suggests that Option B projects be allowed to compete for a TPD allocation because TPD could become available due to load changes, generator changes and other system condition changes.

BAMx supports the Straw Proposal element that requires the projects that seek to interconnect in zones that have no TPD available to proceed only as Option B projects, with the exception of any project(s) identified as a preferred resource in any non-CPUC jurisdictional LSE's resource plan approved by its LRA.

CPUC recommends the study elements of the straw proposal should separate transmission planning and analysis from the rest of the Queue reforms so that the transmission planning and analysis be allowed to achieve technical optimization for the overall public good.

Golden State Clean Energy supports continued use of Option B as it provides an additional method of expanding the transmission system and generation interconnection alternatives.

Intersect Power states, if projects are willing to put forth the proposed financial security postings required of Option B projects, they should be permitted to participate in the interconnection study process irrespective of whether a zone has existing or planned TPD available. Eventually, zones that exhibit substantial commercial interest will no longer have available TPD, and thus, will qualify for Option B projects. Limiting the ability to participate now simply delays the timing of when option B is allowed.

Middle River Power states, the proposal is reasonable, but developing a precise minimum viability score for Option B projects to proceed may be difficult and contentious.

NextEra states, in the absence of any cost caps associated ADNUs, projects will continue to be exposed to unsustainable costs throughout the study process should other projects that triggered those upgrades drop out years later. Option B projects should have the option to self-build these self-funded projects.

Power Applications and Research Systems suggests the ISO should identify whether the Option B resources can be Deliverable to Non-CAISO entities that have their own RA services to increase interest in adoption of the Option B alternative.

Rev suggests that for areas where the TPD estimates are getting close to the available transmission capability, which will result in a very small number of Option A projects, give flexibility for projects to participate as Option B. Rev does not support creating minimum viability score for Option B projects.

SEIA suggested Vistra proposal for a network upgrade subscription model to make a viable interconnection pathway be considered.

Shell states that the proposal that fifty percent of the IFS posting by Option B projects be non-refundable if a project withdraws after the interconnection request is determined to be complete, is excessive. The cost of the ADNUs at that point are only an estimate, which raises additional risk for Option B projects.

Vistra states, Option B should be open to projects willing to trigger ADNU individually or collectively to increase FCDS in any area. The ADNU in an Option A zone may be the lowest cost ADNU on the system.

Discussion of Stakeholder Comments and Questions

Stakeholders requested that Option B projects be allowed in the interconnection priority zones and any projects that did not score high enough to be studied should be allowed to elect to move forward as an Option B project. The ISO maintains that areas with available deliverability capacity are open to all projects through a competitive process where projects compete to be studied as Option A projects. Option B is only needed in zones where no TPD capacity is currently available to provide open access to all zones, regardless of the availability of TPD capacity.

Allowing Option B projects in priority zones would result in studying capacity in those zones potentially well above the 150% threshold and would be counterproductive to solving the issue identified in the problem statements of studying capacity levels so high that the study results lose accuracy, meaning, and utility. Furthermore, an additional study would be required after the Option A projects studies are completed, to determine the required ADNUs for the Option B projects. While this has been done in the past as part of the phase I studies, it was only an estimate that was refined in the phase II studies. The FERC Order No. 2023 timeline for studies does not provide enough time to perform this additional study, and the ISO does not believe such studies would be a productive use of limited planning resources. Because Option B projects will not be allowed in areas with available transmission, Option B projects will not be allowed to compete for a TPD allocation.

The ISO does not agree that switching from Option B to Option A at the time of receipt of the cluster study report should be allowed, or that Option A projects in transmission zones with available capacity should be allowed to elect Option B if they do not receive a TPD allocation. Both of these would require a restudy or an additional study and the best way to handle these options would be in the next cluster study.

Stakeholders suggested that if the TPP determines an ADNU is needed that an Option B project is funding, then projects should be released from their obligation to fund the ADNU once the approved project sponsor has executed its agreement. The ISO agrees with this and includes it in its proposal. Additionally, stakeholders asked whether reimbursement of the cost for an Option B ADNU should be an option if the sponsors for an ADNU are able to demonstrate benefits to the system, e.g., deliverability for future projects in that area or reliability improvements. Because the Option B ADNU will not be in the base cases until the Option B interconnection customer commits to constructing the ADNU, the TPP process will be able to determine if the ADNU is appropriate and the best solution for these potential benefits.

Stakeholders requested that the ISO provide estimates of revenues from the CRRs related to any required ADNUs so potential Option B sponsors can better understand the net costs of the upgrades. The ISO does not believe it is appropriate for the ISO to provide estimates of the future revenue potential of any revenue producing element within the ISO markets. Furthermore, in the calculation of potential CRR revenues that could be derived from any new system capacity that a particular transmission element could produce there are assumption to the calculation that need to be made by the developer of the particular project.

A number of suggestions were provided related to the posting and financing of Option B ADNUs where posted security should be transferred elsewhere if the PTO is not building the Option B upgrade, e.g., to another entity established by Option B projects to facilitate upgrade construction or another entity hired by Option B projects to build the upgrade, and, Option B projects sharing an ADNU should be allowed to negotiate alternative funding, including but not limited to mutually established earlier postings or other financial protections of each other. The ISO proposes these issues to be handled in a manner similar to Appendix DD Section 11.3.1.4.4 “Posting Related to Interconnection Customer’s Stand Alone Network Upgrades”. The parties having cost responsibility for an Option B ADNU are free to self-build the upgrade and to negotiate third party agreements for the funding the ADNU. The ISO memorializes such agreements in each party’s GIA.

In addition, upon withdrawal of a project with shared cost responsibility for an Option B ADNU, any interconnection financial security posted for the ADNU by the withdrawing project should go to other projects sharing the upgrade. The ISO believes this can be handled similar to Appendix DD Section 7.6 “Application of Non-Refundable Amounts.”

Regarding the comments associated with the requiring minimum scoring criteria for Option B projects, the ISO will not propose the use of minimum scoring. The required site control and the required up-front partial IFS posting of the cost of the ADNU, based on the amount of deliverability requested, as part of its interconnection request during the cluster application window is sufficient to ensure that only serious projects will request Option B.

One stakeholder suggested that any project(s) in a zone with no available transmission that are identified as a preferred resource in any non-CPUC jurisdictional LSE's resource plan approved by its LRA not be required to proceed as Option B. The reasoning is that transmission needs assessed in the past TPP cycles were not always informed by the non-CPUC jurisdictional LSEs' resource plans, placing the LSEs of non-CPUC jurisdictional LRAs at a disadvantage. The ISO is concerned that a "carve-out" for non-CPUC jurisdictional LSEs would be difficult to implement, requiring a number of criteria designed to ensure the process is not gamed, all for a use-case that would be rare if ever needed. The ISO believes that as a project is in the planning stages, well ahead of the appropriate interconnection request window, the LSE has time to submit the project into the TPP to have its transmission requirements studied.

One stakeholder was concerned with the proposal that fifty percent of the IFS posting by Option B projects be non-refundable if a project withdraws after the interconnection request is determined to be complete, is excessive. The cost of the ADNUs at that point are only an estimate, which raises additional risk for Option B projects. In response, the changes to the GIDAP in the IPE initiative, as well as the FERC Order No. 2023, ensure that interconnection requests have an increased level of readiness than in the past. Developers should not submit interconnection requests to the ISO without first performing some level of screening studies. However, the ISO will move the date the IFS posting becomes non-refundable to the date that interconnection requests must be deem valid, and will decrease the posting required for Option B interconnection requests to 5%. The ISO notes that Option B interconnection customers will still be subject to all new financial requirements under Order No. 2023.

Proposal

The ISO proposes the following modifications to Option B in the ISO Tariff Appendix DD. Modifications from the Straw Proposal include;

- Revisions to the initial Interconnection Financial Security (IFS) posting requirement (item 5),
- Removal of the option to request an estimate of the cost for an ADNU that has yet to be developed in a cluster study so that in situations where no applicable ADNU cost estimate is available, the project would be required to post an amount based on a generic posting amount, and

- New criteria for when the TPP determines an ADNU that an Option B project is funding is needed to support a CPUC portfolio.

Only projects seeking to interconnect in areas that have no available or planned TPD capacity are eligible to select Option B. Option B will not be available to projects that were not selected to be studied in transmission zones that have available or planned capacity.

The Option B path ensures that projects seeking to interconnect in areas with no available deliverability capacity have a path forward. If an Option A project is unable to receive an allocation of TPD, it will not be eligible to convert to Option B because that would require a restudy.

1. Option B projects will not have to compete for TPD in the allocation process because they will trigger and finance all of the delivery network upgrades they will require, without reducing the available deliverability from other delivery network upgrades needed by Option A projects.

2. Option B projects that require Local Delivery Network Upgrades (LDNUs) will be eligible for cost recovery of the IFS posted for the LDNU in the same manner as an Option A projects. LDNUs are more project specific than ADNUs that, outside of the Option B process, are developed in the TPP. In the transition to the study approach based on the available deliverability within zones, the ISO believes it is appropriate to allow developers to be reimbursed for LDNUs. This will also result in the Option B path being more viable.

3. An Option B project's funding of the construction of its required ADNU will not receive repayment. The interconnection customer will be eligible to receive Merchant Transmission Congestion Revenue Rights (CRRs) in accordance with CAISO Tariff Section 36.11.[25]

4. Option B projects will be given a project status of Full Capacity Deliverability Status (FCDS) or Partial Capacity Deliverability Status (PCDS), as specified in its GIA and in accordance with the Resource Adequacy counting rules.

5. The ISO will publish the estimated cost of ADNUs that were identified in the most recent cluster study reports in dollars per MW (escalated cost rate ($k/MW)). The project would be required to make an initial IFS posting of 5% of the estimated cost of the ADNU, based on the capacity amount of deliverability requested in its

[25] Clarifying that the interconnection customer will not own the ADNU they fund under Option B.

interconnection request during the cluster application window. Fifty percent of the IFS posting would be non-refundable if the project withdraws after the due date for interconnection request validations to be complete. The deposit will have a minimum requirement of $500,000 and a maximum required of $5,000,000. The deposit is set to an amount deemed to be high enough to incent only interconnection customers that are confident of their project’s viability under the Option B path.

6. If no applicable ADNU cost estimate is available, the project would be required to post an amount equal to $10,000 per MW, but not less than $500,000 and not to exceed $5,000,000.

7. Option B projects that complete the cluster study process will be required to increase their posting to 50% of its cost responsibility for ADNUs to remain active.

8. If a future TPP determines an ADNU that an Option B project is funding is needed to support a CPUC portfolio, then any projects funding the ADNU will be released from their obligation to fund the ADNU and be refunded its posting for the ADNU once the approved project sponsor executes its agreement. However, the projects would then be required to seek an allocation of TPD through the affidavit process to obtain an allocation of TPD.

2.6. Study Process

The ISO appreciates the thoughtful stakeholder proposals from early working group meetings on improvements to the study process, as well as support for a single-phase study process. As noted, the ISO intends to comply with the FERC Order No. 2023 study process to the greatest extent possible. Order No. 2023 requires a study process consisting of:

- A “cluster study” that identifies the interconnection facilities, reliability network upgrades, and delivery network upgrades each interconnection request requires;
- A restudy evaluating the impact of withdrawals on the cluster study results; and
- An interconnection facilities study that provides more granular and accurate cost estimates for the upgrades and facilities identified in the cluster study report.

