October 17, 2024

The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

**Re: California Independent System Operator Corporation**
**Docket No. ER25- ___-000**

**Tariff Amendment to Implement Queue Management Proposals of Interconnection Process Enhancements 2023 Initiative**

Dear Secretary Reese:

The California Independent System Operator Corporation (CAISO) submits this tariff amendment to enhance generator interconnection agreements (GIAs) and interconnection procedures after the interconnection studies.[1] These enhancements will help the CAISO manage the large volume of interconnection requests already studied but awaiting GIAs or the construction of network upgrades. The enhancements also will help serve first-ready projects while incentivizing projects not to linger in queue. The reforms are the result of an extensive and robust stakeholder process that lasted more than a year, and strike an appropriate balance between the competing interests of the various stakeholders while ensuring the needs of ratepayers are met. The CAISO requests that the Commission accept these tariff revisions effective December 17, 2024 (*i.e.*, 61 days after the date of this filing). Doing so will provide the CAISO, transmission owners, interconnection customers and stakeholders with transparency and certainty for GIA negotiations that will begin January 2025.[2]

The CAISO's proposed enhancements consist of six independent, severable sets of tariff revisions:

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[1] The CAISO submits this filing pursuant to section 205 of the Federal Power Act (FPA), 16 U.S.C. § 824d, and Part 35 of the Commission's regulations, 18 C.F.R. Part 35. Capitalized terms not otherwise defined herein have the meanings set forth in appendix A to the CAISO tariff, and references to specific tariff sections and appendices are references to sections and appendices in the existing CAISO tariff unless otherwise specified.

[2] The GIA tariff revisions and the implementation deposit will not apply to interconnection customers that have already executed GIAs.

1. Making the Small GIA (SGIA) plant data recording and reporting requirements consistent with the Large GIA (LGIA) requirements for asynchronous resources;

2. Updating the GIA phase angle measuring unit (PAMU) data granularity;

3. Unifying shared network upgrade construction requirements;

4. Updating Material Modification Assessment (MMA) request timelines and deposits;

5. Creating a new "implementation deposit" for specific customer costs after the interconnection studies; and

6. Limiting lingering in queue after deliverability transfers.

Stakeholders generally supported the CAISO's proposals. The CAISO notes that each set of revisions is separate and not dependent on the other, from both a substantive and an implementation perspective.[3] The CAISO has filed them together because they were part of the same stakeholder process, because they represent enhancements to the generator interconnection process, and because a single filing promotes administrative efficiency. The CAISO discusses each enhancement below.

The tariff revisions proposed in this filing only pertain to the CAISO's Generator Interconnection and Deliverability Allocation Procedures (GIDAP)[4] and its associated GIAs,[5] and thus only impacts queue clusters 14 and earlier.[6] In other words, the tariff revisions proposed in this filing do not pertain to cluster 15 and later at this time. The CAISO is not proposing to implement these enhancements for cluster 15 and beyond[7] to avoid overlapping tariff revisions

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3 *See NRG Power Mktg., LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017).

4 Appendix DD to the CAISO tariff.

5 Appendices EE and FF to the CAISO tariff.

6 Even as such, the GIA-related revisions and implementation deposit do not apply to those interconnection customers that already have executed GIAs. The CAISO believes this approach is consistent with the filed rate doctrine and the Commission's practice for applying new interconnection rules in Order Nos. 842, 845, and 2023. The MMA and deliverability transfer revisions would only apply if such interconnection customers submitted MMA requests or deliverability transfer requests after these tariff provisions become effective.

7 Pending appendices KK, LL, and MM to the CAISO tariff.

with the CAISO's pending Order No. 2023 compliance filing.[8] Unlike the CAISO's recent cluster 15 intake filing,[9] the tariff revisions here touch on some reforms from Order No. 2023. Although the CAISO believes these tariff revisions would comply with Order No. 2023, the CAISO believes it will be more clear and simpler to file these tariff revisions based on an approved set of tariff revisions from Order No. 2023. Additionally, the tariff revisions proposed in this filing would not impact cluster 15 for years because they pertain to post-study processes, and cluster 15 will not commence its cluster study until mid-2025.

The CAISO's proposed tariff revisions meet both the just and reasonable standard and the independent entity standard.[10] The tariff revisions address issues unique to the CAISO, based on recent experience, and were generally designed to work without significant conflict with the CAISO's tariff provisions modeled on Commission *pro forma* Large Generator Interconnection Procedure and Generator Interconnection Agreement provisions, including under Order Nos. 2003, 845, and 2023. The proposed revisions build upon the CAISO's interconnection procedures, with independent entity variations previously accepted by the Commission.

## A. The IPE 2023 Stakeholder Initiative

For more than 15 years, the CAISO has continually reviewed and enhanced its generator interconnection procedures in a number of Commission proceedings to keep pace with California's Renewables Portfolio Standard and the associated evolution in generation development.[11] In February 2023, the CAISO established the IPE 2023 initiative as the latest step in this ongoing review and enhancement process to address the issues with the current interconnection queue described above.[12]

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8 Docket No. ER24-2042-000.

9 *California Independent System Operator Corp.*, 188 FERC ¶ 61,225 (2024).

10 In its generator interconnection rules, the Commission has consistently permitted Independent System Operators and Regional Transmission Organizations to adopt variations from the Commission's *pro forma* approach under an "independent entity variation" standard. *See, e.g.*, Order No. 2023 at P 1764.

11 *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 154 FERC ¶ 61,169, at P 2 (2016) (describing CAISO generator interconnection enhancement initiatives since 2008); *Cal. Indep. Sys. Operator Corp.*, 180 FERC ¶ 61,143, at P 2 (2021) (describing additional generator interconnection enhancement initiatives); *Cal. Indep. Sys. Operator Corp.*, 182 FERC ¶ 61,196, at P 16 (2023) (accepting CAISO tariff revisions to enhance generator interconnection process).

12 *See* https://www.caiso.com/documents/interconnection-process-enhancements-2023-issue-paper-and-straw-proposal-posting-on-030623.html (CAISO market notice announcing the initiative).

The IPE 2023 initiative is part of the larger set of foundational framework improvements being coordinated among the CPUC, the CEC, and the CAISO 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 the Memorandum of Understanding described above. The CAISO also has engaged in numerous discussions with other local regulatory authorities, utilities, and LSEs that are not CPUC-jurisdictional to ensure the CAISO's planning reflects their needs. The IPE 2023 initiative leverages the improved coordinated planning resulting from the Memorandum of Understanding and these discussions, and will result in a more efficient interconnection process while helping to further break down barriers to efficient and timely resource development.

The stakeholder process for Phase 1 of the IPE 2023 initiative has three separate but related tracks.[13] As a result of enhancements developed in Track 1, the CAISO filed tariff revisions in June 2023 to extend the remaining interconnection study deadlines for cluster 14 and pause the interconnection study process for cluster 15, which the Commission accepted as described above.[14] The Commission already approved the majority of the tariff revisions from Track 2, which addressed the intake process for cluster 15 and beyond.[15]

Track 3 of the stakeholder initiative is underway and will consider additional issues raised by stakeholders regarding the allocation of TP deliverability and intra-cluster prioritization for cluster 14 and earlier.[16]

## B. Stakeholder Process for this Tariff Amendment

The stakeholder process for Track 2 of the IPE 2023 stakeholder initiative was extensive and lasted from May 2023 until June 2024. The stakeholder process began with working group discussions to establish principles and problem statements related to interconnection request intake and queue management. Participants proposed concepts and worked with the CAISO to explore and refine them throughout the course of the initiative. Several stakeholder proposals are reflected in this final filing.

During the stakeholder process, the CAISO held over a dozen stakeholder meetings and posted multiple issue papers and proposals, each revised based on stakeholder feedback and the CAISO's own review. Stakeholders consisted

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[13] The IPE 2023 initiative consists of two phases, only the first of which is in progress. The CAISO will start the second phase at a future point.

[14] *Cal. Indep. Sys. Operator Corp.*, 184 FERC ¶ 61,069 (2023).

[15] *Cal. Indep. Sys. Operator Corp.*, 188 FERC ¶ 61,225 (2024).

[16] On July 5, 2024, the CAISO issued a straw proposal for Track 3.

of developers, utilities, local regulatory authorities, and industry trade groups. These stakeholders had numerous opportunities to provide both comments in-person at the meetings and written comments. In addition, stakeholders were given the opportunity to comment on a near-final version of the CAISO's proposed tariff revisions.[17] The CAISO provides responses to stakeholder comments below in this transmittal letter.

The CAISO Governing Board (Board) authorized the CAISO to submit this tariff amendment at its meeting held on June 12, 2024.[18]

## C. Proposed Tariff Revisions

### 1. Consistent Data Recording Requirements for All Asynchronous Generating Facilities

In 2019, the Commission approved a set of new GIA requirements for asynchronous generating facilities[19] to mitigate reliability issues caused when generators go offline or cease to inject current into the grid due to the routine clearing of high voltage transmission faults or transient voltage.[20] The requirements also established a platform to collect information to help educate the CAISO, its grid operators, and stakeholders on the operation of inverter-based generators. The requirements were based on careful work among the CAISO, transmission owners, inverter manufactures, generation owners, the North American Electric Reliability Corporation (NERC), and the Western Energy Coordinating Council (WECC). All of the requirements applied to large and small generating facilities alike,[21] with the exception of fault recording requirements,

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[17] Materials related to the stakeholder process are available at the IPE 2023 Stakeholder Page. The stakeholder materials include the CAISO's issuance of the *2023 Interconnection Process Enhancements: Track 2 Final Proposal* (Mar. 28, 2024) (Track 2 Final Proposal), which is also provided in attachment C to this filing, and its companion *2023 Interconnection Process Enhancements: Final Addendum to Track 2 Final Proposal* (June 5, 2024) (Track 2 Final Addendum), which is also provided in attachment D to this filing.

[18] *See* https://www.caiso.com/meetings-events/calendar/month/2024/06/01. The materials provided to the Board included a memorandum from Neil Millar, Vice President of Infrastructure and Operations Planning dated June 6, 2024, which is also provided in attachment D to this filing (Track 2 Board Memorandum). In addition to addressing the subjects reflected in the instant tariff amendment, the Track 2 Final Proposal, Track 2 Final Addendum, and Track 2 Board Memorandum address other subjects to be addressed in a future tariff amendment or amendments.

[19] An asynchronous generating facility is defined as "An induction, doubly-fed, or electronic power generating unit(s) that produces 60 Hz (nominal) alternating current." Appendix A to the CAISO tariff. Solar and wind units are the most common inverter-based resources, for example.

[20] *California Independent System Operator Corp.*, 168 FERC ¶ 61,003 (2019).

[21] With the Commission's standard 20 MW marking the difference between large and small.

which only applied to large generators.[22] At the time, the CAISO wanted to ensure the technology was available and affordable, and thus exempted small generating facilities.

Since 2019, the CAISO's asynchronous generating facility requirements have significantly helped to mitigate reliability issues on the CAISO controlled grid, despite the vast and rapid proliferation of inverter-based resources. The CAISO's recording requirements, especially, have helped the CAISO, reliability entities, and stakeholders understand voltage and frequency disturbances, and identify and mitigate their causes. The system simply would not be as reliable as it is now without this data. At the same time, the CAISO and stakeholders have lamented exempting small generating facilities from the reporting requirements. Despite their size, the proliferation of small generating facilities plays a critical role in ensuring reliability, and the lack of data requirements on them often leaves critical holes in the history of grid events. Moreover, the technology used to comply with the recording requirements is commonplace and relatively inexpensive to generating facilities. The CAISO thus proposes to subject new small asynchronous generating facilities to the same data recording requirements as large facilities.[23] This will greatly aid the CAISO, reliability entities, and stakeholders in diagnosing system faults and preventing future events.

### 2. Enhancing Phase Angle Measuring Units Data

The LGIA data recording provision currently requires asynchronous generating facilities to provide all PAMU data at a resolution of 30 samples per second.[24] PAMUs track voltage shifts on grid facilities. They are generally part of circuit relays, and are a key element in understanding any voltage problems on the grid. With the increase in asynchronous generating facilities on the grid, the CAISO and stakeholders have found 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. The CAISO proposes to change this sample size to 16 samples

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[22] The CAISO also proposes to harmonize two slight differences in language between the LGIA and SGIA requirements. The SGIA lacked the clarification that an Asynchronous Generating Facility shall remain online for the voltage disturbance *unless clearing the fault effectively disconnects the generator from the system*. The SGIA also had a header titled "Low Voltage Ride-Through (LVRT) Capability" even though its subsections contained provisions on both low *and high* voltage ride-through. These clarifications will avoid any ambiguity between the two GIAs.

[23] Proposed Attachment 7 to Appendix FF to the CAISO tariff (including the PAMU revision discussed below). Just as when the original provisions were established in 2019, small generating facilities that already have GIAs are still under their prior requirements. Under Section 25.4.2 of the CAISO tariff, only if the small generating facility replaces its facility/inverters in the future would it become subject to the current requirements.

[24] Section A(vi) of Appendix H to Appendix EE to the CAISO tariff.

per cycle,[25] which is already the common setting for present day relays. This change will apply to the LGIA and the proposed recording requirements to the SGIA, discussed above. The change will provide the CAISO with 960 samples per second versus the current 30, and will greatly aid the CAISO, reliability entities, and stakeholders in understanding and mitigating voltage issues on the grid. Because this granularity is already a common default setting for relays, the CAISO does not expect any inconvenience or new expense from this change.

### 3. Shared Network Upgrade Construction

In the CAISO, interconnection customers finance the facilities and network upgrades necessary to interconnect the new generation, and the transmission owner generally designs, procures equipment, and constructs them.[26] The GIAs typically set forth specific milestones for phased financing and construction: the interconnection provides payments toward construction as the transmission owner requires it for the construction schedule. GIAs also require interconnection customers to provide notices to proceed with construction to ensure the transmission owner does not begin to incur significant expenses without the interconnection customer's understanding.

Interconnection customers frequently share network upgrades to maximize economies of scale and save ratepayers costs. These interconnection customers' study results and GIAs set forth their cost responsibility for the shared network upgrades based on the applicable proportional impact method. This system works very well for producing studies and keeping everyone's costs as low as possible; however, it often presents a challenge for transmission owners to actually begin construction. Even if one interconnection customer is ready and eager for the transmission owner to begin construction, other interconnection customers sharing one upgrade among many others may have other timetables. The transmission owner often is stuck waiting for the last or least-ready interconnection customer because the transmission owner cannot commence construction without all the interconnection customers' funds for the shared network upgrade. This can be especially problematic, for example, when the interconnection customer with the largest share of the costs has the latest commercial operation date.

In the interest of first-ready, first-served policies, the CAISO proposes to unify payment and authorization schedules among interconnection customers sharing network upgrades. Interconnection studies already identify when network upgrades are shared, along with their construction timelines, but GIAs

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[25] Section A(i)(1) of Appendix H to Appendix EE to the CAISO tariff; Attachment 7 to Appendix FF to the CAISO tariff.

[26] Interconnection customers also can exercise a self-build option, but this occurs infrequently.

frequently differ based on the construction timeline of each interconnection customer. The CAISO proposes to require interconnection customers sharing a network upgrade to provide the financing and authorization to construct the shared network upgrade simultaneously, and based on the construction timeline necessary to achieve the earliest interconnection customer's commercial operation date.[27] All other network upgrades can have their own separate milestones based on the needs of the interconnection customers and transmission owner.

