Interconnection Process Enhancements 2021

Revised Straw Proposal

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1 Introduction

The Interconnection Process Enhancements (IPE) Initiative is the ISO's ongoing commitment to improve its Generator Interconnection and Deliverability Allocation Procedures (GIDAP) and make process enhancements as resource interconnection needs evolve.

The 2021 IPE initiative is being conducted at a particularly critical inflection point in resource development in California, and in the ISO footprint in particular, as current circumstances have led to a confluence of issues that are needing consideration in the ISO's interconnection processes, related transmission and resource planning occurring at the ISO and state agencies, the procurement activities of load serving entities, and state policy development. Meeting the challenges facing timely, effective, reliable and economic resource and transmission development over the next decade and beyond will require enhancements and improved coordination across all fronts, and progress on each front must be considered in the context of improvements occurring in other parallel paths as well.

The impact of the drive towards higher levels of year over year resource development cannot be overstated. The ISO's 2021-2022 transmission planning currently underway is based on resource portfolios developed through CPUC processes that are more than double the previous plan's forecast for additions. The draft forecast requirements to be used in the 2022-2023 cycle indicate potentially a four-fold increase in new resource requirements over the forecast relied upon in the approved 2020-2021 plan[1]. At the same time, the CPUC authorized more midterm procurement in its June 24, 2021 decision that last year's 10 year plan was based on, and which was the largest single procurement authorization by the CPUC. Responding to these signals and previously approved authorizations, the resource development industry responded with a record-setting number of new interconnections requests in April, 2021, with 373 new interconnection requests being received in the ISO's Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[2] The 605 projects totaling 236,225 MW, 164,153 net MW at the Point of Interconnection (POI), currently in the queue exceeds mid-term requirements by an order of magnitude. This level of hyper competition actually creates distractions and commandeers precious planning, engineering and project management resources from the ISO and Participating TOs. Developing interconnection proposals for 10 to 15 times the volume of resources needed in that time frame, challenges the procurement activities being smoothly aligned

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

[2] ISO Board of Governors July 7, 2021 Briefing on renewable and energy storage in the generator interconnection queue, http://www.caiso.com/Documents/Briefing-Renewables-Generator-Interconnection-Queue-Memo-July-2021.pdf

with transmission planning and state policy needs (including for resource diversity) when procurement responsibility is spread over more than 40 load serving entities.

The ISO's interconnection queue and transmission planning process (TPP) has to this point been very successful in meeting emerging needs and challenges as it evolved over the last ten to fifteen years. The ISO's current processes in fact already incorporate many of the reforms set out for discussion in the recent Advance Notice of Proposed Rulemaking released by the Federal Energy Regulatory Commission[3]. However, the volume of requirements, pace of development and intensity of competition clearly call for additional reforms to current processes designed around more measured pace of planning, procurement and resource development. A broader spectrum of reform considerations is needed than adjustments to any one process in isolation, and reforms and enhancements must be considered holistically. To aid the ISO in its own considerations, the ISO commissioned a review of other practices in the US, looking not only at other ISOs and RTOs but also other FERC-jurisdictional and non-jurisdictional organizations to explore other practices that may prove helpful. This review, conducted by Grid Strategies LLC[4], was posted to the ISO website on December 13, 2021.

Progress must be made on a number of fronts including the generation interconnection process; the 2021 IPE initiative is therefore focused on the interconnection process and enhancements specifically, and other tracks of process improvement will proceed through other efforts.

Accordingly, the 2021 IPE initiative will discuss and address interconnection-related issues the ISO and stakeholders have identified given current circumstances, and will seek to resolve concerns that have surfaced since the last IPE initiative in 2018.[5] The ISO seeks to consider potential changes to address the rapidly accelerating pace of new resources needing connection to the grid to meet system reliability needs and exponentially increasing levels of competition among developers resulting in excessive levels of new interconnection requests being received.

This Revised Straw Proposal is intended to present proposed solutions that focus on near-term process enhancements based on comments received from stakeholders from the Issue Paper and Straw Proposal.

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[3] Comments of the California Independent System Operator Corporation on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generation, Docket No. RM21-17-000: *http://www.caiso.com/Documents/Oct12-2021-Comments-AdvanceNoticeOfProposedRulemaking-BuildingTransmissionSystemoftheFuture-RM21-17.pdf*

[4] "Resolving Interconnection Queue Logjams - Lessons for CAISO from the US and Abroad" October 2021, Rob Gramlich, Michael Goggin, Jay Caspary, Jesse Schneider. http://www.caiso.com/InitiativeDocuments/ResolvingInterconnectionQueueLogjamsFinalReport.pdf

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

2 2021 IPE Process Development

During the initial planning for the 2021 IPE initiative, the ISO identified certain issues to address related to the broader need for reforms, both in the short term and longer term, and also a number of relatively minor enhancements needed since the previous 2018 IPE initiative that also warranted attention.

This initiative will have two distinct, but simultaneously run, phases. Phase 1 will focus on near-term enhancements to the existing interconnection processes that the ISO can resolve for Cluster 14 and before the summer of 2022. Phase 2 will focus on resolving longer term modifications and broader reforms to align interconnection processes with procurement activities. The ISO will conduct both phases simultaneously with phase 1 targeting the ISO Board of Governors in May 2022, and phase 2 targeting November 2022.

During the Cluster 14 open window, the ISO received 373 interconnection requests, which resulted in the Supercluster Interconnection Procedures initiative that started on June 14, 2021[6]. The supercluster initiative focused specifically on addressing the immediate timing issues associated with the unprecedented number of interconnection applications to ensure parties were well informed of the timing impacts and that an effective plan could be put in place to deal with the situation. In the supercluster initiative, the ISO committed to continue to discuss topics that were not resolved in the time available within that initiative that could affect the Cluster 14 supercluster Phase II processes[7]. Topics that would impact Cluster 14 Phase II will be handled in the phase 1 portion of this initiative as described above. Another impact of the Cluster 14 supercluster is that the current GIDAP may need to be modified to be more adept at dealing with the current significant generation expansion and to better accommodate interconnecting significant amounts of new generation expeditiously to meet near-term reliability challenges. These potential changes will need more time to discuss and come to consensus with stakeholders and will be handled in the phase 2 portion of this initiative as described above.

The issues being addressed in this initiative fall into one of three categories; topics that would aid in moving resources more efficiently and effectively through the queue, topics that would aid in managing the overheated interconnection queue, and topics addressing other residual issues warranting attention at this time.

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

[7] The supercluster initiative needed to produce a filing to FERC quickly to receive a FERC order in a time frame that would allowed Cluster 14 to move forward as expeditiously as possible under a revised schedule.

3 Moving resources through the interconnection queue more efficiently and potentially more quickly

3.1 Removing downsizing window and simplifying downsizing request requirements

- Background

  In the December 6, 2021 Issue Paper and Straw Proposal, Section 3.1, the ISO proposed to transition from an annual month-long open window for receiving downsizing requests and allow them to be submitted at any time. The downsizing requests would be held by the ISO for the next reassessment study where the impact of the upgrades associated with the downsized resource would be determined. The ISO also intends to simplify the downsizing request process where appropriate.

- Stakeholder Feedback

  The ISO received stakeholder comments from 15 stakeholders on this topic, of which all stakeholder support the ISO's proposal to transition from an annual month-long open window for receiving downsizing requests and allow them to be submitted at any time. CalWEA, the CPUC, PG&E, REV Renewables, LSA/SEIA, and Middle River Power (MRP) support the proposal with the following requests for clarification:

  CalWEA wants to ensure the tariff is clear that upgrades will be reviewed in the annual reassessment, which is what we are proposing.

  CPUC requested a flowchart of the current downsizing process as compared to the proposed simplified process to illustrate how much time could be saved. In addition, they would like a similar flowchart of all changes proposed in IPE.

  PG&E would like some level of variability to the response time to the MMA-like portion of the process due to volume and timing due to possible competing timelines associated with the interconnection process.

  REV Renewables needs clarification regarding acceptance or denial of a downsizing. The process is that the downsizing will be accepted upon submission, but the removal or retention of assigned upgrades will be determined in the next reassessment study based on the reduced MW size of the project.

  LSA/SEIA, while supportive, is concerned about adding this MMA-like process to the current MMA process that is experiencing delays. Clarification is requested as to whether this process will be different or the same as the current MMA process and targeted timeline. Clarification is also requested around the criteria that will be used in the "case-by-case" determination for a project to have upgrades removed prior to the reassessment.

MRP is supportive but requests sufficient resources be devoted to a continuous downsizing request process.

- Revised Straw Proposal

Based on stakeholder feedback the ISO proposes to maintain its original proposal to simplify the downsizing process, which currently encompasses six pages of Appendix DD. The ISO proposes to remove the downsizing application window, the unique downsizing deposit, and the downsizing agreement (Appendix HH), among other simplifications. Instead, the downsizing process will be modified to allow downsizing requests to be submitted at any time and be processed through the existing MMA process.[8] Once the downsizing request is received by the ISO the project would be deemed downsized to the requested capacity. Those projects that have no network upgrades would be approved through the MMA process and the GIA would be amended. If a project has one or more network upgrades, the project would be included in the next annual reassessment to determine if the project's network upgrades are still required along with any potential cost allocation adjustments. Once the reassessment process is completed, then the downsizing MMA response would be received by the customer. Tariff rules that prevent interconnection customers from downsizing merely to reduce their cost allocations and non-refundable interconnection financial security before withdrawal will remain in place. The ISO believes the simplification of the downsizing process will enable interconnection customers to right-size their projects more easily and with less administrative burden for all parties. The impact to the MMA process is expected to be slight based on historical downsizing request data. A total of seven (7) downsizing requests have been received and processed in the last five reassessment report periods (2017-2021), and two requests submitted for study the 2022 reassessment study.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

3.2 Should Transmission Plan Deliverability (TPD) Allocation process revisions be considered?

- Background

The TPD Allocation process has worked well since the TPD allocation process was initiated for cluster 5, including instituting allocation groups in the 2018 IPE initiative. With the trend of very large numbers of IRs submitted in recent clusters the ISO requested input on potential revisions or enhancements to the allocation process. In

[8] Appendix DD, Section 6.7.2.3 requires an MMA to be completed within 45 days unless the ISO notifies the Interconnection Customer and provides an estimated completion date and an explanation for the delay.

the December 6, 2021 Issue Paper and Straw Proposal, section 3.3, the ISO proposed reducing the current seven allocation groups to three, including eliminating group three – proceeding without a PPA. Additionally, the ISO proposed simplifying the allocation retention requirements and further clarify the requirement related to a PPA requiring deliverability such that the PPA must be with an offtaker to fulfill its own RA obligation.

- Stakeholder Feedback

  The ISO received stakeholder comments from 19 stakeholders with nearly all supporting or not commenting on the simplification of the allocation groups. Both PG&E and the Six Cities fully support all aspects of the proposal. However, a majority do not agree with the elimination of the current group three – proceeding without a PPA. The majority of those who support keeping allocation group three suggested modifications to it where additional qualification criteria be included to for a projects to be eligible to use the group.

  - Commenters that support the proposal with modifications include:

    Thirteen stakeholders, ACP-California, Balanced Rock Power, Broad Reach Power, California Energy Storage Alliance, CalWEA, Golden State Clean Energy, Hanwha Q Cells, LSA/SEIA, Middle River Power, REV Renewables, RWE Renewables, Strata Clean Energy, and Upstream are in this category and present a number of varying suggestions. Some of these agree with the ISO that projects without a PPA have a higher risk of not being constructed than those with PPAs, but state that allocation group 3 is used by many as means to obtain PPA.

    A number suggest retaining allocation group 3 or develop a similar new group, possibly group 4 that allows projects to be eligible for a TPD allocation without a PPA, but requiring a higher requirements for eligibility. Others suggest the new group be a path for merchant or “ready” projects.

    LSA/SEIA suggests the current Allocation Group 3 should become a new Group 4, with retention criteria that require shortlisted or in active negotiations for a qualifying PPA by the next allocation cycle; have executed a qualifying PPA by the next cycle after that; and obtained any regulatory approval by the cycle after that.

  - Four stakeholders do not support the proposal that a PPA must be with an offtaker to fulfill its own RA obligation, but some did support elimination of Group 3.

    Amazon Energy LLC, California Energy Storage Alliance, Golden State Clean Energy and NextEra suggests the result of requiring the PPA be with an offtaker to fulfill its own RA obligation will make it unlikely that non-LSE parties will advance the development of deliverable energy projects and suggests that the market be allowed to evolve to allow entities to provide more flexible products to load serving entities.

- The CPUC suggests consideration of a way to ensure procurement efforts center on projects that meet important readiness factors, align with existing and planned transmission capacity, reflect long-term transmission planning, and support state policy and procurement goals.