In other words, the ISO will perform the reliability and deliverability studies as it does today with the Phase II interconnection study. Cluster study results will provide the same information as the Phase II study results.

2.6.1. Off-Peak and Operational Deliverability Assessments [New]

Order No. 2023 prescribes very fast timelines for cluster studies: 150 days for the cluster study, 150 days for the cluster restudy, and 90-180 days for the interconnection facilities study.[26] The ISO believes that complying with these prescribed timelines requires the ISO to conform the scope of its interconnection studies to FERC's *pro forma*. Doing so would require the ISO to remove the off-peak deliverability assessment (and therefore all associated statuses), and the operational deliverability assessment. In addition to enabling the ISO to meet FERC's prescribed timelines, the ISO does not believe the off-peak deliverability assessment has significant value since FERC rejected the market consequences of being Off-Peak Energy Only. Additionally, the ISO believes it can provide many elements of the operational deliverability assessment in the transmission plan deliverability allocation process results.

The ISO thus proposes to remove both the off-peak and operational deliverability assessments to enable the ISO to meet Order No. 2023's prescribed timelines. The ISO solicits feedback on this proposal, and intends to remove the assessments through IPE and its related filing under Section 205 of the Federal Power Act. However, the ISO also may have to remove these assessments through its Order No. 2023 compliance filing because FERC may not allow longer timelines that would accommodate them. Because removing the assessments may not be clear from the scope of Order No. 2023, the ISO has included them here for transparency and feedback on the assessments' values.

2.7. Modifications to Deliverability [Updated]

Background

The ISO's Discussion Paper and Straw Proposal noted timing challenges for projects entering the queue. Projects aligned with the CPUC's 2022-2023 IRP and TPP portfolios will likely need to stay in the queue for a number of years, waiting for required upgrades to be completed. Projects become eligible to seek an allocation after the cluster studies are completed and then have a limited period where they are eligible to seek an allocation before being converted to Energy Only. The TPD allocation process gives highest priority to projects that have executed a PPA or are shortlisted. For projects with longer lead-time network upgrades, the window of opportunity to seek an

[26] Depending on the detail requested by the customer.

allocation can be several years before their network upgrades can be completed and possibly before LSEs are seeking to procure projects with later CODs.

Because most offtakers require a project to be eligible for resource adequacy (RA), the TPD allocation process is very important to project developers. Thus, it is necessary to consider changes to the TPD allocation criteria within the framework of the proposed changes to the interconnection process within IPE and the changes required by FERC Order No. 2023.

The resource portfolios designate the specific resource types and the amounts to be developed, which the TPP uses to determine the transmission projects needed to support those specific resource plans. This can result in the CPUC designating an area for significant resource development that would not typically be the focus of large transmission expansion due to the relatively lower load levels and low load growth of the area. When such an area becomes the focus of significant generation development due to an emerging generation technology or an opportunity for resource diversity, a large transmission project may be needed to support the emerging need. In these circumstances, the basis for the TPP project is serving the specific technologies in the portfolio. In other words, the TPP project would not be needed but for the CPUC portfolio identifying the technology at the specific location.

Several stakeholders suggested specific mechanisms to recognize the unique need for certain long lead-time resources in the interconnection process. The ISO must ensure transmission capacity is reserved for the specific technologies the transmission project is designed to serve. It may take many years for the transmission project to be permitted, constructed, and go into service, requiring the associated TPD to not be allocated until the emerging technology is ready to enter the TPD allocation process. An example is transmission being developed to support the significant capacity amounts of offshore wind designated by the CPUC portfolio for Northern California.

The ISO is committed to bringing new, approved, and necessary transmission resources into service as soon as possible to ensure reliability and an affordable pathway to decarbonization. The pace of generation development and procurement, however, must align with the pace of transmission development. The State is experiencing heightened levels of competition for new generation, as evidenced by the swelling of the ISO's interconnection queue in Clusters 14 and 15. The ISO has approved many new transmission projects in the last two TPP cycles and is committed to facilitating their on-time completion. But many of these projects will take 8-10 years to complete. Available transmission capacity on the system is finite, which limits the amount of TPD the ISO can allocate to assure generators they can deliver to load during stressed system conditions.

Recognizing these challenges, stakeholders have asked the ISO to provide longer-term interim deliverability for projects that can go into commercial operation prior to the completion of associated network upgrades.

The ISO proposes a related change in the Deliverability Assessment Methodology initiative, providing deliverability to resources waiting for the n-2 related deliverability upgrades to be completed, assuming they would not cause cascading outages. Also within that initiative, the ISO proposes to increase the cost threshold for determining whether a delivery network upgrade (DNU) is a LDNU or an ADNU. The change would allow more DNUs to be deemed LDNUs, which would allow larger/more costly DNUs to move forward within the GIDAP and allow interconnection customers to choose to fund them instead of waiting for the TPP to propose them as ADNUs. This would give interconnection customers greater control over the destiny of their projects.

In the IPE Straw Proposal the ISO proposed limiting the allocation of TPD to EO projects and to construct a methodology where a multi-year interim deliverability allocation process could bridge the gap between the in-service date of an LDNU and the project's requested COD. Other more substantial changes to the TPD allocation process have been deferred until a greater level clarity and certainty has been achieved from the Deliverability Assessment Methodology initiative and from the IPE 2023 initiative.

The ISO suggests keeping all of the TPD allocation related issues together in one holistic discussion. The complete discussion of the changes to the TPD allocation process will be initiated in a later IPE 2023 Track 2 paper, and the ISO will move forward with the proposals for allocating TPD to Energy Only projects and the multi-year interim deliverability allocation process at that time. The ISO recognizes that the TPD allocation discussions may not have advanced to the final proposal stage in time for the May 2024 ISO Board of Governors meeting. If that is the case, the TPD allocation discussions will continue in an IPE 2023 Track 3, targeting the July 2024 Board of Governors meeting.

3. Contract and Queue Management

3.1. One-Time Withdrawal Opportunity [Updated]

Background

Many projects unduly linger in the queue while they compete in multiple requests for offers (RFOs). Some of these may have significant financial commitments, including deposits and financial security postings, so a voluntary withdrawal from the queue could pose financial risk to the projects. Further, there may be inadequate incentives for projects to withdraw if they can remain in the queue and continue to seek a buyer for the project. These lingering projects also may impact upgrade requirements for later-queued projects. Allowing lingering projects a one-time incentive to withdraw may change the cost calculus for lingering projects, which will improve study results for other-queued projects and potentially allow for cancellation of some network upgrades.

In the Straw Proposal, the ISO proposed a one-time opportunity for projects to withdraw from the queue and receive any unused portion of their interconnection financial security postings and site-exclusivity deposits, possibly over time. Under this proposal, the withdrawn projects' previously non-refundable portion of the IFS that was posted for still-needed upgrades would continue to be held and used by the PTO to fund these upgrades. Once the upgrades are in service, the PTO would refund the withdrawn project's money to the interconnection customer consistent with the existing Tariff reimbursement requirements. As proposed, this opportunity would apply to all active projects in the queue, including Cluster 14.

The proposal attempted to create a solution that reduces the PTOs' financing cost burden for the still-needed network upgrades under a one-time withdrawal opportunity by delaying the refund of the current non-refundable portion of the security posting until the upgrade is in-service or later removed from the project's responsibility.

Stakeholder Feedback

Most stakeholders support the concept of allowing a one-time withdrawal opportunity. Stakeholders acknowledged that the one-time refundable withdrawal could provide significant opportunity to reduce existing queue volumes and eliminate the need for no-longer-necessary network upgrades.

Despite the conceptual support, however, the ISO received significant concern from the PTOs on the proposed reassignment of costs and the implications on the PTOs that would be required to obtain cash for upfront funding of these upgrades. Although the ISO hoped to mitigate the cost transfer with the delayed refund of IFS postings, the PTOs have been clear that these postings are insufficient to enable the PTOs to assume total short-term financing and funding responsibility for precursor network upgrades (which would not be removed following the withdrawal process because later-queued projects require them). Additionally, PTOs raised the following concerns:

- Non-refundable portions of the 2nd IFS posting requirement for network upgrades may be treated as a contribution in aid of construction (CIAC) or income to the Participating TO, which is subject to tax at a rate of 24%.
- If PTOs hold cash from ICs, they may be subject to paying interest on such cash until it is fully refunded.

AES, CalCCA, Cal Advocates, and Calpine support the proposal as reasonable and will benefit ratepayers by eliminating projects that take resources just to remain in the queue. Avantus requested additional information documenting that the “non-refundable” portion held by PTO until upgrade is in service would be immediately released should it be determined the NU is no longer necessary because of withdrawal of one or more projects.

EDF-R supports the proposal but encourages the ISO to reconsider the proposal and withhold less security than currently proposed. EDF-R believes the current proposal is overly conservative, and a proposal that more precisely weighs PTO financial risk will encourage more projects to withdraw, which the ISO queue urgently needs. EDF-R notes that in the past three years, 237 projects have withdrawn, representing 64 GW, and ISO has only needed to withhold $2 million (12%) of the total collected funds to cover still needed network upgrades. In this timeframe, $16 million was distributed to the TRR by funds not needed by the PTO to fund still needed upgrades. EDF-R believes this proposal is too conservative and suggests a revised proposal, withholding less funds than currently proposed, but still an amount of funds that is likely to cover any network upgrades, will further incentivize projects to withdraw from the queue.

Calpine supports the proposal as well as the ISO’s observation that cascading the costs of network upgrades associated with withdrawn projects to later queued projects would be unfair and unjust. Calpine agrees that conversations about the funding of the amnesty-driven cascade of network upgrade costs with the TOs should continue.

Others, such as LSA, Intersect Power, Avantus, New Leaf Energy note that the ISO proposal should not only focus on upgrades assigned to withdrawing projects. They note that PTO and ratepayer funding of Network Upgrades will be reduced by elimination of upgrades assigned to later-queued projects, and this element is not considered at all in the proposal. The deferral of refunds generally will reduce the incentive for projects to elect this option, so reduction or elimination of this withholding element through consideration of these other benefits would help mitigate that undermining of the associated project-withdrawal incentive.

NLE and NextEra Energy Resources question whether the proposal provides sufficient incentive for projects to withdraw. REV supports the one-time withdrawal opportunity proposal, and requests clarification that applicability to “all active projects” includes those in Cluster 14. REV supports CAISO’s proposal to hold the IFS that is still needed to fund the PNU until the PNU is in service as a way to reduce the cost-shift burden. SDG&E supports the one-time withdrawal opportunity, as an initial step to ensure that only the most viable projects remain in the queue. SDG&E proposes the ISO require the

3rd posting as a requirement to move on to the GIA phase. This requirement would reflect the appropriate commitment for the final stages of the interconnection process. This is conceptually similar to FERC's "LGIA Deposit" requirement.

SCE does not support the proposal. PG&E supports CAISO's efforts to clean up the queue and provide interconnection customers a one-time withdrawal opportunity, however the one-time withdrawal opportunity should be constructed in a manner as to not incentivize the current issue to re-manifest in the future with interconnection customers again. PG&E also notes that the amount of time needed for a reassessment will be dependent on the number of projects that withdraw, but it is vital PTOs have adequate time to complete these studies. PG&E suggests that the ISO first undertake its TPD allocation process for the upcoming 2023-2024 Transmission Plan prior to initiating the window for developers to withdraw from queue. Otherwise, PG&E is concerned that if the withdrawal opportunity is prior to the TPD allocation for the 2023-2024 Transmission Plan, interconnection customers will wait for the TPD allocation in hopes of being allocated TPD and will decide not to pursue withdrawing from the queue due to wanting to see if they get TPD.