Once identified in the interconnection studies, or no later than when the first interconnection customer sharing the assigned network upgrade executes its GIA with a third posting deadline[28] for the network upgrade, the CAISO and Participating TO will notify the other interconnection customers sharing the network upgrade when their third posting will be required based on the construction timeline required to meet the earliest in-service date of the interconnection customers sharing the network upgrade.[29] Interconnection customers and transmission owners may have separate posting and authorization deadlines for each shared network upgrade and other non-shared network upgrades.

All Interconnection Customers sharing the assigned network upgrade must execute an engineering and procurement agreement or a GIA prior to submitting the third posting for the shared network upgrade.[30] Engineering and procurement agreements provide interconnection customers with a custom agreement for a specific procurement activity before the interconnection customer is ready to execute its GIA.[31] Generally interconnection customers share network upgrades in the same cluster and thus receive draft GIAs simultaneously; however, to ensure sufficient notice and time for negotiation, the CAISO proposes to include a requirement that where any interconnection customer sharing the assigned network upgrade has not executed a GIA or engineering and procurement agreement, the transmission owner will tender (1) a draft engineering and procurement agreement if the interconnection customer parked its interconnection request, or (2) a draft GIA or GIA amendment, to the interconnection customer no later than 120 days before the third posting deadline. The interconnection customer must execute the engineering and

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27 Proposed Section 11.3.2.6 of Appendix DD to the CAISO tariff.

28 Third postings provide the financial security necessary to finance the network upgrade. Transmission owners and interconnection customers also can specify if their GIAs cash payments to finance network upgrades if they prefer.

29 *Id.*

30 *Id.*

31 These agreements also can be common for facilities with extremely long lead times, helping parties avoid construction delays.

procurement agreement or GIA or request that the GIA be filed unexecuted prior to the deadline to post. The failure by an interconnection customer to timely (a) execute an engineering and procurement agreement or GIA or request an unexecuted filing, (b) submit the authorization to proceed, or (c) submit the third posting for the shared assigned network upgrade will result in the interconnection request being deemed withdrawn. These provisions will ensure that all interconnection customers sharing a network upgrade have sufficient time to negotiate their agreements and arrange financing, but without the risk that one interconnection customer can "drag its feet" and delay the construction of the shared network upgrade to the other interconnection customers' detriment.

For transparency and tracking, the CAISO also proposes to require each interconnection customer to provide the CAISO and the transmission owner with written notice that it has posted the required interconnection financial security no later than the applicable final day for posting.[32] No later than 30 days after the interconnection customers sharing the assigned network upgrade provide authorization and financing, the transmission owner will commence construction activities on the shared network upgrade.

Together, the proposed tariff revisions will ensure transmission owners can, and will, construct transmission facilities as soon as possible for first-ready projects. The proposed tariff revisions will avoid construction delays and their cascading issues, helping to bring much-needed transmission capacity to the grid.

**4. Limitations on Deliverability Transfers**

After the study processes and the deliverability allocation process, the CAISO allows interconnection customers to transfer deliverability to other generating units at the same substation and same voltage level.[33] Most transfers occur within the same generating facility, allowing a generating facility to optimize its deliverability allocations among its generating units based on procurement needs. For example, if a generating facility has 100 MW of solar and 100 MW of energy storage, and each generating unit has its own 50 MW deliverability allocation, the owner may want to transfer the 50 MW of deliverability from the solar unit to the storage unit if a load-serving entity wants 100 MW of deliverable storage based on its procurement mandates.[34]

32 *Id.*

33 Section 8.9.9 of Appendix DD to the CAISO tariff.

34 This is a simplified example in that the qualifying capacity of the different generating technologies remains constant. Deliverability, however, is not necessarily always fungible 1:1, and is based on the current deliverability assessment methodology.

Recently, however, the CAISO and stakeholders have become concerned that generating units assigning away their deliverability unduly linger in queue. The developer may be marketing the project to other load-serving entities, or waiting to see if it can "double dip" the now-Energy-Only resource in the deliverability allocation process and reacquire deliverability. Meanwhile, the project may try to avoid GIA milestones through suspension or modification. This is an undesirable result that causes queue backlogs, construction delays, and wasted administrative resources. Projects that become Energy Only under these circumstances rarely, if ever, achieve commercial operation.

Accordingly, the CAISO believes that developers should only proceed with deliverability transfers when they recognize the unit transferring its deliverability is no longer viable. The CAISO thus proposes that customers must remove the Energy Only generating capacity giving up its deliverability unless it provides an Energy Only power purchase agreement, which demonstrates that the generating capacity itself is viable without needing to reacquire deliverability.[35] Interconnection customers can remove the assignor generating capacity either through withdrawal or downsizing.[36]

Separately, but still related to deliverability transfers, the CAISO proposes to include clarifying language of existing policy: when an interconnection customer has restrictions to acquire or retain its deliverability, any assignee of the deliverability inherits those restrictions.[37] For example, if an interconnection customer acquires deliverability because it was shortlisted for a power purchase agreement, the CAISO tariff requires it to provide an executed power purchase agreement by the next year.[38] If it assigns that deliverability before the next year, the assignee must provide an executed power purchase agreement by the next year. Essentially, interconnection customers cannot use deliverability transfers to try to circumvent the CAISO's filed rate. Including this clarifying provision will enhance transparency on this fact.

### 5. Modification Request Updates

The CAISO maintains one of the most flexible MMA processes in the nation, allowing interconnection customers to effect complex modifications such as energy storage additions, generating technology changes, and repowers

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35 Proposed Section 8.9.9. of Appendix DD to the CAISO tariff.

36 For example, if the entire generating facility assigned away its deliverability, it would withdraw. If only a portion of the generating facility assigned away its deliverability, it would downsize that portion.

37 Proposed Section 8.9.9. of Appendix DD to the CAISO tariff.

38 Section 8.9.3 of Appendix DD to the CAISO tariff.

without submitting new interconnection requests. The CAISO tariff requires interconnection customers requesting MMAs to provide a $10,000 deposit but be accountable for costs beyond that deposit. The CAISO tariff also contemplates that MMAs be completed within 45 days, although MMAs may take longer so long as the CAISO explains why additional time is required and provides a timetable for completion.[39]

Although the CAISO's flexibility in studying complex MMAs allows interconnection customers to optimize their projects, it comes at an administrative cost to the CAISO and transmission owners. In 2023, for example, the CAISO completed 122 MMAs. This year, the average cost for an MMA was $11,871, with individual assessments costing up to $43,636 for complex engineering analyses. So far this year half of MMAs have cost more than the $10,000 MMA deposit, requiring the CAISO to invoice interconnection customers after the fact. Inflation also has contributed to this issue, as the $10,000 MMA deposit has not been updated for many years. Because MMAs are numerous and complex, the average time to complete MMAs generally is beyond the initial 45 days contemplated by the CAISO tariff. Although many simple MMAs can be approved in one to two weeks if the initial data provided is accurate and complete, many take much longer. In 2023, 64 of the 122 MMAs took between 45 and 90 days. As a result, the CAISO frequently must rely upon its authority to extend the 45-day timeline and explain why more time is required.

Interconnection customers understand the present state of the MMA process, and do not want to sacrifice MMA flexibility on the altar of quicker, cheaper assessments. However, the current tariff sets misleading expectations for MMAs. It also creates administrative burdens for the CAISO and transmission owners to extend deadlines and request additional funds, and for interconnection customers to send additional funds after their deposits. All parties would prefer to avoid these outcomes. As such, the CAISO proposes to update the MMA deposit to $30,000, and the estimated time to complete an MMA to 60 days. Although both figures are higher than recent averages, they are still less than peak figures. Moreover, stakeholders indicate they would rather have a higher figure that stays ahead of inflation and generally provides some level of refund than have to submit additional funds because actual costs exceeded their initial deposit.

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39 Section 6.7.2.3 of Appendix DD to the CAISO tariff.

### 6. Implementation Deposit

The CAISO has several dozen employees that dedicate the majority of their time to generator interconnection issues.[40] These include:

- Interconnection specialists who spend all of their time managing interconnection requests from submission to receiving their final study report;
- Planning engineers who model new transmission and generator interconnections, and perform interconnection and modification studies;
- Contract negotiators who negotiate GIAs, GIA amendments, and affected system agreements;
- Contract analysts who prepare new or revise existing metering and participating generator agreements, and manage all agreements associated with generator interconnection;
- Queue management staff who manage interconnection requests between GIA execution and commercial operation;
- Resource implementation staff who arrange for the actual synchronization of the generator onto the grid and who add the resource to the network model; and
- Data acquisition staff who ensure the resource will be properly metered and provide forecasting data and real-time telemetry to the CAISO.[41]

Transmission owners have similar if not identical roles among their staff, but frequently collect a development cost with the network upgrades as part of construction costs. Although the CAISO collects interconnection study deposits, these deposits only cover costs through the completion of the phase II/interconnection facilities study. The CAISO estimates that study deposits cover less than half the total staff and man-hours dedicated to interconnection-customer-specific work.[42]

Staff time and costs after the studies come from the CAISO's conventional annual revenue requirement, that is, its general budget. However, the CAISO does not assess its annual revenue requirement on interconnection customers. Instead, the CAISO assesses its annual revenue requirement on CAISO *market*

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40 Excluding many managers, accountants, and lawyers who also spend the majority of their time on interconnection issues.

41 Many of these staff members work on similar matters for generators already online, but the majority of their time is dedicated to interconnection customers.

42 In other words, not merely generalized interconnection work, but work that actually can be assessed to specific, individual interconnection customers.

participants in the form of the CAISO's Grid Management Charge.[43] This results in obvious cost allocation inefficiencies. First, the many interconnection customers that withdraw before participating in the CAISO markets will never contribute toward the costs incurred for them between interconnection studies and commercial operation. Instead, market participants will pay those costs. Second, interconnection customers have no incentives to try to keep costs low because they will not be assessed their costs individually. A 500 MW complex, multi-unit hybrid resource with advanced metering will face the same costs as a straightforward single generator: nothing. Essentially, it is questionable whether costs are allocated correctly (if at all) to the beneficiaries of significant, customer-specific work between interconnection studies and commercial operation.

To address this cost allocation issue, the CAISO proposes to require a new "implementation deposit" of $35,000 within 30 days of the effective date of an interconnection customer's GIA.[44] Based on the CAISO's analysis of man-hours spent and staff billing rates for specific interconnection requests in the years between studies and commercial operation—especially during the intensive new resource implementation process—the CAISO believes $35,000 will be sufficient to cover most interconnection requests costs without undue risk of needing to re-invoice interconnection customers.[45]

The implementation deposit will be applied to pay for prudent costs incurred by the CAISO or its consultants to manage the interconnection request between GIA execution and commercial operation. This deposit will cover costs including queue management, preparing GIA amendments, preparing market agreements, modeling and testing for synchronization, preparing for metering

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43 That is, to scheduling coordinators based on energy, demand, ancillary services, or other specific charges. *See California Independent System Operator Corp.,* Letter Order accepting Grid Management Charge, Docket No. ER23-2974-000 (Dec. 21, 2023); *see also* Section 11.22 and Appendix F of the CAISO tariff.

44 Proposed Section 13.3.1 of Appendix DD to the CAISO tariff. Wholesale distribution access tariff interconnection customers also go through a portion of the CAISO's new resource implementation process to model them in the CAISO markets and verify metering and telemetry. The CAISO proposes to require a $6,000 implementation deposit from them at the beginning of the new resource implementation process (generally a few months before commercial operation, as specified in the GIA).

Like other deposits, the CAISO will deposit the implementation deposit in an interest bearing account at a bank or financial institution designated by the CAISO.

The CAISO only proposes to require this deposit going forward. In other words, the CAISO will not require implementation deposits from interconnection customers that already have executed GIAs.

45 The IPE stakeholder initiative had proposed and approved a deposit up to $100,000 (and $10,000 for WDAT customers); however, the CAISO's analysis of labor on existing projects demonstrates that the lower figures proposed here will be sufficient.

and telemetry, and incorporating the generating units into the CAISO markets.[46] CAISO staff will track their time to specific interconnection customers, just as they do today for interconnection studies. As such, interconnection customers with more complex and numerous needs after the studies will be assessed more costs than interconnection customers that sail smoothly to commercial operation. The implementation deposit will directly offset costs currently assessed to market participants through the Grid Management Charge.

Upon commercial operation or withdrawal from queue, the CAISO will refund remaining deposit funds, with any interest earned, to the interconnection customer. The CAISO does not propose to use the implementation deposit as a "decision point" or incentive to withdraw from queue or progress. As such, the implementation deposit for GIDAP interconnection customers will not be subject to any refundability penalty if and when the customer withdraws. The CAISO will simply refund the deposit minus costs incurred for that interconnection customer.

The CAISO believes the implementation deposit properly aligns costs with benefits under the Federal Power Act, and respectfully requests that the Commission approve these tariff revisions as just and reasonable.

## D. Effective Date

The CAISO requests that the Commission accept the tariff revisions contained in this filing effective December 17, 2024 (*i.e.*, 61 days after the date of this filing), in anticipation of executing GIAs for cluster 14, which recently completed its interconnection studies.

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[46] The CAISO will not use implementation deposit funds to offset or obviate processes that require separate deposits including MMAs, Permissible Technological Advancements, and Limited Operation Studies.

**E. Communications**

Pursuant to Rule 203(b)(3) of the Commission's Rules of Practice and Procedure,[47] the CAISO requests that all correspondence, pleadings, and other communications regarding this filing should be directed to following:

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**F. Service**

The CAISO has served copies of this filing on the CPUC, the CEC, and all parties with scheduling coordinator agreements under the CAISO tariff. In addition, the CAISO has posted a copy of the filing on the CAISO website.

**G. Contents of Filing**

In addition to this transmittal letter, this filing includes the following attachments:

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| Attachment A | Clean[48] CAISO tariff sheets incorporating this tariff amendment |
| Attachment B | Red-lined document showing the revisions in this tariff amendment |
| Attachment C | Track 2 Final Proposal |
| Attachment D | Track 2 Board Memorandum |

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47 18 C.F.R. § 385.203(b)(3).

48 For Section 25.5, the baseline tariff language in the tariff record includes currently pending language in the CAISO's Order No. 2023 compliance filing (ER24-2042). For Appendix EE, Article 5, the baseline tariff language in the tariff record includes currently pending language in the 2024 tariff clarifications filing (ER24-2687). The CAISO will reconcile all tariff revisions as necessary based on the Commission's orders.

## H. Conclusion

For the reasons set forth above, the CAISO respectfully requests that the Commission accept the tariff revisions proposed above effective December 17, 2024.

Respectfully submitted,

***/s/ William H. Weaver***

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**Attachment A – Clean Tariff**

**Tariff Amendment – Queue Management Proposals of IPE 2023 Initiative**

**California Independent System Operator Corporation**

**October 17, 2024**

**Section 25**

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**25.5.2**

The Generating Unit owner will provide the CAISO a $50,000 deposit for repowering requests, or a $30,000 deposit for all other modification assessments at the time the request is submitted. Except as provided below, any modification assessment will be concluded, and a response provided to the Generating Unit owner in writing, within sixty (60) calendar days from the date the CAISO receives all of the following: the Generating Unit owner's written notice to modify the project, technical data required to assess the request, and payment of the applicable deposit. If the modification assessment cannot be completed within that time period, the CAISO will notify the Generating Unit owner and provide an estimated completion date and an explanation of the reasons why additional time is required.