- ISO response to Stakeholder comments

Broad Reach Power suggests moving this to the Phase 2, but the ISO believes it is important to be able to implement this proposal for the 2022-2023 TPD allocation cycle that begins with affidavits being due in December 2022. They also suggested allowing parked projects to progress on GIAs during parked years and allow projects to park without restriction for at least two years. The ISO has considered the option to allow parked projects to be tendered a GIA while parked, but there are a number of unknowns in this circumstance that would likely require amendments to any GIA tendered. To name a few; would the GIA be an energy only GIA that might later have to be converted to a FCDS GIA? If there are DNUs in the Phase II study report would those have to be removed or dealt with in an amendment later if the project does convert to energy only? The ISO also believes the current requirements to enable a project to park are reasonable and appropriate to protect other projects and if no TPD remains in a project's study area it is very likely that none will be available the following year.

The CPUC Staff seeks further details on the proposal to adjust the scoring weights included in the GIDAP BPM Section 6.2.9.4 and how such adjustments would improve procurement of and the allocation of deliverability to more viable projects that align with transmission availability and state policy goals. The purpose of this would be to ensure the appropriate allocation order by ensuring that the scoring is appropriately designed to ensure the most ready projects are able to obtain higher scores than less ready projects. Changes to the scoring would also be considered to help limit the number of ties that results in a number of projects receiving partial allocations when an area reaches its allocation limit and multiple projects with the same score are next in line.

Upstream is concerned that eliminating the current Allocation Group three would restrict the ability of an energy storage resource to come online as a merchant facility. The ISO believes that a merchant facility should be willing to go into operation and seek an allocation in the proposed allocation group 3 shown below. Moreover, the ISO proposes below that the PPA must procure the deliverable capacity for a minimum of five years to be eligible. Upstream also proposes that the ISO allow Independent Study Process (ISP) projects to seek an allocation as soon as their System Impact Study and Facility Studies are complete, before their cluster deliverability studies are complete. The ISO believes that that would constitute queue jumping, allowing the ISP project to get ahead of the other projects in its deliverability studies.

LSA/SEIA requested an explanation of why EO capacity requesting deliverability must be studied to "ensure the project is not behind a deliverability constraint." In accordance with Appendix DD Section 8.9.2,[9] only FCDS and PCDS projects may trigger the construction of Delivery Network Upgrades. Energy Only projects requesting deliverability may only qualify for an allocation of TPD if they do not trigger a DNU to accommodate an allocation. Therefore, Energy Only projects must be studied to determine their eligibility.

- Revised Straw Proposal

The ISO considered the suggestions for modifying the current Allocation Group three, but came to the conclusion that the suggestions were in conflict with the original intent that group three would only be for projects proceeding without a PPA. Doing so would require the group to be open to all projects without a PPA and the design of an elaborate scoring methodology to rank projects based on many factors, such as cost to interconnect, progress towards site control, status of permitting, proposed and achievable commercial operation date, and likely others. Such "scoring" is more appropriate for the procurement process. Moreover, such a process could result in all remaining TPD to be allocated in the next cycle, leaving nothing but TPD that was lost in the retention process available to be allocated in the future. Waiting to allocate TPD to projects that have executed PPAs or have been shortlisted aligns the allocation process with the planning and procurement processes, without getting ahead of the procurement process.

The ISO continues to propose reducing the current seven allocation groups to three, including eliminating group three – proceeding without a PPA. The table below and the notes that follow provide a summary of the three proposed allocation groups.

[9] Appendix DD Section 8.9.2: Only these three foregoing groups [allocation groups 1-3] may trigger the construction of Delivery Network Upgrades pursuant to Section 6.3.2. After the CAISO has allocated TP Deliverability to the three foregoing groups, the CAISO will allocate any remaining TP Deliverability to Energy Only Interconnection Customers requesting Deliverability based on the reassessment study and in the following order:

Proposed Allocation Groups

Allocation Group	Status of Project	Allocation Requirement	Can Build DNUs for Allocation?	Allocation Rank
1	Any project (active IR or achieved commercial operation)	Executed PPA requiring FCDS or interconnection customer is a LSE serving its own load	• FCDS & PCDS projects (see Note 1) • EO projects (see Note 2)	Allocated 1st
2	Any project (active IR or achieved commercial operation)	Shortlisted for PPA or actively negotiating a PPA	• FCDS & PCDS projects (see Note 1) • EO projects (see Note 2)	Allocated 2nd
3	Any project that achieved commercial operation	Commercial operation achieved	• FCDS & PCDS projects (see Note 1) • EO projects (see Note 2)	Allocated 3rd

Note 1: FCDS & PCDS projects can fund the construction of DNUs assigned to them in their study reports to give them their current level of requested deliverability.

Note 2: EO projects can only utilize any remaining capacity from existing and yet to be constructed DNUs that is not assigned to a FCDS or PCDS project.[10]

Additional Criteria:

- Projects with Energy Only Deliverability Status requesting deliverability, including Partial Capacity Deliverability Status projects that elected to convert any non-allocated portion of their project to Energy Only must be studied to ensure the project does not trigger a DNU to accommodate an allocation and must submit to the ISO a $60,000 study deposit for each Generating Facility seeking TP Deliverability.
    - TPD will only be allocated up to the amount of deliverable MW capacity procured by the PPA.
- The GIDAP BPM Section 6.2.9.4 defines the process where points are allotted to projects based on the project's maturity in areas such as their PPA, permitting and land acquisition. The points are used to rank the projects for determining the order that they are considered for allocating any available TPD. The ISO proposes that during the process of updating the BPM following the FERC

[10] Summarizing Appendix DD, Section 8.9.2, only FCDS and PCDS projects may trigger the construction of Delivery Network Upgrades pursuant to Section 6.3.2. After the CAISO has allocated TP Deliverability to FCDS and PCDS projects, the CAISO will allocate any remaining TP Deliverability to Energy Only Interconnection Customers requesting Deliverability based on any remaining deliverability available.

approved tariff changes, the ISO will consider making adjustments to the scoring process and weights within Section 6.2.9.4. The intent is to ensure that the more ready projects are considered for an allocation first and to provide more differentiation between projects to reduce the likelihood of ties.

- Further clarify the requirement related to a PPA requiring deliverability.

  The intent of constructing delivery network upgrades and allocating deliverability is to allow the facility to participate in the Resource Adequacy program (RA). Although the tariff requires the PPA to require deliverability, it is ambiguous the deliverability required by a PPA is ultimately utilized by, or offered to, an entity with an RA obligation. The ISO proposes to revise the tariff to clarify that beginning with the 2022-23 TPD allocation cycle, a PPA must be with an offtaker to fulfill its own RA obligation. In other words, the PPAs of offtakers that do not have RA obligations will not be eligible for groups 1 or 2. Furthermore, the PPA must procure the deliverable capacity for a minimum of five years to be eligible. These are proposed to ensure that the TPD capacity built at transmission ratepayer expense to provide sufficient transmission capacity for the RA requirements and CPUC policy to be met is fully and effectively utilized to the greatest extent possible.

- Revisions to the TPD retention process.

  In addition to the seeking TPD allocation modifications above, the ISO proposes to eliminate all TPD retention criteria except that those projects that received an allocation in group to 2 (as currently shortlisted or negotiating a PPA), must submit an executed PPA by the retention affidavit due date in the allocation cycle following the year the allocation was received.[11]

The ISO proposes to address this issue within the scope of Phase 1: Long-Term Enhancements.

3.3 How can the interconnection process and procurement activity align with transmission system capabilities and renewable generation portfolios developed for planning purposes?

- Background

The ISO's transmission planning process includes a framework for developing policy-driven transmission associated with state (and federal, although that has not yet been relevant) policy needs and direction. However, that policy direction in the transmission planning process is not coordinated with interconnection requests seeking to utilize that capacity as it is being developed, nor with the procurement

[11] Appendix DD Section 8.9.3 (3): If the Generating Facility received TP Deliverability on the basis of negotiating or being shortlisted for a power purchase agreement, it must have executed the agreement by November 30 of the year it received TP Deliverability.

activities of the large number of load serving entities now having procurement obligations. In the December 6, 2021 Issue Paper and Straw Proposal, section 3.4, the ISO sought stakeholder feedback on two concepts: 1) the concept of not only developing transmission capacity for planning purposes associated with achieving specific resource development; and, 2) as a further step, withholding that capacity specifically for the policy-driven processes for which it was planned rather than relying on it for any and all interconnection requests received through the request windows. The above concepts could potentially help where new capacity is created or capacity is currently available and not already allocated to resources in the queue, but would not help where the overheated queue has already resulted in all available and planned capacity being allocated.

- Stakeholder Feedback

ACP-California, California Energy Storage Alliance (CESA), Golden State Clean Energy, NextEra, PG&E, SCE, and Six Cities support this issue being addressed within the scope of Phase 2: Long-Term Enhancements. ACP-California and CESA urge the ISO to utilize the ISO's 20-Year Transmission Outlook to assist in this developing proposals for this issue. Additionally, PG&E requests the ISO require that solutions developed in the TPP require some work with relevant LSEs to determine the best and most feasible solutions. PG&E notes that more joint work will allow the ISO and PTOs to meet procurement goals. Further, SCE encourages the ISO to develop proposals for this issue based on the needs and direction provided in the CPUC's IRP process. Finally, Six Cities urges more discussion on this issue in order to explore the root cause of the lack of alignment between planning and procurement activities arise and to determine if this issue is driven by a need for improved coordination with LRAs or other reasons.

The CPUC supports the ISO developing proposals to improve the coordination between procurement activities and transmission planning process. They acknowledge there is room for improvement in coordination efforts and state they are taking additional action by starting the Transmission Development Forum and Tracking Energy Development (TED) Task Force to improve coordination with the ISO and others. Further, the CPUC request the ISO describe the issue of lack of coordination in more detail to ensure the design of the most effective solution. Similar to other stakeholders, the CPUC supports more discussion regarding the withholding and reservation of transmission capacity for projects that achieve policy goals. Specific to determining what qualifies for withheld transmission capacity, the CPUC requests the ISO consider 1) the resource types and amounts mapped to the relevant busbars and 2) the resource types that could utilize the transmission capacity to achieve policy goals. Additionally, the CPUC suggests that when a transmission upgrade is withheld, it is announced in a timely and transparent manner and that the ISO prioritize withholding transmission capacity for long-lead time and location constrained resources types.

CalWEA recommends this issue be addressed by the CPUC through the IRP process by optimizing the portfolio in a manner that does not seek to avoid transmission upgrades. REV Renewables also suggest the ISO work with the CPUC and other state agencies on this effort to better align procurement process with the ISO's TPP. Hanwha Q Cells notes this issue should be focused on adding efficiency to help California achieve its 2045 carbon neutrality goal.

EDF-Renewables support the ISO leveraging the published Grid Strategies Report published on December 13, 2021 for reference to actionable steps to improve joint agency coordination. They recommend the ISO consider how and if its proposals in this initiative address changes needed as identified by the report. Specifically, EDF-Renewables support further discussion on the Grid Strategies suggestion of developing more stable interconnection costs to reduce uncertainty on developers and procurement entities.

ACP-California, CESA, and Middle River Power are unsure of a process that develops transmission capability targeting developing specific "policy-driven" resources and reserves transmission capability only for resources that meet the "policy-driven" definition. ACP-California notes that it is unclear how the ISO will pick "winners and losers" between similar "policy-driven" resources that are trying to interconnect. However, ACP-California advocates this type of proposal may work in the Diablo area that warrants unique policy-driven attention specific to Offshore Wind resources. ACP-California explains they are supportive of modifications to the transmission planning and deliverability allocation process that would allow for the ISO to receive public policy direction from the CPUC to "reserve" capacity for specific resource types such as geothermal or offshore wind. Alternatively, Middle River Power supports an open season model would be more beneficial as new technologies emerge and would not strand significant transmission investment.

RWE Renewables neither supports nor opposes this proposal. However, they are in favor of a proposal that is technology neutral. Similar to other stakeholders, they believe this proposal warrants more discussion and coordination with transmission planning. REV Renewables is also supportive of a proposal that is unbiased in its assessment of project technologies or locations.

Golden State Clean Energy do not support a proposal that considers a reservation system within the policy-driven process as a means of ensuring the intended resources are allocated deliverability. They note this proposal does not consider the current impediments to planning for new infrastructure and does not align with the ISO's position that deliverability is not a right conferred on interconnection customers. Alternatively, Golden State Clean Energy support a proposal that focuses on locational considerations and least-regrets policy resource zones based on the ISO's 20-year transmission outlook and zonal assessment supported by the state agencies and the SB 100 report. Finally, Golden State Clean Energy note that to the extent policy development requires changes to the TPP, the ISO should start a new initiative narrowly scoped to address changes to the IPE and TPP in tandem to ensure needed policy reforms are addressed.

