



California ISO

2023 Interconnection Process Enhancements

Track 2 Final Proposal

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Executive Summary

The recommended changes in this final proposal 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 as quickly and as efficiently as possible, the ISO proposes further revisions to a package of reforms that emphasize up-front project viability and competition for resources identified in local and state resource planning efforts.

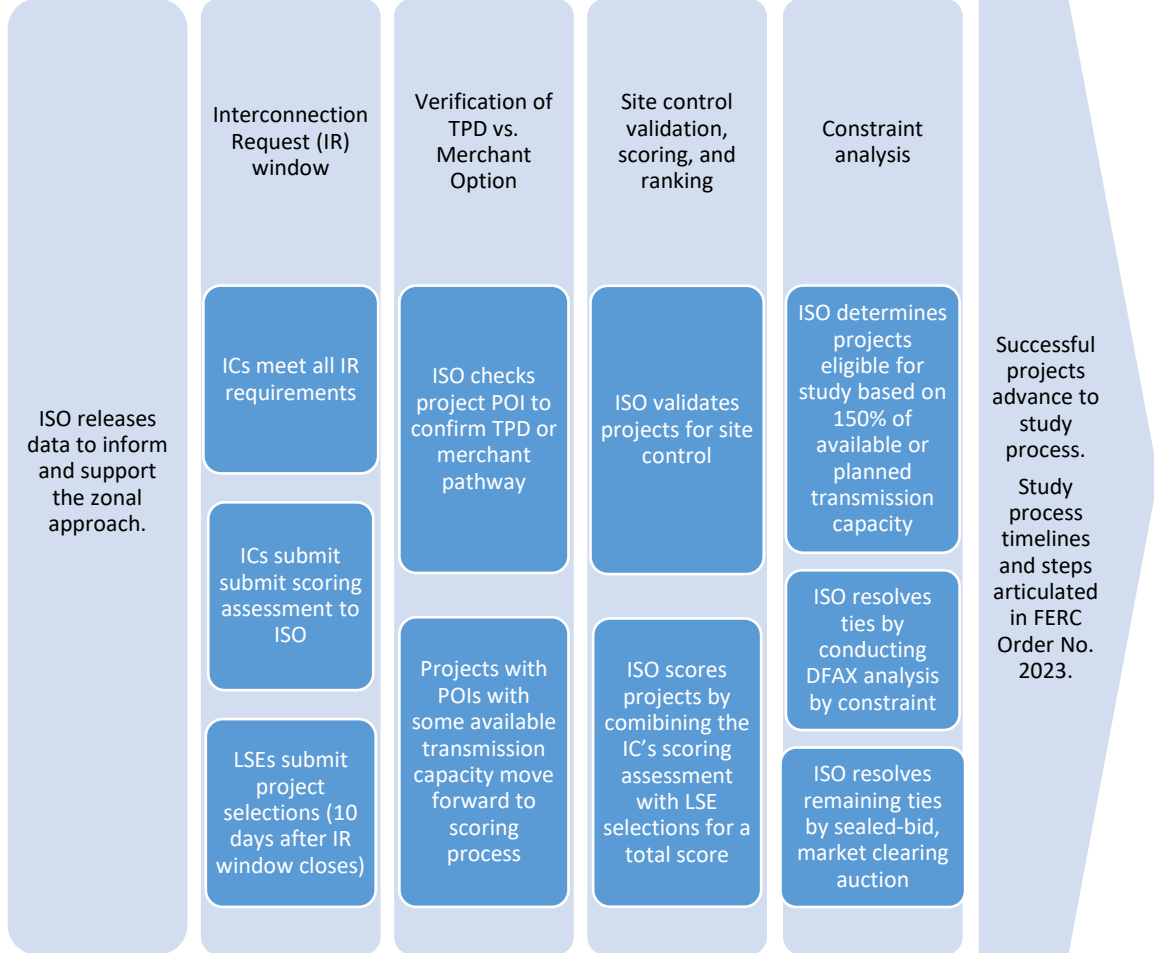
This policy initiative builds upon the new requirements established in FERC Order No. 2023, issued in July of 2023, which sets new standards for interconnection processes around the country. The ISO intends to complement FERC Order No. 2023 requirements with these additional interconnection process enhancements.

This final proposal also reflects the strategic direction established by a December 2022 Memorandum of Understanding between the ISO, California Public Utilities Commission (CPUC), and California Energy Commission (CEC). The proposal is part of a broader effort to tighten linkages among resource and transmission planning activities, interconnection processes, and resource procurement, as the ISO works with stakeholders and local, state and federal authorities to accelerate development and deployment of critical resources.

Between June 2023 and March 2024, the ISO held 13 public stakeholder meetings, with approximately 175 individuals attending each meeting virtually and in-person. Within that timeframe, the ISO posted five papers and received and responded to 6 rounds of written comments from a total of 70 organizations. Early in the initiative, stakeholders participated in working group discussions to establish principles and problem statements related to interconnection request intake and queue management. Participants also proposed concepts and worked with the ISO to explore and refine them throughout the course of the initiative.

The reforms establish a new process for evaluating and advancing interconnection applications that best align with resource planning, transmission availability, and procurement. The ISO's intent is to accelerate progress toward execution of interconnection agreements and commercial operations for the most viable and competitive projects, in areas that align with local and state resource plans.

Figure 1. Proposed Interconnection Request (IR) intake process



Prior to the opening of the interconnection request window, the ISO will provide information that helps stakeholders identify areas with available transmission capacity. Generation projects seeking to interconnect outside of the priority “transmission plan deliverability (TPD) zones” may proceed as merchant projects, and will self-fund their associated network upgrades.

With the introduction of new scoring criteria, the reformed process will emphasize project readiness and competition for projects to advance to the study stage. Project scores will be based on indicators related to commercial interest, project viability, and system need. Notably, in evaluating commercial interest, the ISO will incorporate preliminary, non-binding feedback on specific projects from load-serving entities (LSEs). In addition, the ISO provides an opportunity for non-LSE offtakers (e.g. commercial entities) to express an interest in specific projects. These commercial selections will improve the scores of certain projects, increasing the likelihood of those projects advancing to the study process and

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ultimately competing for transmission plan deliverability (TPD) and offtake agreements.

Highest ranking projects will advance to the study phase in descending order of a project's score, until the available and planned transmission capacity for each constraint is filled to 150% of that capacity. Ties will be resolved by calculating and selecting the lowest Distribution Factors (DFAX). If ties still exist, the ISO will conduct a market-clearing sealed-bid auction to advance to the study process that will align with the process required under FERC Order No. 2023.

The final proposal also includes important reforms to manage the ISO's growing volume of existing interconnection requests. More explicit viability criteria for projects in the queue will ensure continued progress toward commercial operations, and if projects fail to demonstrate progress, time-in-queue requirements will enable the ISO to withdraw inactive projects. In addition, the ISO will require participating transmission owners (PTOs) to commence network upgrades upon receipt of the first notice to proceed, preventing delays that have plagued the queue. The proposal also includes elements to streamline the modification process and require earlier financial security postings for projects with shared network upgrades.

The ISO recognizes that several topics unearthed in this initiative require more discussion, particularly around TPD allocations. In order to continue to improve and reform the interconnection effort, and to rapidly onboard increasing amounts of new generation, the ISO will initiate a new track of this initiative shortly after completion of track two, to continue discussions on the deliverability allocation methodology modifications that were proposed in the Draft Final Proposal and addressed by stakeholders in response to these proposed modifications.

Changes from the draft final proposal are based on stakeholder comments, and include the following:

- Refinements to a proposed timeline of the reformed interconnection process as it is expected to align with FERC Order No. 2023 requirements;
- Further explanation of the 150% zonal limitation and how to fulfill 150% of each constraint;
- Modifications to the proposed treatment of Energy Only resources;
- Additional details on the Cluster 15 intake process and schedule;

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- Adjustments to a set of objective indicators for scoring criteria to evaluate project readiness;
- Updates to the viability criteria and a time-in-queue requirement for all projects in the queue.

During the course of this initiative, stakeholders raised a number of important issues regarding the allocation of transmission plan deliverability (TPD). The ISO intends to initiate a new track of this Interconnection Process Enhancements initiative, track 3, to address these issues in the spring and summer of 2024.

1. Introduction and Background

With this paper, the California ISO provides its Track 2 final 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 high level of resource development activities reflected in interconnection requests to the ISO, this Track 2 final proposal advances 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, including many requests in areas that have not been prioritized in the state's resource planning. 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 to help meet California's energy policy objectives in a timely and efficient manner. The overall strategic direction of these efforts 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, 2023, 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 similar 2010 MOU between the parties.

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- The CPUC will provide clear direction to its jurisdictional load-serving entities (LSEs) to concentrate procurement in the key transmission 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 and local 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 relative to many energy supply resources. Procurement of new energy supply must consider the availability of transmission to ensure reliable delivery of power to the grid. Also, supply resources will be stranded if they are developed before this infrastructure is planned, approved, permitted, and constructed.

The ISO's strategic intent is for the revised interconnection procedures to give greater priority to interconnection requests aligned with priority zones where transmission capacity exists or has been approved for development. This will help shape the interconnection queue as the resource development community responds with proposed projects in areas enabled by existing or approved transmission. Additionally, the revised procedures 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 is focused 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 dramatic increase in projects in the queue, existing tools to move projects to commercial operation are insufficient. There are, for example, 188 gigawatts (GW) in the queue pre-Cluster 15, and 354 GW in Cluster 15 alone. The ISO, LSEs, and industry need a significantly reformed process to advance viable projects and prevent those that are stagnant from hindering the progress of viable projects in the queue.

The ISO also understands the need to ensure consistent treatment on matters of generator interconnection and transmission planning of all offtakers within the ISO footprint, including CPUC jurisdictional LSEs, non-CPUC jurisdictional LSEs,

and non-LSEs. Additionally, the ISO 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. ISO staff believes that these proposed tariff changes will be submitted for approval to the Board of Governors only and that the WEIM Governing Body will have no role in the decision. This final proposal describes a number of new or modified elements to the ISO's interconnection process. In Section 1, the ISO describes the stakeholder working group process and implications of FERC Order No. 2023 on the IPE initiative. Section 2 includes details of the final proposal elements related to interconnection request intake, and Section 3 outlines a number of proposed changes to the ISO's contract and queue management practices. Sections 4 and 5 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 interested parties in an intensive working group process to inform multiple iterations of this proposal. The ISO views FERC Order No. 2023 as the new baseline for its interconnection process. The FERC Order necessitates additional changes to the ISO's interconnection process, which impacts the scope of this initiative.

During stakeholder working group meetings in summer 2023, the ISO and participants developed agreed-upon principles and problem statements as listed below to assist in aligning objectives and developing solutions. Problem statements addressed two categories of challenges with the interconnection process – interconnection request intake and queue management. Once the agreed-upon principles and problem statements were established, working group

³ Several stakeholders have noted the need for consistent treatment of various types of offtakers, including CPUC-jurisdictional, non-CPUC jurisdictional, and non-LSE offtakers. Currently, the ISO reviews power purchase agreements (PPAs) with entities without a RA obligation to verify the agreement requires Full Capacity Deliverability Status, and to ensure there are no corporate relationships between the contracting entities. The ISO rejects agreements that it deems are designed to circumvent the ISO'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.

meetings focused on proposed concepts and solutions. Stakeholders participated by providing informal survey responses, candid feedback, their experience, expertise, and thoughtful proposals that aligned with the agreed-upon principles and problem statements. The ISO greatly appreciates the time and effort participants spent to shape this 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 POI or upgrades;
2. Ensure meaningful study results that take into account system capability, resource planning from the CEC, CPUC, and other LRAs engaged in these activities; and procurement;
3. Align interconnection and transmission plan deliverability processes with resource procurement functions;
4. Enhance 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 ability of the interconnection process to support the procurement necessary to meet CPUC resource portfolios, CEC Senate Bill 100⁴ 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 the reforms must also:

- 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.

⁴ California Renewables Portfolio Standard Program. 2018.
<https://legiscan.com/CA/text/SB100/id/1819458>

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, 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 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, meeting 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](#).⁵ On March 21, 2024, FERC issued Order No. 2023-A, revising some requirements.⁶ The ISO intends to comply with the order as fully and quickly as possible, with a compliance filing this spring.⁷ 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.

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 heat map;⁸
- Entry fees and deposits for queue entry;
- Site control requirements as defined in FERC Order No. 2023;

⁵ The order was subsequently published in the Federal Register on September 6, 2023.

⁶ Because Order No. 2023-A was issued shortly before the publication of this paper, this paper generally reflects Order No. 2023's original requirements. The ISO is reviewing Order No. 2023-A.

⁷ The compliance deadline will be 30 days from the date Order No. 2023-A is published in the Federal Register. Generally, this occurs within 1-2 weeks of FERC's issuing the order. The ISO would expect to submit its compliance filing in late April or early May.

⁸ The ISO notes, however, that additional information-sharing is proposed in this final proposal, to provide stakeholders with necessary information in advance of the interconnection request application window and to effectuate the zonal approach.

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- Study process timelines;
- Financial posting requirements and withdrawal penalties;
- Affected system processes;
- Consideration of grid-enhancing technologies; and
- Consideration of planned storage operation

The ISO does not foresee Order No. 2023 compliance having a significant impact on Clusters 14 or earlier.

The ISO proposes that Clusters 14 and earlier generally remain subject to the GIDAP requirements, and Clusters 15 and beyond will be subject to a new set of procedures and GIAs adopting Order No. 2023 revisions. The ISO will modify both the GIDAP and the new procedures as necessary based on this IPE initiative. It is important to note, however, that these plans ultimately are subject to FERC's direction in Order No. 2023.

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 received ISO Board of Governors approval and is seeking FERC approval to not 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.

The ISO Tariff Appendix DD, Section 17. Cluster 15 Unique Procedures, Subsection 17.1 Study Procedures and Timelines, provides for the following:

- c. An Interconnection Customer that withdraws its Interconnection Request prior to April 1, 2024 will receive a refund of its Interconnection Study Deposit, including any interest earned, minus any costs expended under the GIDAP on the Interconnection Customer's behalf. If an Interconnection Customer submitted a Site Exclusivity Deposit, it will receive a complete refund of its Site Exclusivity Deposit, including any interest earned. Withdrawals effected pursuant to this provision will not affect Interconnection Customers' rights to withdraw after April 1, 2024, and receive any corresponding refund and interest under the GIDAP, including without limitation Section 3.5.1.1.

While other tariff sections would allow for similar treatment of withdrawing projects after April 1, 2024, the ISO proposes to revise this and other dates in

Section 17 to align with the commencement of the interconnection studies for Cluster 15. These changes will likely be included in the ISO's compliance filing to FERC Order No. 2023. This will provide the ISO and interconnection customers with an appropriate milestone for the applicable deadlines and the flexibility to determine what the appropriate date should be within the IPE initiative. The ISO's intent is to provide reasonable timelines for interconnection customers to withdraw or proceed, modify their projects, and comply with all new requirements for Cluster 15's cluster study.

2. Interconnection Request Intake

2.1. The Zonal Approach: Data Accessibility [Updated]

Background

As noted in the first principle stated above, 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. The ISO will continue to provide a merchant pathway for projects that seek to interconnect where no transmission exists or has been approved.

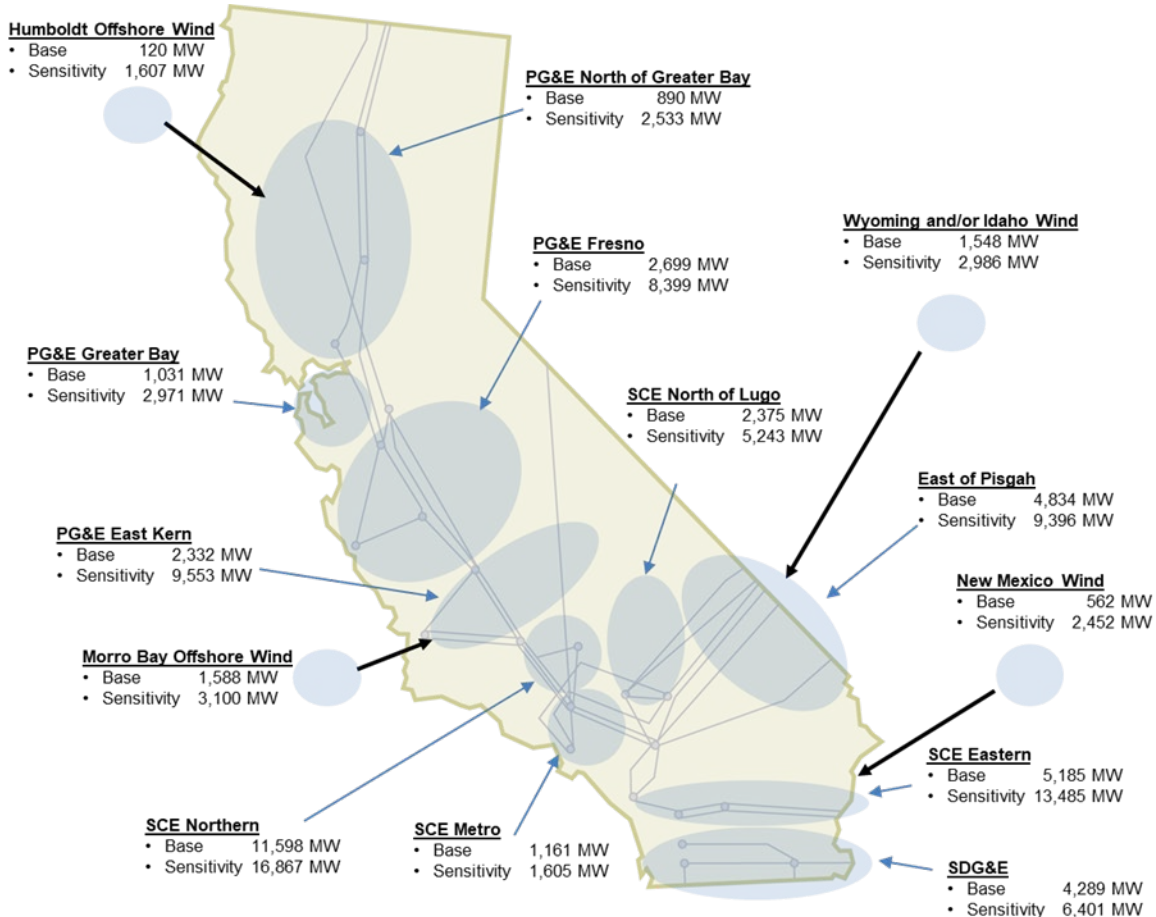
The ISO relies in particular on the CPUC for its lead role in developing resource forecasts for the 10-year planning horizon, with both the ISO and CEC providing input to the CPUC for those resource forecasts. The ISO also relies on the CEC for its lead role in forecasting customer load requirements. 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.