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**Appendix DD**

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**6.7.2.3** The Interconnection Customer shall provide the CAISO a $30,000 deposit for the modification assessment at the time the request is submitted. Except as provided below, any modification assessment will be concluded, and a response provided to the Interconnection Customer in writing, within sixty (60) calendar days from the date the CAISO receives all of the following: the Interconnection Customer's written notice to modify the project, technical data required to assess the request and payment of the $30,000 deposit. If the modification request results in a change to the Interconnection Facilities or Network Upgrades the modification assessment could take up to one hundred twenty (120) total calendar days. If the modification assessment cannot be completed within that time period, the CAISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

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**6.7.2.7** Interconnection Customers may request to downsize their Interconnection Service Capacity pursuant to Section 6.7.2.3. Interconnection Customers with Network Upgrades requesting to downsize will not see the impacts to their Network Upgrades or cost responsibility until the CAISO publishes the reassessment results that include the downsized capacity pursuant to Section 7.4 unless the CAISO can determine the impacts prior to the reassessment. Interconnection

Customers with Network Upgrades must submit downsizing requests, including the $30,000 deposit, by November 30 to be included in the following annual reassessment. Once the CAISO publishes the reassessment results, the Participating TO will tender a draft amendment to the Interconnection Customer's Generator Interconnection Agreement to incorporate any required changes. If an Interconnection withdraws or is deemed withdrawn, any partial recovery of the Interconnection Financial Security for Network Upgrades under Sections 11.4.2.1 and 11.4.2.2 will be calculated based on the Generating Facility's most recent MW capacity prior to its downsizing request.

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### 8.9.9 Deliverability Transfers

Deliverability may not be assigned or otherwise transferred except as expressly provided by the CAISO Tariff. An Interconnection Customer may reallocate its Generating Facility's Deliverability among its own Generating Units or Resource IDs at the Generating Facility and to other Interconnection Customers interconnected at the same substation and at the same voltage level. The Generating Facility's aggregate output as evaluated in the Deliverability Assessment cannot increase as the result of any transfer, but may decrease based on the assignee's characteristics and capacity. Unless the Interconnection Customer provides the CAISO with an executed Energy Only power purchase agreement for the capacity losing Deliverability at the time it requests the Deliverability transfer, the assignor capacity must be removed from queue by withdrawal or downsizing the Generating Facility. The CAISO will inform the Interconnection Customer of each Generating Unit's Deliverability Status and associated capacity as the result of any transfer. The results will be based on the current Deliverability Assessment methodology.

An Interconnection Customer may request to reallocate its Deliverability among its Generating Units and to other Interconnection Customers interconnected at the same substation and at the same voltage level pursuant to Section 6.7.2.2 of this GIDAP, Article 5.19 of the LGIA, and Article 3.4.5 of the SGIA, as applicable. A repowering Interconnection Customer may transfer Deliverability as part of the repowering process pursuant to Section 25.1.2 of the CAISO Tariff. An Interconnection Customer expanding its capacity behind-the-meter pursuant to Section 4.2.1.2 also may transfer Deliverability as part of that process, or subsequently under the other processes in this Section. The assignee of a Deliverability transfer does not need to submit a modification request to receive a transfer.

Following a Deliverability transfer, the assignee inherits any requirements, restrictions, or obligations the assignor had as a result of receiving the Deliverability allocation or to retain the Deliverability, including without limitation requirements under Sections 6.7.4, 8.9.2.2, 8.9.2.3, and 8.9.3.

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### 11.3.2 Third Posting for Queue Cluster Customers and Second Posting for Independent Study Process Customers

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### 11.3.2.6 Shared Network Upgrades

Interconnection Studies and GIAs will identify when Network Upgrades are shared, and their estimated construction timelines. Once identified in the Interconnection Studies, or no later than when the first Interconnection Customer sharing the Assigned Network Upgrade executes its GIA with a third posting deadline for the Assigned Network Upgrade, the CAISO and Participating TO will notify the other Interconnection Customers sharing the Assigned Network Upgrade when this third Interconnection Financial Security posting will be required based on the construction timeline required to meet the earliest In-Service Date of the Interconnection Customers sharing the Assigned Network Upgrade. All Interconnection Customers sharing the Assigned Network Upgrade must submit (a) their authorizations to proceed with design and procurement of the shared Network Upgrade and (b) the third posting for the shared Network Upgrade, by the same deadline. Interconnection Customers and Participating TOs may have separate posting and authorization deadlines for each shared Network Upgrade and other non-shared Network Upgrades, but Interconnection Customers sharing Assigned Network Upgrades must have the same deadlines for them. At all times, Interconnection Customers must have sufficient Interconnection Financial Security under this Section 11, inclusive of any second and third posting obligations.

All Interconnection Customers sharing the Assigned Network Upgrade must execute an engineering and procurement agreement under Section 12 or a GIA prior to submitting the third posting for the shared Network Upgrade. Where any Interconnection Customer sharing the Assigned Network Upgrade has not executed either agreement, the Participating TO will tender (1) a draft engineering and procurement agreement if the Interconnection Customer is parked, or (2) a draft GIA or GIA amendment, to the Interconnection Customer no later than one-hundred twenty (120) days before the third posting deadline. The Interconnection Customer must execute the engineering and procurement agreement or GIA or request that the GIA be filed unexecuted prior to the deadline to post. The failure by an Interconnection Customer to timely (a) execute an engineering and procurement agreement or GIA or request an unexecuted filing, (b) submit the authorization to proceed, or (c) submit the third posting for the shared Assigned Network Upgrade, under this Section, will result in the Interconnection Request being deemed withdrawn and subject to Section 3.8. The Interconnection Customer will provide the CAISO and the Participating TO with written notice that it has posted the required Interconnection Financial Security no later than the applicable final day for posting.

No later than thirty (30) days after each Interconnection Customer sharing the Assigned Network Upgrade complies with this Section, the Participating TO will commence Construction Activities on the shared Assigned Network Upgrade.

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## Section 13 Generator Interconnection Agreement (GIA)

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## 13.3 Execution and Filing

The Interconnection Customer shall either: (i) execute the appropriate number of originals of the tendered GIA as specified in the directions provided by the CAISO and return them to the CAISO, as directed, for completion of the execution process; or (ii) request in writing that the applicable Participating TO(s) and CAISO file with FERC a GIA in unexecuted form. The GIA shall be considered executed as of the date that all three Parties have signed the GIA. As soon as practicable, but not later than ten (10) Business Days after receiving either the executed originals of the tendered GIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted GIA, the applicable Participating TO(s) and CAISO shall file the GIA with FERC, as necessary, together with an explanation of any matters as to which the Interconnection Customer and the applicable Participating TO(s) or CAISO disagree and support for the costs that the applicable Participating TO(s) propose to charge to the Interconnection Customer under the GIA. An unexecuted GIA should contain terms and conditions deemed appropriate by the applicable Participating TO(s) and CAISO for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted GIA, they may proceed pending FERC action.

### 13.3.1 Implementation Deposit

Within thirty (30) days of the effective date of the GIA, the Interconnection Customer will provide the CAISO with a $35,000 implementation deposit. Generating facilities interconnecting pursuant to a Participating TO Wholesale Distribution Access Tariff must submit a $6,000 implementation deposit at the commencement of the CAISO new resource implementation process. The CAISO will deposit the implementation deposit in an interest bearing account at a bank or financial institution designated by the CAISO. The implementation deposit will be applied to pay for prudent costs incurred by the CAISO or third parties at the direction of the CAISO to manage the Interconnection Request between GIA execution and the Commercial Operation Date, including without limitation executing GIA amendments, modeling and testing for synchronization, preparing for metering and telemetry, and incorporating the Generating Units into the CAISO Markets. The CAISO will not use implementation deposit funds to offset or obviate processes that require separate deposits under this GIDAP, including without limitation Material Modification Assessments, Permissible Technological Advancements, and Limited Operation Studies.

The Interconnection Customer will be responsible for the actual costs incurred by the CAISO and applicable Participating TO(s). If the actual costs are less than the deposit provided by the Interconnection Customer, the Interconnection Customer will be refunded the balance, including interest earned. If the actual costs are greater than the deposit provided by the Interconnection Customer, the Interconnection Customer will pay the balance within thirty (30) days of being invoiced. The Participating TO(s) will invoice the CAISO for any work within seventy-five (75) days of the Commercial Operation Date or withdrawal, and, within thirty (30) days thereafter, the CAISO will issue an invoice or refund to the Interconnection Customer, as applicable, based upon such submitted Participating TO invoices and the CAISO's own costs.

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## Appendices EE (LGIA)

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**5.5** **Equipment Procurement.** If responsibility for construction of the Participating TO's Interconnection Facilities or Network Upgrades is to be borne by the Participating TO, then the Participating TO shall notify the Interconnection Customer and the CAISO in writing within thirty (30) days and commence design of the Participating TO's Interconnection Facilities or Network Upgrades and procurement of necessary equipment after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

**5.5.1** The CAISO, in coordination with the applicable Participating TO(s), has completed the Phase II Interconnection Study or Governing Independent Study Interconnection Study pursuant to the applicable Generator Interconnection Study Process Agreement or other applicable study process agreement;

**5.5.2** The Participating TO has received written authorization to proceed with design and procurement from the Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.5.3** The Interconnection Customer has provided security to the Participating TO in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

**5.6** **Construction Commencement.** The Participating TO shall notify the Interconnection Customer and the CAISO in writing and commence construction of the Participating TO's Interconnection Facilities and Network Upgrades for which it is responsible within thirty (30) days after the following additional conditions are satisfied:

**5.6.1** Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

**5.6.2** Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the Participating TO's Interconnection Facilities and Network Upgrades;

**5.6.3** The Participating TO has received written authorization to proceed with construction from the Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.6.4** The Interconnection Customer has provided payment and security to the Participating TO in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

**5.7** **Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Any Party may, at any time, request a progress report from another Party. If, at any time, the Interconnection Customer determines that the completion of the Participating TO's Interconnection Facilities will not be required until after the specified In-Service Date, the Interconnection Customer will provide written notice to the Participating TO and CAISO of such later date upon which the completion of the Participating TO's Interconnection Facilities will be required.

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## Appendix H

**INTERCONNECTION REQUIREMENTS FOR AN ASYNCHRONOUS GENERATING FACILITY**

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**vi. Transient Data Recording Equipment for Facilities**

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The data must be time synchronized, using a GPS clock or similar device, to a one millisecond level of resolution. All data except phase angle measuring unit data must be sampled at least every 10 milliseconds. Data recording must be triggered upon detecting a frequency ride-through event, a transient low voltage disturbance that initiated reactive current injection, momentary cessation or reactive current injection for a transient high voltage disturbance, or an inverter trip. Each recording will include as a minimum 150 milliseconds of data prior to the triggering event, and 1000 milliseconds of data after the event trigger. The Asynchronous Generating Facility must store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all data within 10 calendar days of a request from the CAISO or the Participating TO.

The Asynchronous Generating Facility must install and maintain a phase angle measuring unit or functional equivalent at the entrance to the facility or at the Generating Facility’s main substation transformer. The phase angle measuring unit must have a resolution of at least 16 samples per cycle. The Asynchronous Generating Facility will store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all phase angle measuring unit data within 10 calendar days of a request from the CAISO or the Participating TO.

**<u>Appendix FF (SGIA)</u>**

**Attachment 7**

**Interconnection Requirements for an Asynchronous Small Generating Facility**

Attachment 7 sets forth requirements and provisions specific to all Asynchronous Generating Facilities. Except as provided in Section 25.4.2 of the CAISO tariff, existing individual generating units of an Asynchronous Generating Facility that are, or have been, interconnected to the CAISO Controlled Grid at the same location are exempt from the requirements of this Attachment 7 for the remaining life of the existing generating unit.

**A. Technical Standards Applicable to Asynchronous Generating Facilities**

**i. Voltage Ride-Through Capability**

An Asynchronous Generating Facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

1. An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, having a duration equal to the lesser of the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum normal clearing time associated with any three-phase fault location that reduces the voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

2. An Asynchronous Generating Facility shall remain online for any voltage disturbance caused by a single-phase fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, with delayed clearing, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum backup clearing time associated with a single point of failure (protection or breaker failure) for any single-phase fault location that reduces any phase-to-ground or phase-to-phase voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

3. Remaining on-line shall be defined as continuous connection between the Point of Interconnection and the Asynchronous Generating Facility's units, without any mechanical isolation. Momentary cessation (namely, ceasing to inject current during a fault without mechanical isolation) is prohibited unless transient high voltage conditions rise to 1.20 per unit or more. For transient low voltage conditions, the Asynchronous Generating Facility's inverters will inject reactive current. The level of this reactive current must be directionally proportional to the decrease in per unit voltage at the inverter AC terminals. The inverter must

produce full reactive current capability when the AC voltage at the inverter terminals drops to a level of 0.50 per unit or below. The Asynchronous Generating Facility must continue to operate and absorb reactive current for transient voltage conditions between 1.10 and 1.20 per unit.

Upon the cessation of transient voltage conditions and the return of the grid to normal operating voltage (0.90 < V < 1.10 per unit), the Asynchronous Generating Facility's inverters automatically must transition to normal active (real power) current injection. The Asynchronous Generating Facility's inverters must ramp up to inject active (real power) current with a minimum ramping rate of at least 100% per second (from no output to full available output). The total time to complete the transition from reactive current injection or absorption to normal active (real power) current injection must be one second or less. The total time to return from momentary cessation, if used, during transient high voltage conditions over 1.20 per unit or more must be one second or less.

The Asynchronous Generating Facility's inverter will be considered to have tripped where its AC circuit breaker is open or otherwise has electrically isolated the inverter from the grid. Following an inverter trip, the inverter must make at least one attempt to resynchronize and connect back to the grid unless the trip resulted from a fatal fault code, as defined by the inverter manufacturer. This attempt must take place within 2.5 minutes from the inverter trip. An attempt to resynchronize and connect back to the grid is not required if the trip was initiated due to a fatal fault code, as determined by the original equipment manufacturer.

4. The Asynchronous Generating Facility is not required to remain on line during multi-phased faults exceeding the duration described in Section A.i.1 of this Attachment 7 or single-phase faults exceeding the duration described in Section A.i.2 of this Attachment 7.

5. The requirements of this Section A.i of this Attachment 7 do not apply to faults that occur between the Asynchronous Generating Facility's terminals and the high side of the step-up transformer to the high-voltage transmission system.

6. Asynchronous Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

7. Asynchronous Generating Facilities may meet the requirements of this Section A of this Attachment 7 through the performance of the generating units or by installing additional equipment within the Asynchronous Generating Facility or by a combination of generating unit performance and additional equipment.

8. The provisions of this Section A.i of this Attachment 7 apply only if the voltage at the Point of Interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds, excluding any sub-cycle transient deviations.