LSA/SEIA oppose this proposal because it favors specific technology types, namely new offshore/imported wind and geothermal resources. They note this proposal is not consistent with the ISO tariff and associated rules which are technology-neutral and based on open-access principles. SCE also notes they do not support "withholding" capacity for any specific resources because it would violate open-access principles.

REV Renewables believe the ISO should not withhold any capacity for any projects studied in any process. They suggest that for out-of-state wind resources that are in CPUC renewable generation portfolios that they be evaluated at their points of interconnection in BAs outside of the ISO rather than at the ISO boundary injection points. REV Renewables note this evaluation would provide the ISO a better determination of transmission needs to deliver out-of-state renewable generation.

- Revised Straw Proposal

The ISO remains concerned that lack of coordination among the transmission planning process—and policy-driven transmission in particular—the interconnection process, and load serving entities' procurement processes continue to create the opportunity for transmission to be utilized by resources not envisioned in the original policy direction but earlier-positioned in the queue, resulting in challenges in meeting state resource policy goals. The ISO will not advance a specific proposal at this time, but will seek further stakeholder input on this issue in a separate stakeholder working group.

3.4 Should a solicitation model be considered for some key locations and constraints not addressed in portfolio development, where commercial interest is the primary driver?

- Background

While the ISO raised this issue somewhat generically in its December 6, 2021 Issue Paper and Straw Proposal section 3.6, two alternative concepts underpinned the request for stakeholder feedback: (1) a solicitation model to clarify in an overheated area which projects should proceed into the interconnection process; and (2) a solicitation model to assess interest in an area in which transmission capacity may be expanded in the planning process, with commitments from the resources helping support the transmission development.

- Stakeholder Feedback

Several entities (including CESA, MRP, PG&E, EDF-R, NextEra and REV) express support for exploring different solicitation type models. CESA focuses on locations where there is limited existing transmission availability relative to the interconnection requests, where the ISO's solicitation model concept could be considered, along with higher commercial viability criteria, fees, and/or deposits could be applied as screening and scoring criteria. EDF-R believes that solicitation model proposals need to be sufficiently detailed before their merit can be evaluated.

With respect to proposal (1), EDF asserts that a solicitation model to identify which projects should be carried forward into the interconnection process conducted in conjunction with load serving entity procurement processes, EDF-R requests that any coordination ISO does with LSEs as a part of the LSE's RA solicitation efforts be completely transparent to the interconnection customer.

EDF-R, REV and MRP supports further discussion on proposal (2) a solicitation model confirm interest in an area in which transmission capacity may be expanded with commitments from the resources helping support the transmission development.

PG&E expressed interest but looked to hear from the development community on the two solicitation models to identify projects which should be carried forward into the interconnection process and to identify interest in the development of transmission capacity where commercial interests would fund the transmission development in exchange for rights to interconnect ahead of projects in the queue.

- Revised Straw Proposal

The ISO will not advance a specific proposal at this time, but will seek further stakeholder input on this issue in a separate stakeholder working group.

3.5 Should the ISO develop an emergency generation interconnection process?

- Background

In the September 30, 2021 preliminary issue paper, section 3.2, the ISO sought stakeholder input on whether a new accelerated process should be considered for projects that can demonstrate an advanced readiness that would allow them to quickly go into operation relative to other projects. As noted in the December 6, 2021 Issue Paper and Straw Proposal, section 3.7, stakeholders were in three equally sized camps. Some stakeholders supported this but did not provide specific ideas on how to implement such a process. Some request the ISO clearly define "readiness" criteria for them to consider. The rest, primarily from the resource development community, opposed. Given the reluctance from the industry to adopt such measures, and the challenges to define and validate "ready" criteria that would be acceptable to the earlier-queued projects being leapfrogged, the ISO did not recommend a proposal for long term access to be based on this approach.

Nevertheless, the ISO believes it should develop a similar but distinct framework for urgent, reliability-driven interconnection service for interim interconnection. Such interconnections would resemble the emergency generation put in place this past summer in response to the governor's proclamation. The ISO proposed an expedited process to the extent a potential capacity shortfall is determined by the ISO that requires a proclamation from the governor and a state agency would need to determine the generator(s) required to meet the shortfall. The ISO would then work with the applicable Participating TO, state agency, and generator to expedite the interconnection process. The generator would be allowed to interconnect for a maximum of three years or a shorter period of time determined by the state. In addition, the emergency generator can be accommodated using existing interconnection service, does not require substantial Network Upgrades to be built,[12] and cannot harm any third party. The ISO proposed to address this issue within the scope of Phase 2: Long-Term Enhancements.

- Stakeholder Feedback

The ISO received stakeholder comments from fifteen stakeholders on the topic of developing an emergency generation interconnection process. Six Cities, CPUC, Clearway, CESA, ACP California, REV Renewables, Middle River Power and RWE Renewables all indicate support for this proposal. A few of these stakeholders state the emergency process must be clearly defined, only applied under emergency authorization as a last resort, and must avoid queue jumping. Additionally, a number of these stakeholders support, or requested clarifications on, providing interim deliverability for these projects. Middle River Power comments that no project that was first interconnected under the WDAT process should be allowed to use these new emergency tariff provisions.

CalWEA, Upstream, and Balanced Rock Power oppose this proposal. CalWEA states the ISO should focus on expediting the completion of upgrades that are delaying many projects in the queue from becoming operational. The ISO should address this fundamental problem rather than create shortcuts that CalWEA

[12] Generally *some* telecommunications facilities are necessary for any new generator, and because they extend to the ISO side of the point of interconnection, are classified as network upgrades. The intent is to prevent generation that would require more substantial upgrades and facilities that take meaningful time, effort, and expense. Such generation is ill suited for emergency situations and risks queue jumping.

believes will mostly benefit PTO projects. Upstream strongly opposes the ISO proposal to create a reliability-driven interconnection service for interim interconnection on the basis that there are a significant number of queued projects that can come online in 2023 and 2024 and this proposal is not needed. Upstream also made an alternative proposal to allow Fast Track and ISP projects to submit for an Energy Only TP Deliverability Study (See 8.9.2 of Appendix DD) as soon as the ISP System Impact Study and Facility Studies are complete and with the next TP. Balanced Rock Power opposes the proposal to allow PTOs to interconnect their UOS for a period of three years or less as this essentially permits “queue jumping” and bridges the period of time between calling the UOS a “distribution asset” and the time the PTO can file an interconnection request under its Wholesale Distribution Tariff.

SCE, EDF Renewables, PG&E, and Strata Clean Energy neither support nor oppose this proposal. SCE commented that a “first ready” is a dramatic departure from the “first come, first served” approach and suggest any further discussion on the broader topic be done outside of the current IPE. EDF Renewables is reluctant to support such a measure and the ISO should focus on a holistic restructuring that includes a more agile and time-efficient approach to generator interconnection studies and transmission planning. PG&E agrees this topic should be included in IPE but has concern with the development of a separate process for urgent reliability-driven projects since the same resources that would support these projects support other work needed to interconnect projects and complete their upgrades. PG&E also has observed that accelerated projects are often incapable of achieving the dictated schedule and that the acceleration can result in time-consuming mistakes in the interconnection process. Strata Clean Energy did not specifically comment on the current proposal to develop an emergency interconnection process, but supports dropping the proposal for “ready” projects because accelerated study processes already exist. ISO should look to improve on these existing processes.

- Revised Straw Proposal

There is significant support for the ISO proposal to develop a transparent, tariff-based emergency generation interconnection process in lieu of petitioning for further waivers. This ISO agrees with stakeholders that this process must be clearly defined, only be utilized under an emergency authorization, and must avoid queue jumping. The ISO also agrees with stakeholders that if available, interim deliverability can be provided but only for the duration of the emergency order, not exceeding three years.

Upstream’s alternative proposal to allow Fast Track and ISP projects to submit for an Energy Only TP Deliverability Study as soon as the ISP System Impact Study and Facility Studies are complete and with the next TP is being addressed in the proposal to revise the Transmission Plan Deliverability (TPD) Allocation process in section 3.2.

The ISO proposes the following for the emergency generation process:

1. The ISO will accept emergency generation study requests only pursuant to a specific emergency state mandate, and only for interconnections and additions specifically designated by a state agency, not including counties, municipalities, or CCAs.
2. The ISO also must agree the interconnection is warranted to potentially maintain reliability, and that the interconnection will mitigate reliability risks.[13]
3. The interconnection customer will submit an emergency generation study request, a $50,000 study deposit, and all necessary technical information to assess the new generation.
4. Because the ISO anticipates these studies and interconnections will be rapid, the ISO does not propose to include any study timelines in the tariff.
5. The interconnection cannot negatively impact the cost or timing of any queued project unless the impacted project belongs to the same developer and the developer consents to the impact.
6. The interconnection cannot require network upgrades above $ 1 million or that cannot be constructed in fewer than six months.
7. The installed generation will have interconnection service for no more than three years. For interconnection service beyond that period, the developer must obtain service through another tariff process, such as a new interconnection request.
8. During the three-year period, the generation will be ineligible for any deliverability except Interim Deliverability, consistent with Section 4.6 of the GIDAP.

Although originally proposed to be addressed within the scope of Phase 2: Long-Term Enhancements, the ISO proposes to include this proposal within the Phase 1: Short Term Enhancements. This topic received general support from stakeholders and may be necessary to have in place before Summer 2022.

[13] The intent of (1) and (2) is to prevent anyone from abusing this process to interconnect generation outside of its specific purpose.

4 Managing the overheated queue

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

- Background

  In the September 30, 2021 preliminary issue paper, section 4.1, the ISO sought stakeholder input on whether the bar for entry into the interconnection process should be raised to discourage numerous IR submissions by a single developer, such as requiring higher fees or deposits for submitting an IR, or imposing other requirements. Stakeholders were generally supportive for higher fees or imposing other requirements.

  In the December 6, 2021 Issue Paper and Straw Proposal, section 4.1 the ISO proposed that for the first two projects submitted by a parent company/entity the study deposit would be $250K per request, for projects 3-5 the study deposit would be $500K per request, and for any more than 5 projects, the study deposit would be $1M per request. The same percentages would be at risk as currently defined in the tariff. The ISO also proposed (1) to increase the site exclusivity deposit requirements to $250k for small generators and $500k for large generators; and (2) if a project withdraws after the interconnection request is deemed complete, 50% of the in-lieu site exclusivity deposit becomes nonrefundable.

- Stakeholder feedback

  - Proposal to increase study deposits

    Five stakeholders, Six Cities, SCE, Balanced Rock Power, Strata Clean Energy, and Upstream support the ISO's proposal to increase study deposits as is.

    Four stakeholders support the ISO's proposal to increase study deposits but with modifications. PG&E states that there should also be a cap in the number of interconnection requests (IRs) a company or affiliate can submit in total and at a given POI. Q Cells suggests the fee structure proposed by the ISO is excessive and recommends 1-5 IRs = $200K and > 5 IRs = $500K. NextEra proposes 1-5 IRs =$250K, 6-10 IRs = $500K, and >10 IRs = $1M. RWE Renewables supports raising costs but recommend a project cost scale or $/MW study deposit and further discussion on amount at risk.

    Seven stakeholders oppose the ISO's proposal to increase study deposits. CalWEA opposes higher fees and study deposits that could be a barrier for smaller developers and any measures to pare down the queue should be aimed at developers that submit an inordinate number of applications, therefor recommends keeping study deposits for the first five IRs at the current level. CESA is open to considering some increase in study fee that is tied to actual study costs or historical precedent (e.g. $250K). Broad Reach Power ACP California stated the ISO did not provide evidence that multiple requests submitted by a single party were less serious than those parties that submitted few requests and the ISO proposal is unduly discriminatory. EDF Renewables stated the ISO proposal presupposes the outcome of FERC ANOPR RM21-17 which seeks to identify how to determine a just and reasonable limit to IRs. The ISO should continue to require $150K for IR. If the ISO proceeds, the ISO should provide reciprocal clarity in amount of information provided at scoping meeting and separate what amounts are “study deposit”, and “scaling non-refundable fees”. ACP California states the ISO Proposal is discriminatory. Recommend the ISO consider higher capital at risk requirements and increase transparency and provide info on the high-level likely viability early in the queue process. REV Renewables – Support higher fees but not the tiered structure for multiple IRs. Supports an increase to $250K, and could support beyond $250, but only on a per project basis. LSA/SEIA is neutral on increase to $250K, but strongly opposed to increasing scale with multiple requests. The ISO offered no evidence that entities that submit multiple requests are less solid or successful than entities that submit low numbers of IRs.