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 2 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

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planning process (TPP).⁹ The transmission zones illustrated below are also aligned with the transmission interconnection areas used in the generation interconnection process.

Figure 2. 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 substations¹⁰ within each of the transmission areas or zones

⁹ 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>

¹⁰ The resource-to-busbar mapping process is documented in the CPUC report "Methodology for Resource-to-Busbar Mapping & Assumptions for the Annual TPP" with further refinements as

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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.

Table 1. Example interconnection planning areas based on CPUC busbar mapping effort.¹¹

Transmission Area	Substation	Voltage	Resource Type	22-23 TPP 38 MMT Proposed Base Case Final Mapped Amount		
				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

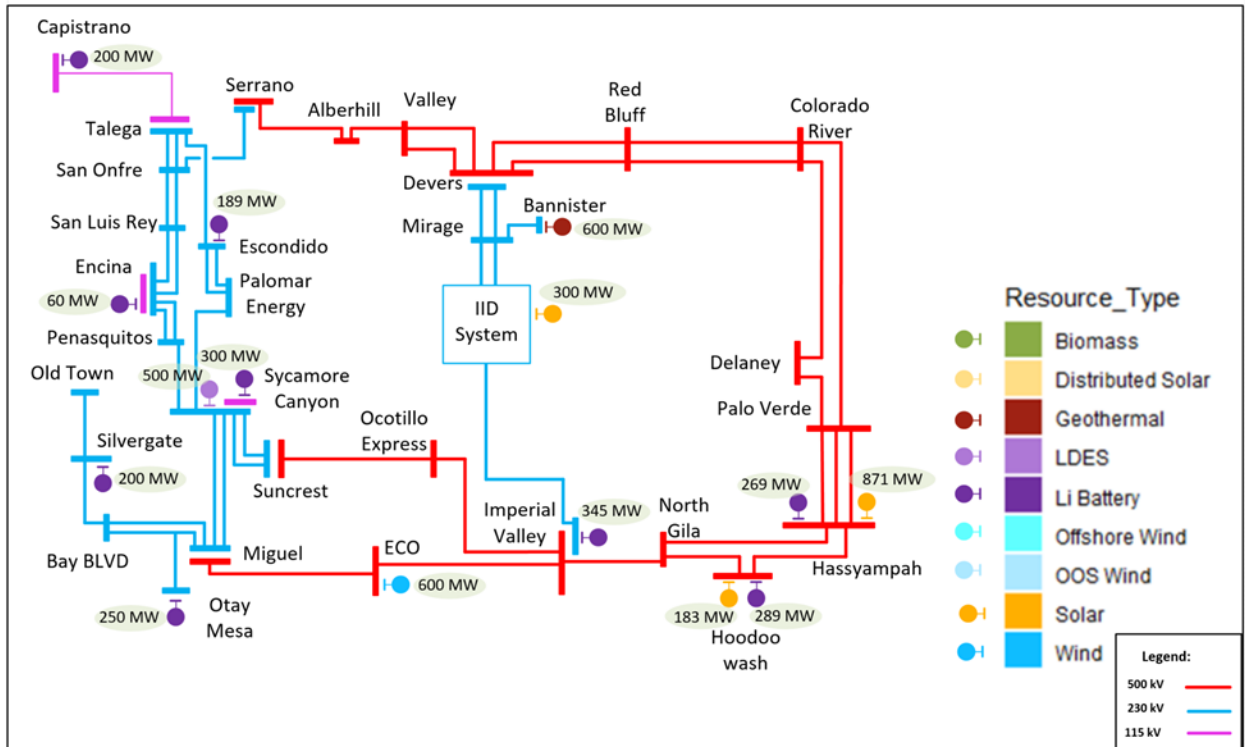
The ISO’s 2022-2023 Transmission Plan provided a single-line diagram for each of the transmission zones, indicating the capacity and technology type where the resources in the portfolio were mapped to the electrical grid in the zone. Figure 3, below, is an example of the resource mapping in the San Diego transmission zone from the 2022-2023 Transmission Plan.¹²

described in the CPUC staff report “Modeling Assumptions for the 2022-2023 Transmission Planning Process”.
https://files.cpuc.ca.gov/energy/modeling/Busbar%20Mapping%20Methodology%20for%20the%20OTPP_V2021_12_21.pdf

¹¹<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF>
¹¹https://files.cpuc.ca.gov/energy/modeling/BusbarMapping_Dashboard_38MMT_V2022_02_08_v2.xlsx

¹² 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 3. 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.

The ISO also provides data on the capability within the transmission zones in the ISO’s Transmission Capability Estimates for the CPUC’s Resource Planning Process¹³ and for the ISO’s annual Transmission Plan Deliverability (TPD) Allocation Report.¹⁴ Within the workbook for the transmission capability estimates for identified constraints in each of the transmission zones/areas, the available TPD is identified associated with the constraint along with the area deliverability

¹³ <https://www.caiso.com/Documents/White-Paper-2023-Transmission-Capability-Estimates-for-use-in-the-CPUCs-Resource-Planning-Process.pdf>

¹⁴ <https://mpp.caiso.com/tp/Documents/2023%20TPD%20Allocation%20Report.pdf> (on Market Participant Portal)

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network upgrade (ADNU) that would be needed to increase the TPD. For each ADNU, the estimated increase in TPD and the estimated cost and duration to construct the ADNU are provided. Some constraints may overlap more than one transmission zone. Table 2 illustrates the constraints in the San Diego transmission zone, as an example.

Table 2. Constraints in the San Diego Transmission Zone¹⁵

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 4 and Table 3 from the 2023 Transmission Plan Deliverability Report¹⁶ 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.

¹⁵ <http://www.caiso.com/Documents/Transmission-Capability-Estimates-for-use-in-the-CPUCs-Integrated-Resource-Planning-Process.xlsx>

¹⁶ 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 4. Map of transmission system area for one constraint within the San Diego transmission zone

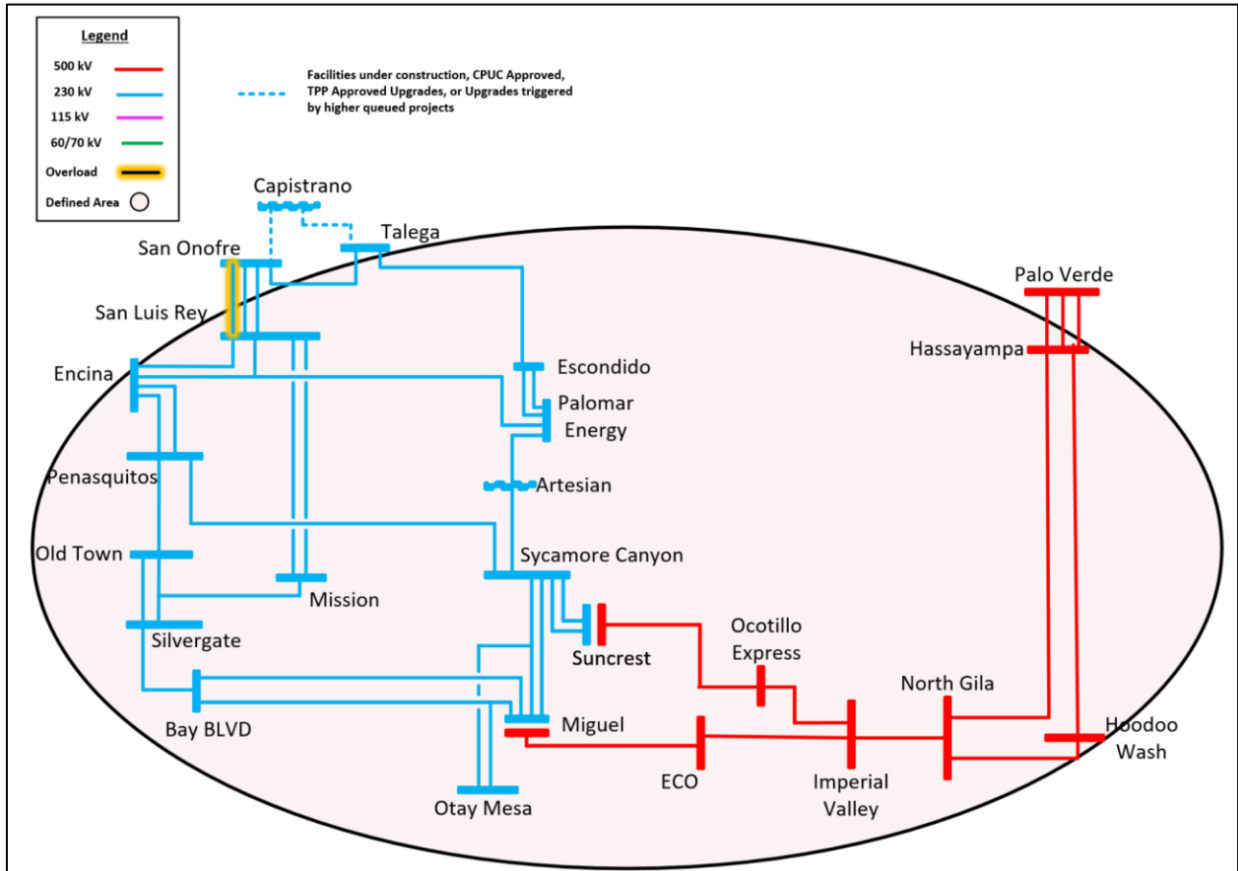


Table 3. Available TPD for one constraint within the San Diego transmission zone

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

The participating transmission owners (PTO) provide additional information on interconnection requirements in their respective Transmission Interconnection Handbooks.¹⁷ This includes information on specific POI that cannot accommodate further interconnections. The ISO suggests that stakeholders review the information above when assessing potential points of interconnection they are considering. The ISO will reference or document this guidance to interconnection customers prior to the 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
- any capacity remaining and available for future allocation.

Stakeholder feedback and discussion

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 and timing of interconnection, and (2) an alternative self-funding path to enable projects to interconnect outside of the priority zones.

Many stakeholders including American Clean Power (ACP) California, AES, California Community Choice Association (CalCCA), California Energy Storage Alliance (CESA), Clearway Energy Group, EDF-Renewables (EDF-R), Large-scale Solar Association (LSA), NextEra Energy Resources noted their support for the ISO providing additional information as early as possible to yield thoughtful interconnection requests when the request window opens.

¹⁷ 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.

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Several parties, including the Solar Energy Industries Association (SEIA), also asked the ISO to provide a list of all substations within each identified zone, and summarize substation feasibility information, at a minimum for all substations included in the CPUC's portfolio mapping. The ISO will provide the list of substations within each zone. The ISO will post the redacted individual cluster reports as indicated below.

SEIA also asked for short-circuit data and breaker ratings. The short-circuit models and breaker ratings are posted with the short-circuit models on the ISO market participant portal (MPP) for each cluster study. Recurrent also asked that, in addition to sharing the substations, the ISO share the Local Capacity Requirement Areas (LCRAs) they come under so developers can assess whether their projects may really qualify for the system need scoring item. The local capacity areas are defined in the local capacity requirement technical study reports.¹⁸ Recurrent also asked if interconnection customers can find the 'Constraint-Boundary-Substation-List' for SCE and SDGE. The ISO will post the list for SCE and SDG&E in addition to the list for PG&E.

Cluster 15 interconnection customers ask how they can best determine the transmission capability for the area the project belongs to. In addition to the transmission constraint information already available, the ISO will provide the TPD that has already been allocated behind the constraints as discussed at the December 18 stakeholder call.

Several parties, including Clearway, supported the proposal to post redacted individual interconnection reports. Recurrent asked when the ISO will upload redacted interconnection reports on the MPP Portal. The ISO will begin working on posting the redacted Cluster 14 Phase II reports after the posting of this final proposal, with a target to post by June 1.

AES recommended a vintage-based approach to TPD allocations, which the ISO suggested discussing in track 3 of the IPE initiative. Track 3 will begin shortly after track 2 concludes.

¹⁸ <https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Local-capacity-requirements-process-2024>

BAMx supported the zonal approach and the option to self-fund network upgrades through a modified merchant deliverability process for projects outside of zones. CalCCA also supported the provision of data prior to interconnection request submittals to ensure alignment with resource and transmission planning and procurement.

AES also supported the ISO providing a single capacity number for each zone, but seeks clarification if each zone's capacity number will be the accepted MWs for each Transmission Plan Deliverability (TPD) zone. If so, AES seeks clarification on when the ISO will provide the single capacity numbers for each zone for each year. The ISO is not able to share a single capacity number for each zone because there can be multiple constraint-based capacity limitations within a zone and across zones, making it inappropriate to publish a single number per zone.

In addition, AES sought a list of substations where there is no available capacity to interconnect from PTOs, and suggested that at a minimum, the ISO should include the breaker ratings in the short-circuit models in the cluster Interconnection Area Reports and all attachments to the published Appendix A individual interconnection reports with confidential information removed. The ISO has seen information on POIs with no capacity shared in PTO handbooks and encourages stakeholders to reach out to the PTOs to ask them to include this information in their interconnection handbooks if they do not already. Regarding inclusion of additional information, the ISO has proposed to include all attachments to Appendix A reports (with confidential information redacted). The ISO already provides the breaker ratings in short-circuit models in the cluster study.

Power Applications and Research Systems, Inc. (PARS) suggested that the ISO clearly distinguish between "zones" and "study areas." The ISO notes that the transmission zones and the GIDAP study areas are the same and are described in Chapter 3 of the 2022-2023 TPP report.

Power Flow Development, LLC noted a broader concern that following the 2024 deliverability allocations, limited deliverability will remain in the ISO. The ISO understands this concern and will continue the TPD allocation modifications discussion in an IPE track 3, which will work to develop a process that functions well with the new procedures proposed in this Track 2 initiative.

Recurrent also asked if projects connecting to substations with no prior queue requests can seek information from Participating Transmission Owners (PTOs) on Interconnection Reliability Network Upgrade (IRNU) requirements to connect

their projects. There is no formal process or requirement for this, however, PTOs may be able to provide available information on specific substations on a best efforts basis.

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 “Merchant Deliverability” 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 been 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 it is easier to assess the available interconnection capability at points of interconnection. This will include:

- Single-line diagrams of the interconnection area with the CPUC portfolio resources identified at the substations to which the CPUC has mapped resources in its busbar mapping process;
- Transmission constraints that have been identified within each interconnection area, with the available TPD, the area deliverability network upgrade (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.

The ISO will also provide:

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- A list of substations within each of the identified transmission interconnection areas;
- For each transmission constraint, points of interconnection where resources in the queue were located in the studies behind the constraints;
- The TPD that has been allocated for each transmission constraint.

The ISO proposes to provide the first consolidated report by April 1, 2024 to inform Cluster 15.

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 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 described below.

Because of the issues described above, the identification of the amount of available transmission capacity, whether currently available or planned, needs to be based on the available capacity associated with the various constraints within a given zone. The ISO had anticipated using the CPUC resource portfolio to determine the available capacity by subtracting the amount of allocated TPD in each zone from the new resource capacity identified for each zone in the CPUC's portfolio. This method would be used for determining which zones have available capacity and would be designated a TPD option zone for the study process. Zones with no available capacity, based on this methodology, would be designated as Merchant option zones. However, the ability for a project to be able to proceed to the study process begins with determining if there is available

capacity for the project based on the constraints associated with the project's POI. There are cases where the determination of available capacity based on the CPUC portfolio does not align with the amount of available capacity associated with the particular constraints within the zone. This can be due to the lag between the publication of the portfolio and the completion of the ISO transmission plan based on that portfolio. As a result, the available transmission for a zone would be overstated until the transmission plan based on that portfolio is approved by the ISO Board of Governors. There are also issues where a project approved in the transmission plan provides more available capacity than the portfolio seeks because the best transmission project provides somewhat more capacity than the portfolio calls for.