9. Asynchronous Generating Facility inverters may not trip or cease to inject current for momentary loss of synchronism. As a minimum, the Asynchronous Generating Facility's inverter controls may lock the phase lock loop to the last synchronized point and continue to inject current into the grid at that last calculated phase prior to the loss of synchronism until the phase lock loop can regain synchronism. The current injection may be limited to protect the inverter.

Any inverter may trip if the phase lock loop is unable to regain synchronism 150 milliseconds after loss of synchronism.

10. Inverter restoration following transient voltage conditions must not be impeded by plant level controllers. If the Asynchronous Generating Facility uses a plant level controller, it must be programmed to allow the inverters to automatically re-synchronize rapidly and ramp up to active current injection (without delayed ramping) following transient voltage recovery, before resuming overall control of the individual plant inverters.

**ii. Frequency Disturbance Ride-Through Capacity**

An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the NERC Reliability Standard for Generator Frequency and Voltage Protective Relay Settings as they may be amended from time to time.

**iii. Power Factor Design Criteria (Reactive Power)**

An Asynchronous Generating Facility not studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer, as defined in this SGIA in order to maintain a specified voltage schedule, if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability. An Asynchronous Generating Facility studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer, as defined in this SGIA in order to maintain a specified voltage schedule. The power factor range standards set forth in this section can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and CAISO. The Interconnection Customer shall not disable power factor equipment while the Asynchronous Generating Facility is in operation. Asynchronous Generating Facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Phase II Interconnection Study shows this to be required for system safety or reliability.

**iv. Supervisory Control and Data Acquisition (SCADA) Capability**

An Asynchronous Generating Facility shall provide SCADA capability to transmit data and receive instructions from the Participating TO and CAISO to protect system reliability. The Participating TO and CAISO and the Asynchronous Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed Asynchronous Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability.

**v. Power System Stabilizers (PSS)**

Power system stabilizers are not required for Asynchronous Generating Facilities.

### vi. Transient Data Recording Equipment for Facilities

Asynchronous Generating Facilities must monitor and record data for all frequency ride-through events, transient low voltage disturbances that initiated reactive current injection, reactive current injection or momentary cessation for transient high voltage disturbances, and inverter trips. The data may be recorded and stored in a central plant control system. The following data must be recorded:

**Plant Level:**

(1) Plant three phase voltage and current
(2) Status of ancillary reactive devices
(3) Status of all plant circuit breakers
(4) Status of plant controller
(5) Plant control set points
(6) Position of main plant transformer no-load taps
(7) Position of main plant transformer tap changer (if extant)
(8) Protective relay trips or relay target data

**Inverter Level:**

(1) Frequency, current, and voltage during frequency ride-through events
(2) Voltage and current during momentary cessation for transient high voltage events (when used)
(3) Voltage and current during reactive current injection for transient low or high voltage events
(4) Inverter alarm and fault codes
(5) DC current
(6) DC voltage

The data must be time synchronized, using a GPS clock or similar device, to a one millisecond level of resolution. All data except phase angle measuring unit data must be sampled at least every 10 milliseconds. Data recording must be triggered upon detecting a frequency ride-through event, a transient low voltage disturbance that initiated reactive current injection, momentary cessation or reactive current injection for a transient high voltage disturbance, or an inverter trip. Each recording will include as a minimum 150 milliseconds of data prior to the triggering event, and 1000 milliseconds of data after the event trigger. The Asynchronous Generating Facility must store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all data within 10 calendar days of a request from the CAISO or the Participating TO.

The Asynchronous Generating Facility must install and maintain a phase angle measuring unit or functional equivalent at the entrance to the facility or at the Generating Facility’s main substation transformer. The phase angle measuring unit must have a resolution of at least 16 samples per cycle. The Asynchronous Generating Facility will store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all phase angle measuring unit data within 10 calendar days of a request from the CAISO or the Participating TO.

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**Attachment B – Marked Tariff**

**Tariff Amendment – Queue Management Proposals of IPE 2023 Initiative**

**California Independent System Operator Corporation**

**October 17, 2024**

**Section 25**

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**25.5.2**

The Generating Unit owner will provide the CAISO a $50,000 deposit for repowering requests, or a $3~~1~~0,000 deposit for all other modification assessments at the time the request is submitted. Except as provided below, any modification assessment will be concluded, and a response provided to the Generating Unit owner in writing, within ~~forty-five~~sixty (60~~45~~) calendar days from the date the CAISO receives all of the following: the Generating Unit owner's written notice to modify the project, technical data required to assess the request, and payment of the applicable deposit. If the modification assessment cannot be completed within that time period, the CAISO will notify the Generating Unit owner and provide an estimated completion date and an explanation of the reasons why additional time is required.

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**Appendix DD**

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**6.7.2.3** The Interconnection Customer shall provide the CAISO a $3~~1~~0,000 deposit for the modification assessment at the time the request is submitted. Except as provided below, any modification assessment will be concluded, and a response provided to the Interconnection Customer in writing, within ~~forty-five~~sixty (60~~45~~) calendar days from the date the CAISO receives all of the following: the Interconnection Customer's written notice to modify the project, technical data required to assess the request and payment of the $3~~1~~0,000 deposit. If the modification request results in a change to the Interconnection Facilities or Network Upgrades the modification assessment could take up to ~~ninety~~ one hundred twenty (~~9~~120) total calendar days. If the modification assessment cannot be completed within that time period, the CAISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

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**6.7.2.7** Interconnection Customers may request to downsize their Interconnection Service Capacity pursuant to Section 6.7.2.3. Interconnection Customers with Network Upgrades requesting to downsize will not see the impacts to their Network Upgrades or cost responsibility until the CAISO publishes the reassessment results that include the downsized capacity pursuant to Section 7.4 unless the CAISO can determine the impacts prior to the reassessment. Interconnection Customers with Network Upgrades must submit downsizing requests, including the $3~~1~~0,000 deposit, by November 30 to be included in the following annual reassessment. Once the CAISO publishes the reassessment results, the Participating TO will tender a draft amendment to the Interconnection Customer's Generator Interconnection Agreement to incorporate any required changes. If an Interconnection withdraws or is deemed withdrawn, any partial recovery of the Interconnection Financial Security for Network Upgrades under Sections 11.4.2.1 and 11.4.2.2 will be calculated based on the Generating Facility's most recent MW capacity prior to its downsizing request.

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### 8.9.9 Deliverability Transfers

Deliverability may not be assigned or otherwise transferred except as expressly provided by the CAISO Tariff. An Interconnection Customer may reallocate its Generating Facility's Deliverability among its own Generating Units or Resource IDs at the Generating Facility and to other Interconnection Customers interconnected at the same substation and at the same voltage level. The Generating Facility's aggregate output as evaluated in the Deliverability Assessment cannot increase as the result of any transfer, but may decrease based on the assignee's characteristics and capacity. Unless the Interconnection Customer provides the CAISO with an executed Energy Only power purchase agreement for the capacity losing Deliverability at the time it requests the Deliverability transfer, the assignor capacity must be removed from queue by withdrawal or downsizing the Generating Facility. The CAISO will inform the Interconnection Customer of each Generating Unit's Deliverability Status and associated capacity as the result of any transfer. The results will be based on the current Deliverability Assessment methodology.

An Interconnection Customer may request to reallocate its Deliverability among its Generating Units and to other Interconnection Customers interconnected at the same substation and at the same voltage level pursuant to Section 6.7.2.2 of this GIDAP, Article 5.19 of the LGIA, and Article 3.4.5 of the SGIA, as applicable. A repowering Interconnection Customer may transfer Deliverability as part of the repowering process pursuant to Section 25.1.2 of the CAISO Tariff. An Interconnection Customer expanding its capacity behind-the-meter pursuant to Section 4.2.1.2 also may transfer Deliverability as part of that process, or subsequently under the other processes in this Section. The assignee of a Deliverability transfer does not need to submit a modification request to receive a transfer.

Following a Deliverability transfer, the assignee inherits any requirements, restrictions, or obligations the assignor had as a result of receiving the Deliverability allocation or to retain the Deliverability, including without limitation requirements under Sections 6.7.4, 8.9.2.2, 8.9.2.3, and 8.9.3.

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**11.3.2 Third Posting for Queue Cluster Customers and Second Posting for Independent Study Process Customers**

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**11.3.2.6 Shared Network Upgrades**

Interconnection Studies and GIAs will identify when Network Upgrades are shared, and their estimated construction timelines. Once identified in the Interconnection Studies, or no later than when the first Interconnection Customer sharing the Assigned Network Upgrade executes its GIA with a third posting deadline for the Assigned Network Upgrade, the CAISO and Participating TO will notify the other Interconnection Customers sharing the Assigned Network Upgrade when this third Interconnection Financial Security posting will be required based on the construction timeline required to meet the earliest In-Service Date of the Interconnection Customers sharing the Assigned Network Upgrade. All Interconnection Customers sharing the Assigned Network Upgrade must submit (a) their authorizations to proceed with design and procurement of the shared Network Upgrade and (b) the third posting for the shared Network Upgrade, by the same deadline. Interconnection Customers and Participating TOs may have separate posting and authorization deadlines for each shared Network Upgrade and other non-shared Network Upgrades, but Interconnection Customers sharing Assigned Network Upgrades must have the same deadlines for them. At all times, Interconnection Customers must have sufficient Interconnection Financial Security under this Section 11, inclusive of any second and third posting obligations.

All Interconnection Customers sharing the Assigned Network Upgrade must execute an engineering and procurement agreement under Section 12 or a GIA prior to submitting the third posting for the shared Network Upgrade. Where any Interconnection Customer sharing the Assigned Network Upgrade has not executed either agreement, the Participating TO will tender (1) a draft engineering and procurement agreement if the Interconnection Customer is parked, or (2) a draft GIA or GIA amendment, to the Interconnection Customer no later than one-hundred twenty (120) days before the third posting deadline. The Interconnection Customer must execute the engineering and procurement agreement or GIA or request that the GIA be filed unexecuted prior to the deadline to post. The failure by an Interconnection Customer to timely (a) execute an engineering and procurement agreement or GIA or request an unexecuted filing, (b) submit the authorization to proceed, or (c) submit the third posting for the shared Assigned Network Upgrade, under this Section, will result in the Interconnection Request being deemed withdrawn and subject to Section 3.8. The Interconnection Customer will provide the CAISO and the Participating TO with written notice that it has posted the required Interconnection Financial Security no later than the applicable final day for posting.

No later than thirty (30) days after each Interconnection Customer sharing the Assigned Network Upgrade complies with this Section, the Participating TO will commence Construction Activities on the shared Assigned Network Upgrade.

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**Section 13 Generator Interconnection Agreement (GIA)**

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## 13.3 Execution and Filing

The Interconnection Customer shall either: (i) execute the appropriate number of originals of the tendered GIA as specified in the directions provided by the CAISO and return them to the CAISO, as directed, for completion of the execution process; or (ii) request in writing that the applicable Participating TO(s) and CAISO file with FERC a GIA in unexecuted form. The GIA shall be considered executed as of the date that all three Parties have signed the GIA. As soon as practicable, but not later than ten (10) Business Days after receiving either the executed originals of the tendered GIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted GIA, the applicable Participating TO(s) and CAISO shall file the GIA with FERC, as necessary, together with an explanation of any matters as to which the Interconnection Customer and the applicable Participating TO(s) or CAISO disagree and support for the costs that the applicable Participating TO(s) propose to charge to the Interconnection Customer under the GIA. An unexecuted GIA should contain terms and conditions deemed appropriate by the applicable Participating TO(s) and CAISO for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted GIA, they may proceed pending FERC action.

### 13.3.1 Implementation Deposit

Within thirty (30) days of the effective date of the GIA, the Interconnection Customer will provide the CAISO with a $35,000 implementation deposit. Generating facilities interconnecting pursuant to a Participating TO Wholesale Distribution Access Tariff must submit a $6,000 implementation deposit at the commencement of the CAISO new resource implementation process. The CAISO will deposit the implementation deposit in an interest bearing account at a bank or financial institution designated by the CAISO. The implementation deposit will be applied to pay for prudent costs incurred by the CAISO or third parties at the direction of the CAISO to manage the Interconnection Request between GIA execution and the Commercial Operation Date, including without limitation executing GIA amendments, modeling and testing for synchronization, preparing for metering and telemetry, and incorporating the Generating Units into the CAISO Markets. The CAISO will not use implementation deposit funds to offset or obviate processes that require separate deposits under this GIDAP, including without limitation Material Modification Assessments, Permissible Technological Advancements, and Limited Operation Studies.

The Interconnection Customer will be responsible for the actual costs incurred by the CAISO and applicable Participating TO(s). If the actual costs are less than the deposit provided by the Interconnection Customer, the Interconnection Customer will be refunded the balance, including interest earned. If the actual costs are greater than the deposit provided by the Interconnection Customer, the Interconnection Customer will pay the balance within thirty (30) days of being invoiced. The Participating TO(s) will invoice the CAISO for any work within seventy-five (75) days of the Commercial Operation Date or withdrawal, and, within thirty (30) days thereafter, the CAISO will issue an invoice or refund to the Interconnection Customer, as applicable, based upon such submitted Participating TO invoices and the CAISO's own costs.

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<u>**Appendices EE (LGIA)**</u>

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**5.5 Equipment Procurement.** If responsibility for construction of the Participating TO's Interconnection Facilities or Network Upgrades is to be borne by the Participating TO, then the Participating TO shall notify the Interconnection Customer and the CAISO in writing within thirty (30) days and commence design of the Participating TO's Interconnection Facilities or Network Upgrades and procurement of necessary equipment ~~as soon as practicable~~ after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

**5.5.1** The CAISO, in coordination with the applicable Participating TO(s), has completed the Phase II Interconnection Study or Governing Independent Study Interconnection Study pursuant to the applicable Generator Interconnection Study Process Agreement or other applicable study process agreement;

**5.5.2** The Participating TO has received written authorization to proceed with design and procurement from the Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.5.3** The Interconnection Customer has provided security to the Participating TO in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

**5.6 Construction Commencement.** The Participating TO shall notify the Interconnection Customer and the CAISO in writing and commence construction of the Participating TO's Interconnection Facilities and Network Upgrades for which it is responsible within thirty (30) days ~~as soon as practicable~~ after the following additional conditions are satisfied:

**5.6.1** Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

**5.6.2** Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the Participating TO's Interconnection Facilities and Network Upgrades;

**5.6.3** The Participating TO has received written authorization to proceed with construction from the Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.6.4** The Interconnection Customer has provided payment and security to the Participating TO in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

**5.7 Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Any Party may, at any time, request a progress report from another Party. If, at any time, the Interconnection Customer determines that the completion of the Participating TO's Interconnection Facilities will not be required until after the specified In-Service Date, the Interconnection Customer will provide written notice to the Participating TO and CAISO of such later date upon which the completion of the Participating TO's Interconnection Facilities will be required.