Vistra asks the CAISO to confirm that this proposal will not push cost responsibility onto any projects that remain.

Discussion of Stakeholder Comments and Questions

Several stakeholders noted that the proposal fails to recognize the potential cost savings of this proposal. The ISO notes that it recognizes the potential benefits of such an opportunity, resulting in improved study results, cancellation of some no longer necessary network upgrades, and enabling later-queued and new projects that are more viable to move forward. However both the costs and the benefits of this proposal are equally difficult to quantify.

The challenge lies in the re-assignment of costs and financial responsibility of precursor network upgrades (PNUs) associated with withdrawn interconnection projects that remain needed for other resources remaining in the queue. Under the ISO Tariff, if an interconnection customer has executed a generator interconnection agreement (GIA) and withdraws, then the PTO must fund that project's allocated cost share of any network upgrades still needed by later-queued projects. The cost of these projects coupled with the responsibility for obtaining financing for them exceeds the amount of interconnection financial security (IFS) postings made by the interconnection customer who was initially assigned responsibility for that upgrade.

The ISO has observed that PTO access to capital is increasingly a barrier to timely completion of network upgrades. Therefore, the assignment of additional costs and financing obligations could exacerbate delays of network upgrades, which are critical to getting more deliverability on the system to meet the ISO's reliability and policy needs. In response to SCE's tax burden concerns, the ISO believes that because the IFS funds will ultimately be refunded to the IC, they would not be treated as a CIAC. Under the current tariff, when the PTO receives non-refundable funds as CIAC, the PTO is not required to reimburse those funds to an interconnection customer, which are then treated as taxable income.

Proposal

While the ISO would like to continue to explore this opportunity, the Participating Transmission Owners (PTOs), the concerns raised by the PTOs are genuine cause for reconsideration. Thus, the ISO sees two possible paths forward:

1. Seek additional sources of funding for network upgrade costs associated with withdrawals, either through a green bank or government grant or loan program.

This proposal requires identification of a willing funding entity to assume costs and financing obligation associated with these network upgrades. Depending on the funding source and mechanism, this could reduce ratepayer impacts associated with network upgrades. One challenge associated with this alternative is that the ISO cannot currently predict how many ICs will take advantage of the opportunity to withdraw, nor can the ISO predict which network upgrades would be affected by voluntary withdrawals. Depending on the number of ICs that take advantage of the opportunity, the amount of funding necessary could be in the tens or hundreds of millions of dollars. This could be mitigated if ICs made commitments to withdraw ahead of time, conditioned on use of this funding. The ISO would need this commitment and funding in place prior to implementing this opportunity.

2. Remove this option from IPE and focus on other mechanisms to encourage withdrawals of stagnant projects.

The ISO includes a number of proposals below, designed to encourage withdrawals of stagnant projects without the added administrative burden on the ISO and without imposing a financial risk to the PTOs.

Unless the ISO is able to identify acceptable third-party funding for the affected network upgrades, the ISO proposes to drop the one-time refundable withdrawal opportunity in favor of other queue management proposals that will set clearer requirements for projects in the queue to either perform or withdraw.

Should the ISO proceed with this proposal, the ISO will need to consider the timing of a subsequent reassessment study in order to clear the queue. It would be ideal to implement this element of the proposal as early as possible (and possibly separately from other IPE elements) in order to realize the benefits of withdrawn projects and updated information in future interconnection clusters.

3.2. Limited Operation Study Process Updates

Background

Under Section 14.2.4 of the GIDAP, projects are currently limited to requesting a Limited Operation Study (LOS) five months before the project's synchronization date. Including the full timeline of developing, reviewing, and finalizing the LOS plan and then completing the LOS itself, interconnection customers may be left with few months to make business and construction decisions based on the results. The reason for the five-month timeline is that the PTO must conduct the LOS using operations data and not planning data. Longer lead times would substantially diminish the accuracy of the LOS results, potentially making them infeasible for the PTO and the customer. This is not a trivial issue. A LOS is premised on the interconnection customer lacking its identified reliability network upgrades. Inaccuracies in the LOS could result in reliability and safety issues.

Additionally, developers frequently submit modification requests simultaneous with their LOS request, which may impact the ability to start the study or publish results of a completed LOS. The ISO seeks to clarify situations where modifications requests are submitted that may impact the LOS process or study results.

Stakeholder Feedback

Avantus Clean Energy, the CPUC, Cal Advocates, Calpine, CalWEA, Clearway Energy Group, EDF-Renewables, Nextera, Ormat Technologies, Rev Renewables, SDG&E, SCE, PG&E, Upstream, and Vistra all provided comments generally supporting the straw proposal to extend the current five month timeframe to submit a LOS to nine months.

Many stakeholders from the development community raised concerns that 9 months is still insufficient for providing results and allowing developers to make sound commercial and financial arrangement for their project and request for the nine month proposal to be extended as long as 24 months or even include operational or short circuit evaluations in the planning studies.

In addition, Clearway believes the timing of an LOS request should be driven by upgrade delays instead of an arbitrary window prior to COD. To maximize the usefulness of the LOS, PTOs should be required to notify interconnection customers as soon as any Network Upgrade is delayed, and the customer should be able to request an LOS at that point, even if it is more than 9 months prior to synchronization.

Additionally, stakeholders seek clarification on the correlation between a modification request/results and the potential impact to starting, reviewing, or restarting an LOS.

Discussion of Stakeholder Comments and Questions

The ISO recognizes the desire for the LOS to be completed sooner than 9 months from synchronization. However, the LOS requires analyzing the grid's current ability to accommodate additional generation with the assumption that the assigned reliability network upgrades are not online. Performing this evaluation earlier would lead to less accurate results and risk reliability and safety of the ISO Grid. The ISO cannot extend this LOS start timeline beyond nine months prior to synchronization. As stakeholders noted, the LOS already represents a re-evaluation of the customer's interconnection studies. Additionally, earlier LOSs also would divert planning and operational resources away from the primary interconnection studies.

The ISO also understands the request to clarify when a LOS re-evaluation relative to an MMA being requested or completed would be expected.

Regarding Clearway's comments on network upgrade delays, Clearway already describes the *status quo*. PTOs notify interconnection customers and the CAISO of all construction delays and new construction milestones when known. The parties then update study results and GIAs as necessary and as soon as possible. But an LOS is a customer election depending on a ready generator, not necessarily a delayed upgrade. Likewise, many generators would not want an LOS simply because they have a delayed upgrade, especially early in the study process. The issues are related, but distinct.

Proposal

The ISO proposes to increase time to submit a LOS request to 9 months before synchronization. This allows additional time for processing the request, drafting and issuing the study plan, and 45 days to complete the study with the intent of providing interconnection customers additional time to evaluate the results and make decisions accordingly. The reason for adjusting the policy is to assist projects in knowing if the project can synchronize to the grid (and to what extent), or must await its assigned reliability network upgrades. However, the ISO's proposed change does not reflect a greater ability to study synchronization further into the future. The extension simply recognizes that the administrative process to optimize the LOS frequently eats into the study horizon. By allowing the request to be submitted at 9 months, the ISO and PTO can conduct the study in time to allow the IC to take advantage of the results to the greatest extent.

The ISO also proposes to clarify the interaction between the MMA and LOS. The ISO will clarify in the Business Practice Manual for Generator Management that any modification request submitted simultaneously with an LOS that may impact the LOS must be deemed complete and valid prior to the ISO starting the LOS. If an MMA is submitted after an LOS is completed and the MMA results may impact the LOS, the ISO may need to re-evaluate the LOS results or potentially require the interconnection customer to submit a new LOS request to ensure the modification results do not impact the reliability of the ISO Grid. The customer also could withdraw the MMA to avoid disrupting the LOS.

3.3. Consistent requirements for all asynchronous generating facilities.

Background

The ISO has seen increased deployment of asynchronous resources and has experienced operational issues with a varying size of resources. Currently, the requirements for large and small generating facilities differ in the operating, recording, and reporting requirements for inverters. The ISO seeks to bring consistency for all generating facilities.

Stakeholder Feedback

Cal Advocate, EDF-R, SCE, SEIA, Sonoma Clean Power Authority, and Vistra support the proposal to bring consistency to the two agreements.

Proposal

For consistency across all asynchronous generating facilities, the ISO proposes to make Attachment 7 of the Small Generator Interconnection Agreement (SGIA) – Interconnection Requirements for Asynchronous Generating Facilities consistent with Appendix H of the Large Generator Interconnection Agreement (LGIA).

3.4. Remove Suspension Rights from LGIA[27]

Background

As presented in the August 1st workgroup discussion, to date, only one of seven projects over the past several years that have requested suspension has achieved commercial operation, two have withdrawn, two are currently in suspended status, and two are still active in the queue. The ISO's concern is that interconnection customers have the ability to use the current suspension provisions to enter the interconnection process with not-ready projects and then use suspension while they attempt to find an off-taker.

Stakeholder Feedback

The development community, including AES, ACP, CESA, EDF-R, ENGIE NA, Intersect Power, LSA, New Leaf Energy, Nextera Energy, Rev Renewables, SEIA, Terra-Gen, and MN8 oppose any proposals that would remove or alter the ability for a project to request suspension of LGIA. The general belief is that suspension rights provide indispensable flexibility to generators in the interconnection process, a process where they generally do not have much flexibility.

SCE, PG&E, esVolta, and the CPUC public advocates office support the removal of suspension rights. SCE shares CAISO's concern that with a move to a "first-ready, first-served" paradigm, developers may seek to exercise the suspension provision with more frequency, which will halt and place the entire project on hold for up to three (3) years (except shared Network Upgrades) if retained because they have a "not-ready" project. SCE notes that developers have historically rarely invoked the current suspension provision (Article 5.16 of the LGIA), due in part to having the option to extend their project's commercial operation date multiple times through the modification process (resulting in deferment of project payments, financial security, and milestones).

CESA supports proposing language to limit suspension rights to more specific circumstances or for more limited durations rather than removing them altogether.

ACP commented further that given the infrequent use of suspension rights, however, it seems the proposed elimination may not provide significant benefits to managing the queue. Thus, ACP encourages ISO to consider whether it can maintain suspension rights going forward. If ISO proceeds and ultimately makes a proposal to FERC on this topic then, at a minimum, the proposal should clearly highlight the other ways in which

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[27] Suspension rights are in Section 5.16 of Appendix EE of the ISO tariff.

the ISO process provides sufficient flexibility to interconnection customers as compared to many other interconnection processes. Given the unique nature of its process, ISO should ensure the removal of suspension rights does not become precedent setting.

Calpine inquired if there would be a mechanism available to otherwise viable projects to delay, for example, changes in market conditions or equipment supply or regulatory requirements. The modification process does allow for extension of the COD provided certain criteria are met.

Discussion of Stakeholder Comments and Questions

The ISO recognizes the desire from the development community to retain suspension rights.