To address these issues, the ISO is modifying its methodology for determining the amount of available capacity for each zone. The ISO will base this determination on the availability of capacity associated with the known constraints within each zone. This method will provide a more accurate and transparent determination of available capacity within a zone and for determining what zones are TPD option zones and which are Merchant option zones. The CPUC resource portfolio will continue to inform the transmission plan, which determines the amount of capacity on the system and in the zones.

Updated Queue Reports

The ISO updated the information within the Queue Report in Q2 of 2023 to include additional details 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 2.

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

Interconnection Heat Map

FERC Order No. 2023 requires transmission operators to make available a heat map, along with specific associated information, 30 days after the cluster study and 30 days after the Restudy. The ISO is in the process of developing requirements for the heat map and associated information and is working to provide an initial heat map based on the Cluster 14 Phase II base cases as well as the 2024 Reassessment base cases. Because this initial heat map is not part of compliance with FERC Order No. 2023,¹⁹ it will likely not be available 30 days after the Cluster 14 Phase II reports are issued. The ISO is targeting for the initial heat map information to be available within Q3 of 2024. The heat map 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 heat map based on the latest cluster study and restudy, the ISO proposes to provide the heat map information after the annual TPD allocation study. Additional information will be provided to generators assessing potential points of interconnection by virtue of having the heat map 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. After Order No. 2023 compliance, the ISO will continue to provide the data described in this proposal in addition to data required under Order No. 2023.

Interconnection Area Reports

Interconnection Area Reports from each Cluster Study are currently made 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 in redacted form to remove 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 ISO file an

¹⁹ Order No. 2023 does not require heat maps until "after the first cluster study after the Commission-approved effective date of the transmission provider's filing."

unexecuted GIA with FERC.” At a minimum, this information will be redacted, unless an LGIA has been executed, and the ISO 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 other LRAs and non-CPUC jurisdictional entities to determine their approved resources in their individual Integrated Resources Plans (IRP) to include in the transmission planning analysis. As part of the 2024-2025 transmission planning process, the ISO will request 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 Process Timeline

Background

The ISO provided a generic timeline of the interconnection process in the draft final proposal, taking into account FERC Order No. 2023 requirements and layering in the need to provide updated information to inform stakeholders and implement the zonal approach to interconnection.

Stakeholder feedback and discussion

The California Public Utilities Commission Public Advocates Office supported the proposed generic timeline and information accessibility.

ACP-California asked the ISO to provide a timeline for Cluster 16 as soon as possible. The ISO includes Cluster 16 in a proposed timeline below, which would be subject to FERC’s rulings on the ISO’s IPE and Order No. 2023 filings.

In terms of sequencing, AES, CESA, Middle River Power, New Leaf Energy, NextEra, Q Cells USA Corp (Qcells), SEIA, Strata Clean Energy, Terra-Gen, and Vistra suggested opening the request window after the TPD allocation study for stakeholders to view deliverability information before submitting interconnection requests. New Leaf Energy also suggested opening the interconnection request window after the ISO releases the draft Transmission Plan in late March. The

ISO agrees, as depicted in the revised proposed timeline below. In addition, Rev Renewables (Rev) and the SEIA requested that the ISO share the cut-off point for determining the available capacity for the next cluster. The ISO plans to release the results of the TPD allocation study in July of each year, and the ISO will complete the heat map roughly one month later, which gives the interconnection customers roughly two months to use the information.

AES asked for clarity around the single phased study process, specifically how restudies would be performed and whether the existing cost cap for network upgrades would apply. Issues associated with study timelines are dictated primarily by FERC Order No. 2023, and the timeline provided below seeks to incorporate those FERC Order No. 2023 requirements as well as necessary IPE reforms. Items related to the study plan and cost cap will be addressed in the ISO's Order No. 2023 filing. In addition to these timeline questions, AES made some recommendations regarding TPD allocations, which would be appropriate items to discuss in track 3 of the IPE initiative, which the ISO intends to initiate shortly after conclusion of track 2.

AES recommended the ISO to update the list of substations in each interconnection priority zone after the TPD allocation study results so customers can accurately locate the interconnection priority zones for Cluster 15. The ISO clarifies that these substations will not change based on the TPD allocation study results. The ISO will not be able to provide information on the amount of a capacity each substation can receive because this is project specific.

CalWEA recommended that the timeline also include the timing of when the three TPD allocation opportunities start for a particular cluster, when the CPUC provides IRP resource portfolios, and when available capacity information will be published by the ISO. The timeline includes detail on the information the ISO will provide for interconnection purposes, including the first opportunity for each cluster to seek TPD allocations. Because the ISO's transmission planning process uses the CPUC's resource portfolio as an input, stakeholders should infer that the CPUC's Preferred System Plan is adopted prior to each year's transmission plan.

CESA asked whether summary data from the submitted TPD affidavits could be provided to better inform whether an interconnection request is submitted. The ISO provides as much information as currently possible in the TPD Allocation Report, but can explore additional transparency in track 3 of this initiative, which will focus on deliverability allocations.

Clearway requested that the ISO confirm that the TPD Allocation study to be performed in 2025 be tied to the timing of the Board of Governors' approval of the 2024-2025 Transmission Plan and will include all the approved projects as topology assumptions to allocate TPD to generation projects that are mature in the study process. The revised timeline envisions this sequencing.

NextEra and Recurrent raised specific questions around the timeline as it relates to Clusters 15 or 16. The revised timeline below clarifies the different timeframes for each cluster cycle.

Recurrent asked specific questions regarding scoping calls and Interconnection Financial Security (IFS) posting with restudy and interconnection facility studies. This is part of the ISO's Order No. 2023 compliance filing and the details on the specific timeframes and milestones will be included in that.

The Six Cities asked whether the proposed timeline suggests a gap in the 2024-2025 Transmission Plan and what the ISO will do to address such a gap. In particular, if there is no transmission capacity within a zone, and a non-CPUC jurisdictional LSE has identified a required project, Six Cities asked how the ISO will ensure that such a project can advance through the interconnection study process on a non-discriminatory basis. The ISO has coordinated with non-CPUC jurisdictional LSEs and they have submitted their resource plans into the 2024-2025 transmission planning process. The ISO will continue to coordinate with non-CPUC jurisdictional LSEs in this manner.

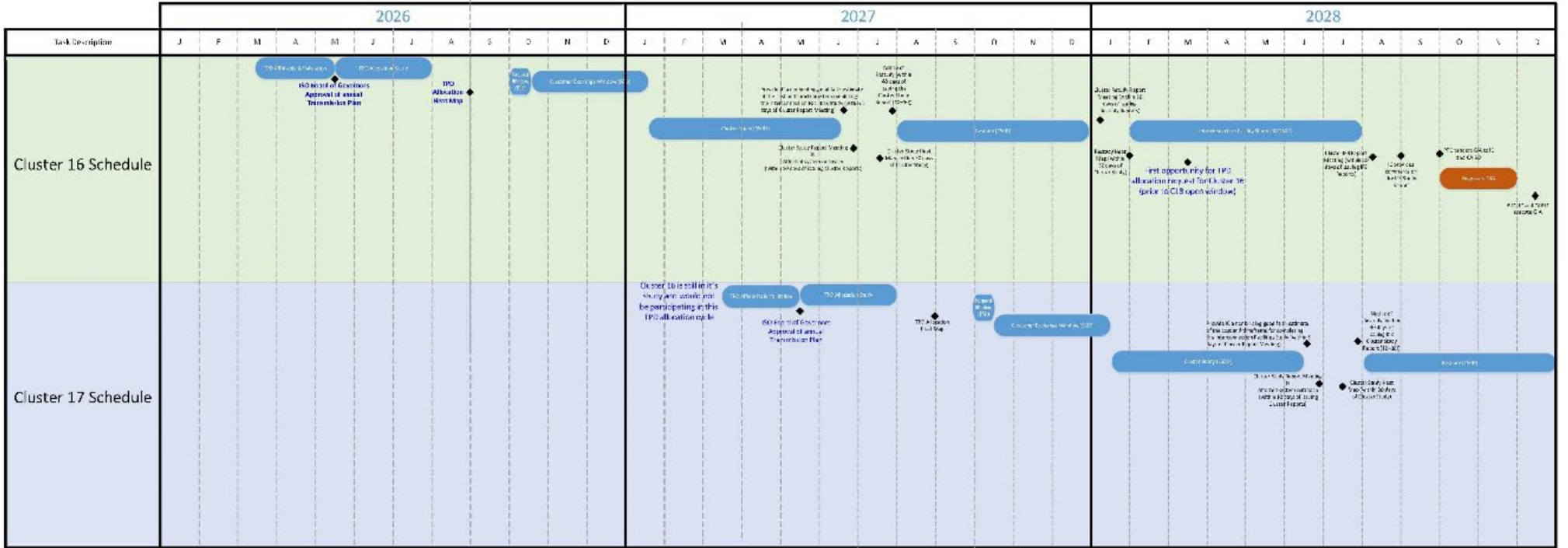
Terra-Gen requested that the ISO add the timing and details of security postings to the timeline. This information will be included in the ISO's compliance filing for Order No. 2023.

Vistra suggested modifications to the timeline to differentiate cluster timelines for previous clusters, adding the interconnection facility study, and adding years 3-7 and proceeding to the Generator Interconnection Agreement (GIA) timeline. The revised timeline includes differentiated cluster timelines, including Cluster 15.

Proposal

The ISO offers a revised proposed schedule in Figure 5 to demonstrate the relative timing of information availability related to key milestones and reports throughout the transmission planning, TPD allocation, and interconnection process.

Figure 5. Proposed basic schedule for information availability and interconnection study process.



2.3 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 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. In addition to FERC's new requirements, the ISO proposes that interconnection customers must submit a score-sheet in their interconnection request. This will be similar to the TPD scoring affidavits submitted today, but with different criteria.

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 do not sufficiently reduce the capacity to be studied in each zone, the ISO proposes a sealed-bid auction.

As discussed below, the ISO does not propose to require interconnection customers to submit sealed bids for the potential zonal auction with interconnection requests. The ISO explains each component, below.

2.3.1. Site Control

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 before their cluster study commences, or they will not be included in the Cluster 15 study.

Several stakeholders requested sufficient notice and clarification of whether and when Cluster 14 projects would be required to obtain site control as required under Order No. 2023. The ISO does not propose to apply this requirement to Cluster 14 projects as part of the IPE initiative. The ISO also does not intend to subject Clusters 14 and earlier to new site control requirements through Order No. 2023. However, the ISO will be subject to FERC's compliance directives,

which may differ from the ISO's proposed compliance. The ISO does not believe additional site control measures must apply to earlier clusters given where they are in the queue, commercial viability criteria requirements for site control, and the fact that Cluster 14 site exclusivity deposits are now non-refundable.²⁰

2.3.2. Entry Fees and Deposits

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.

2.3.3. Treatment of Full Capacity Deliverability Status and Energy Only resources [New]

Background

In the draft final proposal, the ISO proposed to process all interconnection requests in the same manner, regardless of whether they seek Full Capacity Deliverability Status (FCDS), Partial Capacity Deliverability Status (PCDS) or Energy Only status within zones with available transmission capacity, with Energy Only resource capacity not counting toward the 150% cap.

Stakeholder feedback and discussion

In their comments, AES, CalWEA, CESA, LRE, LSA, and SEIA raised concerns that under the proposed scoring criteria, an Energy Only project will likely be unable to receive enough points to ever be studied.

ACP-California requested additional details regarding how Energy Only projects seeking to interconnect under the Merchant Deliverability option would be treated and requested the Final Proposal ensure that Energy Only projects can interconnect in Merchant Deliverability zones but that they cannot use this approach to “free ride” on the upgrades paid for by others under the Merchant Deliverability approach.

²⁰ Section 16.1(l) of the GIDAP.

PG&E opposed allowing for all Energy Only projects scoring high enough to be studied without counting towards the 150% zonal cap and stated that the addition of Energy Only projects is not necessary for meeting energy-only resource needs identified in the CPUC's Integrated Resource Planning (IRP) process, as at least one-third of projects that are being studied in a TPD option zone will potentially not get deliverability. PG&E further stated that FERC Order 2023 mandates completion of cluster studies in 150 calendar days. Not putting a limit on Energy Only projects puts the PTOs at potential risk of not meeting the mandated study deadlines.

The ISO has considered stakeholder concerns along with the various stakeholder suggestions for improving the process for Energy Only projects and puts forth the following revised proposal for processing Energy Only interconnection requests.

Proposal

The proposal continues to require FCDS, PCDS, and Energy Only projects to meet the same site control requirements, provide the same entry fees and study deposits, and provide a self-assessment interconnection request score sheet.

FCDS, PCDS interconnection requests in TPD option zones continue to go through the scoring process and compete to be studied. Projects that have co-located technologies, such as solar PV and BESS that are seeking different deliverability statuses for those technologies (e.g. Partial Capacity Deliverability Status (PCDS)), will be scored as a single aggregated project.

The interconnection procedures for Energy Only projects will include two options. The first option is for projects that seek to interconnect in zones where the CPUC IRP base case portfolio identifies the need for Energy Only resources. Projects in this path will be eligible for reimbursement of the cost of reliability network upgrades (RNUs) funded by the interconnection customer. This option is the Reimbursement option.

The second option is for all other Energy Only resources seeking to interconnect in zones where the CPUC's IRP base case portfolio has not identified the need for Energy Only resources or that seek to interconnect in zones that the CPUC has identified the need for Energy Only resources, but opt to be studied and without having to be scored and to interconnect without being eligible for reimbursement of the cost of RNUs funded by the interconnection customer. This option is the Non-reimbursement option. Other than the use of the CPUC

portfolios, the identification of zones where Energy Only resources are eligible for reimbursement is totally decoupled from the TPD zone/Merchant zone criteria.

Energy Only projects seeking to interconnect under the Non-reimbursement option will not be required to submit scoring information because all such projects will be eligible to be studied. Projects seeking to be studied under the Reimbursement option will compete to be studied using the same scoring metrics used for FCDS projects. However, Reimbursement Energy Only projects will only be scored against the other such projects in their zone. These interconnection requests will be accepted up to a 150% study limit based on the amount of Energy Only capacity in the CPUC portfolio for each zone. Projects seeking to interconnect using the Non-reimbursement option can be studied in zones that are eligible under the Reimbursement option. Such projects would not have to compete to be studied in the scoring process and would continue to be ineligible for reimbursement of RNUs.

2.4. Interconnection Request Intake Process [New]

Below, the ISO outlines the interconnection request intake process for projects seeking to interconnect in TPD option zones and merchant zones. The process described below provides more information on the steps the ISO will implement during the interconnection request intake process and does not modify the intake proposal. However, the steps for Energy Only projects are related to the revised proposal for Energy Only projects in the prior section.

Process for projects seeking to interconnect as FCDS in TPD option zones

The TPD option zones are such zones where at least 50 MW of available capacity exists within the zone based on an assessment of the known constraints within the zone.

1. Projects must meet the complete IR requirements before the close of the IR window and no changes in point of interconnection (POI) will be allowed after the window closes.
2. The ISO will check projects seeking to interconnect in TPD option zones to determine if their POI are behind any known constraint with no available transmission capacity. Projects with POI behind no known constraints or constraints with some available transmission capacity move forward.

3. The ISO will validate complete and confirmed projects for Site Control. Those that meet requirements move forward.
4. The ISO will score projects that met the above requirements using the IC's scoring information, which the ISO will validate and combine with any scores from the LSE selection process for a total score.
5. The ISO will rank project scores for each TPD option zone that has IRs.
6. Using the projects scores, the ISO will determine the projects that are eligible for study based on the 150% of available or planned transmission capacity behind each known constraint.
 - In the case of scores being tied and not enough available transmission capacity for all tied projects to be selected, project's DFAX will be used to break the ties.
 - Any ties that remain due to having same DFAX are designated to move into the auction process.
7. The ISO will conduct an auction if necessary to complete list of projects to be studied.
8. The ISO will validate the remaining technical data for each IR that has been determined to be eligible for study.
9. The ISO will conduct zonal level group scoping meetings for all zones (TPD and Merchant, including all Energy Only projects).

Process for projects seeking to interconnect as FCDS in merchant option zones

The Merchant option zones are such zones where less than 50 MW of available capacity exists within the zone based on an assessment of the known constraints within the zone.

1. Projects must meet the complete IR requirements before the close of the IR window, including the additional Commercial Readiness Deposit (\$10,000 per MW) and no changes in point of interconnection (POI) will be allowed after the window closes.
2. The ISO will check projects to confirm their POIs are in a Merchant option zone.

3. The ISO will validate complete and confirmed projects for Site Control – those that meet requirements move forward.
4. The ISO will validate the technical data for each IR that has been determined to be eligible for study.
5. The ISO will conduct zonal level group scoping meetings for all zones (TPD and Merchant, including all Energy Only projects).

Process for projects seeking to interconnect as Energy Only

Eligibility for Energy Only projects under the Reimbursement option includes projects seeking to interconnect in zones where the CPUC portfolio's amount of Energy Only Delivery Status resources are greater than zero MW in that zone. Energy Only projects under the Non-reimbursement option may seek to interconnect in any zone, regardless of the findings of the CPUC IRP process.