A number of stakeholders, whether they supported or opposed the ISO Proposal above, requested clarity on how the ISO would enforce/identify the number of IRs per parent company/entity and how it would apply to complex project ownership such as joint ventures.

- Proposal to increase site exclusivity deposit with non-refundability provisions.

Seven stakeholders, Six Cities, SCE, Balanced Rock Power, PG&E, Middle River Power, RWE Renewables and LSA/SEIA support the ISO’s proposal as is. RWE Renewables states there needs to be an alternative when site is on federal/state/tribal lands.

Five stakeholders support the ISO proposal to increase the site exclusivity deposit but with modifications to the refundability provisions. Upstream recommends refundability of site exclusivity be 50% nonrefundable 30 days after scoping meeting. REV Renewables suggest 50% refundability be tied to the completion of the scoping meetings and would like clear definition of site exclusivity. Also suggests non-refundable site exclusivity deposits be used for additional studies needed for impacted projects. CalWEA recommends refundability of site exclusivity be 50% nonrefundable 30 days after Phase 1 results meeting Strata Clean Energy recommends aligning refundability provisions of the site exclusivity deposit with the study deposits. Next Era opposes loss of site exclusivity deposit if forces to withdraw prior to Phase II studies.

- Revised Straw Proposal

  The ISO plans to further consider its proposal for increasing study and site exclusivity deposits and will include a revised proposal in the next paper.

  The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

4.2 Should site exclusivity be required to progress into the Phase II study process?

- Background

  In the December 6, 2021 Issue Paper and Straw Proposal, section 4.2, the ISO proposed to require site exclusivity (SE) to move into the Phase II study process, beginning with Cluster 14.

- Stakeholder Feedback

  The ISO received stakeholder comments from eighteen stakeholders on this topic. Majority of stakeholders support implementing this SE requirement starting with Cluster 14 believe reasonable measures to identify viable projects is necessary for credible results in the C14 Phase II study and the extended C14 study timeline gives developers until the end of 2022 to obtain SE. As an alternative, some would support an increase in financial commitment such as making the SE deposit non-refundable as a requirement in addition to the existing requirements to enter the Phase II study process. Hanwha Q Cells does not support deposits in lieu of SE and feel Phase II is the appropriate timeline for a project to have SE. SCE suggests that SE be through the COD as currently required, and adjusted if/when the COD is revised due to circumstances such as IC request or PTO delay/construction sequencing.

  Those that oppose implementing this SE requirement starting with Cluster 14 believe it would be problematic as Phase I results are “advisory.” They recommend implementing a higher deposit and “capital-at-risk” option for C14 projects that cannot demonstrate SE but wish to proceed to Phase II and if implementation is considered for C14, notice should be provided to all market participants in advance of issuing the C14 Phase I reports.

  ACP-California also recommend additional discussion on the definition of SE for off-shore wind projects and if there should be special timing considerations that need to be taken into account, such as the timing of the BOEM lease auctions.

- ISO response to Stakeholder comments

  The table below shows that 68 percent of the Cluster 14 interconnection requests provided a deposit in lieu of SE documentation. The data also shows that 32 percent, 119 projects, were able to provide SE documentation, which demonstrates the requirement for SE by Phase II is not unreasonable and that requiring SE for Cluster 14 Phase II studies is not unreasonable given that projects would have until the end of 2022 to provide the SE documentation (see proposed timing for when documents would be due in the proposal below).

C14 IR Site Exclusivity Data		
IRs with Deposit	253	68%
IRs with SE Documents	119	32%
Total	372	

The ISO is experienced with reviewing SE documentation as part of the interconnection request validation process and believes the added workload between the Phase I and Phase II studies can be accommodated.

- Revised Straw Proposal

  The existing tariff definitions and requirements for SE are referenced below. With the exception of adding defined requirements for wind projects, no changes are proposed.

  ISO Tariff Appendix A:

  - Site Exclusivity

    Documentation reasonably demonstrating:

    (1) For private land:

    (a) Ownership of, a leasehold interest in, or a right to develop property upon which the Generating Facility will be located consisting of a minimum of 50% of the acreage reasonably necessary to accommodate the Generating Facility; or

    (b) an option to purchase or acquire a leasehold interest in property upon which the Generating Facility will be located consisting of a minimum of 50% of the acreage reasonably necessary to accommodate the Generating Facility.

    (2) For public land, including that controlled or managed by any federal, state or local agency, a final, non-appealable permit, license, or other right to use the property for the purpose of generating electric power and in acreage reasonably necessary to accommodate the Generating Facility, which exclusive right to use public land under the management of the federal Bureau of Land Management shall be in a form specified by the Bureau of Land Management.

  ISO Tariff Appendix DD Section 3.5.1 (iii):

> The demonstration of Site Exclusivity, at a minimum, must be through the Commercial Operation Date of the new Generating Facility or increase in capacity of the existing Generating Facility.

The ISO proposes to add item (3) to the Appendix A SE definition for offshore wind projects; e.g., site control for offshore wind projects requires a demonstration of a lease-hold to site the wind project that has been secured from the relevant agency (state or federal).

- The ISO seeks stakeholder input on the appropriate criteria for defining SE for offshore wind projects.

The ISO proposes to require site exclusivity to move into the Phase II study process and that the SE documents would be due 10 business days prior to the initial IFS posting due date for each project. Based on a significant majority of stakeholders agreeing that SE be required to proceed into the Phase II study process, and implementing the requirement for Cluster 14, the ISO proposes to implement the requirement for Cluster 14 Phase II study eligibility.

The ISO believes this will help mitigate the overheated queue and allow Phase II studies to focus on the most committed projects and for the Phase II study results to be more accurate and less subject to change. The ISO notes that this proposal still provides more flexibility than other ISO/RTOs in obtaining a final site. Both PJM Interconnection and the Southwest Power Pool require SE to submit IRs, and MISO requires SE or higher deposits than the ISO. The ISO also notes that it proposes increasing the in lieu of SE deposit requirement and making a portion of it non-refundable if the customer withdraws, as explained in section 4.1, above.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

5 Other Issues

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

- Background

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

The ISO addressed this issue with stakeholders and filed a narrowly focused proposal to FERC in 2017. FERC ultimately found that the ISO failed to support its proposal as just and reasonable and not unduly discriminatory and rejected the ISO's filing without prejudice, which allows the ISO to refile a proposal.[14]

In the December 6, 2021 Issue Paper and Straw Proposal, section 5.1, the ISO proposed that the addition of the capital costs for low voltage (<200kV) network upgrades driven by generation interconnections to the LTRR of a Participating TO will not cause the aggregate of the net investment for all low voltage network upgrades driven by generation interconnections included in the LTRR to exceed fifteen (15) percent of the aggregate of the net investment for all low voltage transmission facilities of that Participating TO reflected in their LTRR in effect at the time of the in-service date of the network upgrade. Any costs for low voltage network upgrades in excess of the 15 percent threshold will be financed by interconnection customers without cash reimbursement.

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

- Stakeholder Feedback

  The ISO received stakeholder comments from 12 stakeholders of which PG&E strongly supported the proposal outlined above and SCE does not oppose.

  Four stakeholders oppose the ISO's proposal and some of these stakeholders suggested alternative proposals. VEA estimates that the ISO's 15% cost cap proposal would result in excess of $3 million in cost exposure for Valley's members where VEA's total capital budget for 2022 is about $6 million. VEA states their resource needs are fully sourced for the foreseeable future and there is no cost justification for allocating these interconnection related costs to VEA's members. VEA proposes a new category of interconnection cost allocation for resources that have the following characteristics: (i) the resource is a carbon free resource that interconnects to low-voltage facilities of a PTO located outside of California; and, (ii) the output of the resource has not been purchased by the interconnecting PTO or an entity located outside of California. For a resource that meets these standards, the network upgrades would be included in the High Voltage TAC. CalWEA strongly opposes requiring that interconnection customers finance network upgrade costs exceeding the funding cap. Treatment of network upgrade costs should not differ simply due to a different interconnection voltage level. ACP California states the ISO's proposal fails to properly allocate costs to beneficiaries, could be unduly discriminatory to, and likely serve to inhibit, generation that interconnects to the VEA area. Recommends that ISO further consider implementation of alternatives submitted in VEA's prior comments. LSA/SEIA oppose the ISO's proposal because it is unjust and unreasonable to impose different and discriminatory refundability rules in different ISO-area locations. Recommends addressing FERC's problems with earlier proposal; consider system wide uniform LVTAC rate; system wide LVTAC adder to fund interconnection-related upgrades; allocation of "excess" costs to other PTO LVTAC rate based on contracting of projects in the VEA area by LSE's in other PTO areas; or approaches originally recommended by VEA.

  There were six entities that neither support nor oppose the proposal but provided comments. Six Cities states the current structure and delineation between high and low voltage is not in need of revision, however the ISO proposal addresses Six Cities concerns with transfer of cost from low voltage to high voltage. Useful for the ISO to provide examples how this proposal would apply to each PTO. CPUC requested clarifications to a number of questions, including how it impacts PTOs besides VEA. Also notes that cost allocation mechanism for distribution upgrades triggered by interconnection is under consideration as part of Phase 2 of CPUC's Rulemaking ® 17-07-007. CalCCA supports allocation methodology that allocates costs to all those who receive benefits. The ISO's proposal to cap the percentage of interconnection-related network upgrade costs in each PTO's LTRR improves the current structure with respect to protecting local ratepayers from the cost impact of network upgrades that benefit all customers. However, the ISO should describe how the proposal will treat upgrades that benefit all customers if they fall under the proposed cap. If the purpose of the network upgrades is for generation projects to be deliverable anywhere on the grid, then all customers benefit and should share the costs. Hanwha Q Cells generally supports pushing costs regionally so that local customers are not burdened, and communities do not push back on projects due to high local costs. Further, Q CELLS believes that interconnection customers should receive a fair treatment from a cost reimbursement standpoint if the generation addition provides grid benefits to ratepayers outside the local area of the PTO. REV Renewables state the ISO should reconsider the cost allocation rules in broad context of the FERC Advanced Notice of Proposed Rulemaking: Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection - Docket No. RM21-17-000 ("ANOPR"). Given the overwhelming comments received on the ANOPR, reforms to the transmission planning, cost allocation, and interconnection processes are imminent in order to support transformation of the electricity sector. The definition of "local" vs "regional" was one of the most discussed topics in this proceeding. The CPUC's comments on the ANOPR, for example, provide several references to and examples of the ISO processes, questioning whether the definition of "local" should be redefined to include facilities lower than 200 kV. Additionally, whether these lower voltage facilities should be competitively built, which could reduce overall upgrade costs. Strata would like to gain more understanding on how ISO expects to mitigate risk on a single set of ratepayers and how the funding cap is established.

- Revised Straw Proposal

The ISO plans to further consider its proposal and will include a revised proposal in the next paper.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

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

- Background

In the last decade, there have been virtually no instances where a generator's interconnection to a neighboring balancing authority area would affect the reliability of the ISO grid. In interconnection terms, the ISO is almost never an "affected system." However, recently the ISO has received a few notices from neighboring BAAs that a proposed interconnection may affect the ISO, and therefore warrants study. The ISO developed a study process and agreement for such studies in the Contract Management Enhancement initiative. However, that initiative deferred the question to IPE of how any network upgrades required to mitigate reliability impacts would be reimbursed.[15] The ISO also needs to determine what base cases would be used for affected system studies.

In the December 6, 2021 Issue Paper and Straw Proposal, section 5.2, the ISO proposed the base case assumptions for the ISO as an affected system study to be based on previously queued projects as of the affected system study agreement execution date. The ISO also proposed to use its existing policy for RNU reimbursement for RNUs resulting from an affected system study. Under FERC Order No. 2003, the ISO must provide some form of remuneration for the financing of network upgrades, either in the form of cash reimbursement or transmission rights, which would be Merchant Transmission CRRs for the ISO. The ISO believes providing cash reimbursement is preferable for several reasons:

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

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

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

- Stakeholder Feedback

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

  Five stakeholders, CalWEA, LSA/SEIA, Strata Clean Energy, Hanwha Q Cells, and Middle River Power, support the ISO's proposal to use its existing policy for RNU reimbursement for RNUs resulting from an affected system study. LSA/SEIA also urges the ISO to seek reciprocal arrangements with other jurisdictions. Hanwha Q Cells state that timelines for repayment should be shorter than one-time cash payment at the end of 20 years and should provide an option other than Transmission Service Credits.