Referring to FERC's order accepting tariff revisions to PJM Interconnection' Tariff, FERC "find[s] that PJM's proposal to eliminate suspension rights and instead allow developers to extend milestones (other than site control) for up to one year for any reason meets the independent entity variation standard." Additionally, FERC understands that "PJM's proposal should give project developers certainty over the length they can extend milestones, establish objective criteria for such extensions …" Whereby FERC makes a final note that "PJM's proposed replacement of its suspension provisions with a one-time milestone extension reasonably balances the need for flexibility with the need to encourage project developers to complete generation projects in a timely manner, consistent with the purposes of Order No. 2003."

Provided FERC's order for PJM to remove suspension rights and consistent with ISO milestones extension provisions where project may extend its milestones via a modification request or utilizing Construction Sequencing without the need for a modification request, the ISO believes that suspension rights currently give customers too much unilateral power to remain stagnant in the queue. The ISO does not intend to curb reasonable and warranted extensions; merely prohibit unchecked and unreasonable extensions. The ISO has seen no evidence of suspension being used for actual permitting or construction obstacles. Rather, developers suspend construction that was never underway to begin with while they try to find an off-taker and financing. In any case, the ISO believes that customers needing to delay construction milestones can do so through an MMA request.

Proposal

The ISO proposes to remove suspension rights for all projects that execute a Large

Generator Interconnection Agreement (LGIA)[28] in the future.

3.5. Limitations to Transmission Plan Deliverability (TPD) Transferability

Background

The ISO is committed to providing projects the flexibility to become commercially viable and achieve commercial operation. As such, the ISO recently permitted projects the right to transfer deliverability from one project to another at the same point of interconnection. The ISO does not propose to eliminate such transfer rights, but place reasonable limitations to such transfer opportunities to prevent gaming. The ISO recognizes that deliverability transfers enable the most viable projects to proceed.

After the ISO permitted the transferring of a project's TPD to another project at the same point of interconnection, several projects attempted to transfer TPD to later queued projects that would not otherwise be subject to the same tariff requirements as the project that received the original TPD allocation (usually the TPD requirements for proceeding without a power purchase agreement). Because these transfers would circumvent tariff rules, the ISO has rejected them.

The ISO also has observed that the assignor projects (transferring their TPD) withdraw from queue or become stagnant as the developer tries to find an off-taker and re-seek deliverability. The ISO believes this is an undesirable result causing queue backlogs. Energy Only projects rarely, if ever, achieve commercial operation. The ISO believes developers should only proceed with TPD transfers when they recognize the project transferring its TPD is no longer viable.

Stakeholder Feedback

Cal Advocates supports the proposal

AES, CESA, Clearway, EDF-R, Intersect Power, LSA, Strat Clean Energy, Terra-Gen, and Upstream oppose TPD transfers that require the transferring project to withdraw. AES believes the ISO should maintain flexibility in TPD transfers to ensure that developers can contract to convert projects with assigned TPD into projects that can reach COD.

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[28] SGIAs do not have suspension provisions.

Leeward Renewable Energy also expressed concerns with this proposal and recommends that the CAISO continue to allow TPD transfers in situations where the transferee project has an earlier COD than the transferor project. The transferee project would then be subject to the same tariff requirements as the transferor project. This change would alleviate CAISO's concern about delays while still maintaining flexibility in the interconnection process. In situations where projects with TPD allocation may no longer be feasible, this modification allows a viable project an easy path to obtain the TPD allocation and bring additional reliability quickly onto the grid. Without this change, the alternative is having the non-viable project sit idle on the TPD allocation or having to wait for a new queue cycle before allocating that TPD.

AES believes that in the short-run, ISO should allow more flexibility in TPD transfers since these projects have already been studied, ISO should make it as easy as possible to convert this sunk cost in terms of studies and TPD allocation into operational MWs.

The CPUC public advocates office supports the CAISO's Straw Proposal on the TPD Transferability proposal as being reasonable, not unduly discriminatory or preferential, and supporting ratepayer's access to efficient resource procurement.

CESA questions the concern that TPD will become a tradable commodity given the proposed viability scoring criteria to enter the queue and the study limit of 150% zone's transmission capability.

Clearway commented that the ISO has not clearly demonstrated what problem TPD transfers are creating today. While the Straw Proposal suggests that there could be exceptions to the blanket limitation on TPD transfers, this does not provide sufficient certainty to developers, off-takers, and financing partners. A project that is transferring deliverability may still be viable at its original size: for example, it may be proceeding to a PPA as an Energy Only project in an area where Energy Only projects are included in the CPUC's busbar mapping.

EDF-R disagrees that Energy Only projects are always non-viable. Energy Only projects are more marketable now than they have been historically, and given the supply environment there is reason to believe their viability could increase. For example, in October of 2023 Silicon Valley Clean Energy (SVCE) executed a contract with the Grace Orchard Solar project. Grace Orchard is slated to come online in the summer of 2027 and will provide SVCE 120 MW of renewable solar energy, accounting for 8-9% of SVCE's 2028 annual retail sales. As LSE's push to meet SB 100 goals of serving all retail electricity from renewable resources and zero-carbon resources by 2045, more Energy Only projects are likely to be needed. In addition, the ISO's proposal contradicts TPD policies that allow for Energy Only project to seek FCDS. EDF-R agrees that Energy Only projects can and do "clog up" the interconnection queue but believes the

ISO should resolve this issue with queue management proposals, not a policy that specifically targets projects assigning their deliverability to another project.

SCE appreciates the CAISO's proposal to withdraw projects from the queue upon the approval of a corresponding TPD transfer. From a queue management perspective, this would be a straightforward approach to remove seemingly non-viable projects from the queue. However, SCE cautions that there may be a need for a more balanced assessment of the prevailing situation relative to Energy Only projects in the queue and encourages the CAISO to consider the projects through a procurement lens. LSEs have executed contracts for Energy Only projects to achieve Renewable Portfolio Standard (RPS) and clean energy goals. Deeming an Energy Only project as not commercially viable could result in fewer renewable resources and could increase the cost of clean energy. If a developer decides to transfer deliverability from a solar project to an energy storage project behind the same POI to meet the needs of an LSE, this should not automatically cause the solar project to be considered not viable or not needed by the system.

Discussion of Stakeholder Comments and Questions

In response to stakeholder comments, the proposal below maintains flexibility in TPD transfers to ensure that developers can contract to convert projects with assigned TPD into projects that can reach COD. This flexibility is provided to projects to transfer the TPD, whereby the key element of maintaining viability is helping one project to proceed forward and removing the now less-viable project from the queue.

The ISO believe this proposal provides certainty to developers, off-takers and financial partners such that the project transferring such TPD is not able to proceed forward in such a viable or financially beneficial manner where the project receiving such TPD can.

The updated proposal below recognizes that with the proposed changes to the TPD allocation process, after a deliverability transfer, the remaining Energy Only generation would only be able to seek an allocation of TPD using allocation Group C, after achieving commercial operation. Although possible, very few projects have utilized that path.

Proposal

The ISO maintains the proposal that a project transferring its deliverability must withdraw from the queue or downsize its generating capacity to its remaining deliverability. If a project is in Partial Capacity Delivery Status (PCDS) and transferring all of its allocation, the project must withdraw the entire project from the queue at time of the transfer. However, recognizing stakeholder claims that there may be some Energy

Only procurement, the ISO will forgo such withdrawal of the transferring project if the transferring project provides an Energy Only Power Purchase Agreement at the time of such transfer request.

The ISO also will add clarifying language to the tariff that TPD transfers cannot be used to escape deliverability retention requirements. If the assignor received TPD from Group 3, for example, the assignee would inherit all of those obligations and restrictions as if it had sought deliverability in that group. This clarification will provide more transparent notice that TPD transfers cannot be used to circumvent tariff requirements.

3.6. Viability Criteria and Time in Queue [Updated]

Background

Although the ISO has tariff and BPM language to limit a project's time in queue, enforcing these provisions often requires a time-intensive, project-specific analysis and assumption to ensure the project is still in compliance. Additional straightforward milestones, black-and-white requirements, and universal time-in-queue limitations will help manage older projects, provide clear and transparent rules, and prevent projects from stagnating.

FERC Order No. 2023 includes specific timelines and guidance for projects to negotiate and execute GIAs as well as a limitation of three cumulative years to extend the commercial operation date. These policy changes will be effective when the ISO's makes its compliance filing.

The straw proposal proposed an unavoidable time-in-queue for projects to execute the interconnection agreement and provide their third financial security posting and notice to proceed. This revised straw proposal suggests strict commercial viability criteria and time-in-queue requirements for all projects in the queue.

Stakeholder Feedback

The CPUC Public Advocates office, CalCCA, Calpine, Clearway, EDF-R, Intersect Power, Leeward Renewable Energy, Middle River Power, Ormat Technologies, REV Renewables, Nextera Energy, SCE, SDG&E, Upstream, MN8, Vistra and CPUC staff support the straw proposal and believe it will incentivize lingering projects to withdraw or move forward in the development process.

ACP does not necessarily oppose the imposition of unavoidable time in queue limitations, but any such requirement must be accompanied by requirements for the PTOs, which will enable interconnection customers to meet the deadlines. For instance, ACP advocates that the ISO should impose a deadline for the PTOs to tender a GIA for execution if it is going to impose unavoidable GIA execution dates for customers. The ISO does not disagree and notes that Section 11 of Appendix DD specifically states when the GIA is to be tendered.

Calpine sees one aspect of the time-in-queue proposal as viable: Because the IC has full control over the submission of a higher (100 percent) security deposit, a date-certain submission may be appropriate. A date-certain for those deposits, when combined with non-refundability conditions, creates another important decision point on project viability. Indeed, viable projects may not have any concerns with additional deposits and questionable project may withdraw. The ISO agrees with Calpine's observation. However, Calpine believes that fixed dates on a Notice to Proceed (NTP) and the execution of a GIA are often beyond the control of the Interconnection Customer. In fact, exigent circumstances such as supply-chain disruptions and other external factors often interfere with issuance of an NTP. In addition, Calpine noted that there are over 430 projects in the current queue (excluding C15) that have not executed GIAs. In Calpine's experience, GIA execution is largely dependent upon timely responses from the PTO and forcing an IC to withdraw because of the absence of responses from a PTO would be unjust. Calpine continues suggesting that with over 400 projects yet to finish, establishing a hard deadline on LGIA execution seems unreasonable. The ISO has different data. As of November 7, 2023, there are 282 projects in the queue without executed GIAs. Of them, 204 are Cluster 14, which have not yet received their Phase II study results. Thus, there are 78 projects without GIAs and 24 of those are in progress. Absent having a specific requirement on all parties, the ISO has found that GIAs are not executed on a timely basis.

Clearway encourages the ISO to facilitate sales of older projects that are lingering in the queue by publishing information on these projects' current owners. This was discussed in IPE 2021 and the interconnection customers did not want the ISO to release information on their project regarding the owner or parent company. The ISO then offered to post a list if the interconnection customer wanted the ISO to post a list of project available, but to date, no one has asked the ISO to post anything. The ISO also questions the value of selling older projects. When this occurs, the purchaser often has limited abilities to remain in queue and retain or acquire deliverability, but is motivated to do so to recoup investment. Sold projects then end up stagnant in queue longer, and still ultimately withdrawing, instead of simply withdrawing earlier.