1. Projects must meet the complete IR requirements before the close of the IR window and no changes in point of interconnection (POI) will be allowed after the window closes.
2. The ISO will check Reimbursement option projects to confirm whether their POI is in a Reimbursement eligible zone.
3. The ISO will validate complete and confirmed projects for Site Control – those that meet requirements move forward.
4. The ISO will score projects that met the above Reimbursement option requirements using the IC's scoring information, which must pass validation. The ISO will then combine project scores with any scores from the LSE selection process for a total score.
5. The ISO will not score projects seeking to interconnect under the Non-reimbursement option.
6. The ISO will rank scores of projects in Reimbursement zones against other Energy Only projects within the same zone.
7. The ISO will determine the projects that are eligible for study based on the 150% threshold limit per Reimbursement zone.
 - a. The ISO will use project DFAX to break any ties.

- b. If any ties remain, projects will be selected starting with the smallest and moving upwards in size until the 150% threshold is met or surpassed.
8. Reimbursement option projects that are not selected for study in the scoring process may convert to the Non-reimbursement option.
9. The ISO will validate the technical data for each IR that has been determined to be eligible for study.
10. The ISO will hold zonal level group scoping meetings for all zones (TPD and Merchant, including all Energy Only projects).

2.4.1. Fulfillment of 150% of Available and Planned Transmission Capacity [Updated]

Background

To fulfill each of the zones described 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 provided to stakeholders prior to the interconnection process.

In the process of selecting projects that can proceed to the study process within each TPD zone, the ISO will add projects to various POIs in descending order of a project's score, until the available and planned transmission capacity for each constraint is filled to 150% of that capacity. Projects at a POI that are affected by a constraint with no available or planned transmission capacity will not be included in the study for that TPD option zone. Projects in a TPD zone and at a POI that has not been previously studied will be evaluated using engineering judgement or based on its effectiveness to the known constraints.

Stakeholder feedback and discussion

Stakeholders were divided in their support for fulfillment of 150% of available and planned transmission capacity.

The ISO issued a survey to Cluster 15 interconnection customers to understand how Cluster 15 projects would score and compete based on available

transmission capacity. In addition, the ISO ran a test of the constraint analysis using Cluster 15 projects and survey results. Results are shown in Table 4.

The test started with 508 Cluster 15 projects. The initial constraint check brought 508 down to 200, which we applied scores to (based on Cluster 15 survey results) and moved those 200 into the study process based on highest scores until we reached 150% of each constraint, which left 112 projects. The initial constraint check eliminated so many projects (300 projects, from 508-200) because there were several large areas behind constraints that have no available transmission capability. Notably, in this test run, the DFAX was only used to resolve one tie, and no auction would have been needed. The TPD and Merchant zones are not reflected in this test.

Table 4. Results of Cluster 15 test run

	Initial number of IRs	Advance to scoring	Advance to study (150%)
Total	508	200	112

Proposal

The ISO continues to propose the 150% sub-zonal constraint limitations as a means to reasonably filter the most ready projects to the study process, maintain open access, and ensure competition after the studies are complete. Further analysis of Cluster 15 data and survey results will inform any potential final modifications to the 150% sub-zonal constraint limitation.

The ISO modifies its proposal so any TPD zone where the available capacity is 50 MW or less will be studied as a Merchant option zone. The ISO also clarifies that the TPD option zones are zones where at least 50 MW of available capacity exists within the zone based on an assessment of the known constraints within the zone. Merchant option zones are zones where less than 50 MW of available capacity exists within the zone based on an assessment of the known constraints within the zone.

2.5. Cluster 15 Intake Process and Schedule

The following is the Cluster 15 intake process and schedule the ISO plans to submit to FERC in its FERC Order No. 2023-A compliance filing.

2023 Interconnection Process Enhancements
Final Proposal

1. Between October 1, 2024 and December 1, 2024, interconnection customers may modify their interconnection requests in accordance with ISO Tariff Appendix DD Section 17.1(b).
 - a. All interconnection request scoring information is due to the ISO by December 1, 2024.
 - b. Any information required by Order No. 2023 and not already submitted to the ISO is due to the ISO by December 1, 2024 (*e.g.*, changes to deposit requirements, site control documentation).
 - c. All interconnection requests must be complete by December 1, 2024, with no opportunity to cure (for completeness, *i.e.*, missing information).
2. All LSE project selection information is due to the ISO by December 11, 2024.
3. Between January 1, 2025 and May 1, 2025, the ISO will;
 - a. check interconnection requests against all proposed criteria (see outline in Section 2.4) to determine which interconnection requests are eligible to move forward to validation, and
 - b. iterate with interconnection customers to validate all complete interconnection requests and cure any technical errors.
4. An interconnection customer that withdraws its interconnection request prior to January 1, 2025, will receive a refund of all interconnection deposits including any interest earned, minus any costs expended on the interconnection customer's behalf. After this date, interconnection customers' rights to withdraw and receive refunds will be based on the applicable tariff provision.
5. The ISO will complete all zonal level group scoping meetings for all zones (TPD and Merchant, including all Energy Only projects) by no later than May 31, 2025.
6. The development of the Cluster 15 base case to be completed and the cluster study to begin by June 1, 2025.

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

Background

In the Discussion Document, the ISO raised the possibility of a scoring process based on criteria that would rank interconnection requests on their readiness. The ISO explored with stakeholders the various factors that indicate project viability and readiness, and conducted a survey of stakeholders to better understand various approaches and considerations in the development process.

The ISO is asking stakeholders to adapt to a process under which interconnection requests should be based on real and ready projects. The intent is to encourage interconnection customers to invest time and money in individual projects prior to submitting an interconnection request. The ISO believes this is consistent with the new site control requirements in FERC Order No. 2023. However, while the ISO expects to advance the most ready projects, stakeholder feedback was clear that the ISO should not expect binding commercial discussions to have taken place prior to an interconnection request. The ISO sought feedback from stakeholders on how best to incorporate LSE interest earlier in the process. Such LSE feedback will help satisfy the MOU goal of aligning resource and transmission planning with procurement and interconnection. The ISO also seeks scoring criteria and individual indicators that are objective and minimize the potential of protracted exchanges regarding interpretations of certain criteria. Finally, stakeholders – particularly current or future interconnection customers – have suggested scoring criteria that is sufficiently granular to minimize ties and effectively distinguish projects from one another. The previous proposals have explored three key categories for evaluating projects to advance to the study process: commercial interest, which includes an opportunity for LSEs and non-LSEs to express interest in particular projects; project viability, and system need.

Stakeholder feedback and discussion

Several stakeholders were broadly supportive of the scoring criteria, with modifications, including ACP-California, CalCCA, PG&E, SDG&E, and SDG&E. Other stakeholders, such as AES, CalWEA, ENGIE NA, Intersect Power, SEIA, Strata Clean Energy, and Terra-Gen expressed concerns that the scoring criteria do not provide enough granularity and place too much emphasis on LSE interest very early in the project development cycle.

EsVolta, MN8, Rev Renewables, and Q Cells USA Corp. expressed opposition to zonal limitations, scoring criteria, and the auction approach. MN8, Strata Clean Energy, and Terra-Gen recommended implementation of implementing Order 2023 before returning to the stakeholder process. The ISO reminds stakeholders of the magnitude of Clusters 14 and 15 and the urgency of moving new projects through the intake process in order to meet reliability needs and rapidly transmission to clean electricity. Previous phased approaches have not sufficiently addressed the unprecedented interconnection queue volumes, and the associated challenges those volumes present to the process, ISO staff, PTOs and interconnection customers.

The ISO has reflected on the voluminous feedback from stakeholders throughout the IPE initiative, and understands that prospective scoring criteria will impact stakeholders' commercial positions. In many cases, certain stakeholders argued that a certain point value was too high while other stakeholders argued it was too low. Nevertheless, the ISO continues to try to strike the right balance of diverse needs and positions in a manner that will result in granular, objective, and simple criteria to determine which projects are best positioned to advance to the study process.

Commercial interest

LSE Allocation Process

AES, CaWEA, ENGIE NA, Intersect Power, MN8, Power Flow Development, Rev Renewables, SEIA, Strata Clean Energy, Terra-Gen expressed concerns that the commercial interest category – particularly the LSE allocation – would determine which projects advance to the study process. Several of these stakeholders recommended reducing the LSE interest category down to 20% or 10% of the total scoring process. The ISO understands this concern and seeks to balance the weights of the relative categories so the commercial interest would align with procurement directed by state and local regulatory authorities, and provide the granularity necessary to differentiate projects, while still factoring in other key elements of project development, such as project viability and system need.

LSEs largely supported the LSE allocation process, with suggested modifications to the proposed changes to the full allocation election, limits on LSE-build projects, and non-LSE interest points, described below.

CalWEA asked the ISO to explain how total available capacity on the system is calculated and provide a realistic estimate of that capacity. The ISO provides additional clarity in the proposal below.

Six Cities requests information on how the ISO will determine available and planned transmission capacity for the purpose of the LSE allocation process, and identify and provide an estimate of the amounts currently available. The ISO provides this clarification in the proposal below.

SDG&E noted broad support for use of the scoring criteria, but expressed concerns with disparities in service territory associated with departed load, noting the need to comply with a system-wide RA obligation and sometimes having to procure as a backstop procurement entity for the region. Although the ISO's objective is to ensure and enable feedback from LSEs, the ISO does not see this as a gap in the ISO capacity allocation determination. Those regional LSEs from whom load has departed will still have an opportunity to provide allocations for projects in which they are interested. The ISO understands the challenges for small LSEs, which are addressed below in the full allocation election section.

Terra-Gen reiterates prior comments that additional indications of LSE interest provide little differentiation between the viability of projects given the CPUC portfolio must be achieved to meet state policy objectives, and such interest will most likely be non-binding since costs and timing are uncertain. The ISO has been clear with stakeholders around the need to incorporate LSE procurement interest earlier in the process in order to both assess viability and, importantly, to ensure alignment with the resource and transmission planning. While these expressions of interest are non-binding, they provide some helpful granularity to the scoring process to avoid ties and auctions. The ISO has also proposed a weighting that is designed to enable projects to move through the scoring process without LSE allocations.

Recurrent asks at what point the project finds out whether scores were awarded to a project and what score the project received from an LSE. The ISO proposes that this information is communicated directly from the LSE to the interconnection customer, but the ISO will record LSE allocations in its interconnection management system.

Non-LSE Interest

ACP-California, Golden State Clean Energy, Independent Energy Producers, Rev Renewables, SEIA, and Terra-Gen²¹ supported inclusion of points for non-LSE offtakers, with many stakeholders suggesting increasing the points value for commercial interest to 50 or 100 to put LSE interest and non-LSE interest on 'equal footing'.

PG&E, SCE, SDG&E, and CalCCA expressed concerns with the opportunity for interconnection customers to receive points for non-LSE interest. In particular, LSEs note that these offtakers do not have the same RA obligations as LSEs whose customers have paid for the transmission system and who need deliverability to meet state and local requirements. The ISO understands this but also recognizes that non-LSEs are actively procuring resources and therefore offers a lower maximum point value for projects that can demonstrate interest from non-LSEs.

SCE requested limiting the type of projects non-LSEs can assign points to Energy Only project or co-located projects with an FCDS application that includes a renewable project, and suggested additional requirements to the affidavit. The ISO has considered the likelihood that non-LSEs may be interested in non-Energy Only resources, however the ISO does not propose to limit the eligibility of certain projects to receive non-LSE interest points.

PG&E suggested that the proposal is contrary to the intent of the MOU, noting that the introduction of non-LSE points for projects at the cluster stage of the process introduces inappropriate influence for competition of TPP expansion capacity from a group of participants who were not involved in the planning stage and for whom the TPP-approved projects were not designed.” The ISO appreciates this recognition of the linkage to the MOU, but finds it important to retain a pathway for non-LSEs to express interest in projects, which may occasionally fall outside of the resource planning process. PG&E continues to note concerns with the proposal in that there is no limit on the number of non-LSEs that can participate, there is no limit on the number of projects that each entity can give a letter to, and there is no natural limit on projects because the allocation of points would not be based on load share or any reasonable and

²¹ Note that Terra-Gen opposed the broader framework for intake, but suggested retaining the proposed limit on LSE-built projects, non-LSE interest, and full allocation election items if the ISO moves forward with the concept of scoring criteria.

quantifiable measure. This results in an easier logistical hurdle for non-LSEs to receive higher priority on their project(s) over an LSE.

SDG&E sought clarity on whether one non-LSE can award points to multiple projects. As reflected below, the ISO does propose to limit non-LSE interest to one project, and includes additional requirements for the information that must be provided in the affidavit to prevent abuse of the allocation.

NextEra and SCE requested clarification that a project can only receive non-LSE interest points from one non-LSE offtaker. The ISO clarifies below that a project can only receive a maximum of 25 points for this category. The ISO agrees that this detail is important to prevent outsized representation in the scoring process.

NPCA noted that the draft final proposal makes tradeoffs, and highlighted the multiple checks on the LSE allocation process and the other opportunities for projects to earn points through non-LSE interest and/or project viability and system need points. NPCA suggests that the limits on the LSE interest points provide more than ample opportunity for non-LSE supported projects to earn points from other sources and be prioritized for study. The ISO agrees and is seeking a balance between various types of resources and procurement entities. The fundamental goal is to gather initial feedback from potential offtakers on the relative commercial interest in projects. The ISO reiterates that these allocations are not binding nor are they designed to guarantee that any particular projects moves to the study process. Rather, the ISO seeks a holistic assessment of readiness that will depend on multiple criteria.

CalCCA and SDG&E urged the ISO to better define the process that will be used to allow and verify non-LSEs to assign points so that the process is transparent and subject to a tariff. The ISO understands this concern and will provide guidance based on experience. Non-LSE procurement can take many shapes, so prescriptive, narrow definitions would result in false positives or favor certain non-LSEs over others. The ISO's intent is to ensure it does not prevent legitimate non-LSE procurement.

AES asked whether non-LSEs need to have Market Base Rates filed at FERC. The ISO is not the regulator of whether any entity needs market based rates. It is not a requirement to qualify to award points, as proposed here.

SDG&E requested clarification on whether the LSE capacity allocation will be made public. The ISO does not intend to make capacity allocations public, and believes this information should be treated as confidential information to the ISO, the LSE, and the project receiving points. The ISO notes that FERC-jurisdictional entities may need to modify their tariffs to provide processes that award points in a just and reasonable manner. The ISO defers to them on that issue and how they award points or publish the information.

Further, CalCCA suggested revisiting the prioritization of non-LSE projects with RA contracts in the deliverability allocation process. LSA and Terra-Gen suggested the ISO require a deposit if the developer or non-LSE does not have a RA arrangement with an LSE.

Intersect Power noted the need to reconcile the interconnection request intake scoring with the TPD allocation scoring process. PG&E noted that the 2021 IPE Track 2 tariff changes allowing non-LSEs to obtain TPD with certain restrictions is independent from establishing a process for selecting which projects proceed to the cluster study and should not be precedential. Also, that TPD allocation process will still exist for all projects at a later point in the process, and that process does not contravene the MOU. The ISO agrees that these are appropriate considerations for Track 3, which will explore the deliverability allocation methodology.

ACP noted that the ISO can monitor for any “crowding out” of LSE projects in future cycles and adjust accordingly. The ISO agrees that this approach does represent its best attempt to balance the real commercial interest that exists in California with the known and very critical need for new resource development that is driven by state and local resource planning, guided by the ISO’s transmission plan, and effectuated by LSE procurement.

Full Allocation Election

In the draft final proposal, the ISO proposed a full allocation election, which would allow an LSE to award 100 points to one project if an LSE has a high priority interest in that project but does not have sufficient capacity to allocate to that project’s full MW size. The ISO proposed to limit use of this full allocation election to one project per cycle per LSE, and limiting this election to projects less than 150% of that LSE’s individual capacity allocation for that particular cycle.

Terra-Gen recommended that the ISO continue to include the full allocation election. NCPA, BAMx and Six Cities had questions and requested clarifications on this approach.

As an alternative to the minimum point allocation, BAMx and NCPA suggested that if the ISO moves forward with the full allocation election, multiple LSEs should be allowed to aggregate their full allocation election priority interest in one project when the individual LSEs participating in the aggregation do not have sufficient aggregate capacity to allocate that projects' full MW size. The ISO clarifies this in the proposal below, noting that the intent of the LSE allocation process is to allow multiple LSEs to express interest in the same project, so a single project could receive capacity allocations (points) from multiple LSEs, up to 100% of the project's capacity (100 points). This type of aggregation would not be necessary, however, if an LSE opted to use the full allocation election, which would automatically award the project 100% of its capacity (100 points). Therefore, LSEs could partner with other LSEs to ensure a project receives 100 points or a single LSE could elect to award its full allocation to a specific project.

NCPA noted that its initial proposal to award each LSE with a minimum number of points (e.g., twenty points or its load ratio share, whichever is larger) is both conceptually cleaner and simpler to administer. The ISO understands how this approach would address the specific challenge that this methodology presents for small LSEs but is concerned that it would result in undue preference.

Limits on LSE-owned projects

Generally, the development community strongly supported the one-project limit on LSEs self-owned/self-built projects per cycle, and LSEs overwhelmingly opposed the limitation on the grounds that it was arbitrary and discriminatory.

CPUC-jurisdictional LSEs note that the CPUC already holds them to high standards regarding self-built projects. The ISO understands that utility-owned generation contracts receive scrutiny during the procurement process, but the ISO's specific concern is that no such scrutiny exists this early in the interconnection process, and without some sensible limit or meaningful oversight, the LSEs could skew the market toward utility-owned projects such that independent power producers are not afforded a fair opportunity to compete.