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**Appendix H**

**INTERCONNECTION REQUIREMENTS FOR AN ASYNCHRONOUS GENERATING FACILITY**

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**vi. Transient Data Recording Equipment for Facilities ~~above 20 MW~~**

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The data must be time synchronized, using a GPS clock or similar device, to a one millisecond level of resolution. All data except phase angle measuring unit data must be sampled at least every 10 milliseconds. Data recording must be triggered upon detecting a frequency ride-through event, a transient low voltage disturbance that initiated reactive current injection, momentary cessation or reactive current injection for a transient high voltage disturbance, or an inverter trip. Each recording will include as a minimum 150 milliseconds of data prior to the triggering event, and 1000 milliseconds of data after the event trigger. The Asynchronous Generating Facility must store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all data within 10 calendar days of a request from the CAISO or the Participating TO.

The Asynchronous Generating Facility must install and maintain a phase angle measuring unit or functional equivalent at the entrance to the facility or at the Generating Facility's main substation transformer. The phase angle measuring unit must have a resolution of at least ~~30~~ 16 samples per ~~second~~cycle. The Asynchronous Generating Facility will store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all phase angle measuring unit data within 10 calendar days of a request from the CAISO or the Participating TO.

**Appendix FF (SGIA)**

**Attachment 7**

**Interconnection Requirements for an Asynchronous Small Generating Facility**

Attachment 7 sets forth requirements and provisions specific to all Asynchronous Generating Facilities. ~~All other requirements of this Agreement continue to apply to all Asynchronous Generating Facility interconnections consistent with Section 25.4.2 of the CAISO tariff.~~ Except as provided in Section 25.4.2 of the CAISO tariff, existing individual generating units of an Asynchronous Generating Facility that are, or have been, interconnected to the CAISO Controlled Grid at the same location are exempt from the requirements of this Attachment 7 for the remaining life of the existing generating unit.

## A. Technical Standards Applicable to Asynchronous Generating Facilities

### i. ~~Low~~ Voltage Ride-Through ~~(LVRT)~~ Capability

An Asynchronous Generating Facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the requirements below.

1. An Asynchronous Generating Facility shall remain online for the voltage disturbance caused by any fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, having a duration equal to the lesser of the normal three-phase fault clearing time (4-9 cycles) or one-hundred fifty (150) milliseconds, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum normal clearing time associated with any three-phase fault location that reduces the voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

2. An Asynchronous Generating Facility shall remain online for any voltage disturbance caused by a single-phase fault on the transmission grid, or within the Asynchronous Generating Facility between the Point of Interconnection and the high voltage terminals of the Asynchronous Generating Facility's step up transformer, with delayed clearing, plus any subsequent post-fault voltage recovery to the final steady-state post-fault voltage unless clearing the fault effectively disconnects the generator from the system. Clearing time shall be based on the maximum backup clearing time associated with a single point of failure (protection or breaker failure) for any single-phase fault location that reduces any phase-to-ground or phase-to-phase voltage at the Asynchronous Generating Facility's Point of Interconnection to 0.2 per-unit of nominal voltage or less, independent of any fault current contribution from the Asynchronous Generating Facility.

3. Remaining on-line shall be defined as continuous connection between the Point of Interconnection and the Asynchronous Generating Facility's units, without any mechanical isolation. Momentary cessation (namely, ceasing to inject current during a fault without mechanical isolation) is prohibited unless transient high voltage conditions rise to 1.20 per unit or more. For transient low voltage conditions, the Asynchronous Generating Facility's inverters will inject reactive current. The level of this reactive current must be directionally proportional to the

decrease in per unit voltage at the inverter AC terminals. The inverter must produce full reactive current capability when the AC voltage at the inverter terminals drops to a level of 0.50 per unit or below. The Asynchronous Generating Facility must continue to operate and absorb reactive current for transient voltage conditions between 1.10 and 1.20 per unit.

Upon the cessation of transient voltage conditions and the return of the grid to normal operating voltage ($0.90 < V < 1.10$ per unit), the Asynchronous Generating Facility's inverters automatically must transition to normal active (real power) current injection. The Asynchronous Generating Facility's inverters must ramp up to inject active (real power) current with a minimum ramping rate of at least 100% per second (from no output to full available output). The total time to complete the transition from reactive current injection or absorption to normal active (real power) current injection must be one second or less. The total time to return from momentary cessation, if used, during transient high voltage conditions over 1.20 per unit or more must be one second or less.

The Asynchronous Generating Facility's inverter will be considered to have tripped where its AC circuit breaker is open or otherwise has electrically isolated the inverter from the grid. Following an inverter trip, the inverter must make at least one attempt to resynchronize and connect back to the grid unless the trip resulted from a fatal fault code, as defined by the inverter manufacturer. This attempt must take place within 2.5 minutes from the inverter trip. An attempt to resynchronize and connect back to the grid is not required if the trip was initiated due to a fatal fault code, as determined by the original equipment manufacturer.

4. The Asynchronous Generating Facility is not required to remain on line during multi-phased faults exceeding the duration described in Section A.i.1 of this Attachment 7 or single-phase faults exceeding the duration described in Section A.i.2 of this Attachment 7.

5. The requirements of this Section A.i of this Attachment 7 do not apply to faults that occur between the Asynchronous Generating Facility's terminals and the high side of the step-up transformer to the high-voltage transmission system.

6. Asynchronous Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

7. Asynchronous Generating Facilities may meet the requirements of this Section A of this Attachment 7 through the performance of the generating units or by installing additional equipment within the Asynchronous Generating Facility or by a combination of generating unit performance and additional equipment.

8. The provisions of this Section A.i of this Attachment 7 apply only if the voltage at the Point of Interconnection has remained within the range of 0.9 and 1.10 per-unit of nominal voltage for the preceding two seconds, excluding any sub-cycle transient deviations.

9. Asynchronous Generating Facility inverters may not trip or cease to inject current for momentary loss of synchronism. As a minimum, the Asynchronous Generating Facility's inverter controls may lock the phase lock loop to the last synchronized point and continue to inject current into the grid at that last calculated phase prior to the loss of synchronism until the phase lock loop can

regain synchronism. The current injection may be limited to protect the inverter. Any inverter may trip if the phase lock loop is unable to regain synchronism 150 milliseconds after loss of synchronism.

10. Inverter restoration following transient voltage conditions must not be impeded by plant level controllers. If the Asynchronous Generating Facility uses a plant level controller, it must be programmed to allow the inverters to automatically re-synchronize rapidly and ramp up to active current injection (without delayed ramping) following transient voltage recovery, before resuming overall control of the individual plant inverters.

**ii. Frequency Disturbance Ride-Through Capacity**

An Asynchronous Generating Facility shall comply with the off nominal frequency requirements set forth in the NERC Reliability Standard for Generator Frequency and Voltage Protective Relay Settings as they may be amended from time to time.

**iii. Power Factor Design Criteria (Reactive Power)**

An Asynchronous Generating Facility not studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer, as defined in this SGIA in order to maintain a specified voltage schedule, if the Phase II Interconnection Study shows that such a requirement is necessary to ensure safety or reliability. An Asynchronous Generating Facility studied under the Independent Study Process, as set forth in Section 4 of Appendix DD, shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the high voltage side of the substation transformer, as defined in this SGIA in order to maintain a specified voltage schedule. The power factor range standards set forth in this section can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and CAISO. The Interconnection Customer shall not disable power factor equipment while the Asynchronous Generating Facility is in operation. Asynchronous Generating Facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Phase II Interconnection Study shows this to be required for system safety or reliability.

**iv. Supervisory Control and Data Acquisition (SCADA) Capability**

An Asynchronous Generating Facility shall provide SCADA capability to transmit data and receive instructions from the Participating TO and CAISO to protect system reliability. The Participating TO and CAISO and the Asynchronous Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed Asynchronous Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability.

**v. Power System Stabilizers (PSS)**

Power system stabilizers are not required for Asynchronous Generating Facilities.

### vi. Transient Data Recording Equipment for Facilities

Asynchronous Generating Facilities must monitor and record data for all frequency ride-through events, transient low voltage disturbances that initiated reactive current injection, reactive current injection or momentary cessation for transient high voltage disturbances, and inverter trips. The data may be recorded and stored in a central plant control system. The following data must be recorded:

**Plant Level:**

(1) Plant three phase voltage and current
(2) Status of ancillary reactive devices
(3) Status of all plant circuit breakers
(4) Status of plant controller
(5) Plant control set points
(6) Position of main plant transformer no-load taps
(7) Position of main plant transformer tap changer (if extant)
(8) Protective relay trips or relay target data

**Inverter Level:**

(1) Frequency, current, and voltage during frequency ride-through events
(2) Voltage and current during momentary cessation for transient high voltage events (when used)
(3) Voltage and current during reactive current injection for transient low or high voltage events
(4) Inverter alarm and fault codes
(5) DC current
(6) DC voltage

The data must be time synchronized, using a GPS clock or similar device, to a one millisecond level of resolution. All data except phase angle measuring unit data must be sampled at least every 10 milliseconds. Data recording must be triggered upon detecting a frequency ride-through event, a transient low voltage disturbance that initiated reactive current injection, momentary cessation or reactive current injection for a transient high voltage disturbance, or an inverter trip. Each recording will include as a minimum 150 milliseconds of data prior to the triggering event, and 1000 milliseconds of data after the event trigger. The Asynchronous Generating Facility must store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all data within 10 calendar days of a request from the CAISO or the Participating TO.

The Asynchronous Generating Facility must install and maintain a phase angle measuring unit or functional equivalent at the entrance to the facility or at the Generating Facility's main substation transformer. The phase angle measuring unit must have a resolution of at least 16 samples per cycle. The Asynchronous Generating Facility will store this data for a minimum of 30 days. The Asynchronous Generating Facility will provide all phase angle measuring unit data within 10 calendar days of a request from the CAISO or the Participating TO.

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**Attachment C – Track 2 Final Proposal**

**Tariff Amendment – Queue Management Proposals of IPE 2023 Initiative**

**California Independent System Operator Corporation**

**October 17, 2024**

# 2023 Interconnection Process Enhancements

## Track 2 Final Proposal

March 28, 2024

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California Independent System Operator

## Contents

# 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.

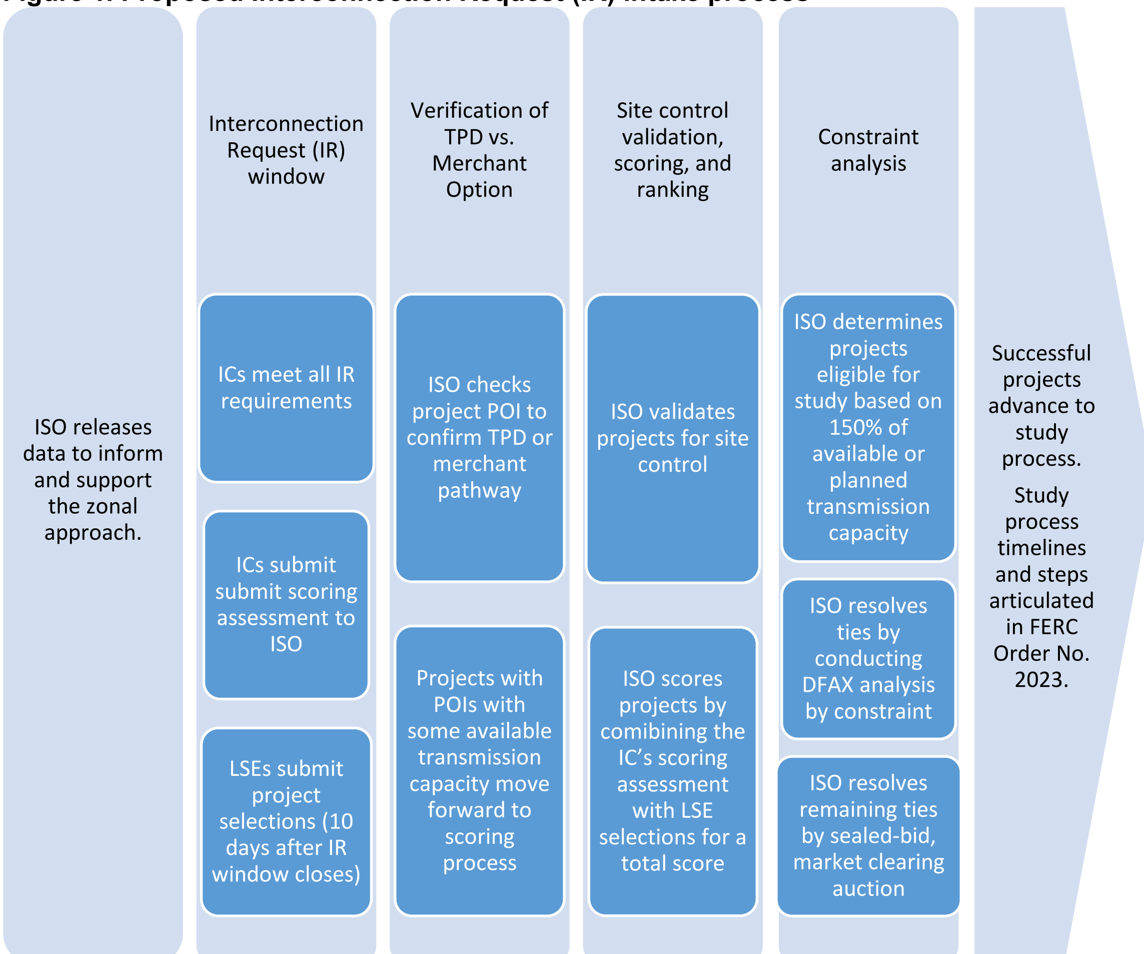
This policy initiative builds upon the new requirements established in FERC Order No. 2023, issued in July of 2023, which sets new standards for interconnection processes around the country. The ISO intends to complement FERC Order No. 2023 requirements with these additional interconnection process enhancements.

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 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;

- 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:

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[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.

- 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 100[4] 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.

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[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.