  Two stakeholders opposed this proposal. Six Cities is not convinced the ISO's proposal is reasonable or appropriate. Is the ISO's position that FERC policy has specifically dictated that network upgrade costs due to affected system impacts must be reimbursed? Or only that FERC's general policy provides for network upgrade cost reimbursement, and since network upgrades may be identified as a result of affected system studies, affected system upgrades should be subsumed within that policy? The concept of providing reimbursement has less to do with the jurisdictional status of neighboring entities and whether or not their policies provide for reimbursement of network upgrades at all, and has more to do with fairness and reciprocity. SCE opposes the ISO's current proposal and agrees with the ISO's proposal regarding Affected Systems in its Contract Management "COMA" Enhancements Initiative Issue Paper / Straw Proposal issued August 10, 2021, that "Participating TOs will not reimburse external interconnection customers for network upgrades. This practice is consistent with neighboring utilities' practices for ISO interconnection customers.

  Two stakeholders that neither support nor oppose the ISO's proposal but provided comments. RWE Renewables is neutral but would definitely ask the ISO to make sure that the same is reciprocated by the affected system i.e. ISO projects would receive a similar repayment mechanism from the affected system. PG&E supports the inclusion of this enhancement in the IPE and agrees that it should be addressed in the long-term phase of the IPE. PG&E looks forward to further discussions with the ISO and other stakeholders on this enhancement and how it would affect the timelines of studies and cost reimbursement.

- Revised Straw Proposal

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

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

  The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

5.3 Expanded errors and omissions process to provide criteria and options when changes to network upgrade requirements occur after Financial Security (IFS) postings have been made

- Background

  In the December 6, 2021 Issue Paper and Straw Proposal, section 5.3, the ISO proposed that any cost responsibility increases associated with an error or omission discovered after a project makes its second IFS posting should be the responsibility of the party that made the error or omission. Specifically, the MCR and MCE cannot be increased due to an error or omission discovered after the second IFS posting due date has passed.

  The ISO further proposed that when an error or omission is discovered after a project has made either its first or second IFS posting that increases the aggregate of all costs for the project to interconnect, regardless of whether the cost is refundable, or pushes back its earliest achievable ISD, the project would be given the option to either accept and move forward with the changes or withdraw and receive a full refund for its IFS and a refund of any unused study deposit. The ISO proposed a cost increase threshold of five (5) percent and a minimum of a 12 month delay in the earliest achievable ISD.

- Stakeholder Feedback

The ISO received comments from 14 stakeholders commented on this topic of which eight support the proposal as outlined above and five support with modifications.

Those that support the proposal, but have suggested modifications, suggest adding language that acknowledges that the deliverability start date is also critical to commercial viability and include a delay in the effective date of FCDS/PCDS by more than 12 months and including a delay in the IC breaching its executed PPA. Middle River Power supports, but suggested increasing the cost threshold from 5% to 10%, and minimum increase to the ISD should be cut from 12 months to six months. PG&E feels the requirement should be implemented at the 3rd IFS posting, not the 2nd. Items that they feel need addressing are increased costs, project delays, and cost shifts between IC and the PTO when errors/omissions are triggered by delayed or canceled TPP projects or a new DNU identified in subsequent reassessments. Impact of delays from the IC side due to suspension or parking a project and the effect on projects moving forward without delays also needs to be covered.

SCE opposes the ISO's current position of placing cost responsibility on PTOs in those rare instances (low probability) were a substantial error or omission for Network Upgrades above the Interconnection Customer's maximum cost responsibility (MCR) is discovered after the Interconnection Customer has made its initial and second IFS posting. SCE agrees on the duration aspect (12-months), but believes that the 25% amount approved for the Supercluster process reflects the magnitude of likely errors/omissions that could prove disruptive to an IC yet remain in the "rare/large" side of the equation to qualify for full refund of IFS posting amounts.

- ISO response to Stakeholder comments

The ISO disagrees with SCE that this issue is a rare occurrence. The ISO included this issue in IPE based on the sheer number of times this issue has occurred in recent years. The policy proposed is what the ISO has been using, but feels more explicit tariff language would be beneficial. Without this policy the cost caps that are a key component of the GIDAP are less meaningful. ICs may lose portions of initial or second postings they wouldn't have made in the first place had the error or omission not occurred. Participating TOs have some level of ability to protect themselves from making errors or omissions, but ICs can do nothing to protect themselves against errors and omissions.

- Revised Straw Proposal

The ISO proposes that any cost responsibility increases associated with an error or omission on the part of the Participating TO that is discovered after a project's due date for its second IFS posting would be the responsibility of the Participating TO. The MCR and MCE cannot be increased due to an error or omission discovered after the second IFS posting due date has passed. Any changes or modifications to the project by the interconnection customer that increase the cost responsibility for the project would be the responsibility of the interconnection customer.

The ISO further proposes that when an error or omission on the part of the Participating TO is discovered after a project's due date for either its first or second IFS posting that increases the aggregate of all costs for the project to interconnect, regardless of whether the cost is refundable, or pushes back the project's earliest achievable ISD or the in service date for any DNUs required by the project to achieve its requested deliverability status, the project would be given the option to either accept and move forward with the changes or withdraw and receive a full refund for its IFS and a refund of any unused study deposit. The ISO proposes a cost increase threshold of ten (10) percent and a minimum of a 12 month delay in the earliest achievable ISD or delay in completion of DNUs. The ISO believes these figures correctly balance the low probability of a detrimental error or omission with the high impact they can pose to interconnection customers and potential offtakers. Changes or modifications to the project by the interconnection customer would not be a cause for the interconnection customer to receive this proposed refund.

  - One additional option for an interconnection customer to qualify for the full IFS refund could be when a project impacted by a Participating TO error or omission results in the termination of the project's PPA. The ISO is seeking stakeholder input on including the termination of the project's PPA in the eligibility criteria for receiving a full IFS refund and what appropriate documentation of should be.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

5.4 Clarify definition of Reliability Network Upgrade (RNU)

- Background

In the December 6, 2021 Issue Paper and Straw Proposal, section 5.4, the ISO proposed to clarify its existing policy that a RAS is always considered an RNU, regardless of the study that identified the need for the RNU. Because RASs are RNUs, they are included, and will continue to be included, in the RNU reimbursement calculation.[16]

- Stakeholder Feedback

The ISO received comments from eight stakeholders on this issue, of which five stakeholders support the ISO's proposal to clarify the existing policy that a RAS is always considered an RNU. CalWEA, LSA/SEIA, and RWE Renewables oppose the proposal. Specifically, CalWEA's comments were regarding concerns that are not applicable to the definition of RNUs and RWE Renewables opposes citing lack of clarity on the proposal.

LSA/SEIA noted in their comments that if a RAS is needed for a project to reliably connect, even as an EO project, then they do not oppose a requirement that it be completed before COD. If the RAS is triggered by construction and operation of a DNU, then EO projects should not require the RAS for interconnection and operation, and FCDS/PCDS projects should not require the RAS for interconnection and operation until the triggering DNU(s) go into service.

- Revised Straw Proposal

The ISO is not making changes to its December 6, 2021 Issue Paper and Straw Proposal. The ISO proposes to clarify its existing policy that a RAS is always considered an RNU, regardless of the study that identified the need for the RNU. Because RASs are RNUs, they will be included in the RNU reimbursement calculation, consistent with the current practice.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

5.5 Transferring Participating Transmission Owner (TO) Wholesale Distribution Access Tariff (WDAT) Projects into ISO Queue

- Background

In the December 6, 2021 Issue Paper and Straw Proposal, section 5.5, the ISO proposed to move forward with developing tariff language for allowing the ISO to accept interconnection request transfers from the Participating TO's WDAT queue to the ISO queue.

- Stakeholder Feedback

[16] ISO Tariff Appendix DD Section 14.3.2.1(1). Costs above the cap are eligible to receive Merchant Transmission Congestion Revenue Rights.

The ISO received comments from 11 stakeholders on this issue, of which all stakeholders support the ISO's proposal to develop tariff language for allowing the ISO to accept interconnection request transfers from the Participating TO's WDAT queue to the ISO queue. LSA/SEIA and RWE Renewables support the proposal; however, request ISO and PTOs provide public information about the operational control of substations and lines in an effort to diminishing this being a problem.

- Revised Straw Proposal

Based on stakeholder support, the ISO is proposing to not change its December 6, 2021 Issue Paper and Straw Proposal to move forward with developing tariff language for allowing the ISO to accept interconnection request transfers from the Participating TO's WDAT queue to the ISO queue.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

5.6 Changing Sites and POIs during IR Validation

- Background

In the December 6, 2021 Issue Paper and Straw Proposal, section 5.6, the ISO proposed the timing of the process for changing POIs remain consistent with current ISO practice that the interconnection customer must confirm its POI within five business days of the project's scoping meeting and any change in POI will be limited to within the same transmission study area as the POI originally requested in its Interconnection Request. If an interconnection customer requests a change of its POI consistent with this criteria, it may change its site as well. Site changes will only be permitted in conjunction with a permissible change in POI.

- Stakeholder Feedback

The ISO received comments from 12 stakeholders on this issue, of which all stakeholders support the ISO's proposal. CalWEA, LSA/SEIA, RWE Renewables, SCE, and PG&E offer requests for clarification to the current approach.

CalWEA supports this proposal and requests the ISO and PTOs clearly define the study area boundaries and make the definitions available to the public.

LSA/SEIA supports with clarifications that the term "transmission study area" be clearly defined, and state that site changes are allowed later through the MMA request process as long as the POI (substation and voltage level) stays the same.

PG&E is supportive and adds that the IC should be limited to one or two alternative POI discussion during the scoping meeting and should follow the requirements the ISO has identified for location. PG&E also requests language is included to make it clear that PTO and ISO staff are not allowed or able to provide technical advice to

ICs and that the scoping meeting is not intended to identify POIs for theoretical generation projects.

SCE supports the ISO's proposal that the timing of the process for changing POIs whether in accordance with GIDAP Section 6.7.2.1 or otherwise, remain consistent with current ISO practice that interconnection customer(s) must confirm its POI within five business days of the project's scoping meeting pursuant to the ISO's GIDAP BPM v.27 Section 6.2.2 and any change in POI will be limited to within the same transmission study area (e.g., within the same county, one transmission line, or one switchyard from the original) as the POI originally requested in its Interconnection Request.

RWE Renewables supports the proposal, but would like to reiterate that these issues could be avoided by providing transparent data to IR customers which can, in turn, help when selecting POIs. RWE would also like the ISO to clarify what "Same Transmission Study Area" means in the proposal.

- Revised Straw Proposal

Based on stakeholder support, the ISO is proposing to not change its December 6, 2021 Issue Paper and Straw Proposal to move forward with the proposal that the timing of the process for changing POIs remain consistent with current ISO practice. This practice outlines that the interconnection customer must confirm its POI within five business days of the project's scoping meeting and any change in POI will be limited to within the same transmission study area as the POI originally requested in its Interconnection Request. If an interconnection customer requests a change of its POI consistent with this criteria, it may change its site as well. Site changes will only be permitted in conjunction with a permissible change in POI.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

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

- Background

The December 6th Issue Paper and Straw Proposal identified five specific questions the ISO requested to be answered to determine if this issue had merit in this process. The issue was also raised on a generic basis to see if there were any opportunities for the ISO to move projects out of the queue that were languishing and taking deliverability that could be allocated to other queued projects that were moving forward with permitting, procurement, and construction.

Once a project executes the GIA, a welcome letter is sent to the project outlining various requirements, including the requirement to provide a status report. These reports provide the ISO with the project's updated status, including the GIA milestones status and various required steps in the project's development. In some instances, the ISO has projects that have received the welcome letter but never provided the required reports, even after numerous attempts by the ISO to find out the project status.[17] A number of these eventually withdraw once they reach the seven year time limit, or when they do not meet a GIA milestone and are in breach of the GIA.

- Stakeholder Feedback

In the Issue Paper, the ISO asked for feedback on the following:

1) Should projects that are energy-only be allowed to stay in the queue forever?

CalWEA doesn't see any harm in EO projects remaining in the queue except that it could contribute to the need for short circuit duty mitigation. If an EO project contributes to critical short circuit duty needs and has made no progress towards COD beyond the 7-year period, the project could be terminated.

The Six Cities, SCE, LSA/SEIA, MRP and RWE agree with the ISO's concerns that interconnection customers that are occupying space in the interconnection queue without taking meaningful steps to advance their projects should not be entitled to remain in the queue indefinitely.

LSA/SEIA notes that BPM for Generator Management, Section 6.5.2.1 states that "projects requesting to remain in the queue" beyond the applicable limit "clearly demonstrate that:" (1) engineering/permitting/construction will take longer than that; (2) the delay is beyond the IC's control; and (3) "the requested COD is achievable in light of any engineering, permitting and/or construction impediments." This language does not seem like a license to stay in the queue "forever." However, LSA/SEIA do not object to consideration of reasonable EO viability criteria or time limits.