Rev Renewables proposed a further restriction that no utility-owned project should be more than 50% available capacity in a transmission zone to ensure the utility-owned project does not dominate the zone, particularly in years with low

amounts of available capacity. The ISO understands the concern behind this suggestion; however the ISO does not view this as an issue with LSE-owned generation, per se. If the ISO were to address the concern of dominating a particular zone, such a limit should be applied to any individual project, whether independently developed or LSE-owned.

Despite CalCCA and SCE's opposition to the proposed one-project limitation of LSE-owned resources, they both propose an alternative capacity cap on LSE-owned resources, based on a percentage of ISO allocated capacity. Both entities proposed an initial limit of 50% of the LSE's capacity allocation.

In reviewing the data, the ISO has seen a maximum of three projects proposed by a single CPUC-jurisdictional LSE in Clusters 10-14 (constituting more than 15% of the estimated capacity allocation for that LSE for Cluster 15) and a maximum of six projects in Cluster 15, (86% of that LSE's estimated capacity allocation). Because Cluster 15 was an exceptional year, the ISO will use data from Clusters 10-14 to inform the final proposal.

The ISO understands that mechanisms currently exist to ensure sufficient competition in the procurement process, particularly the CPUC-jurisdictional LSEs. While the ISO believes that some reasonable limitation is prudent, it recognizes that the draft final proposal to apply a limit of one project across a diverse set of LSEs may be overly restrictive in certain instances. The ISO instead proposes a more flexible, modified approach based on historical data that can be scaled to each LSE's capacity allocation, and offers LSEs a choice between a number of projects and percentage of each LSE's allocation that can be applied to LSE-owned projects in each LSE allocation cycle (cluster).

Project viability

Independent Energy Producers Association (IEPA), Intersect Power, NextEra, and Vistra suggested highlighting the project viability category above commercial interest and system need. Several other parties suggested revising the relative weighting between commercial interest, project viability, and system need.

The ISO received mixed feedback on the value of awarding points for initiating an engineering design plan. GSCE supported the engineering design plan but recommends a single "check the box" requirement for demonstrating certain requirements. PARS notes that the electrical design world looks at increments of 15%, 30%, 60%, 90%, and 100% completion. SEIA suggested graded scoring,

particular for project viability factors, such as the engineering design plan. Leeward Renewable Energy (LRE) did not see value in awarding points for engineering design plan completeness.

AES, esVolta, Golden State Clean Energy recommended the ISO revise the project viability category to enable a graduated score based on the percentage of site control of the gen-tie. GSCE noted that this can be demonstrated in the engineering design plan. EDF-R recommended deleting this indicator from the proposal, as developers do not have sufficient information to meet this requirement until the information is provided in the study report. Capstone Power did not support the criterion of 100% of site control of the gen-tie, and esVolta asked whether there is a separate site control requirement for site control of the gen-tie for public vs. private sites. Additionally, esVolta sought clarity on where the gen-tie would be measured to and from. The ISO has reconsidered this criterion and proposes to delete it because, as noted by EDF-R, the path of the gen-tie is highly uncertain prior to completion of interconnection studies. In addition, it would be time-consuming and imprecise to validate the level of site control secured for a gen-tie.

EsVolta opposed awarding points for expansion projects, claiming that the proposal is discriminatory, in conflict with the objectives of the MOU, and could lead to gaming or market power. In response, esVolta suggested that the ISO require any expansion project to have received market based rate authorization from FERC. Further, esVolta suggested that expansion projects should be fully permitted, which could be validated by an affidavit from the interconnection customer swearing that the project has received all permits necessary to commence construction. The ISO notes that the criteria for awarding point in this category require a project to be under construction or in operation – both of which are past the permitting phase for a project. The ISO also does not believe market-based rate authority is a useful signal, nor within the ISO's purview.

NextEra and Rev Renewables suggested that the ISO add 10 points for facilities with executed LGIAs/NTPs, and combining 'Expansion of a generation facility that is currently under construction' with 'Expansion of an operating facility', for an award of awarded 20 points. The ISO does not agree with this approach and views these as two distinct levels of development and viability.

Clearway, Intersect, LRE, LSA, and PARS noted that several parties have suggested incorporating developer experience into the project viability score. The ISO does not propose this approach on the grounds that it is highly subjective

and difficult to measure, particularly given the likelihood of change of ownership and acquisition of specific companies and interconnection staff. The transmission planning processes that evaluate experience, for example, are highly time-intensive and expensive—funded by the applicants—and only evaluate a few projects at a time. Instead, the ISO expects developer experience to be a factor in the rest of the scoring criteria, with more experienced companies demonstrating their ability to better navigate the process of data analysis, scoring, and LSE interest discussions.

Clearway, LRE, and LSA also recommended reinstating the criteria for major purchases (Master Service Agreement or Purchase Order) of long lead-time equipment. The ISO discussed its rationale for removing that indicator in the draft final proposal, which was heavily informed by stakeholder feedback.

Prologis suggested that the ISO impose site control requirements on Cluster 14 projects as the simplest way to eliminate non-viable projects. The ISO notes that Cluster 14 site exclusivity requirements are non-refundable, and Cluster 14 will be subject to the commercial viability requirements proposed in this paper.

System need

NextEra noted that system need is already accounted for in zonal allocations and should be reduced in the scoring criteria. Conceptually, the ISO agrees that most system need should be accounted for in the resource planning process as the basis for the zonal model, however there are certain resources that present significant value to the ISO that warrant additional consideration in the scoring process. Local RA is important to prioritize to ensure near-term and mid-term reliability through near-term deployment. Long lead-time resources align with resource and transmission plans, but these resources are not likely to score well with other indicators because they have different development considerations.

NextEra also suggested that every project is likely to score the same for the system need category. The ISO agrees that there is not much granularity in these scoring indicators, however these are important considerations for ensuring alignment with the MOU.

MN8 suggested that points for projects that address a limited set of specific system needs be capped in proportion to the size of a given need, and that specific entities be responsible for awarding points to Local RA and long lead-time projects (i.e. the CPUC and LRAs award points for long lead-time resources and LSEs with local capacity needs award points to ICs). The ISO appreciates

the desire to scale points to given need, but as described above, extra allocations may be necessary to ensure that certain projects are studied, to provide for the specific needs called for in the portfolio. Regarding which entities award the projects, the ISO does not want to intervene in the process of awarding points by dictating which entities can award points to specific projects. The process described in the proposal below enables LSEs to demonstrate their interest in specific resource types. The ISO recognizes, however, that FERC-jurisdictional LSEs may be required to memorialize in their tariffs just and reasonable methods to allocate points.

Local RA

Regarding the point allocation for resources that can provide Local RA, New Leaf Energy asks for additional clarification in several areas; the ISO clarifies that in order to define “ISO demonstrated need,” the ISO will use the annual local capacity technical studies.

Additionally, NLE suggested the following:

- Projects in both LCRAs and sub-LCRAs showing deficiencies should be eligible for points. The ISO has precisely defined the LCRA boundaries but has not defined the precise sub-LCRA boundaries. However, projects clearly effective on a deficient sub-LCRA constraint could also be considered for points.
- The ISO should include a buffer of a reasonable amount (e.g. 10%) on the reported LCRA deficiencies when performing the need determination, as the deficiencies reported in the study are only estimates that are based on load and available supply estimates. The LCR reports do not currently include a buffer, and including one could add additional areas as being deficient when they are not. Therefore, the ISO does not adopt this approach.
- The ISO should clarify which reported deficiency years it will use in the need determination. The ISO intends to use 2029 in the needs determination.
- The ISO should not adopt the IPE Track 2 Revised Straw Proposal’s 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.”[3]

The ISO response to these comments is that a battery that is not able to be counted as local capacity because of charging restrictions is of no more value than a battery that is outside of the LCR Area. Therefore, such a battery should not be eligible for additional points.

- The ISO should expand eligibility for this criterion to include more LCRAs and sub-LCRAs using the three additional methods to define “ISO-demonstrated need.”

The ISO does not agree with these comments. This scoring needs to be based on studies that are already planned to be performed on a regular schedule. The studies proposed would be based on speculative information and are not currently planned to be performed on a regular schedule, if at all.

Long Lead-Time Resources

CalCCA supports the long lead-time resource category, understanding the intent to ensure resource diversity. ACP-California and CalCCA request more clarity around the categorization of these resources. LSA and Clearway suggested that the capacity (MW) of points awarded to long lead-time resources be limited based on the size of the identified need. New Leaf Energy recommended a time constraint on long lead-time resources, limiting them to a certain number of years in the CPUC’s resource portfolios provided to the ISO for use in the TPP. ACP-California suggests more definition around the category to ensure that the sphere of resources eligible to receive points is appropriately narrow and limited to resources that should receive such treatment. Similarly, New Leaf Energy suggested reducing the number of points available to long lead-time resources by half to avoid a situation where these resources prevent all other projects in a zone from being studied. The ISO understands these concerns and will confer with the CPUC and LRAs to ensure appropriate criteria to determine eligibility for this scoring indicator, which the ISO will communicate to stakeholders in advance of the interconnection request window.

ACP-California suggested that rather than limiting long lead-time resources to areas where the TPP has already approved the necessary transmission, the ISO should allow resources to qualify in areas where the ISO knows transmission approvals will be required based on recent portfolios. ACP-California notes that it is not imperative for this transmission to be approved in order to award points. The ISO will not take this approach. It is critical that the ISO adhere to the process described in the MOU, where the ISO approves transmission based on the resource planning portfolio of the CPUC and other LRAs. The ISO is not in the

position to speculate on or preempt regulatory planning processes. Further, transmission for long lead-time resources should be approved with development cycles in mind, which should give long lead-time resource developers sufficient time to enter into and advance through the interconnection process.

Golden State Wind noted that the long lead-time proposal appears to be the continuation of the capacity-reservation proposal in the TPP enhancements initiative, and notes that a point addition is not the same as a reservation. CalWEA also references the potential to reserve TPD for long lead-time resources. GSW suggested an alternative where the ISO would separately evaluate long lead-time technologies as competing against one another for access to deliverability. The ISO notes that it will address deliverability allocations, including clarifications around allocations for specific long lead-time resources, in a subsequent track of this initiative.

NCPA noted that points for long-lead time resources should not be limited to projects in the CPUC resource portfolio, but should also be available for the portfolios approved by other LRAs and incorporated into the TPP. The ISO agrees and commits to consulting with LRAs as well as the CPUC prior to the scoring process to ensure alignment on eligibility and definitions.

Distribution factor (DFAX) tie-breaker

LSA and Terra-Gen noted a preference for simpler methods like pro-rata awards and acceptance of all projects “on the margin” if the scoring process and DFAX tiebreaker still result in ties, however the ISO did not receive significant additional feedback on this item.

Proposal

The ISO continues to propose refined scoring criteria as a key mechanism to ensure that the most ready projects advance to the study process. The revised criteria, described below, attempt to enable the appropriate level of scoring granularity and opportunities to measure development progress while maintaining a simple process to 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. As discussed in greater detail below, the ISO proposes to receive LSE point allocations directly from

LSEs rather than interconnection customers during the interconnection request application window.

Commercial interest

The ISO proposes two opportunities to obtain points in the commercial interest scoring category: an LSE Allocation Process and an opportunity to earn points by demonstrating commercial interest from a non-LSE/commercial offtaker.

Interconnection projects may only receive 100 points for the Commercial Interest category, though those points may come from a combination of the LSE allocation process and the non-LSE interest indicators. If a project scores 125 points, the ISO will reduce that score to 100. An interconnection project may only obtain 25 points maximum for demonstrations of non-LSE interest, even if more than one non-LSE offtaker is interested in that project, and that any non-LSE/commercial offtaker can only express interest in one project per cluster. Non-LSE/commercial offtakers may not be affiliated with the interconnection customer or its holding company. The ISO proposes that the commercial interest category constitute 30% of the overall project score.

LSE allocation process

As part of the scoring process, the ISO plans to collect feedback in the form of “points” from LSEs to allocate to individual interconnection requests.

Prior to the interconnection request application window, the ISO encourages LSEs to conduct Requests for Information (RFIs) for projects expecting to enter the queue to ensure that LSEs have the necessary information on individual projects in time to make informed decisions during the LSE allocation process of the scoring criteria. The ISO urges the LSEs to communicate clear evaluation criteria for this process to prospective interconnection customers. LSEs should consider revising their tariffs to ensure they award points using fair and reasonable processes.

In addition, the ISO expects interested interconnection customers to participate in LSE RFIs, solicitations, and bilateral discussions with LSEs to market their projects prior to the interconnection request application window to supplement information LSEs will be provided during the scoring process and therefore increase the projects’ opportunity to obtain LSE-awarded points.

Each LSE (CPUC jurisdictional and non-CPUC jurisdictional) will receive a capacity amount to allocate to projects based on available and planned

transmission capacity for a given cluster. The ISO will review and total these scores once it receives information from LSEs. The ISO proposes that non-CPUC jurisdictional LSEs participate in this process in the same manner as CPUC-jurisdictional LSEs.

The ISO proposes to require LSEs to provide the ISO with their elections no later than ten calendar days after the close of the interconnection request window. The ISO will provide LSEs with a standard form for LSEs to use in submitting their project capacity selections. Capacity awarded to projects by LSEs, resulting in points in the scoring process, will not be known or confirmed by the interconnection customer during the interconnection request application window, and therefore will not be included in the interconnection customer's self-assessment.

Allocation methodology

The ISO proposes the following allocation methodology

(a) The ISO calculates total LSE capacity allocation.

In this process, the ISO would determine how much capacity (MW) can be allocated across the ISO footprint, based on available and planned transmission capacity from the previous year's transmission plan base portfolio. To ensure that LSEs are selective in point allocation, 50% of the total TPD capacity for each LSE can be eligible to receive points, as an LSE weighting factor.

Example:

Assume total TPD capacity across ISO footprint is 25,000 MW.

Total LSE Capacity Allocation = TPD Capacity x LSE Weighting Factor = 25,000 x 0.50 = 12,500 MW (to be shared by all LSEs)

(b) The ISO calculates individual LSE capacity allocation.

In this step, the ISO would determine how much capacity (MW) the ISO can award to each individual LSE based on its load share²².

²² Load share based on the California Energy Commission's forecast of LSE annual peak load shares provided to the ISO for determining LSE Year-Ahead RA requirement.

Example 1:

LSE 1 Load Share = 30%

*LSE 1 Capacity Allocation = Total LSE Capacity Allocation x LSE
Load Share = 12,500 MW x 0.30 = 3,750 MW*

LSE 1 is eligible to allocate 3,750 MW of project capacity

Example 2:

LSE 2 Load Share = 5%

*LSE 2 Capacity Allocation = Total LSE Capacity Allocation x LSE
Load Share = 12,500 MW x 0.05 = 625 MW*

LSE 2 is eligible to allocate 625 MW of project capacity

Example 3:

LSE 3 Load Share = 1.0%

*LSE 3 Capacity Allocation = Total LSE Capacity Allocation x LSE
Load Share = 12,500 MW x 0.01 = 125 MW*

LSE 3 is eligible to allocate 125 MW of project capacity

- (c) LSE allocates capacity to selected interconnection requests submitted in the cluster window for new applications

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

Scenario 1

LSE 1 Load Share = 30%, 3,750 MW (provided by ISO in step b)

LSE 1: Selects 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 3,150 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)*

Scenario 2

LSE 2 Load Share = 5%, 625 MW (provided by ISO in step b)

LSE 2: Selects one 1,000 MW project (Project 3) and LSE 2 has partial interest of 500 MW of the project (50% of project capacity was selected by LSE 2)

Partial Support for Project P3

*Capacity allocation needed to support P3 = Partial Interest
MW Interest = 500 MW (LSE 2 has 125 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 2)*

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. (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.)

Scenario 3

LSE 3 Load Share = 1%, 125 MW (provided by ISO in step b)

LSE 3: Selects one 100 MW project (Project 4) and LSE 3, having full interest in all 100 MW of the project

Capacity allocation needed to fully support P4 = 100 MW (LSE 3 has 25 MW capacity allocation remaining)

P4 receives the full points available to a project in the scoring criteria (because 100% of the capacity of each project was selected by an LSE)

Scenario 4

LSE 4 Load Share = 0.5%, 63 MW (provided by ISO in step b)

LSE 4: Selects one 100 MW project (Project 5), having full interest in all 100 MW of the project.

In this scenario the LSE opted to use its full allocation election for one project, which would automatically award the project 100% of its capacity and the project would receive 100 points.

Full allocation election

If an LSE has a high priority interest in one project and does not have sufficient capacity to allocate to that project's full capacity at its POI, the LSE may award all of its capacity towards that one project—and only that one project—and elect to have the project receive the full 100 points. The ISO proposes to limit use of this full allocation election to one project per cycle. The option to award full points to a single project applies to all LSEs, whether CPUC-jurisdictional or not. If an LSE is going to use the full allocation election, it must give its full capacity allocation to that one project. The ISO does not expect larger LSEs to make this election, as they will likely have sufficient capacity to award full capacity to several projects. If LSEs do award capacity to multiple projects, they cannot exceed their capacity allocation and cannot take advantage of the full allocation election. It is specifically designed for circumstances where an LSE's need significantly exceeds their capacity allocation, such as in circumstances of a large resource retirement or the expiration of a power purchase agreement that accounts for a significant portion of an LSE's load.