- 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]

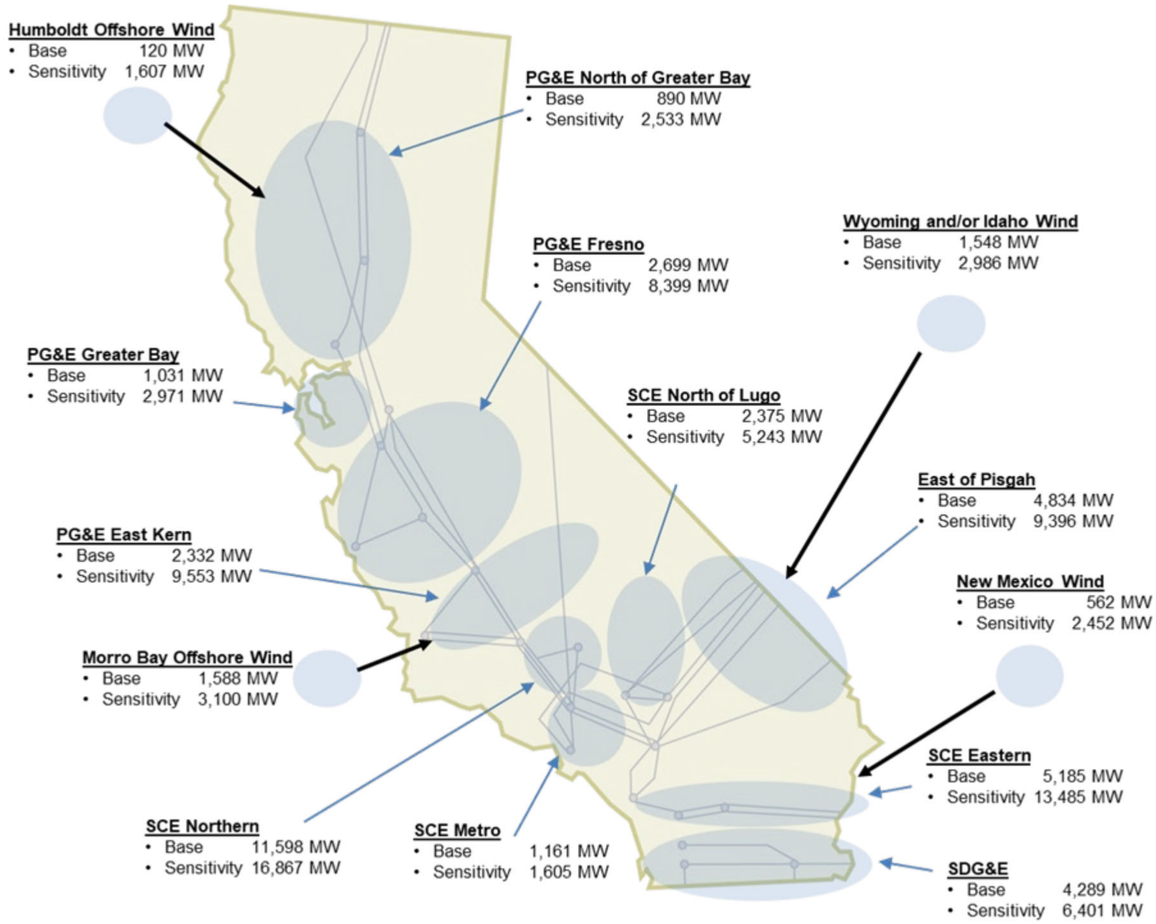
### *Background*

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 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 substations[10] within each of the transmission areas or zones

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[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

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]

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

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

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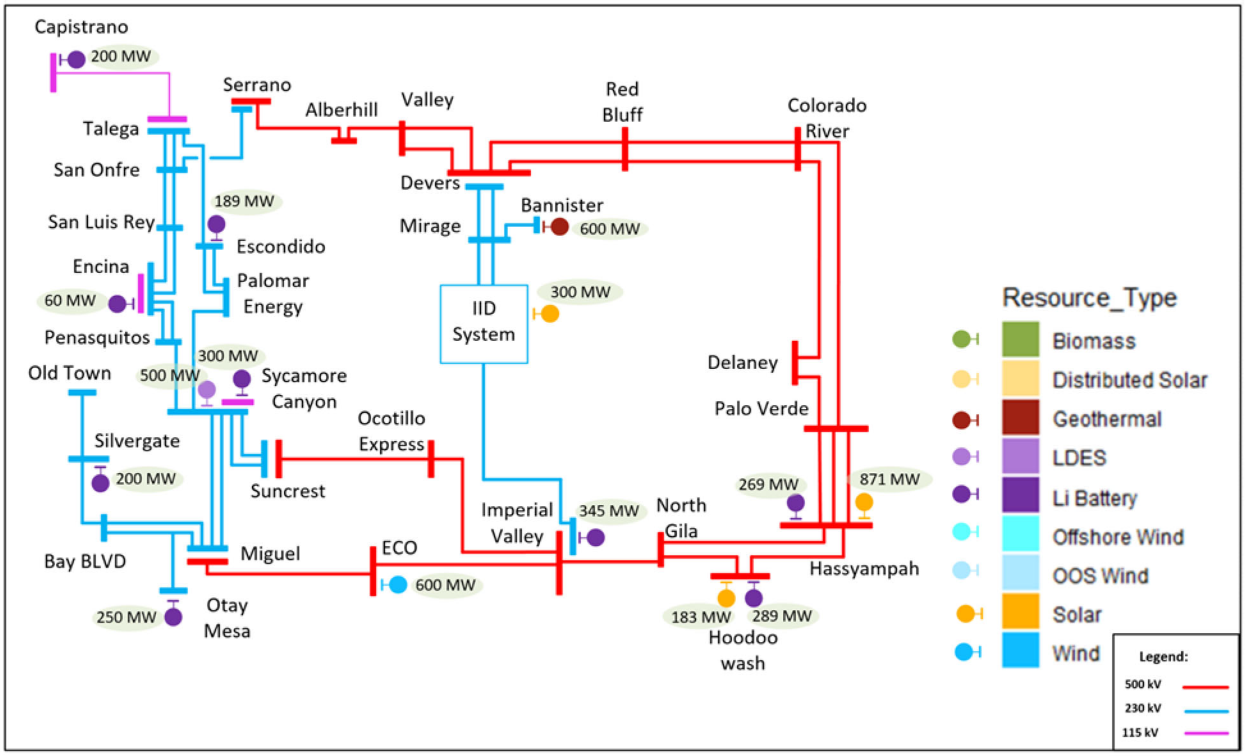
described in the CPUC staff report "Modeling Assumptions for the 2022-2023 Transmission Planning Process".
https://files.cpuc.ca.gov/energy/modeling/Busbar%20Mapping%20Methodology%20for%20the%20TPP_V2021_12_21.pdf
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF
[11] https://files.cpuc.ca.gov/energy/modeling/BusbarMapping_Dashboard_38MMT_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 Process[13] 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-Resrouce-Planning-Process.pdf
[14] https://mpp.caiso.com/tp/Documents/2023%20TPD%20Allocation%20Report.pdf (on Market Participant Portal)

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 Zone[15]**

| | | | 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 Report[16] 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.

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[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**

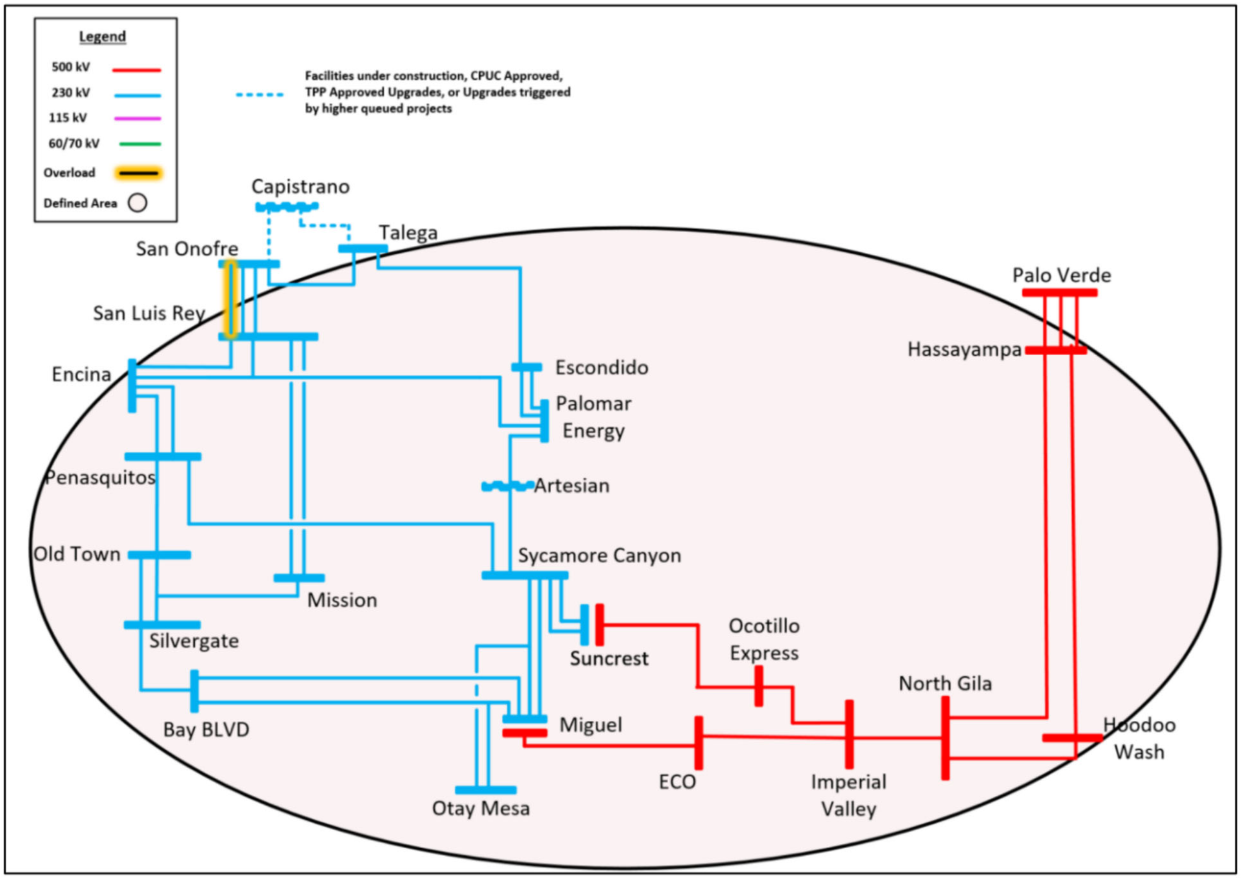


**Table 3.** Available TPD for one constraint within the San Diego transmission zone

| | |
|---|---|
| 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.

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.

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[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 he 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:

- 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 that 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.

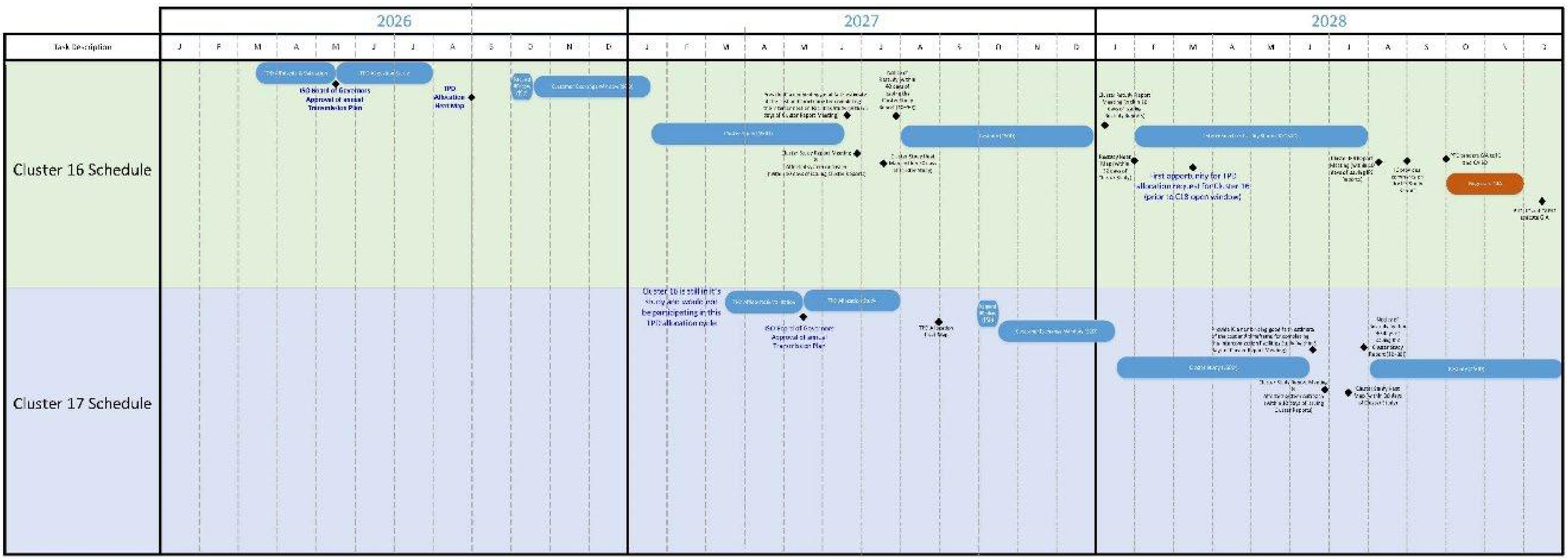
Terra-Gen requested that the ISO add the timing and details of security postings to the timeline. This information will be included in the ISO's compliance filing for Order No. 2023.

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.

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[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.

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 request 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, CalWEA, 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-Gen[21] 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. NCPA 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 gradated 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 projects 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 share[22].

[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)** | | | | |
| □ 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.)<br><br>□ **Check for Full Allocation Election:**<br>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. | 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. |
| □ Non-LSE Interest: Points | 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:<br>a. Attest non-LSE off-taker is supporting this project in support of corporate policy goals on sustainability<br>b. Attest that the size of application is aligned with the non-LSE off-taker needs<br>c. Attest that non-LSE off-taker is not affiliated with the IC or its holding company<br>d. Attest that the non-LSE off-taker has not supported more than one application. |

| | | | | |
|---|---|---|---|---|
| **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 | | | 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 | | | | |
| ☐ Expansion of a generation facility that is currently under construction | 10 | 35% | **35** | IC submits information indicating that new IR uses same or directly adjacent site as a facility under construction |
| ☐ Expansion of an operating facility | 20 | | | IC submits information indicating that new IR uses same or directly adjacent site as an operating facility |
| ☐ 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]** | | | | |
| ☐ 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.

| | | | | |
|---|---|---|---|---|
| Long Lead-time Resources<br><br>□ 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 | | |
| □ 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.

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[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:

| **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-

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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

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

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[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 DNUs, RNUs and LNUs. 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 28$^{th}$ 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 |

**Attachment D – Track 2 Board Memorandum**

**Certificate of Concurrence – Elisabeth Solar**

**California Independent System Operator Corporation**

**August 16, 2024**

# Memorandum

**To:** ISO Board of Governors

**From:** Neil Millar, Vice President of Infrastructure and Operations Planning

**Date:** June 6, 2024

**Re:** **Decision on Interconnection Process Enhancements 2023 - Track 2**

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**This memorandum requires ISO Board of Governors action.**

## EXECUTIVE SUMMARY

The recommended changes in the Interconnection Process Enhancements Track 2 final proposal described here seek to better enable rapid deployment of new generation for reliability, affordability, and decarbonization. Through a robust stakeholder process considering the urgent need to bring historic amounts of new capacity online as quickly and as efficiently as possible, the ISO proposes a package of transformational reforms, which are specifically tailored to the particular circumstances within California, that emphasize up-front project readiness and alignment with local and state resource and transmission planning efforts.

This initiative focused on the specific changes necessary for the ISO's cluster study and queue management processes. With the dramatic increase in projects applying for interconnection and moving into the interconnection queue, existing tools to move projects to commercial operation are insufficient. Upon commencement of this track of the initiative in May of 2023, for example, the ISO had 185 gigawatts (GW) in the queue pre-Cluster 15, and interconnection requests totaled 347 GW in Cluster 15 alone. The ISO interconnection queue now contains more than three times the capacity expected to achieve California's 100% clean energy policy objective in 2045. These volumes reflect the level of competition and interest in developing potential sites, but are decoupled from the number of projects that are expected to be needed by the state and likely to secure power purchase agreements and interconnect to the grid. The ISO, participating transmission owners (PTOs), load-serving entities (LSEs), and industry need a reformed process to advance the most viable projects toward interconnection and commercial operation, and to prevent stagnant projects from hindering the progress of viable projects in the queue. The ISO's intent is to apply these proposed reforms to Cluster 15 to prioritize consideration and study of the most viable interconnection projects that best align with system need, while maintaining open access to the transmission grid.