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

EDF-R has managed many interconnection requests and has submitted dozens of quarterly status reports to the ISO. This requirement is not burdensome, and EDF-

[17] Section 5.7 of the GIA requires the parties to provide information on the project to the other party. This is the provision used to require the status reports.

R, LSA/ SEIA and RWE are comfortable supporting a proposal where a project's failure to provide quarterly status reports is considered a material breach to the GIA and the primary driver for holding a project in breach. EDF-R, LSA/ SEIA and RWE requests ISO explicitly confirm in this initiative that upon notice of this breach the interconnection customer will have 30 days to cure the breach, and submitting a completed Queue Management Status Report is sufficient to cure this breach.

The Six Cities agree that it is necessary to provide improved clarity in the tariff and in interconnection-related agreements regarding expectations of project advancement, and to provide the ISO with a remedy – namely, termination of the interconnection agreement and removal from the queue – when projects do not sufficiently advance and/or appear to be inactive as a result of failures to respond to information requests or submit material modification requests when needed.

LSA/SEIA and RWE do not oppose the ISO issuance of a default notice, and appropriate deficiency remediation timeline (e.g., 30 CDs – see above), when a major milestone is missed. RWE suggested certain instances may require 30+ days but the IC should be in open communication with ISO.

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

SCE supports limiting the number of modification requests [with the number of MMA requests allowed to be discussed with stakeholders] in order to extend a project's COD. It appears to SCE that in many cases interconnection customers are using the MMA process to dramatically lengthen the execution/construction phase of the interconnection process (post GIA). There may be legitimate reasons for doing so, but it appears that at times the ICs are using MMAs as a defacto suspension, without "using up" its suspension rights. Certainly, delays can occur for many reasons, and PTOs can also encounter delays in the execution/construction phase. The problem with execution/construction phase delays is the impact on scarce resources, such as those resources required to engineer, design, and construct the required interconnection facilities and network upgrades on behalf of ICs. With so many projects seeking to come online to meet commercial goals, these resources are scarce and precious. The ISO and PTOs need to be able to use these scarce resources for "real and ready" projects, allowing those to move forward to in-service and commercial operations, while avoiding expending these resources on projects that are not moving forward (for various reasons) and appear to be "queue squatting". Unless an interconnection customer can demonstrate that an extension is required to secure tax credits, or a PPA, (if GIDAP Section 8.9.2.2 does not apply) or to secure the necessary permits to advance a project towards commercial operation, it should not be allowed to make an unlimited number of MMA requests.

If the IC cannot demonstrate to the ISO and PTO's satisfaction, that the delays are reasonable, then interconnection customer(s) should be required to suspend its project by submitting a modification request pursuant to Article 5.16 – Suspension of the GIA or UFA. In accordance with the Generator Management BPM Section 10 - Suspension, interconnection customer(s) must demonstrate to the ISO and PTO(s) how they plan to advance project(s) towards commercial operation prior to coming out of suspension. If interconnection customers fail to do so, the ISO and SCE should have the ability to terminate interconnection customers GIAs or UFAs that are not advancing towards commercial operation.

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

The Six Cities also question if seven years remains the appropriate duration for interconnection customers to remain in the queue. Does the ISO have information about the average length of time in queue for projects that have entered commercial operation? Is there data showing that a different period might be appropriate? If so, revisiting the seven year period could be warranted as a way to remove inactive projects.

SCE supports the ISO developing criteria in Phase 2 of the IPE that grants the ISO and PTO(s) the ability to remove project(s) allocated partial or full deliverability or are energy-only from the queue that fail to advance towards commercial operation in less than seven years by terminating its GIA or UFA, unless interconnection customer(s) can demonstrate that the delay is due to an event not reasonably within its control.

PG&E is supportive of this enhancement's inclusion in the IPE and agrees that it should be addressed in the long-term phase of the IPE. In scenarios where a customer accepts their study, but ceases advancement and communication for over 1 year, the project should be terminated. The continued participation of these inactive projects has a negative effect on the advancement of other generation projects.

LSA/SEIA are not supportive of the ISO taking action other than meeting milestones as it seems beyond the scope of ISO authority, and very burdensome to the ISO, to decide when an IC "should" be taking actions when a GIA milestone has not been missed, and besides the project would not be in violation of the GIA at that point. However, LSA/SEIA have long supported development of a uniform GIA Appendix B milestone table template (and other GIA Appendix formats and content), and that uniform templates could contain standard and appropriate milestones to ensure that a project is not languishing.

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

LSA/SEIA continue to support exploration of voluntary incentives for queue withdrawals, e.g., refundability of security before the 7-year time limit is reached. (LSA/SEIA note that its proposal for enhanced TP Deliverability transfers below is one such proposal, since it would allow projects with deliverability that are not progressing to monetize the value of that deliverability and then withdraw from the queue.)

- Revised Straw Proposal

Based on comments received, this subject should be included in Phase 2 of the IPE initiative. Stakeholders agreed the Energy-Only projects should not be allowed to stay in the queue forever. Suggestions were made to be more assertive in implementing BPM for Generator Management, Section 6.5.2.1 states that “projects requesting to remain in the queue” beyond the applicable limit “clearly demonstrate that:” (1) engineering/permitting/construction will take longer than that; (2) the delay is beyond the IC’s control; and (3) “the requested COD is achievable in light of any engineering, permitting and/or construction impediments.” The ISO supports CalWEA’s proposal that if the Energy-Only project contribute to the short circuit duty on the grid then the project should be terminated.

All stakeholders were in agreement that Interconnection Customers should be reporting the status of their projects and is the customer does not respond, then the ISO should invoke the default clause in the GIA. Section 17.1.1 already provides , the Breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the Breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

For MMAs, SCE proposed limiting the number of COD extension MMAs to securing tax credits, obtaining a PPA or securing permits, otherwise the project should suspend until an actual timeline can be determined.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

5.8 Should parked projects be allowed to submit MMAs while parked?

- Background

  The December 6th Issue Paper and Straw Proposal proposed to not all parked projects to submit a MMA while the project was parked. This issue was raised on a generic basis to see if there was an opportunity to reduce workload for the ISO and Participating TO planners, engineers and project management staff. A project parks when the allocated TP Deliverability is less than requested or the project does not desire to accept the amount allocated. The project can go into parking for up to two years thereby waiting for two additional cycles of TP Deliverability allocation before the project either withdraws or moves forward. During this time, it is not efficient to allow projects to modify their project because the modification is speculative since it has not made a decision to continue in the queue.

- Stakeholder Feedback

  CalWEA, CESA, Broad Reach Power, believe certain MMAs should be submitted while parked and at the same time meet the second IFS posting requirements. LSA/SEIA, NextEra and Middle River Power believe certain MMAs should be submitted while parked and made no comment on the second IFS posting requirements. EDF-R proposed that ISO should implement a PTA-like process that approves MMAs for parked projects so that they know the proposed change is probably ok and the MMA can be submitted once the project is out of parking. This would enable the project to respond to procurement trends and use parking time productively. While preferring that ICs not be allowed to submit MMAs while parked, SCE is willing to consider a limited number of types of MMAs based on criteria developed as part of the stakeholder process provided the second IFS posting is made. EDF-R believes certain MMAs should be submitted while parked – fuel type, technology changes or POI changes – but does not support requiring the second posting be provided.

  Six Cities, SCE, Upstream, Strata Clean Energy and PG&E supports the ISO's proposal to not allow parked projects to submit MMAs.

- Revised Straw Proposal

  The Interconnection Customers want the ability to submit MMAs while parked and PTOs and other transmission owners support the ISO's proposal to not allow parked projects to submit MMAs while parked. Based on this information, the ISO proposes to revise its proposal to allow only fuel-type, technology type (e.g. wind to storage, solar to storage, solar to wind, etc.) and POI changes, but the Interconnection Customer must make the second IFS posting when submitting the MMA.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

6 Other Stakeholder Suggested Proposals

6.1 Adding due dates for curing deficiencies in Appendix B, to avoid delays in starting Phase II studies

- Background

  In the December 6, 2021 Issue Paper and Straw Proposal, section 6.1, the ISO proposed to add a deadline for the validation of Appendix B's, where all Appendix B's and any associated technical data must be deemed valid by 70 calendar days after the date of the Phase I study report. Those not valid would be withdrawn with five business days to cure.

- Stakeholder Feedback

  The ISO received comments from eleven stakeholders on this issue, of which nine stakeholders support the ISO's proposal to add a deadline for the validation of Appendix B's, where all Appendix B's and any associated technical data must be deemed valid by 70 calendar days after the date of the Phase I study report. CalWEA support the proposal and request the ISO to clean up Appendix B to remove unnecessary data requirements. Likewise, EDF-Renewables support the proposal; however, express concern that this proposal adds additional pressure to an already tight timeline, especially to those with later scheduled results meetings. They suggest a nuanced approach, for example, the due date for curing an Appendix B deficiency would be the later of 70 days or 35 days after the project Phase I results meeting. EDF-Renewables also does not support IRs being "deemed complete" before the scoping meeting given the financial consequences the ISO is proposing with respect to scaling nonrefundable interconnection fees.

  LSA/SEIA and Middle River Power oppose the proposal. However, LSA/SEIA could support the proposal with modifications. They note a 70 CD deadline could be tight for projects with meetings as late as 60 CD after the study is released (ISO note: Tariff requirement is 30 CD for results meetings, except for C14). LSA/SEI suggests validation must occur within a set time (e.g., 45 CD) after the results meeting, with a time limit after re-submittal for ISO and PTO to identify deficiencies. This would spread the validation workload throughout the results meeting timeline. Further, Middle River Power expressed opposition to SCE's proposal to have IRs being deemed complete prior to scoping meetings, no comments regarding curing Appendix B deficiencies.

- ISO response to Stakeholder comments

Some stakeholder suggested a combination of an overall set due date and individual due dates for the validation of Appendix B's. The ISO believes that the Phase I results meetings will continued to be held within tariff requirements and that a single due date is sufficient.

- Revised Straw Proposal

The ISO proposal is unchanged from the December 6, 2021 Issue Paper and Straw Proposal. Appendix DD Section 7 states "Within ten (10) Business Days following the Phase I Interconnection Study Results Meeting, the Interconnection Customer shall submit to the ISO the completed form of Appendix B". The ISO proposes to add a deadline for the validation of Appendix B's, where all Appendix B's and any associated technical data must be deemed valid by 70 calendar days after the date of the Phase I study report. Those not valid would be withdrawn with five business days to cure.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

6.2 Making it explicit that when ICs agree to share a gen tie-line, PTO interconnection facilities, and any related IRNUs at a substation across clusters, the shared IRNUs are not subject to GIDAP Section 14.2.2

- Background

SCE's comments to the Issue Paper and Straw Proposal are provided here as a description of the topic details.

SCE would like for the ISO to make it explicit that when an Interconnection Customer requests to share a Generation Tie-Line, PTO Interconnection Facilities, and any related IRNUs at a substation or switchyard (e.g., line position to terminate the shared Generation Tie-Line) with an earlier-queued affiliate or non-affiliate project with an executed GIA across clusters, that the shared IRNUs shall not be subject to GIDAP Section 14.2.2 if the interconnection customer of the earlier-queued project terminates its GIA. It is also our position that the Interconnection Studies and IA will reflect that the interconnection customer of the later-queued project will be jointly and severally liable for up to one hundred percent (100%) of the shared IRNU costs, IFS, and ITCC, if applicable. In essence, the Interconnection Studies for the later-queued project will treat the shared IRNUs as CANUs, not PNUs. This exclusion does not apply in the case where the shared IRNU is a Stand-Alone Network Upgrade (e.g., Loop-In Substation). Once this exclusion is reflected in GIDAP and BPMs, SCE will no longer have to treat applicable GIAs as non-conforming and have to file these GIAs with FERC requesting a waiver of GIDAP Section 14.2.2.

- Stakeholder Feedback

  The ISO received comments from nine stakeholders on the proposal outlined above. SCE, PG&E, Strata Clean Energy, NextEra, and Balanced Rock Power indicated their support for the proposal. Specifically, PG&E agreed that the PTO should not be responsible for funding IRNU's when interconnection customers agree to share these facilities across clusters.