An LSE must specify to the ISO that it is making this special election. The ISO will include a space for this election on the LSE Interconnection Allocation Form

Limits on LSE-owned projects in the LSE allocation process

To avoid preferential treatment of LSE-owned resources in the LSE allocation process, the ISO proposes that in each LSE allocation cycle (each cluster) LSEs may only award capacity to either three self-built projects or 25% of the LSE's capacity allocation per cycle, whichever is greater.

This limitation also applies to both CPUC-jurisdictional and non CPUC-jurisdictional LSEs. The ISO will review data around utility self-build projects after the initial scoring process to determine if the limitations should be reevaluated. In addition to these limitations, the ISO recommends clear and transparent RFI processes leading up to the LSE allocation process. FERC-jurisdictional LSEs, in particular, should consider updating their tariffs to establish clear and fair processes for allocating points.

Commercial interest from a non-LSE offtaker

The ISO proposes an additional opportunity for interconnection requests to obtain points in the Commercial Interest category for projects that are being marketed to non-LSE offtakers, such as corporate and industrial users. Because commercial offtakers do not carry an obligation to serve load or provide RA, the ISO does not propose allowing them to participate in the same allocation process as LSEs. Instead, the ISO will award a maximum of 25 points to each interconnection request for documented, verifiable demonstration of commercial interest from a valid non-LSE offtaker. The project will receive a maximum of 25 points even if more than one demonstration of commercial interest from a non-LSE offtaker is provided. A non-LSE/commercial offtaker can only express interest in one project per cluster.

The ISO will continue to scrutinize every non-LSE commercial arrangement proffered to ensure the company is legitimate, procuring the capacity in a meaningful way, and not affiliated with the interconnection customer or its holding company. The ISO will continue to reject illegitimate power purchase agreements and commercial arrangements created to satisfy tariff criteria artificially before being replaced with legitimate, arrangements that would actually provide financing of a generator.

Project Viability

The ISO proposes refinements to criteria that are most appropriate early in the interconnection process. The ISO requires criteria that can be 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.

The ISO proposes four indicators of project viability, with the entire category comprising 35% of the overall scoring weight.

- Percent completion of engineering design plan, with points commensurate with percent completion of engineering design plan up to a maximum of 50, to be validated based on a set of pre-determined guidelines (e.g. 15% complete=15 points) Expansion of a generation facility that is currently under construction;
- Expansion of an operating facility;

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

System Need

The ISO proposes two indicators of system need, which together would make up 35% of the overall scoring weight:

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

Figure 6 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.

Figure 5. Proposed Scoring Criteria

Indicators of Readiness	Points	Weight (%)	Max Points	Validation
Commercial Interest (Max points= 100)				
<p>□ LSE allocations: 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.)</p> <p>□ Check for Full Allocation Election: In instances where an LSE does not have enough points to award to an entire project, each LSE may award full capacity for one project per interconnection request application window.</p>	100	30%	30	The ISO will provide LSEs with a form to fill out to assign points to desired interconnection requests, to return to the ISO 10 calendar days after the close of the interconnection request application window. The ISO will add the points to each project's score as part of the scoring process.
<p>□ Non-LSE Interest: Points</p>	25			The ISO will provide a form requiring a signed affidavit from a representative that is authorized to execute power purchase agreements, indicating and affirming commercial interest: <ol style="list-style-type: none"> a. Attest non-LSE off-taker is supporting this project in support of corporate policy goals on sustainability b. Attest that the size of application is aligned with the non-LSE off-taker needs c. Attest that non-LSE off-taker is not affiliated with the IC or its holding company d. Attest that the non-LSE off-taker has not supported more than one application.

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Project Viability (Max points=100)²³				
Engineering Design Plan Completeness, with points commensurate with percent completion of engineering design plan up to a maximum of 50, to be validated based on a set of pre-determined guidelines (e.g. 15% complete=15 points)	50	35%	35	Signed affidavit accompanied by documentation of the project's engineering design plan level of completeness certified with a professional engineer's stamp.
Chose no more than one of the three expansion of a generation facility items				
<input type="checkbox"/> Expansion of a generation facility that is currently under construction	10			IC submits information indicating that new IR uses same or directly adjacent site as a facility under construction
<input type="checkbox"/> Expansion of an operating facility	20			IC submits information indicating that new IR uses same or directly adjacent site as an operating facility
<input type="checkbox"/> Expansion of a facility that is under construction or in operation, where the Gen-Tie already has sufficient surplus capability to accommodate the additional resource	50			IC submits information indicating that new IR uses same or directly adjacent site as an existing facility and documents the capacity of the gen-tie, the existing (under construction or in operation) facility and the new facility
System Need (Check one. Max points=100)²⁴				
<input type="checkbox"/> Ability to provide Local Resource Adequacy (RA) in an LCRA with an ISO demonstrated need for additional capacity in that local area	50	35%	35	The ISO will post information describing the areas/sub-areas that have a deficiency of generator capacity and the amount of additional capacity needed to eliminate the deficiency and validate IRs against that information.

²³ Maximum points of 100 for Project Viability = Engineering Design Plan 50% complete (50 points) + Expansion of an existing facility where the existing Gen-Tie already has sufficient surplus capability to accommodate the additional resource (50 points)

²⁴ The ISO assumes that these two categories are mutually exclusive and that projects would not be able to select both.

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<u>Long Lead-time Resources</u> <input type="checkbox"/> Meets the requirements of the CPUC and other LRA resource portfolios where the TPP has approved transmission projects to provide the necessary transmission requirements. ²⁵	100			The ISO will work with the CPUC and LRAs to determine a list of eligibility requirements for this category of resources prior to the interconnection window opening.
Total		100%	100	
Distribution Factor	Value	Tie-Breaker		
<input type="checkbox"/> Value used as tie-breaker (lowest DFAX selected first)				Interconnection request

Distribution factors

The ISO will use each project’s distribution factor (DFAX)²⁶ as a tie-breaker when the selection process reaches the 150% threshold with two or more projects tied and less capacity 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. The ISO will determine the DFAX for any projects that are tied and determine the project(s) that will be studied: interconnection customers should not provide this information. If project ties still exist after the use of projects’ DFAX, 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 associated with each constraint.

²⁵ Only long lead-time resources that are required to meet the CPUC and other LRA resource portfolio requirements are eligible, including resource types that are considered for central procurement under Assembly Bill 1373 (2023), or as specifically identified by the CPUC or LRAs in the portfolios provided to the ISO for use in the transmission planning process.

²⁶ 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.

2.5.2. Auctions

Background

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

The straw proposal and revised straw proposal refined an auction design with the following key attributes:

- A market-clearing, sealed-bid auction for the right to be studied;
- Each zone would be studied at 150% of the individual constraint based and portfolio-driven available and planned capacity;
- Auctions would be conducted only if there is excess proposed capacity after applying a points-based viability scoring system that utilizes a distribution factor (DFAX) as an initial tie-breaker, and only for projects that are deemed equal in viability and DFAX ratings;
- Only tied projects that cause the total MW to cross the capacity limit will participate in the auction;
- Only Interconnection Customers participating in the auction will submit bids on a dollars-per-MW basis;
- Interconnection Customers that win an auction will be studied in their entirety, and will submit at-risk financial security accordingly;
- Interconnection Customers that reach commercial operation will be refunded their at-risk auction financial security;
- Interconnection Customers that withdraw (or are deemed withdrawn) will partially lose their 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 and discussion

Stakeholders remain divided in their positions around the zonal auction, as proposed in the revised straw proposal and slightly modified in the draft final proposal.

Several parties, including CalCCA, suggested that instead of developing an auction, the ISO should focus on development of robust scoring criteria. Several of these stakeholders suggest that if projects receive the same score, the ISO should study all tied projects.

ENGIE, LSA, CESA, Q Cells, REV, and Terra-Gen opposed the auction as a tie-breaker due to the relative complexity of an auction and the likelihood of resolving ties through DFAX. ENGIE recommended the ISO delay the complexity involved with the implementation of an auction to a future queue cycle as it may not be needed.

The following entities expressed support for the auction earlier in this initiative: ACP-California, CPUC (Energy Division), Clearway Energy Group, ENGIE NA, PG&E, Shell Energy, and SCE. Shell Energy supported the auction concept as well, noting that while the use will likely be limited, it represents a novel and elegant manner to allocate scarce interconnection capacity.

The ISO agrees that managing the auction will create an increased administrative burden, but believes it to be less burdensome and more manageable than the alternative of managing and studying far more projects than necessary. The results of the study process will also be more accurate and meaningful as a result of a smaller pool of projects to study and will enable the ISO, utilities and other LSEs and the regulatory community to effectively prioritize and focus their finite resources on successful commercial development of the key infrastructure projects necessary to achieve the state's policy and reliability objectives.

EDF-R requested clarification of whether, if a winning bid fails to post security required by their bid, the ISO would move to provide the opportunity to be studied by the highest bidder.

Proposal

The ISO continues to propose an auction as an essential component to a process that achieves manageable queue volumes and preserves competition among of viable projects in each zone.

Auction Design

After applying both the viability scoring system and the DFAX tie-breaker, if there are still ties, the tied projects will be allowed to participate in a market-clearing, sealed-bid auction as the final tie-breaker for the right to be studied. Shortly after the viability scoring and DFAX processes are completed, the ISO will notify any remaining tied interconnection customers they can participate in the auction tie-breaker and will be requested to submit an auction bid on a dollars per MW basis within two weeks of the ISO notification. 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.

Because it is unlikely that the requested MW capacity in a zone will exactly equal the 150% MW cap, the ISO proposes that projects that submit the highest bids and are either within or the first project that crosses the 150% MW capacity 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. The ISO also proposes to post on the ISO website the clearing price of any auctions conducted, but not the individual project bids.

If a project reaches commercial operation, its auction financial security will be refunded with any applicable earned interest to the interconnection customer within 90 days of the interconnection customer notifying the ISO the project reached commercial operation. Interest will not be accrued if the financial security selected below does not earn interest (such as a letter of credit). If the project withdraws from the 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, and thus 400 MW capacity deemed reasonable to study.*
- *Seven 100 MW projects apply in this capacity*
 - *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 Transmission Revenue Requirements, as recovered through the ISO's Transmission Access Charges. 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:

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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 a 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 business days of the credit rating change.

2.5.3. 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. The straw proposal and revised 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 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 study process required by FERC Order No. 2023. By studying a percentage above the capacity for each zone, the ISO will ensure sufficient availability of resources in and after the study process, balancing resource sufficiency with competition.

Stakeholder feedback

In comments on previous iterations of this proposal, stakeholders asked the ISO to justify a rationale for the 150% capacity limitation, with some expressing concern that this cap would “arbitrarily” reduce the number of projects that can compete. They also flagged the cap’s potential to drive-up RA 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 and each cluster will result in a surplus of studied capacity that will accumulate over time. Unlimited interconnection requests or a higher percentage would continue to grow the queue at an unsustainable rate, slowing study processes and making results less accurate. The ISO intends to create fair and reasonable limits on the amount of new generation it can study on a timely basis, and tested the effect of the 150% cap using Cluster 15 data and a survey of Cluster 15 interconnection customers.

Proposal

The ISO will apply the scoring criteria, DFAX tie-breaker, and if necessary, auction to select projects that can fulfill 150% of the available and planned transmission capacity in each zone.

2.5.4. Modifications to the “Merchant Deliverability”²⁷ Option [Updated]

Background

As discussed above, the zonal approach is foundational to this IPE 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.

The designation used for projects that seek to interconnect and meet the conditions required for the zonal studies where transmission capacity exists is the “Transmission Plan Deliverability option” (TPD option). Projects that seek to interconnect in zones that have no TPD available may only proceed under the designated “Merchant Deliverability option” (Merchant option).

Stakeholder feedback and discussion

AES, CalCCA, ENGIE, GSCE, Intersect, Rev, and SEIA continue to want projects not selected for study in TPD zones to be able to pursue the Merchant option, but most recognize that a current or future mechanism to limit Merchant projects could be needed. BAMx, Cal Advocates, and SCE supported the proposal. The ISO continues to disagree with that proposed approach. The scoring criteria are designed to limit the number of projects studied in zones with available capacity (TPD areas) to 150% of the available capacity. Allowing Merchant option projects in TPD areas defeats that purpose by studying more capacity in these areas than the CPUC portfolio had determined the system needs. Too many projects results in inaccurate study results and goes against the foundational principles agreed to at the beginning of the IPE initiative. The request to allow TPD option projects to switch to the Merchant option would open the door to projects trying to bypass the scoring criteria.

ACP-California and New Leaf Energy stated that the policy needs to ensure that Energy Only projects getting deliverability under Group C (or otherwise) do not

²⁷ Formerly referred to as Option B

utilize the TPD that another project paid for and has yet to secure for its project. The ISO agrees. As long as a Merchant option project has cost responsibility to fund an ADNU, the ISO will not make that capacity available to non-Merchant projects.

LRE and LSA suggested that the GIDAP Section 7.6 should be revised to allow the full benefit of forfeited ADNU security to go to remaining Merchant option projects, where there are multiple sponsoring projects and one or more withdraws. The ISO must revise Section 7.6 of Appendix DD to comply with the FERC Order 2023 requirements, and it would not be appropriate to make additional changes to this section in the IPE 2023 FERC tariff filing. This issue can be taken up in a future IPE initiative if it is determined to be needed.

REV disagreed with ISO's position that the execution of a GIA is used to determine whether a project is released from its obligation to fund an ADNU, stating that once the ISO sees the need for the ADNU, a project should be released from the responsibility to fund the upgrade. The ISO clarifies that once a GIA associated with any network upgrade is executed the network upgrade becomes part of the TPP base case. From that point forward the studies assume the network upgrade will be built and as such, there is no need to further study the need of a transmission element that the model assumes is in service.

The Six Cities opposed the ISO's proposals related to the Merchant option to the extent that the ISO will require a non-CPUC jurisdictional LRA approved project to proceed as a merchant project if it seeks to interconnect in an area with no existing or planned transmission capacity, even if the project is being developed by an LSE pursuant to an LRA-approved resource plan and is located within the LSE's service territory, such as the service territory of a municipal utility. Six Cities claim that the ISO has not historically planned the transmission system to accommodate the resource plans of non-CPUC LRAs, so Six Cities does not believe it is appropriate to apply the merchant deliverability requirements to projects being developed by LSEs pursuant to LRA-approved resource plans. The ISO has increased outreach and coordination in the TPP with the non-CPUC jurisdictional LSEs in the 2024-25 TPP and projects of non-CPUC jurisdictional LSEs will be included in the 2024-25 TPP. The ISO is not aware of any non-CPUC jurisdictional LSE project in Cluster 15 and the 2024-25 TPP will be timely in accommodating any such project proposed for Cluster 16.

Recurrent asked the following questions:

- Does Scoring Criteria apply to Merchant option?

The scoring criteria will not be used for projects applying for the Merchant option. As described in item (5) below, Merchant option projects will be required to make an additional Commercial Readiness Deposit towards the cost of the ADNU with the submittal of its interconnection request. The deposit is set to an amount deemed to be high enough to be an incentive to only those interconnection customers that are confident of their project's viability under the Merchant option.

- Is the Commercial Readiness Deposit refundable post COD of the Merchant deliverable project? Or is the entire amount non-refundable post cluster study even if the project comes into service?

The Commercial Readiness Deposit will be a portion of the overall funding used by the PTO to construction of the ADNU. It will not be refundable.

- Can ISO help interconnection customers understand why the repayments of ADNU funded under Merchant Deliverability Option can only be done via CRR's?

The Merchant Deliverability process is an existing, FERC-approved process, which provides Merchant Transmission CRRs as a form of reimbursement. Creating a new process to determine benefits, costs owed, and new ownership structures is beyond the scope of this initiative.

Proposal

The Merchant option ensures that projects seeking to interconnect in areas/zones with no available deliverability capacity have a path forward to become deliverable by providing the opportunity for such projects to build any required ADNUs as a merchant transmission project. The ISO will not accept Merchant option interconnection requests within zones that have available or planned transmission capacity. However, any TPD zone where the available capacity is less than 50 MW will be studied as a Merchant option zone.

Projects will not be allowed to submit an interconnection request as a TPD option project and later switch to the Merchant option if they are not selected to be studied through the scoring process. In addition, if a TPD option project is

selected and studied, but unable to receive a TPD allocation, it will not be eligible to convert to the Merchant Deliverability option.²⁸

1. Merchant Deliverability option 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 require, without reducing the available deliverability from other delivery network upgrades needed by TPD option projects.
2. Merchant option projects that require Local Delivery Network Upgrades (LDNUs) will be eligible for cost recovery of any posted financial security towards the cost of the LDNU in the same manner as TPD option projects. LDNUs are more project specific than ADNUs that, outside of the Merchant Deliverability 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 Merchant option being more viable.
3. A Merchant Deliverability project's funding of the construction of its required ADNU will not receive repayment. The interconnection customer will be eligible to receive Merchant Transmission CRRs in accordance with ISO Tariff Section 36.11. The ISO does not propose to revisit its policy that the interconnection process cannot enable new transmission owners. Developers can propose transmission projects in the TPP or as Subscriber PTOs.
4. Merchant Deliverability projects will be given a project status of FCDS or PCDS, as specified in their GIA and in accordance with the RA counting rules.
5. The project will be required to make an additional Commercial Readiness Deposit towards the cost of the ADNU with the submittal of its interconnection request during the cluster application window. The additional amount will be \$10,000 per MW, but not less than \$500,000 and

²⁸ Transmission Plan Deliverability projects will still be able to exercise Article 11.4.3 of the LGIA should they ultimately wish to forego cash reimbursement in favor of CRRs. This article does not impact intake or study processes.