NextEra is concerned with the CAISO's persistence in only applying reforms on a solely prospective basis. NextEra has previously commented that without applying reforms to previous clusters and existing older projects, the potential impacts associated with any process improvements would be so far out into the future that they would not address the immediate problem of an interconnection queue that is overburdened with non-viable projects. According to NextEra, the ISO has proposed that the straw proposal apply to Cluster 15 and future clusters but has not sufficiently explained why existing non-viable projects that have lingered due to existing gaps in the current interconnection process cannot be addressed. The ISO may not understand what this comment refers to. The ISO has numerous proposals that apply to the entire queue, including proposals specifically addressing prior clusters and stagnant projects.

SDG&E considers the time-in-queue proposal one of the most important aspects of the IPE proposal. According to SDG&E, it is important to ensure meaningful requirements that will streamline the interconnection process. SDG&E states that while the current time-in-queue proposal is an improvement over the status quo, there are still some ambiguities around what happens to the time in queue limits after projects are converted to Energy Only and surpass the 8 year limit without a PPA. To reduce this ambiguity, SDG&E encourages the ISO to consider removing projects from the queue should projects not meet the notice to proceed and 3rd posting deadlines instead of adding the additional complexity of converting these projects to Energy Only.

Vistra is confused by the dates that the ISO included in its straw proposal because it seems to inadvertently imply that ISO is removing parking from its rules. For example, for Cluster 14 the GIA executed no later than December 31, 2025 does not seem to make sense given the ability to participate in three TPD allocation cycles. The ISO clarifies that projects may only seek a TPD allocation a third time if they are eligible to park for a second term. Following the 2023 allocation cycle, no projects were eligible to park for a second term.

Discussion of Stakeholder Comments and Questions

Upon further review and consideration of the commercial viability criteria (CVC) and time-in-queue rights and obligations and the understanding that long-lead procurement or development may be necessary, the ISO has re-evaluated the current CVC requirements to retain deliverability and the time-in-queue requirements and has revised the proposal.

The benefit of the revised proposal below is that the CVC requirements do not rely on a project's commercial operation date, long-lead upgrade or procurement needs, long-lead development timelines (offshore wind, geothermal, etc.), or a project's TPD status. This updated proposal is predicated on providing projects, following the study process, equal and reasonable time and flexibility to (1) seek and receive a TPD allocation, (2) park as needed, (3) execute an interconnection agreement, (4) seek and execute a power purchase agreement (whether for resource adequacy requiring TPD or for Energy Only), and (5) commence design, permitting, procurement, and construction activities.

One goal of the proposal below establishes a clear standard for all parties, including off-takers, that all PPAs must be executed by a project's very clearly defined 7-year-in-queue mark. If an off-taker knows the deadline, they may work to structure their RFPs in order to execute in a timelier manner *or* move to the next project or cluster of projects based their procurement timeline.

Proposal

The ISO proposes to require all projects in the queue to demonstrate commercial viability if they will remain in queue beyond seven years, regardless of deliverability status. The ISO proposes to require that each project meet the CVC by an unavoidable time-in-queue and annually, otherwise the Interconnection Request is withdrawn or placed in breach of the interconnection agreement, as further described below.

Once CVC has been met, the project is required to demonstrate specific and distinct progress to commercial operation on an annual basis and is prohibited from extending milestones except when aligning the COD with that of an amended purchase agreement (the six-month construction sequencing allowance or PTO construction delays are not applicable here).

As detailed in Table 1 and 2 below, the ISO proposes that all projects will be required to meet the following CVC by no later than the date defined for all active projects currently in the ISO queue through Cluster 14. For all projects in Cluster 15 and later, projects will be required to meet CVC by no later than 7 years from when the original interconnection request was submitted to the ISO:

A. Providing proof of having an (or multiple) executed power purchase agreement (whether for Resource Adequacy requiring TPD or for Energy Only) by providing the ISO a copy of such executed agreement(s) and other supporting documentation as applicable. Power purchase agreements must have a minimum 5-year term and the point of interconnection, capacity, fuel type, technology, and site location consistent with the ISO queue project, Interconnection Customer, and GIA;

    1) In the event the PPA is not consistent with such ISO or GIA criteria above the Interconnection Request will be withdrawn or terminated. If such differences could be corrected with a material modification request, to the extent permitted, the project will be required to immediately submit a modification request to align the interconnection request with the executed PPA. If the modification request is denied, the ISO will place the project in breach of contract.

2) In the event a PTO extension causes the interconnection customer's PPA to be terminated, the interconnection customer will have 12 months from the date of the PTO extension report to provide the ISO with a subsequent executed PPA that demonstrates the same criteria as above. If a PPA is not provided by the due date, the ISO will place the project in breach of contract.

B. Provide the Third Interconnection Financial Security posting

C. Demonstrate Site Control for 100% of the property necessary to construct the facility through the approved Commercial Operation Date.

D. Have an executed Generator Interconnection Agreement ("GIA"); and

E. Be in good standing with the GIA such that neither the Participating TO nor the CAISO has provided a Notice of Breach that has not been cured and the Interconnection Customer has not commenced sufficient curative actions.

F. Provide a report that includes a detailed description and demonstrate status of the following:

1) Progression of the project's established GIA milestones, including, at a minimum:

    i. Notice to proceed has been provided to the PTO

    ii. Third interconnection financial security has been posted in full or the project is up-to-date on the payment schedule defined in the GIA

2) A list of all necessary permit, environmental, or other authorizations required for constructing the Generating Facility and the contact persons and contact information for each required authorization, including, at a minimum:

    i. The Conditional Use Permit

    ii. California Environmental Quality Act (CEQA) permit(s)

    iii. Environmental Assessment Requirements

3) The status of the engineering and design of the generating facility, and network and interconnection upgrades,

4) The status of the procurement of major equipment necessary to construct the generating facility, and

5) The status of the construction activities of the generating facility and interconnection facilities.

Then, annually, the project must continue to demonstrate that:

A. The CVC criteria (A) through (E) above remains valid and accurate;

    1) The project must continue to satisfy this CVC with the PPA it provided in its initial CVC demonstration. In the event a project's PPA is terminated, the project is prohibited from remaining in the queue and continuing to seek another PPA; ISO will place the project in breach of contract.

B. Specific and distinct progress has been made for all of the following items:

    1) GIA Milestones

    2) The submission of or approvals from the regulating authorities for all necessary permit, environmental, or other authorizations required for constructing the Generating Facility including, at a minimum:

        i. The Conditional Use Permit

        ii. California Environmental Quality Act (CEQA) permit(s)

        iii. Environmental Assessment Requirements

    3) The status of engineering and design of the generating facility, and network and interconnection upgrades,

    4) The status of the procurement of equipment necessary to construct the generating facility, and

    5) The status of the construction activities of the generating facility and interconnection facilities.

After a project has met CVC above, and the interconnection request is past 7-years-in-queue, in order to submit a modification request to align its Commercial Operation Date with the PPA, a project must first execute an amendment to the PPA to explicitly define the updated Commercial Operation Date to be defined in the modification and interconnection request.

Failure to meet the GIA or CVC requirements will result in the ISO proceeding to withdraw the interconnection request. With this CVC policy, the ISO proposes to eliminate the monthly or quarterly status report submissions as established in the generator interconnection agreements and rely on the initial and annual demonstration of CVC for project status updates.

The following tables establish the proposed due dates for all projects in the queue through cluster 14 to (1) execute an interconnection agreement, and (2) subsequently demonstrate the project's CVC.

Table 1: GIA Execution Requirement

	# Projects with unexecuted GIAs	MW Capacity at POI	IR Received Date (April)	7 years in queue	Years in Queue as of Nov. 2023	**GIA Executed No Later Than:**	Years-in-queue
Cluster 8 and prior	1	50	2015	2022	8.5+	June 30, 2025	10.2+
Cluster 9	3	450	2016	2023	7.5	June 30, 2025	9.2
Cluster 10	2	300	2017	2024	6.5	June 30, 2025	8.2
Cluster 11	6	921	2018	2025	5.5	June 30, 2025	7.2
Cluster 12	13	3915	2019	2026	4.5	Sept. 30, 2025	6.4
Cluster 13	46	12,117	2020	2027	3.5	Dec. 31, 2025	5.7
Cluster 14*	204	65,506	2021	2028	2.5	April 30, 2026	5.0

*FERC Order No. 2023 may impact or change the timeline for Cluster 14 GIA tendering and execution requirements

Table 2: CVC Demonstration Requirement

	# Projects impacted	MW Capacity at POI	IR Received Date (April)	7 years in queue	Years in Queue as of Nov. 2023	**Demonstrate all CVC No Later Than:**	Years-in-queue	Months to demonstrate CVC after GIA execution
Cluster 8 and prior	49	7,377	2015 and prior	2022 and prior	8.5+	Dec. 31, 2025	10.7+	6 Months
Cluster 9	27	5,367	2016	2023	7.5	Dec. 31, 2025	9.7	6Months
Cluster 10	21	6,501	2017	2024	6.5	Dec. 31, 2025	8.7	6 Months
Cluster 11	30	5,362	2018	2025	5.5	April 30, 2026	8.0	10 Months
Cluster 12	44	14,768	2019	2026	4.5	Sept. 30, 2026	7.4	12 Months
Cluster 13	60	16,323	2020	2027	3.5	April 30, 2027	7.0	16 Months
Cluster 14	204	65,506	2021	2028	2.5	April 30, 2028	7.0	24 Months

Examples:

1. A long-term build project (such as off-shore wind) with a COD needed of 2040 enters the queue in April 2025 with a 7-year CVC requirement of April 2032. With a long-lead development and upgrades of 10 years, the project must start construction by 2030 As long as the project executes a PPA by April 2032 (meaning it had ~4 years to market and seek an off-taker following the study process), and demonstrate all other CVC, it can request a COD that aligns with that PPA.

2. The project has a long-lead upgrade that results in the project COD extending beyond 7-years-in-queue, the project can have any COD it needs, as long as it demonstrates all CVC by 7 years-in-queue (or date established below), continues to demonstrate such CVC annually and makes continual progression to achieve its commercial operation. If a project executes a PPA, it can submit a modification request to align the project COD to the PPA.

3. If the project has Energy Only Deliverability Status, an Energy Only PPA satisfies criterion (A), would permit the project to align its COD with that Energy Only PPA and the project would remain in good standing as long as it meets all CVC by 7-years-in-queue (or date established below) and continues to meet such CVC annually making continual progression to commercial operation.

4. The Queue Management team will continue to work to maintain project's CODs as it does today, allowing modification requests for CODs and managing projects accordingly.

3.7. Project Modification Request Policy Updates

Background

The increase in the volume of modification requests has become challenging to manage and the ISO proposed several suggested approaches to reduce the number of modification requests to a workable level. Currently, projects submit multiple MMA requests for equipment, technology, and configuration changes prior to execution of the Generator Interconnection Agreement (GIA) and through their Commercial Operation Date (COD). In the initial discussion paper and through the IPE stakeholder workgroup meetings, the ISO and stakeholders sought how to reduce the pace and volume of modification requests.

The ISO and stakeholders discussed options that included:

1. Define a list of modifications that would not require a request and that could be approved without a formal review.

2. A tiered approach to simple COD-only requests as compared to complex requests that include technology or interconnection changes. This tiered approach would also consider a different deposit or fee amount.
3. Requiring PTO validation timeline turns.
4. Limit a project to a certain number of MMA requests or require that MMAs may only be either submitted at certain times during the year or based on contract milestones.
5. Implement a financial penalty ($X/day) for projects that do not submit an MMA as requested by the ISO or PTO.