This policy initiative builds upon the new requirements established in Federal Energy Regulatory Commission ("FERC") Order No. 2023, issued in July of 2023, which sets new standards for interconnection processes around the country. The ISO submitted a compliance filing on May 16, 2024, and intends to layer additional reforms on the FERC requirements.

This final proposal reflects the strategic direction established by a December 2022 Memorandum of Understanding among the ISO, CPUC, and California Energy Commission (CEC) as part of a broader effort to tighten linkages among resource and transmission planning activities, interconnection processes, and resource procurement. Together, the reforms establish a new process for evaluating and advancing interconnection applications that best align with resource planning, transmission availability, and procurement interests of all off-takers. The ISO's goal is to accelerate progress toward execution of interconnection agreements and commercial operation for the most viable and competitive projects, in areas that align with local and state resource plans.

Under the reformed interconnection request intake process, the ISO commits to providing information that helps stakeholders, particularly interconnection customers, 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 feedback on specific projects from participating load-serving entities (LSEs). The ISO also provides an opportunity for non-LSE off-takers, such as commercial entities, to express an interest in specific projects, and will award points to projects that can demonstrate such interest from non-LSE off-takers.

Highest ranking projects will advance to the study phase in descending order of project scores 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 project with the lowest distribution factor behind the constraint, and if ties still exist, the ISO will conduct a market-clearing sealed-bid auction to advance to the study process. The study process will align with the process required under FERC Order No. 2023.

The ISO also proposes reforms to its current queue management processes, which are designed to drive viable projects toward commercial operations and to prevent stagnant projects from hindering development of other, later-queued projects. The queue management reforms will apply to all customers in the queue.

Since the informational briefing to the Board on May 23, 2024, the ISO has carefully reviewed each of the additional stakeholder comments submitted to the Board and issued a Final Addendum to the Final Proposal on June 5, noting the following modifications and clarifications:

- A new requirement that load-serving entities (LSEs) opt-in to the LSE allocation process and publicly notice selection criteria by a certain date, in order to ensure increased rigor, transparency, and integrity of the process.
- A commitment to monitoring the results of various components of the interconnection request intake process and coordinating with the California Public Utilities Commission (CPUC), local regulatory authorities, and stakeholders to adjust any necessary components for Cluster 16 and future clusters, including:
    - Transparency of LSE allocation process
    - Trends in LSE allocations to LSE-sponsored projects
    - Opportunities to increase coordination with non-LSEs in the scoring process
- Further clarification of the treatment of mixed-fuel resources depending on their deliverability status
- Clarifications to the engineering design plan scoring criterion

These recent developments reflect modifications to the final proposal but do not change the fundamental elements of the proposal. Both the final addendum and final proposal reflect significant ISO and stakeholder engagement, consideration, and problem-solving throughout this initiative.

Management recommends the following motion:

**Moved, that the ISO Board of Governors approves the proposed track 2 interconnection process enhancements, as described in the memorandum dated June 6, 2024; and**

**Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposal, including any filings that implement the overarching initiative policy but contain discrete revisions to incorporate Commission guidance in any initial ruling on the proposed tariff amendment.**

## DISCUSSION AND ANALYSIS

A central tenet of the ISO's interconnection reform effort is the prioritization of projects that can utilize available transmission capacity. This concept draws from the Memorandum of Understanding with the CPUC and CEC. Under the proposal, the ISO encourages and prioritizes projects that can utilize approved or available transmission capacity, which are located in TPD zones. These zones are the result of state and local regulatory authority resource plans, which then inform the ISO transmission planning process. Generation projects seeking to interconnect outside of the priority TPD zones may proceed as merchant projects, and will self-fund their associated network upgrades.

To effectuate the zonal approach, the ISO will provide information that helps stakeholders identify areas with available transmission capacity prior to each interconnection request application window. The ISO will provide existing information and compile additional information for stakeholders, such as updated queue reports, an interconnection heat map, interconnection area reports from each cluster study, and a review of non-CPUC jurisdictional LSE resource plans.

The ISO will determine whether a zone is a TPD or merchant zone based on the availability of capacity associated with the known constraints within each zone and provide this information to customers prior to each interconnection request window. This method will inform customers of the available interconnection study options based on the zones they are considering for their interconnection request. Upon the close of the interconnection request application window, the ISO engineering team will conduct an initial constraint check to ensure that projects seeking to interconnect in TPD zones are not located behind known constraints where there is no available transmission capability.

To emphasize project readiness and competition for projects to advance to the study stage, the ISO proposes introduction of scoring criteria. Project scores will be based on indicators related to commercial interest (30%), project viability (35%), and system need (35%).

In evaluating commercial interest, the ISO will incorporate preliminary, non-binding feedback on specific projects from participating load-serving entities (LSEs). Participating LSEs can award capacity—proportionate to that LSE's load share obligation—to specific projects, which will be translated into "points" for the project, based on the amount of the capacity that is allocated. Projects can receive between zero and 100 points in the LSE allocation process. The ISO proposes limitations on the amount of capacity LSEs can award to their own LSE-sponsored projects to maintain historical ratios of utility-owned generation and independently developed projects in the queue. The ISO also proposes an option for LSEs to elect to allocate 100 points to a particular project even if that project's capacity exceeds the LSE's allocation for a given cluster. This is intended to enable LSEs with small load shares to ensure sufficient resource availability in the study process.

In addition, the ISO provides an opportunity for non-LSE off-takers (*e.g.* commercial entities) to express an interest in specific projects for a total of 25 points, with only one opportunity to apply these points to a project per entity per cycle, regardless of project size. Non-LSE interest will improve the scores of certain projects, increasing the likelihood of those projects advancing to the study process and ultimately competing for transmission plan deliverability (TPD) and off-take agreements.

The highest-ranking projects will advance to the study phase in descending order of project score, until the available and planned transmission capacity for each constraint is filled to 150% of that capacity. The ISO found that 150% of capacity was appropriate because it satisfies near-term and longer-term capacity needs, provides sufficient competition for LSEs to select from, and reduces the number of interconnection requests to an amount the ISO and transmission owners can study without delays. Ties will be resolved by calculating and selecting the lowest distribution factor, which is a commonly used proxy to determine a generator's impact on transmission constraints, thereby correlating with its costs to relieve the constraint. If ties still exist after the distribution factor tiebreaker, the ISO proposes to conduct a market-clearing sealed-bid auction to advance to the study process.

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 and fund any required Area Delivery Network Upgrades (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. To prevent gaming, 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 option. The ISO proposes a number of changes to the merchant option from the current tariff, to establish a clear pathway for these projects. Merchant projects:

- Will not need to compete for TPD allocations;
- Are eligible for cost recovery of any posted financial security towards the cost of a Local Delivery Network Upgrade (LDNU) in the same manner as Deliverability option projects;
- Are required to pay an additional commercial readiness deposit of $10,000 per MW (not less than $500,000 and not to exceed $5 million) toward the cost of the ADNU with the interconnection request to ensure developer confidence in the project's viability under the merchant option;
- Are required to increase the commercial readiness deposit associated with their merchant ADNU to 50% of cost recovery.

If a future transmission plan determines that an ADNU that a merchant project is funding is needed to support a CPUC portfolio, the ISO provides criteria and a pathway to be released from the merchant project's funding obligation.

The ISO proposes continued alignment with the resource portfolios in its proposed treatment of Energy Only projects by offering two options; the reimbursable option and the non-reimbursable option. Projects that seek to interconnect in zones where the CPUC Integrated Resource Plan base case portfolio and other local regulatory authority resource portfolios identify the need for Energy Only resources will be eligible for reimbursement of the cost of reliability network upgrades (RNUs) funded by the interconnection customer. The ISO proposes to study these projects up to 150% of the Energy Only amount identified by the resource portfolios. All other Energy Only resources seeking to interconnect in zones where the CPUC's Integrated Resource Plan 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. The ISO does not propose any limitation to the amount of non-reimbursable Energy Only projects studied. The ISO has not received an Energy Only interconnection request in the last several clusters.

The final proposal also includes important reforms to manage the ISO's growing volume of active interconnection requests. In particular, viability criteria for projects in the queue will ensure continued progress toward commercial operation. If projects fail to demonstrate progress, time-in-queue requirements will enable the ISO to withdraw inactive projects. In addition, the ISO will require PTOs to commence network upgrades upon receipt of the first notice to proceed, preventing construction delays that occur today. The proposal also includes elements to streamline the modification process, implement a new interconnection deposit, and require earlier financial security postings for projects with shared network upgrades.

The ISO paused Cluster 15 projects in May of 2023, with the Board of Governor's approval, so that the ISO and stakeholders could establish a new process to manage this volume. Timely re-engagement with Cluster 15 in Q4 of 2024 is essential to maintain progress on interconnection and onboard the resources necessary to meet near-term reliability and longer-term policy needs.

The ISO will initiate track 3 of this initiative this summer, focusing on the TPD allocation process and considering intra-cluster prioritization for Cluster 14 and earlier. The TPD allocation process is important to project developers and is currently linked to procurement activities of the LSEs. It is necessary for the ISO to consider changes to the TPD allocation criteria within the framework of the proposed changes to the interconnection process from track 2 of IPE, as well as the changes required by FERC in Order No. 2023. The ISO intends to bring a track 3 proposal to the board in late 2024.

**POSITIONS OF THE PARTIES**

The ISO conducted an intensive stakeholder process, beginning with working group discussions to establish principles and problem statements related to interconnection request intake and queue management. Participants proposed concepts and worked with the ISO to explore and refine them throughout the course of the initiative. Many of the concepts in the final proposal were initially developed by stakeholders, however ultimate positions on the final proposal vary.

The ISO understands the unprecedented impact of these reforms and views reduced queue volumes as a necessary outcome of the process. Importantly, the ISO believes that the final proposal will enable the most viable and needed projects to advance through the study process based on a series of meaningful steps and indicators to ensure sufficient resource availability and diversity in the queue. The proposal reflects the principles developed by the working group participants at the beginning of this initiative.[1]

Below, the ISO summarizes and responds to public comments from the May 23, 2024 informational briefing on the IPE Track 2 final proposal, as well as letters to the ISO Board of Governors for the May 23, 2024 informational briefing and June 12, 2024 decision. The ISO notes that a stakeholder comment matrix is posted with materials for the May 23, 2024 Board of Governors meeting, summarizing stakeholder comments to the final proposal received during the stakeholder initiative.

**Urgency of interconnection reform**

Several parties noted the importance of moving forward with the proposed interconnection reforms, including the California Public Utilities Commission (CPUC), Center for Energy Efficiency and Renewable Technologies (CEERT), California Community Choice Association (CalCCA), Northern California Power Agency (NCPA), Pacific Gas & Electric (PG&E), American Clean Power-California (ACP-California), Southern California Edison (SCE), the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities), and 174 Power Global.

Other stakeholders, including the Aypa Power, California Wind Energy Association (CalWEA), Terra-Gen, Large-scale Solar Association (LSA), Engie, Intersect, California Energy Storage Alliance (CESA), Clean Energy Buyers Association (CEBA), Clearway, Independent Energy Producers Association (IEPA), Solar Energy Industries Association (SEIA), and QCells, urged either modifications or significant rollbacks to the final proposal before Board approval.

**Zonal approach and data availability**

While several stakeholders, including the CPUC, supported the zonal approach as a means to implement the Memorandum of Understanding and incorporate resource and transmission planning inputs into the interconnection process, some stakeholders noted concerns around the impact of the zonal approach in reducing queue numbers. Specifically, LSA expressed concerns that in this next cycle, few if any zones will be designated as TPD zones due to the amount of deliverability that has been allocated to Cluster 14. The ISO understands that Cluster 14 TPD allocations are likely to reduce the number of Cluster 15 projects that will proceed under the TPD pathway. The proposal is designed to right-size the

[1] 2023 Interconnection Process Enhancements Final Proposal. P. 13.

number of projects advancing to the study process with the amount of transmission capacity while ensuring sufficient projects in the queue.

LSA expressed concerns that projects in merchant zones will have to proceed under more onerous rules where interconnection customers will not be reimbursed for Area Delivery Network Upgrades. The ISO agrees that the merchant pathway is more expensive. This is a mechanism for prioritizing interconnections in areas with available transmission capacity. Importantly, however, as discussed above, the ISO made several changes to the merchant pathway to ensure that the pathway is still viable for projects that would like to interconnect outside of the priority zones.

Aypa Power suggested that the ISO remove the zonal, scoring, and auction elements from the current proposal and allow the Order No. 2023 reforms to take effect. The ISO does not see this as a feasible option. Order No. 2023 revisions alone are nowhere near sufficient to address the ISO's overheated interconnection queue. Order No. 2023 addresses national issues. The ISO's proposal addresses its own unique challenges.

Terra-Gen noted that projects in TPD zones but behind sub-zonal constraints with insufficient deliverability would not be accepted for study even if they score very high under the scoring rubric and the ADNUs needed to provide deliverability are relatively economic. Terra-Gen asserts that this treatment would be unfair for projects that chose an over-subscribed point of interconnection in TPD allocation zones. The ISO agrees that such projects would not be accepted for study; however, the ISO has been clear about this treatment and has committed to providing information to interconnection customers so they can avoid Points of Interconnection (POI) that have no available transmission capability prior to the Cluster 15 modification window. The ISO can reconsider such circumstances in the next resource planning and transmission planning process.

CalWEA suggested that TPD capacity data will be inaccurate at the time of study commitments. As described in the final proposal, the ISO is committed to providing up-to-date information on the availability of transmission prior to each interconnection window, and anticipates providing a TPD allocation report by mid-June to account for Cluster 14 TPD allocations. Complete, final information to inform Cluster 15 will be posted in August 2024, prior to the proposed Cluster 15 modification window, which opens on October 1, 2024. Projects also are able to withdraw their requests into early 2025 at no or minimal cost.

Aypa Power expressed concerns around the potential elimination of the use of the ISO interconnection queue to drive future resource portfolios from the CPUC. The CPUC participated in the entire IPE initiative and provided a presentation to stakeholders on July

11, 2023 responding to this concern.[2] The interconnection queue is not the only data source used to assess commercial development interest in the CPUC portfolio development process, and the ISO commits to working with the CPUC and local regulatory authorities to continue to tighten these linkages.

The ISO does not recommend any changes to the zonal approach or data availability, but remains committed to providing clear, transparent, and timely data to stakeholders, and monitoring the results of the constraint analysis.

**Scoring criteria**

*Load-serving entity allocation process*

Several resource developers and developer trade associations suggested that the scoring criteria—particularly the commercial interest category—is not ready for implementation or should not apply to Cluster 15, citing concerns around a lack of oversight and transparency and an outsized role of LSEs in determining the fate of interconnection projects. The ISO maintains, however, that this is a critical piece of the reformed process. Awarding points for commercial interest will enhance competition earlier in the interconnection process and provide arguably the most useful metric in determining whether a project is ready for study. Without sufficient differentiation of projects based on commercial interest, the ISO would rely on either locational or financial mechanisms to obtain more reasonable queue volumes.