- not to exceed \$5,000,000, based on the capacity amount of deliverability requested in its interconnection request. Fifty percent of this additional Commercial Readiness Deposit would be non-refundable if the project withdraws after the due date for interconnection request validations to be complete. The deposit is set to an amount deemed to be high enough to provide an incentive for only those interconnection customers that are confident of their project's viability under the Merchant option.
6. Merchant Deliverability projects that complete the cluster study process will be required to increase their Commercial Readiness Deposit associated with their merchant ADNU(s) to 50% of its cost responsibility for the ADNUs (e.g., if the project provided \$5,000,000 in accordance with (5) above and 50% of the projects cost responsibility of the ADNU is \$20,000,000, then the project would be required to increase its Commercial Readiness Deposit by \$15,000,000). Fifty percent of the Commercial Readiness Deposit associated with the merchant ADNU would be non-refundable if the project withdraws.
 7. If a future TPP determines an ADNU that a Merchant Deliverability project is funding is needed to support a CPUC portfolio, then the following criteria would be used.
 - a. Once Merchant option projects have executed GIAs, the ADNU they are sponsoring would be included in the base case for the next TPP, and the Merchant option projects must then fund the ADNU and proceed as Merchant option project(s). However, if the Merchant option project did not execute GIAs by the time the base case for the current TPP is established (so the ADNU was not included in this TPP base case) and the ADNU is approved as needed in the current TPP, the Merchant option project would:
 - i. Be released from its funding obligation, and its ADNU security would be released.
 - ii. Retain its TPD allocation, if it demonstrates TPD allocation Group A or B compliance within two years. (The deadline would be the affidavit due date of the second TPD allocation cycle after the ISO Board of Governors approves the transmission plan with the ADNU (e.g. for a May 2026 TPP

Plan Board approval date, the Merchant option project must meet retention requirements by the 2028 affidavit due date).

- iii. If a Merchant option project is unable to retain its deliverability or obtain an allocation of TPD within the timeframe for its cluster to obtain an allocation of TPD, the Merchant option project will be converted to Energy Only in the same manner as TPD option projects that are unable to obtain an allocation of TPD.
8. The Merchant option project's eligibility to self-build the merchant ADNU will be governed by the Stand Alone Network Upgrade provisions of the ISO Tariff Appendix DD.

2.5.5. Criteria for Energy Only Projects in Non-reimbursement Zones [New]

Based on concerns by stakeholders that Energy Only projects would have difficulty competing to be studied under the Draft Final Proposal's process where Energy Only projects would be scored and ranked with FCDS projects in TPD zones, the ISO has revised the procedures for Energy Only projects. In Section 2.3.3 the ISO proposes that Energy Only projects could seek to be studied under two options, interconnecting under the Reimbursement option or under the Non-reimbursement option. Eligibility for Energy Only projects under the Reimbursement option are projects seeking to interconnect in zones where the CPUC portfolio's amount of Energy Only Delivery Status resources are greater than zero MW in that zone. Energy Only projects under the Non-reimbursement option may seek to interconnect in any zone, regardless of the findings of the CPUC IRP process. This section provides the ISO proposal related to procedures for Energy Only projects seeking to interconnect in Non-reimbursement zones.

The CPUC's IRP base case portfolio identifies zones where Energy Only resources have been determined to be needed to meet state goals. Energy Only projects seeking to be studied in these zone will compete to be studied using the methodology described in Section 2.3.3. Open access principles require that Energy Only projects seeking to interconnect in any zone have the opportunity to do so. The Non-reimbursement option allows Energy Only projects to be studied without being subject to any scoring criteria and in any zone. However, such projects will not be eligible to be reimbursed of any funding provided by the

interconnection customer for required RNUs or interconnection facilities. The interconnection customer will be eligible to receive Merchant Transmission CRRs for any portion of RNUs it funds and are constructed for its project in accordance with ISO Tariff Section 36.11, similar to the Merchant option.

2.6. Study Process

The ISO appreciates the thoughtful 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,” which identifies the interconnection facilities, reliability network upgrades, and delivery network upgrades that 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.

The ISO received a number of stakeholder questions and comments on the study process, which the ISO will defer until submittal of its Order No. 2023 compliance filing.

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

Background

Order No. 2023 prescribes specific 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.²⁹ 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-

²⁹ Depending on the detail requested by the customer.

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 because there is not difference between Off-Peak Deliverability Status and Off-Peak Energy Only in the ISO Market or in RA counting. Additionally, the operational deliverability assessment tends to only reconfirm the delivery network upgrades that each cluster of generators are waiting for to be completed, and this information is the same precursor network upgrade list that has already been identified.

Stakeholder feedback and discussion

The ISO did not receive any additional stakeholder feedback related to this element of the draft final proposal.

Proposal

The ISO proposes to remove both the off-peak and operational deliverability assessments from the cluster studies to enable it to meet a faster study schedule, and because of the limited value of those studies. The ISO 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 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. The ISO intends to continue to include the off-peak deliverability analysis in the transmission planning process.

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 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 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. In the draft final proposal, the ISO provided an initial proposal for modifying the TPD allocation process recognizing that the TPD allocation discussions may not advance to the final proposal stage in time for the May 2024 ISO Board of Governors meeting.

Stakeholder feedback and discussion

Stakeholders commenting on the proposal provided a number of questions and concerns on the proposal with most requesting that the issue continue to be discussed in an IPE 2023 Track 3 process that provides more time to work through the ISO proposal and suggested stakeholder modifications. The ISO had anticipated the potential need for continued discussion on the issue and proposed an IPE Track 3 focusing on the TPD allocation process that could continue separate from the Track 2 items going to the Board of Governors in May, with Track 3 targeted for the July 2024 Board meeting.

Proposal

The ISO will initiate Track 3 of the IPE initiative, focusing on the TPD allocation process, shortly after conclusion of the Track 2 process. The ISO will target the July 2024 Board meeting to resolve these issues. The ISO will develop a specific schedule for Track 3, and publish a proposal soon.

3. Contract and Queue Management

3.1. Limited Operation Study Process Updates

Background

Under Section 14.2.4 of the GIDAP, projects are currently restricted 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 study, interconnection customers may be left with

just a 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 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 limited operation study is premised on the interconnection customer lacking its identified reliability network upgrades. Inaccuracies in the study 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 when it has been completed. The ISO seeks to clarify situations where modification requests are submitted that may impact the LOS process or study results.

Stakeholder feedback and discussion

The ISO did not receive additional comments on this element of the draft final proposal.

Proposal

The ISO maintains its proposal to increase time to submit an 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 to what extent a project may synchronize to the grid, or must await completion of its assigned reliability network upgrades. The ISO's proposed change does not reflect a greater ability to study system impacts further into the future; the 5-to-9 month extension is the limit to which the ISO can reasonably determine system reliability and provide customers with more time to evaluate and respond to the LOS results.

The ISO also proposes to clarify the interaction between the Material Modification Assessment (MMA) and LOS. The ISO will clarify in the Business Practice Manual for Generator Management that any modification request submitted concurrently 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.

3.2. Consistent Requirements for All Asynchronous Generating Facilities

Background

The ISO has seen increased deployment of asynchronous resources and has experienced operational issues with the 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 and discussion

The ISO did not receive additional comments on this element of the draft final proposal.

Proposal

For consistency across all asynchronous generating facilities, the ISO maintains its proposal 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).

3.3. Limitations to Transmission Plan Deliverability (TPD) Transferability

Background

The ISO is committed to providing projects flexibility to account for project development uncertainties and progress toward commercial operation. As such, the ISO recently granted 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 rather proposes reasonable limitations to such transfer opportunities to prevent gaming. The ISO recognizes

that deliverability transfers generally 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 those later queued to avoid the tariff requirements of the project that received the original TPD allocation (e.g. the TPD requirement to proceed without a PPA). Because these transfers would circumvent tariff rules, the ISO has rejected them.

The ISO also has observed that the assignor projects (i.e. the projects transferring their TPD) either become stagnant or withdraw from the queue as the developer tries to find an offtaker and re-seek deliverability. This is an undesirable result that causes queue backlogs. Projects that become Energy Only under these circumstances 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 and discussion

CalWEA objected to requiring a project that transfers its deliverability to withdraw from the queue or downsize its generating capacity to its remaining deliverability, and that such projects should be allowed to develop as Energy Only because they are subject to the commercial viability criteria and time-in-queue requirements in Section 3.6. The ISO maintains its position that Energy Only projects historically have not proceeded to commercial operation. Withdrawing the Energy Only project or portion of the project will free-up space for projects that are proceeding to commercial operation.

LSA commented that the ISO could support these potentially still-viable Energy Only projects by allowing them one year to provide a PPA or require provision of the third posting and Notice to Proceed under the GIA as an interim viability demonstration. The ISO maintains its position that it is unlikely that an Energy Only project would be able to execute a PPA and proceed to commercial operation. Additionally, the third posting and Notice to Proceed are not considered a demonstration of commercial viability.

Both CalWEA and LSA proposed that the Energy Only project, or portion of the transferring project be able to seek a new allocation. As the Energy Only project or portion of the transferring project will be withdrawn or downsized upon completion of the transfer, seeking a new allocation for that Energy Only project or portion of the project would not be possible.

Proposal

The ISO maintains its earlier 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 entirely from the queue at the time of transfer. However, recognizing stakeholder comments that there may be some Energy Only procurement, the ISO will forego such withdrawal of the transferring project if the transferring project provides an Energy Only PPA at the time of its transfer request.

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

3.4. 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, clearly stated firm 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 submits its compliance filing to FERC.

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 final proposal suggests strict commercial viability criteria and time-in-queue requirements for all projects in the queue. These requirements will supplement new FERC Order No. 2023 restrictions.

Stakeholder feedback and discussion

ACP-California, CPUC-Public Advocates Office, Engie NA, NextEra, PG&E, SCE, supported the CVC proposal.

ACP-California and Engie NA appreciated the adjustments to the PPA requirements when a PPA is terminated due to a PTO Delay as well as the clarification of the CVC requirements.

AES and SEIA said they understand the ISO's proposed commercial viability criteria (CVC) and time in queue requirements and seek clarification if these requirements would also apply to Energy Only projects. AES is also seeking clarification of what portion of the 3rd interconnection financial security would be at risk. Additionally, AES asked if the ISO could elaborate further on the permitting requirements for the CVC, such as, does a list of all permits suffice and, do the annual reports after the CVC requirement require a minimum threshold that permitting needs to meet CVC? The ISO clarified that CVC will apply to all projects in the queue, regardless of TPD status. The 3rd posting (under current tariff policy) and GIA deposit under FERC Order 2023 refund rules will remain in place. Additionally, it is expected that the project has commenced or will be commencing construction activities by the time CVC requirements must be met (or shortly thereafter). Therefore, the initial CVC permitting demonstration will need to note the permits the project has requested, the status of such request, and the expected acceptance date of such permits. The project must then annually demonstrate distinct and specific progress to commercial operation, meaning it would be reasonable that permits are approved or very close to approved by the first CVC annual demonstration.

CalCCA suggested the ISO adopt its proposal to require all projects in the queue to demonstrate commercial viability to remain in queue beyond seven years, regardless of deliverability status as well as each project to meet commercial viability criteria by an unavoidable time-in-queue requirement. The ISO proposal does that, and CVC is subject to all projects, whether FCDS, PCDS, or Energy Only.

CalWEA believes Energy Only projects should be able to acquire a PPA for RA capacity and at that point should request TPD capacity. Projects that elect to build as Energy Only, should commence construction activities immediately following the study results publication. This will ensure adequate time for the

project to achieve commercial operation. Energy Only status is not intended as a vehicle to linger in queue while a project seeks an RA contract.

Upstream suggested that the PPAs used to demonstrate CVC should not include a provision that allows the developer to terminate the PPA. Without this, certain LSEs will turn this into a profit center and offer contracts with a “termination for a fee” provision once the interconnection customer has demonstrated CVC. The ISO has placed no such requirement that PPA should not include a termination clause. The ISO has not and will not dictate PPA terms.

EDF-R, Clearway, Strata Clean Energy, and Upstream are concerned that more than 7 years is insufficient for some Cluster 14 projects to meet CVC given the long timelines and frequent delays for network upgrades to enable Energy-Only interconnection and to enable deliverability. EDF-R does not believe it is reasonable for the ISO to apply commercial viability tests to projects that are on track to meet their earliest-achievable CODs as identified in study reports or PTO delay requests. EDF-R provided an example in which a project’s longest lead network upgrade will take 9 years to construct after GIA execution and in this circumstance, EDF-R believes the project should not be required to provide an executed PPA to stay in queue until 6 years before COD.

Strata Clean Energy likewise believes that time in queue requirements need to have flexibility around long-lead transmission upgrades that are being utilized for awarding deliverability. Additionally, Upstream also noted that Cluster 14 triggered a number of long-lead time RNUs that are required and won’t be placed in-service until well after the ISO’s proposed Cluster 14 CVC date of April 30, 2028. In addition, the majority of approved 2022-2023 TPP Policy-Driven Upgrades that add additional deliverability will not be placed in-service until well after April 30, 2028. For these reasons, according to Strata, the ISO should consider moving the Cluster 14 CVC date to April 30, 2030.

In response to EDF-R and Strata, the ISO notes that a project generally will not commence construction activities until a PPA is executed. Therefore, it seems reasonable that a project would have an executed PPA prior to starting construction (9 years ahead of ISD) and should have no issue providing demonstration of the PPA by the timelines established in this proposal. Additionally, the ISO notes that for long-lead upgrade and project development, construction should commence earlier than the CVC dates identified. Therefore, all contracts, including purchase agreements, should be executed and construction should have commenced well ahead of the 2028 CVC due date for

Cluster 14 at a time that the project should be in a position to meet CVC by the timelines established. The ISO will not change the CVC due dates.

Vistra requested clarification of how CVC and TPD will correlate. Specifically, Vistra asked how the TPD allocation proposal would align with a project's need to meet CVC and provided three scenarios to confirm representation. The ISO notes that the TPD changes are still under review. The ISO expects to align the two processes, however, it will be firm on the CVC requirement dates, requiring the project to meet CVC regardless of the TPD allocation timeline and process.

Vistra also believes the CVC proposal appears to be inconsistent with FERC Order 2023 because Order 2023 requires the project to have 100% site control earlier in the interconnection timeline than the CVC proposal. The ISO is requiring the 100% site control in the policy to ensure projects in Cluster 14 and earlier comply with such requirement. If or once the Order 2023 site control requirement to demonstrate 100% site control earlier in the process is implemented, the earlier timeline would supersede the CVC policy for those projects under Order No. 2023 requirements.

Proposal

The ISO continues to propose requiring all projects in the queue to demonstrate commercial viability to remain in queue beyond seven years, regardless of deliverability status. The ISO also proposes requiring each project to meet the CVC by an unavoidable time-in-queue requirement. Projects must demonstrate annually that CVC remains valid. Failure to meet these requirements will result in withdrawal or default of the project.

The current CVC policy in Appendix DD will apply to all projects currently in the queue through Cluster 14. The CVC requirement for projects to retain TPD when requesting COD changes beyond 7 years-in-queue will remain effective until such CVC due date as identified in Table 5 : *CVC Demonstration Requirement* below for the project's respective cluster. Specifically, projects utilizing the one-year limited exception of the current CVC policy will not be provided PPA due dates beyond the CVC due dates identified in Table 5 below for the project's respective cluster. The current CVC requirements to retain TPD will not apply to Cluster 15 or later.

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 executed PPA.

As detailed in Tables 5 and 6 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. All projects in Cluster 15 and later will be required to meet CVC by 5 years from the publication of the interconnection facilities study, which is the last study in the Order No. 2023 study process. In contrast to current practice, projects will be required to meet these criteria when they are in queue for 5 years from the interconnection facilities study (or Cluster 15 equivalent):³⁰

- Proof of one or more executed power purchase agreements (whether for RA 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 and maintain the following criteria and remain consistent with the project's ISO queue project, Interconnection Request, and GIA:
 - A minimum 5-year term
 - TPD status/requirements that match the project's TPD status with the ISO. For example, if the project is Energy Only at the time of meeting CVC, the ISO will not accept a PPA that requires 'RA benefits' or TPD to be acquired. This is consistent with the ISO's proposal above to remove options to obtain deliverability late in the queue process.
 - Point of interconnection, capacity, fuel type, technology, site location and Interconnection Customer(s) legal entity (or affiliated holding company).
 - If 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,

³⁰ If a PTO construction delay changes the COD or construction schedule beyond the limit, CVC does not apply. Consistent with today, PTO construction delays are caused unilaterally by the PTO, and do not result from any customer action or election.