Additionally, the ISO has recently seen an increase in the number of shortfalls dues to the cost of processing modifications being greater than the current $10,000 deposit.

Stakeholder Feedback

AES supports proposals to (1) increase deposits and (2) require coordination calls among the PTOs, ISO, and IC. While AES supports increasing study deposits from $10,000 to $30,000, AES believes additional study costs should contribute to additional resources to complete MMAs more efficiently and quickly. Cal Advocates, CPUC supports

Cal Advocates supports the CAISO's Straw Proposal to limit project Modification updates as being reasonable, allowing the CAISO to clean up the CAISO interconnection queue, improving CAISO resources used for this task, and lowering costs to ratepayers.

Calpine would like to understand how delays caused by a PTO or ISO failing to adhere to the specific timeline will be managed. Calpine suggests that delays outside of the control of the IC not result in a negative impact and be addressed accordingly. The ISO agrees and is working with the PTOs to improve processes and timing.

Clearway encourages the ISO to continue advancing a fast track for simple project modifications. Clearway disagrees with the statement in the Straw Proposal that "a tiered approach to the type or cost of modification requests does not provide process improvements." While that may be true of the administrative process for handling requests, there is significant opportunity to save time and resources in the analytical process by streamlining simple modifications. Clearway goes on to provide examples – inverter changes, collection system design, gen-tie routing and electrical configuration. The ISO notes that it already has a process for enumerated simple modifications: permissible technological advancements. The ISO has stated that the modifications listed by Clearway require an assessment to determine if the electrical characteristics change. The ISO needs to maintain the reliability of the grid and will make the modification process as fast as possible.

EDF-R disagrees with the ISO's proposal. It could support:

1. raising the deposit for complex changes, but keeping the $10,000 deposit for simpler changes, or
2. raising the deposit to $15,000 so that costs are covered 80% of the time (or more); and
3. increasing the number of changes that can be approved without an MMA, such as forgoing inverter changes until inverter procurement has been performed.

EDF-R also suggests that collectively the ISO may be approaching the MMA communication inefficiently. EDF-R suggests that the ISO include the interconnection customer on all communications with the PTO about MMA requests and does not believe the MMA details could be considered confidential.

LSA and REV Renewables generally support the proposal. LSA appreciates the ISO did not adopt earlier proposals on the timing or number of MMAs; however, both would like the ISO to reconsider revisions that could be made without a MMA request.

LSA further comments that they do not oppose formalizing the current practice of delaying a CS request until a project has started construction, but the requirement to wait until 6 months before the ISD is not justified and would likely be counter-productive.

- Projects seeking to accelerate their CODs, and the PTOs constructing their upgrades, need to know further in advance than 6 months before ISD.
- Likewise, it is to the benefit of both the PTO and the IC to know more than 6 months in advance (actually, less once the processing timing is considered) that the project COD will be delayed, for work-scheduling, financing, and other purposes.

A compromise position might be to allow CS requests for COD extensions to be allowed as early as 12 months before the current In-Service Date, and not to place limits on CS requests for COD accelerations.

SCE and PG&E generally support the proposal. Both believe the additional time needed for a Facility Reassessment Report (FRR) should also increase to 60 days. SCE believes COD-only MMA extensions should only be fee-based, with a fee no less than $7,500.00.

Vistra encourages the CAISO to continue to explore MMA enhancements discussed at the workshops, and even in CAISO's discussion paper. The ISO appreciates that there is no risk-free way to accept modifications without a formal review and evaluation and believe increased efficiencies could be gained.

Discussion of Stakeholder Comments and Questions

Through stakeholder discussions and meetings between the PTO/ISO engineering teams, and given the number of variables, ambiguity, modeling requirements, and nuances between projects, a number of potential commercial or development related risks were identified that limited the types of requests or when they can be submitted. Unfortunately, there is not a risk-free way to accept modifications without a formal review and evaluation.

The ISO also realized that a tiered approach to the type or cost of modification requests does not provide process improvements. For example, regardless of the deposit or fee amount, the ISO and PTO must process the request and financial accounting the same way. Therefore, any tiered modification type or cost approach would not improve the process and would hinder it due to increased tracking and processing requirements.

Additionally, the ISO understands the desire for the interconnection customer to be fully engaged in all communications during a modification process, but this is not possible. For example, the ISO and PTO must discuss system topology and other customers' confidential information in the course of nearly every modification request. The ISO is and will continue to engage all parties as needed and as soon as possible to ensure the processes progress to completions in a timely manner.

Proposal

The ISO proposes the following updates to the MMA and post-COD modification processes:

- Increase deposit to $30,000
- Increase time to complete engineering analysis from 45 days to 60 days
- Increase time to complete the FRR from 45 days to 60 days

The ISO proposes process updates that the Queue Management team will work on to enhance the overall modification processes as follows:

1. Work to host modification calls between the ISO and PTO engineering teams and the interconnection customer following the second or third validation turn.

2. Coordinate with the PTOs to improve the initial and subsequent validation reviews for modification requests.
3. The ISO and PTOs will work to identify specific milestones such as executing the GIA or providing notice to proceed in the modification results.
4. The ISO proposes to update the BPM for Generator Management (Section 6.2.1.4) that projects must have started construction and be within nine (9) months of achieving their then-current synchronization or commercial operation date to submit a construction sequencing delay request. If updates to the COD are necessary beyond the 9 months, a modification request must be submitted.

3.8. Earlier Financial Security Postings for Projects with Shared Upgrades

Background

Appendix B of the LGIA and Attachment 4 of the SGIA establish milestones for the interconnection customer and PTO to meet the commercial operation date specified in the agreement. Section 5.1.1 of the LGIA provides:

> **5.1.1 Standard Option.** *The Participating TO shall design, procure, and construct the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades, using Reasonable Efforts to complete the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades by the dates set forth in Appendix B, Milestones.* (Emphasis added.) The Participating TO shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Participating TO reasonably expects that it will not be able to complete the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades by the specified dates, the Participating TO shall promptly provide written notice to the Interconnection Customer and the CAISO and shall undertake Reasonable Efforts to meet the earliest dates thereafter

Interconnection customers have raised concerns that the PTOs are not meeting the milestone dates, particularly with shared network upgrades. In some instances, the PTOs are waiting until all or the majority of the interconnection customers responsible for the shared network upgrade have provided their Notice to Proceed (NTP). A consequence of this is that a project ready to go is delayed because the PTO is waiting for the NTP for all parties, or the majority of the parties. In the Straw Proposal, the ISO proposed that if one interconnection customer is ready to proceed with construction of a shared network upgrade then all participants in that upgrade must post the needed security for and fully fund that upgrade as applicable. This should occur regardless of their deliverability status or whether the interconnection customer has executed a GIA.

Stakeholder Feedback

The following parties support this proposal: AES, Cal Advocates, EDPR, Intersect, MRP, Ormat, Rev Renewables, SDG&E, SEIA, SCE, and Upstream.

AES and Cal Advocates support requiring all affected customers to post security once the first project provides their Notice to Proceed (NTP) and security.

EDF-R requests the ISO provide details on how those funds will be handled in the event that a project with an unexecuted interconnection agreements withdraws from the interconnection queue. EDF-R opposes the notion that this new procedure should increase financial risks for projects with unexecuted interconnection agreements.

EDPR supports both the concept to accelerate starting network upgrades when the first project posts security and to require all projects related to that upgrade to post financial security. EDPR requested that the ISO allow a project that is required to post financial security for a network upgrade triggered by another project to have a reasonable amount of time to post that financial security.

Intersect Power supports this proposal and encourages the ISO to extend this concept to Pre-Cursor Network Upgrades (PNUs). For example, if a project issues NTP and provides the third posting and has identified PNUs, the parties responsible for those PNUs should be required to fully fund those upgrades at that time. This will become less of an issue if the ISO institutes the time-in-queue Third Posting requirements as described in the Straw Proposal, but that's not a valid reason to omit the concept now.

LSA does not oppose this proposal, as long as it is accompanied by adoption of proposal (j) below. According to LSA, third postings are not justified unless the PTO is required to move ahead with development of the associated upgrades.

While Middle River Power (MRP) supports the ISO's proposal that all customers sharing the network upgrades must make their postings when the upgrade is ready to proceed, MRP requests that the ISO set forth what happens if an interconnection customer does not make their posting at that time. MRP also requested that the ISO formalize its clarification in the September 28th meeting discussions that the NTP and third postings required of all projects does not extend to other upgrades not shared with the first project providing NTP for a specific upgrade.

PG&E requests ISO clarify if the proposal is applicable to projects prior to Interconnection Agreement (IA) execution, particularly those in parked status, or only those with executed IAs.

REV supports this proposal so that if one interconnection customer is ready to proceed with construction of a shared network upgrade then all participants in that upgrade must post the needed security for and fully fund that upgrade as applicable. ISO may need to add an additional milestone date in the process for those that have not yet executed a GIA for this to occur. By requiring posting for shared network upgrades, this will provide a more equitable process for those projects ready to proceed and not hinder their commercial viability while waiting for other customers.

SDG&E supports the proposal for all interconnection customers assigned to a shared network upgrade to post for that upgrade when the upgrade is needed by the first customer. It is a reasonable proposal that ensures that all parties looking to interconnect are sufficiently committed, thus decreasing process delays and streamlining the queue.

SCE supports the ISO proposal that once the developer for the first project provides the Notice to Proceed in accordance with the LGIA, then the ISO in coordination with the Participating TO will officially notify all the other developers whose projects were allocated a pro-rata share of the same shared network upgrade that they will be required to make the 3rd Interconnection Financial Security (IFS) posting for their pro-rata share of the shared network upgrade regardless of their deliverability status or whether they have an executed LGIA. However, ISO's proposal does not go far enough without providing clarification. IFS is not the same as receiving project payments from the other developer(s) to fund, design, engineer, procure, and construct the shared network upgrade. Thus, SCE seeks CAISO's clarification on the following:

1. Will the Participating TO be permitted to sweep the 3rd IFS instrument(s) from the other developers to fund the balance of the shared network upgrade and once the shared network upgrade is placed in service, the shared network upgrade cost will be refunded to all parties in accordance with the Appendix DD to the CAISO Tariff and the terms in the LGIA, assuming the other developer(s) execute a LGIA? or,
2. Will the developer of the first project be required to advance the balance of the shared network upgrade costs by executing an amendment to its LGIA or executing a Letter Agreement in accordance with Section 12 of Appendix DD to the CAISO Tariff knowing that the Participating TO is holding the 3rd IFS Posting from each of the other developer(s) for the balance of the shared network upgrade? Once the shared network upgrade is placed in service, will the Participating TO be able to sweep the collateral instrument(s) and remit the funds

immediately to the developer of the first project while the assigned pro-rata share cost of the shared network upgrade will be refunded in accordance with GIDAP and the terms in the LGIA, assuming the other developer(s) execute a LGIA? or,

3. Is CAISO expecting the Participating TO to fund the balance of the shared network upgrade knowing that the Participating TO is holding the 3rd IFS posting from the other developer(s) for their pro-rata share of the shared network upgrade? If so, SCE would strongly oppose CAISO's position to have Participating TOs finance upfront the balance of the shared network upgrade costs.
4. What happens to the 3rd IFS posting from the other developer(s) for their pro-rata share if they do not execute an LGIA requiring them to make project payments toward the shared network upgrade?