  CalWEA, REV Renewables, LSA/SEIA, and RWE Renewables oppose this proposal. CalWEA noted that they do not support shared IRNUs being exempted from GIDAP 14.2.2 if projects sharing upgrades have no affiliation with each other. REV Renewables does not support this initiative as it shifts costs of the PHUs to the generators and increases the MCE. Changes to the MCE pose a significant risk to the commercial viability of a project. LSA/SEIA opposes because this would treat an IRNU assigned to one or more earlier-queued projects as a CANU for later-queued projects needing that upgrade after GIA execution by an earlier-queued project assigned that upgrade. The issue is limited to projects that drop out after executing GIAs, which is likely a small subset of drop-outs overall. The issue is further limited to the window between GIA execution by the earlier-queued project(s) and the third posting, which provides the PTO full coverage of IRNU costs. The most costly IRNUs – switching stations – have significant lead times, so the third posting for those upgrades would typically be due soon after GIA execution even where the third posting is phased, because other upgrades have shorter lead times.

- ISO response to Stakeholder comments

  Stakeholder comments are fairly evenly split on this issue. The ISO does not have hard data on the frequency of the issues of concern to SCE, but does agree with LSA/SEIA that the likelihood relatively low. However, SCE believes the impact is significant enough to warrant its consideration. SCE has been dealing with the issue by filing for a waiver of Appendix DD Section 14.2.2 and a non-conforming GIA for every instance where parties are sharing facilities. SCE has stated to the ISO that FERC has asked them several times to not file as many non-conforming GIAs. The issue has occurred enough that FERC has noticed the frequency of the issue and SCE would rather have the GIDAP address the issue rather than continue to rely on filings to FERC.

  LSA/SEIA commented that for shared IRNUs each project sharing the IRNU must post as though they will bear 100% of the costs until the third posting is made. However, Appendix DD only requires an IC to post its current cost responsibility for an IRNU. The remaining potential cost responsibility for any non-allocation portion of an IRNU is part of the MCE, which has no current posting requirement.

  SCE's proposal seeks to deal with issues associated with shared generation tie-lines, PTO interconnection facilities, and IRNUs. Shared gen-tie costs do not have the potential to fall to the PTO, but the shared PTO interconnection facilities that result from a shared gen-tie could. Typically, the cost for IRNUs are significantly greater than the cost of PTO interconnection facilities. IRNUs already have a unique cost allocation treatment to handle SCE's concern when projects sharing an IRNU are in the same cluster. The ISO believes it would not be an unreasonable change to include the same protection for cases that an IRNU is shared across cluster groups.

- Revised Straw Proposal

The ISO does not put forth a specific proposal at this time and this topic will be a phase 2 topic to give stakeholders time to work through the issue.

The ISO recommends that the topic be limited to IRNUs because IRNUs already are dealt with in a unique fashion compared to other network upgrades and because IRNUs are more common and more costly than shared PTO interconnection facilities, and as such, IRNUs create a greater risk for the PTOs.

The ISO seeks stakeholder input on having the current treatment of cost responsibility for shared IRNUs within a cluster be extended to cases where the IRNU is shared across clusters. Currently, when an IRNU is shared across clusters, the latter cluster project(s)' cost responsibility is treated as a CANU and the cost is included in the projects' MCE. Once the earlier cluster project executes a GIA the IRNU's treatment as a CANU for the latter cluster projects goes away and the IRNU becomes a PNU with no cost responsibility for the latter cluster projects. The suggested change to the process that the ISO seeks stakeholder input is that the IRNU would remain a CANU for the latter cluster projects even after the earlier cluster project executes a GIA. The IRNU would remain as a CANU for the latter cluster projects, with the cost responsibility included in their MCE until the earlier cluster project makes its third IFS posting for the IRNU, at which time the cost responsibility for the IRNU is removed from the latter cluster projects' MCE and the CANU would become a PNU. Until such time that the IRNU/CANU becomes a PNU, the latter cluster projects' cost responsibility for the IRNU/CANU would be 100 percent in the same manner that a shared IRNU's cost responsibility is set at 100 percent in the MCE for projects sharing an IRNU in the same cluster group.[18] If the earlier cluster project does withdraw, the non-refundable portion of their IFS posting would be subject to Appendix DD Section 7.6 Application of Non-Refundable Amounts.

The ISO proposes to address this issue within the scope of Phase 2: Long-Term Enhancements.

[18] Appendix DD, Section 6.3.1: The Maximum Cost Exposure will include the full costs of conditionally assigned IRNUs.

6.3 Improved Transmission Grid Data Transparency

- Background

  The December 6th Issue Paper and Straw Proposal the ISO agreed with Gridwell that additional data, in a usable format, should be made available to the interconnection customers. The ISO opened the proposal to have stakeholders provide specific items that they wanted to have information on.

- Stakeholder Feedback

  CalWEA, SCE, CESA, EDF-R, LSA/SEIA, NextEra, Middle River Power and RWE support the proposal to provide additional reports. Some proposed examples include:

  - Define the study area boundary in the area reports.
  - Transmission grid data transparency including transfer capability, deliverability constraints, curtailment based on local congestion.
  - Better differentiation within clusters – specifically define the amount of overload that requires the upgrade to be added to the project. This information should be available in all PTO reports.
  - Information provided about areas where TP Deliverability is still available, and how much. The annual TPD Allocation Reports contain useful information about areas where deliverability has run out but relatively little information about where, and much, deliverability remains.
  - ADNUs/other upgrades: This TPP cycle has included a useful discussion about use of the ISO's Transmission Capability report to identify potential cost-effective transmission upgrades to provide additional TP Deliverability in areas of high commercial interest. LSA/SEIA would like the ISO to refine this information to make it useful in identifying "low-regrets" transmission upgrades, for policy purposes.

  Upstream is generally supportive, but noted that most of the data stakeholders are asking for is available on the Market Participant Portal and repackaging this data will "pull" staff away from completing technical studies. Strata's position is similar to Upstream's but believes this issue should be handled in Phase 2 of this initiative.

  LSA/SEIA also commented that project CODs and GIAs should reflect the earlier connection times before the upgrades are triggered (with notice to ICs that projects can lose that "place in line" if CODs are delayed later), without the need for an LOS, and projects to reach COD or FCDS if the upgrades needed for their interconnection or FCDS are complete, even if all the upgrades identified for the cluster as a whole are not yet complete. These items are beyond the scope of this project. A separate stakeholder process took place in 2021 to amend the GIA and these items should have been addressed in that forum.

- Revised Straw Proposal

  The ISO proposes to form a working group to have an offline discussion with interested participants of the specific data being requested, format, and frequency.

  The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

6.4 Modification to Commercial Viability Criteria

- Background

  The December 6th Issue Paper and Straw Proposal agreed with LSA/SEIA's concern that the interconnection customer should not be harmed by taking away a projects deliverability if the Participating TO causes the project to go beyond seven (7) years. The ISO proposed to clarify in the tariff that the commercial viability criteria apply only to extensions of the commercial operation date proposed by the interconnection customer.

- Stakeholder Feedback

  The ISO received stakeholder comments from six stakeholders on adding the scope item from LSA/SEIA to resolve delays caused by PTOs via modifications to commercial viability criteria. LSA/SEIA, Middle River Power, PG&E and RWE Renewables support this added scope item. Additionally, consistent with this proposal, LSA/SEIA request that CVCs only apply if Interconnection Customer submits a modification request to move past the seven year deadline, and not if the project is delayed past the seven year deadline because of PTO delays. They note this would help ensure that infeasible projects do not stay in the queue longer than necessary. Middle River Power notes that commercial viability of a project should only be assessed if the project sponsor submits an MMA and not if the PTO delays cause a modification. Further, PG&E requests the specific criteria for determining a PTO delay versus an interconnection customer delay be discussed during the stakeholder process and agreed upon by stakeholders prior to implementation.

  CalWEA support including this issue within the scope of Phase 1: Near-Term Enhancements. However, they note the proposal LSA/SEIA has offered does not resolve concerns regarding project interconnection before all RNUs are in service. To help with the development of projects, they advocate suggest the ISO allow an early limited operational study (LOS) as early as 24 months before the initial ISD.

  SCE express that while changes in Standards can be disruptive to other processes, the changes are a necessary part of the continuous improvement of the generation/storage industry. Further they noted that each PTO should be allowed to continue to change its Standards as necessary based on the complexity and learnings from study efforts, engineering, and equipment specifications.

- Revised Straw Proposal

The commercial viability criteria should be assessed only if the Interconnection Customer submits the modification request to delay beyond the seven years and not when the Participating TO triggers a delay. With respect to the definition of delay, it should be based on the party that caused the delay. A few examples:

- If the PTO cannot get the equipment needed for the project until after the originally anticipated date and it will delay the In-Service Date, then it is a PTO delay.
- If the IC does not meet a document submittal deadline to the PTO, then it is an IC delay.

With respect to CalWEA's suggestion of a 24 month LOS, this is not practical as discussed in the December 6th Issue Paper and Straw Proposal. At two years prior to synchronization, the assumptions would be that all transmission is built, unless there is a known delay, and all projects are coming online therefore no information could be garnered from that type of a study and it would take resources away from other valuable work. With respect to the Standards, the ISO agrees with SCE that Standards need to continually change to meet evolving reliability needs, developing technologies and changing NERC standards.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

6.5 Network Upgrade Re-Stacking

- Background

The December 6th Issue Paper and Straw Proposal agreed to further explore LSA/SEIA's request for the ISO to consider "re-stacking" NUs, to better match NU in-service dates to project CODs, assigning faster NUs to projects with earlier CODs (to speed COD and/or FCDS for those projects) without delaying COD/FCDS for projects with earlier CODs. (No changes to cost allocation are suggested here.)

- Stakeholder Feedback

The ISO received comments from nine stakeholders on adding this scope item from LSA/SEIA to the initiative. The California Energy Storage Alliance, LSA/SEIA, and RWE Renewables support the proposal of Network Upgrade re-stacking. Specifically, LSA/SEIA notes that Network Upgrade restacking has the potential to accelerate the CODs and deliverability status of projects in later clusters with earlier desired CODs without harming earlier-queued projects with later CODs. Further, they explain that this proposal would impact neither cost allocation nor PTO work sequencing and scheduling. Instead, it would simply align the interconnection and deliverability enabled under existing PTO work sequencing and scheduling for already-planned upgrades with the CODs of projects in the queue.

Middle River Power seek clarification on what re-stacking NUs means and SCE believes this proposal is ultimately an engineering question as to when certain upgrades are required, and the risk of an upgrade becoming "triggered" earlier as opposed to later is a natural outcome of how upgrades are studied.

Finally, CalWEA, Balanced Rock Power, Strata Clean Energy, and Upstream oppose the proposal of Network Upgrade re-stacking without a reallocation of costs to the earlier project.

- Revised Straw Proposal

In the Issue Paper and Straw Proposal section 6.3, the ISO commented that sequencing of Network Upgrade construction is performed by the Participating TOs and is not something that the ISO can do.

The ISO therefore disagrees with implementing the "Nu-Restacking" idea as the ISO believes the nature of the process is such that later Queued Cluster projects are expected to wait on upgrades past the earlier Queued projects. Potentially, queue jumping would be allowed if NU re-stacking was permitted.

The ISO's position is also supported by SCE's comment that "ultimately it is an engineering question as to when certain upgrades are required, and the risk of an upgrade becoming 'triggered' earlier as opposed to later is a natural outcome of how upgrades are studied. Allowing leapfrogging of upgrades ultimately causes the same type of pitfalls as leapfrogging of queue positions. How does one fairly allocate upgrades other than 'who triggers'?"

The ISO proposes to remove this topic from the scope of this initiative.

6.6 Expanding Deliverability Transfer Opportunities

- Background

The December 6th Issue Paper and Straw Proposal proposed to revise the tariff to allow deliverability transfers at the same substation and voltage level instead of the exact point of interconnection (i.e. between two breakers) in the substation.

- Stakeholder Feedback

CalWEA, Golden State Clean Energy, CESA, EDF-Renewables, REV Renewables, LSA/SEIA and RWE Renewables support allowing TPD transfers at the same substation and voltage level. Conceptually, SCE does not oppose transferring deliverability within the same substation but would need to see the rules that allow such a transfer to ensure it remains a fair practice.

Upstream and Balanced Rock Power oppose allowing developers to “sell” deliverability at the same POI because it will lead to anti-competitive behavior. Developers will be incentivized to “box out” other developers from accessing particular POIs across the ISO BAA in an attempt to force the transfer of deliverability. Furthermore, the tariff allows ISO to allocate deliverability but also take deliverability away. This could unnecessarily place the ISO in the middle of third-party commercial transactions where interim/full deliverability was sold and transferred, but then temporarily or permanently taken away. Strata is also concerned about the implications of deliverability being a commodity.