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 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 demonstrate that the project is on a shortlist or is actively negotiating a PPA or provide an executed PPA. If the project demonstrates a shortlist or is negotiating a PPA, the project must provide the ISO with an executed PPA by no later than 24 months from the date of the PTO extension report. If a PPA is not provided by the due date, the ISO will place the project in breach of contract and move to terminate the GIA and withdraw the queue position.
- Provide the 3rd Interconnection Financial Security (following the current Appendix DD policy) or GIA deposit (or other related security) in accordance with FERC Order No. 2023.
- Demonstrate Site Control for 100% of the property necessary to construct the facility through the approved Commercial Operation Date.
- Be in good standing with the GIA such that neither the Participating TO nor the ISO have provided a Notice of Breach that has not been cured and the Interconnection Customer has not commenced sufficient curative actions.
- 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 permits, environmental assessments, or other authorizations required for constructing the Generating Facility and

the contact persons and contact information for each required authorization.

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

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

- The CVC criteria (A) through (E) above remains valid and accurate;
 - 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, it must execute a replacement PPA before the next annual review period.
- Specific and distinct progress has been made for all of the following items:
 - 1) GIA Milestones.
 - 2) Submission of or approvals from the regulating authorities for all necessary permits, environmental assessments, or other authorizations required for constructing the Generating Facility.
 - 3) Status of engineering and design of the generating facility, and network and interconnection upgrades.
 - 4) Status of the procurement of equipment necessary to construct the generating facility. Status of the construction activities of the generating facility and interconnection facilities.

Projects that meet CVC for only a portion of the project (only provide a PPA for 50 MW of a 100 MW project for example) will be required to downsize to the capacity that meets CVC requirements.

After CVC is met, projects will be prohibited from changing POI or project site location, including requesting gen-tie sharing, and changing technology or fuel type, including the addition of or conversion to energy storage. Upon achieving

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COD, the project may request to add energy storage via a Post-COD modification request.

Consistent with the CVC and suspension today, when a project submits a modification request to determine whether suspension will have a material impact on other projects, the ISO will assess whether the suspension will place the project beyond the tariff-prescribed terms. If so, the project must comply with the CVC at the time it enters suspension. This will continue to avoid projects' using suspension to linger in queue while avoiding CVC requirements.

Projects in queue beyond the tariff-prescribed timelines will not have an option to construct as a merchant plant or proceed without a PPA and proceed to construction without having met and continue to meet CVC requirements. This will prevent projects from creating pretexts to linger in queue while searching for an offtaker.

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.

Tables 5 and 6 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 5. GIA execution retirement

	# 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

Table 6. 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:

- A. A long lead-time project (such as offshore wind) with a COD of 2040 enters the queue in 2026 with a seven-year CVC requirement of April 2033. With a long-lead development and upgrades of 10 years, the project must start construction by 2031. Therefore, as long as the project executes a PPA by 2033 (meaning it had roughly four years to market and seek an offtaker following the study process), and demonstrate all other CVC, it can request a COD that aligns with that PPA.
- B. The project has a long-lead upgrade that results in the project COD extending beyond seven years-in-queue, the project can have any COD it needs, as long as it demonstrates all CVC by seven 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.
- C. If the project has Energy Only Deliverability Status, an Energy Only PPA 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 seven years-in-queue (or date established below) and continues to meet

such CVC annually making continual progression to commercial operation.

- D. 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.

3.5. 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 working group meetings, the ISO and stakeholders sought ways 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. Limiting a project to a certain number of MMA requests or requiring that MMAs may only be either submitted at certain times during the year or based on contract milestones.
5. Implementing 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 due to the cost of processing modifications being greater than the current \$10,000 deposit.

Stakeholder feedback and discussion

The ISO did not receive additional comments on this proposal.

Proposal

The ISO maintains its proposal to update the following 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 Facility Reassessment Report 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) to specify that projects must have started construction and be within nine 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 nine months, a modification request must be submitted.

3.6. Earlier Financial Security Postings for Projects with Shared Upgrades

Background

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. 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.

In the draft final proposal, the ISO, in coordination with the PTO, agreed to 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 portion of the shared network upgrade.³¹ If the project is parked, it would need to execute an engineering and procurement (“E&P”) agreement for the shared network upgrades with the PTO within 90 calendar days of notification or be withdrawn.³² 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.³³ The IFS and first payment would be due at the time of execution of the GIA and payments would commence. Failure to post is grounds for termination of the engineering and procurement agreement or GIA.³⁴ 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 subsequently 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

³¹ For Cluster 15 and beyond, in accordance with Order No. 2023, the project will need to post their Commercial Readiness and GIA Deposits along with the discrete portion of the shared network upgrade at least thirty (30) days prior to the commencement of procurement, installation or construction of the shared network upgrade.

³² This is applicable to Cluster 14 and previous clusters.

³³ For Cluster 15 and beyond, the posting for discrete upgrades resolves this issue.

³⁴ Section 8.4.8 of Appendix DD, LGIA Article 2.3 or SGIA Article 3.3, whichever is applicable

and 3rd IFS posting from all of the impacted interconnection customers, it will have 30 business days to commence working on the upgrades.

Stakeholder feedback and discussion

The following parties support this proposal: ACP-California, AES, Cal Advocates, CESA, Intersect, LRE, NextEra Resources, PG&E, REV, SCE, and Upstream. LSA does not object to the proposal. LSA still considers related proposals – separate posting/NTP/payment timing for other upgrades, and PTO obligation to begin the upgrade – as integral to its support for this proposal.

ACP-California would like to continue to explore options to reduce the significant delays to upgrades in other forums, including options for developers responsible for shared network upgrades to delay payment of the third financial security posting if a GIA is not executed by the PTO. The ISO does not have a dedicated policy initiative on this matter but notes that the Transmission Development Forum is an appropriate venue to track the progress of PTO upgrades. Additionally, the ISO is working with local, state, and federal authorities as well as stakeholders to explore broader solutions to the workforce, supply chain, and financial challenges that impact PTO construction timelines.

AES and SEIA are seeking clarity that the policy should apply to all shared network upgrades such as DNU, RNU and LNU. The ISO agrees.

EDF-R noted that the ISO's proposal requires parked projects to execute E&P Agreement but notes that the PTOs are not required to tender, negotiate or execute them. The ISO appreciates EDF-R's comment and the ISO had intended on specifically requiring this in the tariff language that will implement this initiative.

Proposal

The ISO, in coordination with the PTO, agreed to 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 portion of the shared network upgrade.³⁵ If the project is parked, it would need to execute an engineering and procurement (“E&P”) agreement for the shared network upgrades with the PTO within 90 calendar days of notification or be withdrawn.³⁶ 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.³⁷ The IFS and first payment would be due at the time of execution of the GIA and payments would commence. Failure to post is grounds for termination of the engineering and procurement agreement or GIA.³⁸ 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 subsequently 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 from all of the impacted interconnection customers, it will have 30 business days to commence working on the upgrades.

3.7. Revise Timing of GIA Amendments to Incorporate Modification Results

Background

In the draft final proposal, the ISO noted that with the continuous revisions to projects through the MMA process, the contract negotiators for the interconnection customer, PTO and ISO are required to continually amend the GIAs. The ISO proposed that the process of amending the GIA that will include all of the MMAs should start no later than nine months prior to synchronization of

³⁵ For Cluster 15 and beyond, in accordance with Order No. 2023, the project will need to post their Commercial Readiness and GIA Deposits along with the discrete portion of the shared network upgrade at least thirty (30) days prior to the commencement of procurement, installation or construction of the shared network upgrade.

³⁶ This is applicable to Cluster 14 and previous clusters.

³⁷ For Cluster 15 and beyond, the posting for discrete upgrades resolves this issue.

³⁸ Section 8.4.8 of Appendix DD, LGIA Article 2.3 or SGIA Article 3.3, whichever is applicable

the first block or phase of the project to the grid. However, developers and PTOs may have a variety of reasons to amend GIAs to incorporate modifications sooner or later. The ISO will thus continue to provide flexibility for the parties to decide when they will amend GIAs, and will not propose tariff rules regarding when parties can amend GIAs to incorporate modifications. The ISO notes that either party also can submit unexecuted GIA amendments to FERC whenever the other party is reluctant to amend a GIA or there is an impasse in amendment negotiations.

The proposal will also revise the NRI process to align with this proposal. In addition, 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 or if requested by the PTO or ISO. If any party to the GIA requests an amendment to the GIA, then all parties are required to negotiate in good faith and execute the amendment as soon as practical.

Stakeholder feedback and discussion

AES, Cal Advocates, CalWEA, Intersect, LRE, LSA, NextEra Resources, PG&E, REV, SCE, and Upstream supported the proposal of having the option to update the GIA nine months prior to synchronization and aligning the NRI process. The MMA results would include both the results, the financial milestone changes and payment schedules, if applicable. Cal Advocates noted that by addressing the timing of GIA amendments resources would be more efficiently utilized which in turn lowers costs to ratepayers.

AES is concerned that developers are not provided with the most up to date scope and cost when submitting a modification. If there is not a requirement to provide this scope and cost updates, the PTOs will miss additional information that is key to developers. In AES's experience, the amended scope has been missed by the PTOs or is not comprehensive in relation to the previously assigned scope, resulting in additional changes in a later process (*i.e.* execution) that shifts unknown financial risk to the developers. PTOs should be responsible for updating the scope that was originally identified in the studies through a modification. AES recommended that the PTO be responsible for providing a more comprehensive integration of the modification into the past reports. This would further support the ISO's goals of having developers submit project ready and viable projects and modifications in a timely fashion. The ISO noted that if AES desires an amended agreement after each MMA, then it has the ability to

request one and the parties agree that they will as soon as practical negotiate in good faith an amendment to the GIA.

EDF-R requested that the posting schedules also be included in the MMA results. The ISO agrees to add this component to the MMA report, but in some instances it will be easier to amend the GIA versus continuing to add more complexities to the MMA report.

GSW and SCE are concerned that there is not an obligation for the ISO and PTOs to process a GIA amendment upon request (e.g. financing purposes, change of the project, etc.). As stated in the previous section, it is the ISO intent to make the tendering and negotiating requirements explicit on all of the parties if any one party requests an amendment to the GIA.

MRP clarified that its concern was that the ISO and PTOs often do not keep to the timeline for processing MMAs. MRP understands the ISO's observation about the challenges of dealing with a large number of MMAs, but offered that the ISO simply slipping the deadline is not a solution that provides much comfort for the developer, as such a delay impacts the ability, and timing, to obtain financing. MRP would like to see the ISO and PTOs hire the staff they need to timely process these requests or amend the tariff to include achievable deadlines. The ISO has incorporated into this initiative Section 3.7, which captures a more achievable timeline, and Section 3.11 that requires deposits for the ISO's implementation of the projects so that staff is not trying to both manage projects and process MMAs. With these two tariff changes, the ISO believes it will have more staff to better meet the timelines.

SCE also remains concerned that including changes to scope, project payments, costs, financial security amounts (ITCC and IFS) and their due dates, and schedule in the MMA report will require negotiation with the interconnection customer before finalizing these terms and conditions in the report. This will certainly extend the overall timeline to complete the MMA/FRR beyond the 60 or 120 days as prescribed in Section 3.7. In which case, SCE proposes that ISO allow in its final proposal extension of these timelines as addressed in the ISO tariff. (See, for instance, Section 6.7.2.3 in the ISO Tariff addressing Modifications.) The ISO had not intended that each MMA Report be a negotiation among the parties, especially for complex modifications. SCE may request an extension of the MMA Report as already allowed under Section 6.7.2.3, or because SCE is likely to amend every GIA after the report is

published, the MMA report could include the high level changes and allow the negotiation details to be included in the amendment to the GIA.

Proposal

The ISO proposed that the process of amending the GIA that will include all of the MMAs should start no later than nine months prior to synchronization of the first block or phase of the project to the grid. However, developers and PTOs may have a variety of reasons to amend GIAs to incorporate modifications sooner or later. The ISO will thus continue to provide flexibility for the parties to decide when they will amend GIAs, and will not propose tariff rules regarding when parties can amend GIAs to incorporate modifications. The ISO notes that either party also can submit unexecuted GIA amendments to FERC whenever the other party is reluctant to amend a GIA or there is an impasse in amendment negotiations.

3.8. 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 its PPA, which would likely result in financial penalties for the interconnection customer.

The ISO previously proposed that a specific date for the NTP be in the GIA. If an MMA modifies the NTP date, 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 satisfy their PPA requirements. This will allow milestones to be specifically tracked.

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, which should be within 30

business days after receiving the NTP and 3rd IFS posting. 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 and discussion

No comments were received on this initiative.

Proposal

The ISO proposes that a specific date for the NTP be in the GIA. If an MMA modifies the NTP date, 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 satisfy their PPA requirements. This will allow milestones to be specifically tracked. In addition, a new milestone will be added to the GIA 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. 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.

3.9. Deposit for ISO Implementation of Interconnection Projects

Background

The draft final proposal proposed that upon execution of the GIA, the interconnection customer will provide a \$100,000 deposit to the ISO to compensate the ISO for project management and new resource implementation processes for each project in the queue. There are roughly five teams and several people involved in project implementation following GIA execution. This includes:

- Queue Management – project management, facilitating issues, assisting projects to understand next steps
- Regulatory Contracts – implementing amendments to the GIA, developing

market agreements, establishing co-located and hybrid Accumulated Capacity Constraints

- New Resource Implementation – overseeing implementation of projects into the market systems
- Energy Data Acquisition – ensuring the metering and telemetry are accurate and meet market criteria
- Full Network Model – developing and testing the model of the generator in the market systems.

Assuming a \$190 average loaded cost per hour in 2023, the \$100,000 deposit provides the ISO 526 hours to be charged over approximately five years remaining after the study process. This deposit is in addition to those costs or processes that are not currently reimbursed, such as MMAs, LOS, and PTAs. In addition, WDAT projects will need to provide a \$10,000 deposit to go through the NRI process.

Stakeholder feedback and discussion

Recurrent requested that the ISO show some sort of backend calculation that went into determination of the \$100,000 deposit and how it will help fix this problem. As discussed in the Draft Final Proposal, the ISO identified the various business units involved in development of generator interconnection projects and the work each unit is responsible for along with the cost estimate. This assumes the project is in the queue for approximately five years after the study process and proceeds to achieve COD through the New Resource Implementation process. These additional fees will allow for a revenue stream based on cost causation to justify hiring additional staff to work on the generator interconnection processes versus relying on market revenue from the Grid Management Charge.

The ISO agrees with Recurrent that staffing levels are a valid concern for the generator interconnection process to meet the anticipated 7-8,000 MW increase per year over the next 20 years to achieve California's renewable portfolio standard. The ISO is monitoring this issue.

Proposal

The ISO does not propose to make any changes from the draft final proposal. Upon execution of the GIA, the interconnection customer will provide a \$100,000

deposit to the ISO to compensate the ISO for project management and new resource implementation processes for each project in the queue. In addition, WDAT projects will need to provide a \$10,000 deposit to go through the NRI process.

3.10. Update to the Phase Angle Measuring Units Data

Background

The GIA requires an asynchronous generating facility to provide all phase angle measuring unit (PAMU) 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 PAMUs to capture events. The ISO proposes to change this sample size to 16 samples per cycle, which is already consistent with present day relays. This change provides the ISO with 960 samples per second versus the current 30.

Stakeholder feedback and discussion

The ISO confirmed on February 28th that the proposal in the draft final proposal and the draft final proposal presentation were correct, making the PAMU data change from 30 samples per second to 16 samples per cycle. LSA commented that it had insufficient time to vet the clarification with its members and suggested that this proposal be delayed until the July Board meeting. The ISO appreciates LSA's position but given the nature of this component of the initiative, the ISO wants to implement it as soon as possible and does not want to defer it.

Power Applications and Research Systems, Inc. noted that "PMU" stands for Phasor Measurement Unit and requested the ISO not use that acronym for phase angle measuring unit. The ISO agrees.

Proposal

The ISO does not propose to make any changes from the draft final proposal. The ISO proposes that the phase angle measuring unit resolution should be revised in Appendix H of the GIA to 16 samples per cycle, not 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 be submitted for approval to the Board of Governors only and that the WEIM Governing Body will have no role in the decision.

The Board and the WEIM Governing Body have joint authority over any proposal to change or establish a tariff rule applicable to the WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within the WEIM/EDAM Entity balancing authority areas, in their capacity as participants in the WEIM/EDAM. The WEIM/EDAM Governing Body will also have joint authority with the Board of Governors to approve or reject a proposal to change or establish any tariff rule for the day-ahead or real-time markets that directly establishes or changes the formation of any locational marginal price(s) for a product that is common to the overall WEIM or EDAM markets. The scope of this joint authority excludes, without limitation, any other proposals to change or establish tariff rule(s) applicable only to the CAISO balancing authority area or to the CAISO-controlled grid. Note: For the avoidance of any doubt, that the joint authority definition is not intended to cover balancing authority-specific measures, such as any parameters or constraints, the CAISO may use to ensure reliable operation within its balancing authority area.

Charter for EIM Governance § 2.2.1. The tariff changes proposed here would not be “applicable to WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within WEIM/EDAM 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 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 rules of the real-time or day-ahead market.

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.

Date	Milestone
3/28/2024	Final proposal posting
4/4/2024	Stakeholder workshop on final proposal
Late April or early May 2024	FERC Order No. 2023 compliance filing
May 22-23, 2024	Board of Governors Meeting
Spring-Summer 2024	Track 3 discussions on deliverability