Several LSEs provided support for the scoring criteria and have emphasized the importance of incorporating commercial viability screens early in the process. LSE representatives expressed a commitment to running an open and transparent process, with the oversight of their local regulatory authority, including NCPA, CalCCA, PG&E, SCE, and the Six Cities. CEERT and 174 Power Global both supported the LSE allocation process and expressed confidence in the ability of LSEs to run open and fair processes to select projects prior to the interconnection study process. The CPUC has engaged in and supported the initiative, offering support for the LSE allocation process and expressing a commitment to continued coordination and oversight going forward.

A number of resource developers and trade associations called for increased transparency in the LSE scoring process. The ISO considered stakeholder feedback on this matter and posted a final addendum to the final proposal on June 5, 2024, which proposes that an LSE interested in participating in the LSE allocation process must opt-in to the process by providing notice to the ISO of their intent to participate and contact information for the LSE

[2] Presentation – Interconnection Process Enhancements 2023 – Track 2 Working Group – Jul 11, 2023

staff coordinating the LSE allocation process. In addition, the ISO will now require participating LSEs to post selection criteria on a publicly accessible website by a certain date. LSEs that do not opt-in to the allocation process would forego their capacity allocation, which would result in fewer interconnection projects receiving points. The methodology for allocating capacity to each LSE will not change based on LSE participation. The new opt-in requirement and the requirement to post selection criteria will ensure increased transparency and rigor for the LSE allocation process while still respecting jurisdictional authority of the CPUC and local regulatory authorities over procurement.

Some stakeholders suggest that the ISO remove scoring criteria and rely on the zonal constraint analysis and the zonal auctions to study 150% of available transmission capacity. As CalCCA notes, however, by removing the LSE interest scoring criterion, the ISO would sacrifice alignment with resource and transmission planning processes, and "[g]iven that reliability depends critically on having the right mix of resources on the grid, this alignment with planning is important to CAISO's operations."[3]

Several resource developers noted concerns that LSEs would be making decisions on projects with minimal data on interconnection costs and timelines. NCPA and other LSEs noted several other factors LSEs can use to assess how a projects will fit with and complement existing portfolios at the time of the interconnection request. The ISO also has addressed this concern directly in the final addendum to the final proposal, noting that LSEs should seek projects that best align with procurement and resource needs, as indicated by integrated resource plans or other relevant planning documents, and emphasizing that it would be premature to expect agreement between LSEs and interconnection customers on contract terms (*e.g.*, contract price, term length, commercial operation date) in the early stages of project development.

The ISO recommends the opt-in requirement for LSE participation in the LSE allocation process, along with a requirement that each participating LSE provide contact information for the person or department coordinating the LSE allocation process and post selection criteria on a publicly accessible website. This approach respects jurisdictional boundaries and bolsters the integrity of the LSE allocation process, which the ISO expects will lead LSEs to make thoughtful and transparent decisions that best align with their individual procurement needs.

*LSE-sponsored projects*

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[3] California Community Choice Association May 22, 2024 Letter to the Board of Governors Re: Interconnection Process Enhancements. [calcca-public-comment-letter-interconnection-process-enhancements-track-2-proposal-may-22-2024.pdf (caiso.com)](calcca-public-comment-letter-interconnection-process-enhancements-track-2-proposal-may-22-2024.pdf)

Developer trade associations and developers expressed concerns that—despite the limitations on LSE-sponsored projects—the scoring criteria would discriminate against independent power producers and potentially favor LSE-sponsored projects. The CPUC noted support for the proposed treatment of LSE-owned resources, noting that all Investor Owned Utilities (IOU) projects will undergo CPUC review and approval, providing an additional layer of oversight to justify and ensure utility-owned resources are only permitted as needed. The ISO carefully designed limits on LSE-sponsored projects to maintain healthy levels of competition, consistent with the amount of LSE-owned project interconnection requests in the interconnection queue over the past six clusters. The ISO's intent is neither to create new incentives for LSE-ownership, nor to disrupt utility ownership.

The ISO does not recommend changes to this proposal. However, as recommended by ACP-California, IEPA, and others, the ISO commits to monitoring and adapting to the results of the LSE allocation process and coordinating with the CPUC, local regulatory authorities, and stakeholders to ensure competition and open access for both Cluster 15 (which will not yield new utility-sponsored interconnection request applications because the ISO is not accepting new applications as part of the Cluster 15 modification window) and Cluster 16, when LSEs will be aware of this new limitation prior to the interconnection request application window.

*Non-LSE commercial interest*

The ISO has communicated with non-LSEs, specifically CEBA and Amazon, on the commercial interest criteria. Some stakeholders are concerned about the reduced point value for projects with interest from non-LSE off-takers, compared to the maximum points that can be awarded to projects with LSE support. CEBA expressed concern with the differentiation of points between LSE off-takers and non-LSE off-takers, asking the ISO to change the final proposal to ensure that projects with power purchase agreements (PPAs) with non-LSEs are treated equally to those with expressions of LSE interest. ACP-California asked the ISO to monitor the one-project per cycle limit for non-LSE interest.

The ISO notes that the differentiation in process and point eligibility between LSEs and non-LSEs is intentional; LSEs carry an obligation to provide resource adequacy and therefore the ISO must be sure to study sufficient deliverability in the study process. Non-LSEs are not required to provide resource adequacy, however they are actively procuring resources that seek to utilize the available TPD needed for resource adequacy. In response to CEBA's specific recommendation to award higher points to projects demonstrating PPAs with non-LSEs, the ISO notes that throughout the initiative, the majority of stakeholders strongly opposed the use of PPAs as a means for projects to acquire points and advance to the study process. Stakeholders expressed concerns that incentives for PPAs early in the interconnection process would be premature without specific data on project price and commercial online dates, which could undermine procurement processes. Therefore, the ISO does not intend to award points on the basis of a PPA with an LSE or a non-LSE. Certainly, however, having a signed PPA with an interconnection customer would influence an off-taker's willingness to express interest in a project through either commercial interest mechanism.

The ISO commits to continued monitoring of the issue in Cluster 15 and exploring opportunities for increased participation of non-LSEs in Cluster 16 and future interconnection cycles, including:

- Ensuring continued alignment of non-LSE procurement needs and load growth with state and local resource planning.
- Understanding the extent to which non-LSEs currently coordinate with LSEs (e.g. energy service providers) on procurement, and to what extent LSEs are able to allocate capacity to projects that with non-LSE interest as part of the proposed LSE allocation process.
- Considering modifications to the one-project per non-LSE limit and the maximum point values for non-LSE projects.

*Additional scoring criteria*

Intersect Power suggested that the ISO reinstate the criteria for major purchases of long lead-time equipment, specifically for projects that prioritize equipment that is manufactured domestically. The ISO considered awarding points for large equipment purchases earlier in the stakeholder initiative and ultimately dropped the proposal from consideration based on significant stakeholder opposition. Stakeholders argued that specific equipment purchases would be premature prior to interconnection request applications, and the ISO did not find any means to easily validate that such purchases would be dedicated to specific interconnection projects.

Similarly, Intersect suggested that the ISO include permitting indicators as part of the scoring process, which the ISO considered in earlier proposals and also withdrew in the revised straw proposal. Many stakeholders opposed the use of permitting milestones as indicators because there is no consistent permitting pathway or set of permitting requirements for all projects, and such milestones are currently more appropriately evaluated later in the project development and interconnection process.

CalWEA expressed concerns around the lack of a definition of "long lead-time resources" and unresolved questions that will be explored in track 3. The ISO has committed to working with the CPUC and local regulatory authorities to determine eligibility for these resources, and has committed to providing details on eligibility for points in this category prior to the opening of the interconnection application window. Regarding track 3 and the question of whether to reserve capacity for specific resources, the ISO encourages stakeholder comment on that issue as a track 3 matter, however the issue is outside of the scope of the track 2 final proposal.

The ISO does not propose any changes to scoring criteria.

**150% limitation**

Some developers expressed fundamental disagreement with the concept of the 150% cap based on available transmission capacity, arguing that it undermines open access requirements.

A percentage-based cap is necessary to ensure more reasonable study volumes, which will result in more meaningful and accurate study results. The ISO designed the 150% limitation because use of a percentage ensures scalability with resource portfolios from the CPUC and local regulatory authorities, and can therefore align with system need and procurement in a given cluster, even if the need fluctuates from year to year. In addition, the 150% value ensures sufficient supply of interconnection projects advancing through the study process to be competitively procured. Furthermore, the ISO has developed the merchant option, which will not be subject to the 150% limitation and will enable continued open access to the transmission system.

The ISO does not propose any changes to the 150% limitation.

**Auction**

Aypa Power notes that the auction process will increase interconnection costs while other stakeholders suggest removing the scoring process and proceeding with the auction. The ISO believes that each element of the proposed interconnection request intake process is critical to ensuring resource diversity, reliability, competition, and meaningful study results. Specifically, the ISO developed the proposed intake process in a manner that would first emphasize alignment with resource and transmission plans and project readiness, only relying on the auction to break ties. This is consistent with stakeholder feedback we heard from the majority of stakeholders throughout the process.

The ISO does not propose any changes to the auction.

**Treatment of Energy Only resources**

Stakeholders also noted concerns with the Energy Only proposal described above. LSA and Terra-Gen argued that the proposed treatment of Energy Only projects was new in the final proposal and suggest that the proposal will lead to inequities between Energy Only projects depending on the location of the projects.

LSA and Terra-Gen also highlighted a lack of clarity in how of mixed-fuel resources (*e.g.* hybrid and co-located solar and storage) are scored whether they are Energy Only or seeking deliverability. In response to clear and consistent stakeholder feedback during the May 16th stakeholder workshop, the ISO revised the first addendum to clarify that projects will be scored based on their interconnection service capacity. If an interconnection customer seeks any deliverability in any amount, it will need to go through the TPD or merchant option process rather than be treated as an Energy Only resource. This will ensure Energy Only capacity is genuine and not meant to circumvent the screens for deliverable projects. The ISO has included this clarification in the final addendum.

The ISO developed the Energy Only proposal based on stakeholder feedback throughout the initiative and finds it to be an essential component of interconnection reform and an important means to enable continued flexibility for project developers. The CPUC noted that the proposal aligns with the MOU by incentivizing Energy Only resources in areas where the CPUC or local regulatory authorities have indicated a need for such resources.

The PTOs suggested that the ISO should cap the study of non-reimbursable Energy Only projects to ensure more reasonable numbers of projects to study. The ISO notes that it has witnessed zero interest in Energy Only projects in the last five cycles, however future CPUC portfolios do show some Energy Only resources. As such, the ISO believes the risk of too many Energy Only projects is *de minimis*.

The ISO will continue to monitor trends in Energy Only interconnection requests for alignment with resource portfolios, and will address any necessary changes to the treatment of Energy Only projects in future initiatives if necessary.

**Consideration of additional streamlining proposals**

CalWEA suggests that the ISO revisit proposals from earlier in the initiative that would study a “reasonable fraction” of interconnection capacity in each study zone based on applications to achieve reasonably accurate interconnection cost and timeline estimate. The ISO has been clear throughout the process that this pathway would not address the established principles of the Interconnection Process Enhancements initiative, nor is it consistent with FERC Order No. 2023, which sets clear timelines and requirements for the study process. Implementation of Order No. 2023 is a critical first step toward interconnection reform, but it will not sufficiently address the ISO's need to reduce study volumes. Further, Order No. 2023 requirements provide no assurance of alignment with state and local resource or transmission plans, a central underpinning of the IPE reform effort.

Aypa Power claims that the ISO dismissed early developer proposals to restructure, streamline, and automate the interconnection study business practices. The ISO is considering tools and processes internally to assist with the interconnection management process; however, this is an internal discussion intended to complement and enable broader reforms. Further, FERC Order No. 2023 established new, prescriptive requirements to streamline the interconnection study process, which rendered some of the initial stakeholder proposals inconsistent with new baseline requirements. When Order No. 2023 was issued, the ISO prioritized compliance with the Order to enable additional transformational reforms to proceed on top of the new foundation laid by FERC.

The ISO has submitted its compliance filing for FERC Order No. 2023 and does not propose to withdraw the IPE reforms described in this memo, as transformational change is critical now.

**Severability of the interconnection request intake elements**

Several parties suggested that the ISO's eventual tariff filing propose severable treatment for various elements of the interconnection request intake process, specifically the scoring process. The ISO intends to make severable a number of the elements of this final proposal to enable FERC to rule on the various elements of the filing without delaying other impactful reforms.

**Contract and queue management**

Developers, LSEs, and PTOs were all largely supportive of the proposed contract and queue management provisions; however one stakeholder raised concerns around the proposed interconnection deposit and the commercial viability criteria. Clearway suggested that the new interconnection deposit should not apply to projects with signed Generator Interconnection Agreements (GIAs). The ISO's intent is to collect a deposit from all projects that have not signed a GIA 90 days after the FERC Order implementing the requirement. This will preserve current rights while shifting project-specific costs to the projects and away from the grid management charge assessed to all ISO market participants.

Clearway also noted support for the commercial viability criteria requirements in concept but noted that in instances where a project's commercial online date (COD) is delayed due to the PTO, commercial viability criteria should not apply. The ISO generally agrees that projects should not be impacted by unilateral delays caused by the PTO, but should instead be allowed a day-for-day delay in any requirements. The final proposal includes a footnote that addresses this concern, noting "If a PTO construction delay changes the COD or construction schedule beyond the limit, commercial viability criteria 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."[4]

The ISO does not propose changes to these contract and queue provisions but clarifies that the interconnection deposit would not apply to projects that have already signed GIAs and that projects with known, verifiable PTO delays would not be automatically withdrawn from the queue.

**Stakeholder process**

The ISO greatly appreciates stakeholder engagement and perspectives and understands the magnitude of these changes on clean energy development in California and the west. Notably, most stakeholders expressed appreciation for the ISO's process, regardless of their position on the final proposal. A few stakeholders noted that the ISO rushed the proposal or issued revised documents in a manner that suggested that the details were incomplete or not fully considered. The ISO team worked very hard to provide clarity to stakeholders in response to concerns, particularly before moving the final proposal to the Board of Governors. The addendum and subsequent revisions to the addendum provide important clarifications for stakeholders as they develop final positions on the proposal and potentially prepare for a new interconnection process. The ISO is grateful that stakeholders have asked detailed questions that led to the clarifications included in the addenda, and views the revised addenda as an opportunity for stakeholders to receive clear responses to questions and concerns.

While positions on the final proposal cover a broad spectrum, the ISO believes it has developed a process that will provide greater transparency, certainty, and competition early in the interconnection request process while aligning with state reliability and policy needs. The ISO commits to continued stakeholder communication and monitoring of Clusters 15 and 16 should the need for additional reform arise.

## CONCLUSION

The ISO recommends Board of Governors approval of the Interconnection Process Enhancements Track 2 Final Proposal, with the clarifications provided in the Final

[4] 2023 Interconnection Process Enhancements Track 2 Final Proposal. P. 89

Addendum to the Final Proposal. If approved by the ISO Board of Governors, the ISO intends to file changes with FERC this summer to facilitate re-engagement with Cluster 15 by October 2024.

This package of reforms is essential for the ISO to adapt to the increased levels of need and competition for new interconnections to the ISO grid, and to ensure the ISO's continued demonstrated ability to interconnect large quantities of new generation to the grid to meet near-term reliability needs and longer-term policy requirements.