- Revised Straw Proposal

The ISO tariff allows deliverability to be transferred to other projects at the same POI. Expanding ability to transfer deliverability to projects at the same substation and same voltage is the same level at which deliverability is allocated to the Interconnection Customers. The ISO proposes to revise Section 8.9.9 of Appendix DD as follows:

> 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, <u>or to other projects at the same substation at the same voltage level.</u> The Generating Units must be located at the same Point of Interconnection. 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. 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~~ <u>to other Projects at the same substation and voltage level as their Project</u> 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 ISO proposes to revise Appendix A definition as follows:

> Point of Interconnection The point, as set forth in Appendix A to the Large Generator Interconnection Agreement or Attachment 3 to the Small Generator Interconnection Agreement, where the Interconnection Facilities connect to the CAISO Controlled Grid. ~~For Generating Facilities connected to the Distribution System, t~~The Point of Interconnection is the substation at which the Generating Facility connects to the CAISO Controlled Grid. For an EIM Participating Resource or non-participating resource, the Point of Interconnection is the point at which the EIM Participating Resource or non-participating resource connects to an EIM Entity's transmission facilities.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

6.7 Re-examining the ISP electrical independence test

- Background

  The December 6th Issue Paper and Straw Proposal agreed to further explore CalWEA's request for re-examining the ISP electrical independence test. Specifically, the ISO requested stakeholder justification on why the existing tariff criteria (Appendix DD Section 4.2.1.1 is not just and reasonable and specific proposals for revisions to the ISP electrical independence test criteria that provides a methodology that addresses the condition where a Cluster 14 project is impacted or a potential impact cannot be ruled out.

- Stakeholder Feedback

  The ISO received comments from eight stakeholders, all of whom indicated support for re-examining the ISP electrical independence test criteria.

  CalWEA states that the current flow test for independence is based on the flow caused by the Generating Facility being tested divided by the lesser of the Generating Facility's size or the transmission facility capacity. If the result is five percent (5%) or less, the Generating Facility would pass the flow impact test. This means both shift factor and flow impact must be less than 5% to pass the test. CalWEA suggests that ISO modify the criteria such that small projects with close to 0 flow impact can pass the test even if they are electrically close to the transmission facility being tested – their shift factor is higher than 5%.The Generating Facility passes the flow impact test if one of the following is true: 1) flow divided by the Generating Facility's size is 5% or less, or 2) flow divided by the transmission facility capacity is 2% or less.

SCE supports revisiting the GIDAP tariff requirement that a project over 5% shift factor fails the electrical independence test according to Section 4.2.1.1. There may be instances where a small project would fail the criteria, though engineering judgment indicates that the project could be considered electrically independent. Instead of setting new numeric criteria, SCE would suggest that the tariff be revised to allow justification for an exception to this criteria.

Upstream states in its current form the EIT is overly restrictive in determining if a project is independent of other projects in the queue. The Flow Impact Test and the five percent threshold imply that if an ISP project is behind the same constraints as the current cluster, then the ISP is not independent of other projects in the queue. This was true prior to the introduction of the ANU, CANU, and PNU concepts but is now outdated. RNUs identified in the current cluster would be classified as CANUs or PNUs (to the extent a contributing project executes its LGIA). Since the cost responsibility for these RNUs has been assigned to the current cluster, the incoming ISP project would be electrically independent. If current cluster projects withdrew and the need for the RNU went away, then the cost responsibility of the identified RNU would fall on the ISP project and subsequent queue clusters (to the extent that subsequent queue cluster triggered the need for the RNU).

Upstream supports eliminating the Flow Impact Test and Short Circuit Test now that the ISO has introduced the ANU, CANU, and PNU concepts into the tariff. The ISO should also consider allowing PTOs to perform the EIT sixty calendar days after the start of the previous queue cluster study (or engineering judgement) at which point the cluster study would have cleared planning.

- Revised Straw Proposal

  In the Issue Paper and Straw Proposal section 6.4 the ISO asked stakeholder justification on why the existing tariff criteria is not just and reasonable.

  After further examination the ISO does not agree with the proposal to modify the current ISP EIT criteria and is in support of keeping the current ISP EIT criteria as is, as CAISO believes making the proposed change would potentially allow/encourage ISP projects to interconnect in areas which already have a large amount of queue projects that would be unfairly taking up capacity from projects that have come before through the queue.

  The ISO also sees a risk that the addition of these small projects in congested locations will eventually cumulatively impact the system negatively; We see a potential for projects to add 5MW BESS to their existing project and pass the ISP, which in turn will be creating a loophole for adding more MWs, and an accumulation of those can eventually harm the system.

In regards to allowing justification for an exception of criteria, ISO believes it would be too subjective, which will allow room for individual interpretation and possibly get into situations of inconsistency; therefore we disagree with adding any such exception to the tariff language.

The ISO also believes that under current criteria projects connecting to a good location will pass the EIT under existing criteria.

The ISO proposes to remove this topic from the scope of this initiative.

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

- Background

In the December 6th Issue Paper and Straw Proposal, the ISO agreed with REV Renewables suggestion to examine the instances when a developer issues a notice to proceed to the Participating TO, and assess the proposal that the Participating TO/ISO should either a) start planning for all upgrades required for FCDS status, including upgrades triggered by a group of projects or b) allow the project that is ready to achieve COD to proceed as FCDS if ISO/Participating TO make a determination that the network upgrade doesn't get triggered if only this project proceeded forward. The ISO sought stakeholder feedback from stakeholders to determine in these specific instances if FCDS can be provided to the Interconnection Customer that has achieved commercial operation provided the Interconnection Customer agrees to pay the cost of the upgrade(s) that have not yet been built and agrees to defer repayment of Network Upgrades until all upgrades are built or a reassessment study determines that the Network Upgrade(s) is no longer required.

- Stakeholder Feedback

The ISO received stakeholder comments from eight stakeholders regarding REV Renewables added scope item to determine when a developer issues a notice to proceed to the PTO, the PTO/ISO should start planning for all upgrades that are required for a project to attain FCDS. CESA, EDF-Renewables, LSA/SEIA, Middle River Power, REV Renewables, and RWE Renewables support adding this scope item. Additionally, CESA encourages deeper discussion to determine how work plans for network upgrades are prioritizes and initiated. Further, LSA/SEIA and RWE Renewables specifically mention the PTO should begin on all upgrades as soon as the GIA is executed and the notice to proceed is provided. This will have an immediate on upgrade construction schedules and PTO schedules to meet committed milestones.

CalWEA notes that FCDS should only be granted after the required upgrades are in service unless the ISO revises the NQC reduction methodology. They explain that if a resource is designated FCDS before the needed upgrades, the NQC reduction is ultimately unfairly spread to other FCDS resources that do not require upgrades.

Finally, SCE suggests the ISO consider the minimal incremental benefit of including this proposed topic in scope of the initiative versus the significant added implementation complexity.

- Proposal

The ISO had a Transmission Forum stakeholder meeting on January 21, 2022 that allowed each of the Participating TOs to give a presentation on the status of their transmission upgrade projects which was well received. The ISO proposes to include this reporting function as part of the Transmission Grid Data Transparency topic and address this issue within the scope of Phase 1: Near-Term Enhancements.

6.9 Requirement that any IR that proposes to utilize a third party owned gen-tie must provide documentation as part of their IR that demonstrates that the gen-tie owner has agreed to the project using its gen-tie

- Background

In the December 6, 2021 Issue Paper and Straw Proposal, section 6.4, the ISO proposed that any IR that proposes to utilize a third party owned gen-tie must provide documentation as part of their IR submittal documents demonstrating that the gen-tie owner has agreed to the project proposed in the IR using its gen-tie.

- Stakeholder Feedback

The ISO received comments from eight stakeholders on this topic, of whom three stakeholders support with no request for modifications. Both SCE and Middle River Power support the proposal; however make the following recommendations:

SCE agrees with the requirement to provide documentation as part of the IR that demonstrates the owner of the gen-tie agrees to the sharing arrangement. A gen-tie agreement does not necessarily have to be entered into prior to an IR being valid and complete, but will need to be by the time a GIA is executed. Requiring documentation of an “agreement in principle” as part of an IR submittal should help in this situation.

Middle River Power supports this proposal and also recommends that this requirement be applied to IRs proposing to interconnect both to customer-owned facilities in general and PTO-owned facilities where the surrounding land is completely controlled by a third-party generator.

Further, three stakeholders did voice concern with this proposal. Of note, CalWEA does not agree with this proposal and suggest the agreement be reached by the time that Appendix B's are due. They explain that if the IC does not have an agreement from the third party before the Phase I study, the Phase I study can assume a dedicated gen-tie for the purposes of establishing the MCR. Additionally, LSA/SEIA and RWE oppose the proposal for the following reasons:

LSA/SEIA opposes this proposal because it singles out this on element for scrutiny. ISO doesn't screen other gen-tie feasibility aspects, and they see no reason to single out this arrangement. The IC bears the consequences if gen-tie arrangements become infeasible, e.g., if an agreement with the gen-tie owner can't be reached, the gen-tie must be revised like any proposed gen-tie route.

- ISO response to Stakeholder comments

While agreeing with LSA/SEIA that the IC bears the consequences if an agreement with the gen-tie owner can't be reached, the ISO maintains that there can be impacts to other ICs as well. Having projects in the cluster study that have not demonstrated a feasible path to the point of interconnection can harm other projects by requiring cost sharing of upgrades that would not be needed if a project cannot secure a gen-tie sharing agreement and withdraws. Moreover, this proposal will facilitate in managing the overheated interconnection queue by requiring what the ISO believes is an appropriate documentation of due diligence by the interconnection customer.

- Revised Straw Proposal

The ISO modifies its proposal for the IR submittal to require a letter of intent between the non-PTO owned or third party gen-tie or substation and the project seeking to share the gen-tie or substation. The letter of intent must document the intent of the parties to negotiate the terms of the sharing agreement. The proposal is to further require an executed gen-tie sharing agreement to proceed into the Phase II studies. The executed agreement would be due at the time the initial IFS posting is due. This is proposed to be implemented starting with Cluster 15.

If a gen-tie sharing arrangement is requested in conjunction with a request for project modification, the ISO would require an executed gen-tie sharing agreement to proceed with the MMA. The proposal related to MMAs is to be implemented upon FERC approval of the IPE tariff changes.

The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

6.10 Recommendation that after the IR validation, the ISO should be consistent in using RIMS for all documents, details, etc. related to projects

- Background

  In the December 6, 2021 Issue Paper and Straw Proposal, section 6.4, the ISO proposed to further evaluate SDG&E's proposal for the ISO to be consistent in using RIMS for all documents, details, etc. related to the project.

- Stakeholder Feedback

  CalWEA, Golden State Clean Energy, EDF-Renewables, REV Renewables, LSA/SEIA, Middle River Power, and RWE Renewables support the ISO proposal to include all documents in RIMS.

- Revised Straw Proposal

  The ISO proposes that all communication handled now exclusively via email, including deliverability allocation results, financial security posting requests, and MMA documentation (requests, data files and results), repowering and Limited Operation Study documents (request, study plan and study report) should be provided on RIMS in addition to being communicated via email and other written correspondence.

  The ISO proposes to address this issue within the scope of Phase 1: Near-Term Enhancements.

7 Stakeholder engagement

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

Date	Event
09/30/21	Publish preliminary issue paper
10/08/21	Stakeholder suggestions due
10/19/21	Stakeholder workshop on preliminary issue paper
10/28/21	Stakeholder comments due on preliminary issue paper and workshop
12/06/21	Publish issue paper/straw proposal
12/13/21	Stakeholder conference call on issue paper/straw proposal
01/03/22	Stakeholder comments due on issue paper/straw proposal
01/25/22	Publish revised straw proposal
02/01/22	Stakeholder conference call on revised straw proposal
02/15/22	Stakeholder comments due on revised straw proposal
Phase 1	
03/10/22	Publish draft final proposal
03/17/22	Stakeholder conference call on draft final proposal
03/31/22	Stakeholder comments due on draft final proposal
04/11/22	Publish draft tariff language
04/21/22	Publish final proposal
04/25/22	Stakeholder comments due on draft tariff language
04/28/22	Stakeholder conference call on final proposal
05/12/22	Stakeholder comments due on final proposal
May 2022	Board of Governors Meeting
Phase 2	
06/07/22	Publish draft final proposal
06/14/22	Stakeholder conference call on draft final proposal
06/28/22	Stakeholder comments due on draft final proposal
07/26/22	Publish draft tariff language and final proposal
08/09/22	Stakeholder comments due on draft tariff language
08/16/22	Stakeholder conference call on final proposal
08/30/22	Stakeholder comments due on final proposal
November 2022	Board of Governors Meeting

The ISO will hold a stakeholder meeting on February 1, 2022 to review the Revised Straw Proposal. Stakeholders are encouraged to submit comments on this Revised Straw Proposal through the ISO's commenting tool using the link on the initiative webpage by close of business on February 15, 2022.