Discussion of Stakeholder Comments and Questions

The ISO's straw proposal was unanimously supported with clarifications, as discussed in this revised straw proposal, and all stakeholders that commented agreed that if one interconnection customer is ready to proceed with construction of a shared network upgrade then all participants in that upgrade must post the needed security for and fully fund that upgrade as applicable. This should occur regardless of their deliverability status, whether they are parked, or whether they have executed a GIA.

With respect to SCE's request for clarifications, will the Participating TO be permitted to sweep the 3rd IFS instrument(s) from the other developers to fund the balance of the shared network upgrade, no. The ISO's intent of this initiative is that all impacted interconnections customers pay their share of the network upgrade within 60-90 days of notification of one interconnection customers NTP. A number of stakeholders inquired as to if the Interconnection Customer does not execute the LGIA requiring them to make project payments toward the shared network upgrade, IFS posting from the developer will be treated in accordance with Section 7.6 and 11.4 of Appendix DD.

EDPR requested a reasonable time to post once the project is notified. As discussed in the proposal below, the interconnection customer will have 60-90 days to post for the shared network upgrade and then continue to make the appropriate payments for the upgrade as required by the GIA.

LSA commented that the interconnection customer should only have to post if the PTO is going to commence the upgrade. The ISO agrees. The whole reason for requiring all interconnection customers to post for shared network upgrades is to ensure that the PTO can timely build the upgrade to meet the earliest project's schedule and the PTO will have 30 days to commence such activity.

The ISO again clarifies that NTP and third postings required of all projects do not extend to other upgrades not shared with the first project providing NTP for a specific upgrade As the ISO stated, this would require separate NTPs and third-posting dates for the other projects sharing the upgrades that have later schedules for their other upgrades.

Proposal

As discussed above, the ISO in coordination with the Participating TO, will officially notify all the other developers whose projects were allocated a pro-rata share of the same shared network upgrade that they will be required to make the 3rd Interconnection Financial Security (IFS) posting for their pro-rata share of the shared network upgrade. If the project is parked it would need to execute an engineering and procurement agreement for the shared network upgrades with the PTO within 90 CD of notification or be withdrawn. If the GIA is not executed, the interconnection customer will have 90 days to execute the GIA or be withdrawn. The GIA could incorporate two NTPs and 3rd IFS postings, one for the shared network upgrade and one for the remainder of the project. The IFS and first payment would be due at the time of execution and payments would commence. Failure to post is grounds for termination of the engineering and procurement agreement or GIA.[29] If the GIA is already executed, the interconnection customer would have 60 days from the date of notification to post the IFS for the shared network upgrade and make payments to the PTO. The GIA could be amended to incorporate two NTPs and IFS postings, if desired. The shared network upgrade can be any network upgrade (PNU, CANU, ADNU, LDNU, RNU or DNU). If a project withdraws because it has to post earlier than anticipated in its schedule, then withdrawal funds will be treated consistent with Section 7.6 and 11.4 of the tariff. Also, as discussed in Section 3.10 below, once the PTO has received the NTP and 3rd IFS posting, it will have 30 BD to commence the upgrades.

3.9. Revise Timing of GIA Amendments to Incorporate Modification Results

Background

In the straw proposal, the ISO noted that with the continuous revisions to projects through the MMA process, the contract negotiators for the Interconnection Customer,

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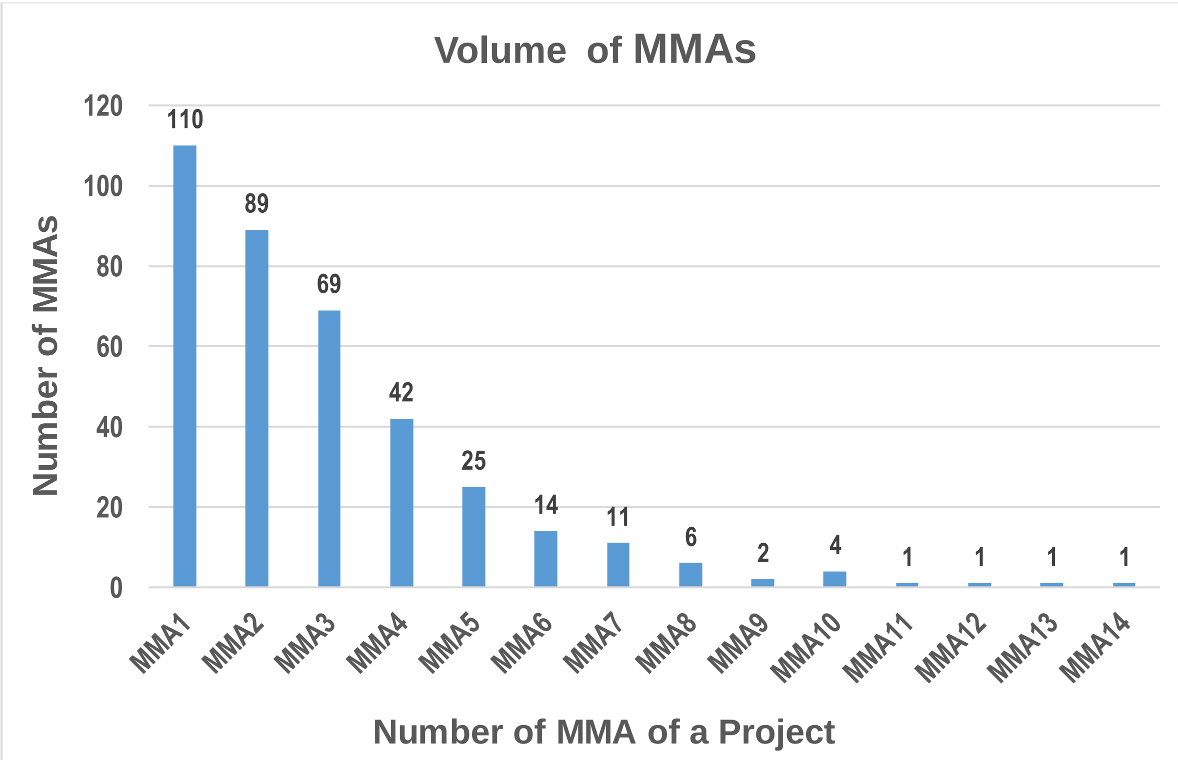
29 Section 8.4.8 of Appendix DD, LGIA Article 2.3 or SGIA Article 3.3, whichever is applicable

Participating TO and ISO are required to continually amend the GIAs. From 2021 to date, the ISO and Participating TOs have processed 376 MMAs.[30]



Some projects have made more than five modification requests, and one project even has had 14 modification requests. Trying to keep up with this ever-changing churn required to move the projects forward is time consuming. In the Straw Proposal the ISO proposed that the MMA results report which incorporates any change to scope, schedule or cost would be the binding document amount the parties and the LGIA would be amended once nine months before the synchronization of the first element of the project.

Stakeholder Feedback

AES, Cal Advocates, Calpine, EDF-R, Intersect, Rev, and Upstream support the ISO's proposal to have the GIA updated nine months before synchronization. The MMA results would include both the results and the financial milestone changes, if applicable.

[30] The volume of MMAs is based on the number of MMAs each project has requested. As an example, 110 projects have one MMA whereas 25 projects have 5 MMAs to date.

Some parties opposed this proposal, such as SEIA, and SCE.

LSA, Intersect Power and REV supports this proposal as long as New Resource Implementation process qualifying criteria are revised to accept MMA approvals in lieu of updated GIAs. REV supports the idea of updating the LGIA post COD and after the final reconciliation amendment is in place.

Intersect Power encourages the ISO to take this one step further and eliminate LGIA amendments entirely as a result of MMA approvals. If the final outcome of an approved MMA is enforceable without having the LGIA amended (which is Intersect Power's experience to-date on multiple projects that have achieved Commercial Operations), then the process of amending the LGIA is a mere formality and is unnecessarily consuming a large amount of valuable PTO and ISO resources to support. Intersect Power encourages ISO to better formalize the understanding that MMA approvals are effective and enforceable within the Tariff and/or Pro Forma LGIA so that financing parties can confidently rely upon the final MMA approvals, in lieu of an amended LGIA, which should eliminate the push from Interconnection Customers to make the subsequent revisions to the LGIA.

MRP notes that an executed modified GIA may be key to securing project financing, and so may not be able to wait until close to synchronization.

SEIA opposes the proposal to modify the GIA nine months prior to the synchronization date included in the GIA. This change poses significant risk to developers as the GIA must be up-to-date and accurate for project development including contracting and PPA negotiations.

SCE opposes the CAISO's position on timing of LGIA and/or UFA amendments to incorporate modification results for the following reasons:

a. The controlling document from a project implementation/execution perspective is not the MMA reports but rather the LGIA and/or UFA, which address the project's scope of work, costs, project payments, milestones, and overall schedule.
b. Waiting to amend the LGIA and/or UFA until a point in time near to when a developer's project synchronizes to the CAISO Controlled Grid to incorporate all approved MMAs is impractical and would create confusion relative to the scope of work, schedule, and the project's overall budget.
    a. SCE's contract execution team relies on a project summary based on the controlling LGIA and/or UFA, not subsequent modification results.

   b. There have been cases where subsequent modification results cancel prior approved project modifications, which causes tracking difficulty and leads to confusion during project implementation.

c. Most approved modification requests trigger changes to scope, cost, and schedule or a combination thereof, which would require an immediate amendment to the LGIA and/or UFA.

d. SCE as a Participating TO opposes being required to finance costs associated with incremental scope triggered by a developer's request to make modification(s) to its project. Accordingly, SCE would oppose any delay in amending the LGIA and/or UFA to collect additional project payments and financial security (ITCC and IFS) that is outlined in an MMA/Facilities Reassessment Report.

e. COD MMA extensions also trigger significant changes to the LGIA and/or UFA that must be captured immediately in an amendment, such as deferment of project payments, updating costs, changes to financial security amounts (ITCC and IFS) and their due dates, and schedule (i.e., recalibration of milestone due dates based on the revised COD).

f. Finally, if CAISO has insufficient staffing levels, they should strongly consider limiting the number of MMA submittals by a developer post LGIA and/or UFA as stated in Section G above to save time and resources.

Vistra commented that this section overlaps a bit with the change to allow LOS to be requested nine months prior to synchronization. This section seems to imply that no MMA may be submitted after nine months prior to synchronization because the GIA so that "all modifications would be incorporated into the agreement nine months before the synchronization date in the GIA", but this seems to conflict with the idea that MMA submitted after the LOS commences may or may not require restarting the LOS. Vistra suggests the CAISO move this discussion into the section with the LOS changes and think through this interconnection more. We reserve our feedback on the LOS, MMA, and GIA changes until there is a clearer understanding of this proposal.

Discussion of Stakeholder Comments and Questions

The ISO agrees that the NRI process would need to be modified if this initiative is approved. The requirements for the bucket filing would be adjusted to meet this new timeline. The ISO also agrees that if an updated GIA is needed for financing purposes, then upon 120 days advance written notice, a GIA incorporating all MMAs to date could be tendered and executed by the parties.

The ISO understands SCE's concerns however, the MMA Report has been expanded to include all of the information required to amend the GIA including any impact to scope, schedule, budget and payments. Moreover, Participating TOs have the ability to amend the GIA after every MMA is completed and keep the agreement up to date for their implementation purposes for the project scope of work, schedule, and the overall budget. This will also assist SCE when they need to tender the GIA nine months prior to synchronization, by updating the GIA with each MMA it would facilitate the draft that would be tendered in advance of synchronization. The MMAs already include changes to scope, cost, and schedule or a combination thereof, and therefore a document is available for the parties to execute the project. If a subsequent MMA changes the scope, cost, and schedule or a combination thereof, then the new MMA report will then be the controlling document. In addition, SCE can include in the MMA report information such as deferment of project payments, updating costs, changes to financial security amounts (ITCC and IFS) and their due dates, and schedule (i.e., recalibration of milestone due dates based on the revised COD).

Vistra misunderstands the proposal. The proposal is attempting to cut down on the number of amendments made to the GIA over time, it is not intended to stop the project from making additional modifications once a true-up of the MMAs and GIA is done in advance of synchronization. In fact, the GIA still needs to be amended after COD to incorporate that actual costs of the project.

Proposal

The ISO proposes in this Revised Straw Proposal that the process of amending the GIA that will include all of the MMAs should start 9 months prior to synchronization of the first block or phase of the project to the grid. Doing so will facilitate inclusion of the final or near-final configuration of the project in the GIA. To effectuate the GIA amendment, the MMA report(s) would be the enforcement document, binding upon all parties, even when the GIA amendment has not been executed yet. All modification reports would include scope changes, project payments, updating costs, changes to financial security amounts (ITCC and IFS) and their due dates, and schedule (i.e., recalibration of milestone due dates based on the revised COD), as applicable. This true-up of the MMA Reports and the GIA does not preclude the project from making additional modification requests if needed.

The proposal is also being expanded to facilitate concerns raised by stakeholders. The NRI process will be revised to align with this proposal and upon 120 days advance written notice, a GIA incorporating all MMAs to date could be tendered and executed by the parties if needed for financing purposes.

3.10. Commence Network Upgrades When the First Notice to Proceed is provided to the PTO

Background

Interconnection customers are concerned that once a notice to proceed (NTP) is provided to the PTO, it may be months before the PTO actually starts engineering, design, or project management of the network upgrade. This can result in the network upgrade being delayed from the original online date in the GIA. This then could force the interconnection customer to be delayed in meeting the timeline in their PPAs, which likely results in financial penalties for the Interconnection Customer.

The ISO's Straw Proposal included that a specific date for the NTP be included in the GIA. If an MMA modifies the NTP date then the new date will be included in the MMA report, which is then an amendment to the GIA. The ISO also agreed that the PTOs need to move forward once the NTP and third security posting is received and meet the Initial Synchronization Date in the GIA to allow interconnection customers to meet their PPA requirements. The ISO also proposed that a new milestone be added requiring the PTO to notify the interconnection customer and ISO when activity has begun on the network upgrade and interconnection facilities. This would provide transparency as to when the upgrades are started and open communication among the parties to ensure that transmission is being built within the terms and conditions of the GIA.

Stakeholder Feedback

Several parties support this element of the proposal, including AES, Intersect, LSA, Middle River Power, Ormat, Rev Renewables, SEIA, SCE, Upstream and Vistra.

AES highly supports requiring PTOs to notify the interconnection customer and ISO that network upgrade activities have begun once the interconnection customer provides the Notice to Proceed and posts the 3rd IFS posting to minimize upgrade delays.

Clearway also commented that this requirement should be strengthened by requiring the PTO to start work within 30 days of the interconnection customer issuing NTP. Delays in network upgrades have become a persistent problem affecting projects across the ISO system, and this requirement would help keep projects on track.

Intersect Power, REV and LSA support this proposal, since an NTP from the Interconnection Customer means nothing if the PTO does not then proceed. Additionally, the ISO should seek to impose an obligation for the PTO to commence, in a timely manner, their work upon receipt of NTP, and lack of action, and supporting evidence, on behalf of the PTO should warrant consequences.

SB Energy agrees with the ISO proposal that a new milestone should be added to the interconnection process, requiring the PTO to notify the interconnection customer and ISO when activity has commenced on the network upgrade and interconnection facilities.

SCE supports ISO's proposal for the LGIA and/or UFA to include specific dates for the developer to provide the notice to proceed (NTP) and the 3rd IFS posting for the following reasons:

a. SCE already provides specific milestones and due dates in its LGIA/UFA Appendix B, Milestone table with respect to notice to proceed (NTP) for design, engineering, procurement, and construction of Participating TO Interconnection Facilities, Network Upgrades, and Distribution Upgrades, if applicable in accordance with Article 5.5.2 of the LGIA and/or UFA.
b. SCE also includes separate and distinct milestones and due dates regarding the 3rd IFS posting pursuant to Article 11.5 of the LGIA and/or UFA, which aligns with the start of Construction Activities, a defined term.
c. SCE also provides notification of the start of construction for PTO Interconnection Facilities, Network Upgrades, and Distribution Upgrades pursuant to Article 5.6.2 of the LGIA and /or UFA.
d. SCE will ensure that these milestone(s) and due dates are applied consistently to all LGIAs and UFAs.
e. SCE agrees with the ISO that if an MMA modifies the NTP dates, these dates will be included in the MMA report and in an amendment to the LGIA and/or UFA.
f. SCE has also streamlined its internal processes to assign resources and initiate a project with a developer within a couple months of executing the LGIA or UFA in order to reasonably target the completion of Participating TO Interconnection Facilities, Network Upgrades, and Distribution Upgrades, if applicable in advance of the approved In-Service Date in the LGIA or Initial Synchronization/Trial Operation Date in the UFA when SCE is the Affected PTO.
g. SCE's Major Projects Organization (MPO) during its implementation meetings provides transparency and open communication with developers to review, track, and adjust milestones as dictated during this phase of the project life cycle in compliance with the terms and conditions of the LGIA and/or UFA.

Discussion of Stakeholder Comments and Questions

As discussed, this proposal provides defined milestones that are established earlier in the process and not subject to other actions. Additionally, it provides transparency as to when the upgrades start and open communication among the parties to ensure that transmission is being built within the terms and conditions of the GIA and any MMA Reports. All Stakeholders support this proposal including the additional transparency with the interconnection customer and the ISO.

The proposal does include a timeline for the PTOs to initiate the projects. With respect to SCE's comments that it has "streamlined its internal processes to assign resources and initiate a project with a developer within a couple months of executing the LGIA or UFA . . . ", the ISO would hope that if the previous initiative of not amending the GIA after every MMA is successful then SCE's new streamlined approach would incorporate that concept in meeting the current dates for completion of the upgrades.

Proposal

The ISO proposes to slightly modify its Straw Proposal. The Revised Straw proposal proposes that a specific date for the NTP must be included in the GIA. If an MMA modifies the NTP date then the new date will be included in the MMA report that is then an amendment to the GIA. The ISO proposes that the PTOs needs to move forward once the NTP and 3rd IFS posting is received and to meet the Initial Synchronization Date in the GIA thereby allowing interconnection customers to meet their PPA requirements. This will allow milestones to be specifically tracked.

The ISO also proposes that a new milestone be added requiring the PTO to notify the interconnection customer and ISO when activity has begun on the network upgrade and interconnection facilities, which should be within 30 business days after receiving the NTP and 3rd IFS posting.

3.11. Deposit for ISO Implementation of Interconnection Projects [New]

Background

This is a new issue not included in the Straw Proposal. Following the study process, a project starts the implementation process as it progresses to commercial operation. Once the project commences engineering, design, procurement, construction, etc., the Participating TOs charge the Interconnection Customers for associated costs. However, costs incurred by the ISO are paid through the Grid Management Charge by Scheduling Coordinators and are not charged to interconnections customers consistent with cost causation. In addition, interconnection customers have noted that the ISO has insufficient resources to respond to all the needs of the interconnection customers for project management, facilitating communications with the Participating TOs and the New Resource Implementation process. The ISO believes that additional project-specific funds for post-GIA work, especially proposing that a deposit be made at the time of execution of the GIA that would be drawn down based on the actual cost of working on the Interconnection Customer's project. Similar to other deposits with the ISO, interest will accrue to the funds until they are spent.

Proposal

The ISO proposes that upon execution of the GIA, the Interconnection Customer will provide a $100,000 deposit[31] to the ISO to compensate the ISO for the project management and new resource implementation processes for each project in the queue. This deposit is in addition to those costs or processes that are not currently reimbursed, such as MMAs, LOS, and PTAs.

3.12. Update to the Phase Angle Measuring Units Data [New]

Background

This is a new issue that was not included in the Straw Proposal. The GIA requires an asynchronous generating facility to provide all phase angle measuring unit (PMU) data at a resolution of 30 samples per second and upon request from the ISO or Participating TOs. With the increase in asynchronous generating facilities on the grid, the ISO is finding that the resolution of 30 samples per second is not granular enough to be of use for any analysis when there are faults on the system and most sites are using their protective relays versus PMUs to capture events.

Proposal

The ISO proposes that the PMU resolution should be revised to 16 samples per second.

4. WEIM Governing Body Role

This initiative proposes certain tariff amendments to enhance the process for studying and approving interconnection requests. ISO staff believes that these proposed tariff changes will go to the Board of Governors only and that the WEIM Governing Body will

[31] Roughly five teams and several people are involved in project implementation following GIA execution. Assuming a $190 average loaded cost per hour, the $100,000 deposit provides the ISO 526 hours to be charged. The ISO does not have history or record of time spent per project as staff's time is not billed to project-specific charge codes for implementation work.

have no role in the decision.

The Board and the WEIM Governing Body have joint authority over any

> *"proposal to change or establish any CAISO tariff rule(s) applicable to the WEIM entity balancing authority areas, EIM Entities, or other market participants within the EIM Entity balancing authority areas, in their capacity as participants in EIM. This scope excludes from joint authority, without limitation, any proposals to change or establish tariff rule(s) applicable only to the CAISO balancing authority area or to the CAISO-controlled grid."*[32]

Charter for EIM Governance § 2.2.1. The tariff changes proposed here would not be "applicable to EIM Entity balancing authority areas, EIM Entities, or other market participants within EIM Entity balancing authority areas, in their capacity as participants in EIM." Rather, they would not be applicable "only to … the CAISO-controlled grid." Accordingly, these proposed changes to implement these enhancements would not fall outside the scope of joint authority.

The WEIM Governing Body also has an advisory role that extends to any proposal to change or establish tariff rules that would apply to the real-time market but are not within the scope of joint authority. This initiative, however, does not propose changes to real-time market rules.

Stakeholders are encouraged to submit a response in their written comments to the proposed classification as described above, particularly if they have concerns or questions.

5. Stakeholder Initiative Schedule

The schedule for stakeholder engagement is provided below. The ISO presented its proposal for Track 1 to the Board of Governors in May 2023. The ISO intends to present Track 2 enhancements to the Board of Governors in May 2024.

[32] Charter for EIM Governance § 2.2.1.

Date	Milestone
12/18/2023	Informational workshop on the zonal approach
12/19/2023	Stakeholder workshop on revised straw proposal
1/9/2024	Comments due on revised straw proposal
2/8/2024	Draft final proposal posting
2/15/2024	Stakeholder workshop on draft final proposal
2/29/2024	Comments due on draft final proposal
3/29/2024	Final proposal posting
4/4/2024	Stakeholder workshop on final proposal
May 2024	Board of Governors Meeting